NYISO Tariffs

New York Independent System Operator, Inc.
NYISO Tariffs

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New York Independent System Operator, Inc.
Open Access Transmission Tariff

1. Definitions

1.1 Definitions - A

Accepted Revision: A change to the terms of an Existing Transmission Agreement for purposes of ISO Settlements, which change is related to a Grandfathered Right or Grandfathered TCC and is made pursuant to the procedures prescribed in Section 17 Attachment K of the ISO OATT.

Actual Energy Injections: Energy injections that are measured using a revenue-quality real-time meter.

Actual Energy Withdrawals: Energy withdrawals which are either: (1) measured with a revenue-quality real-time meter; (2) assessed (in the case of LSEs serving retail customers where withdrawals are not measured by revenue-quality real-time meters) on the basis provided for in a Transmission Owner's retail access program; or (3) calculated (in the case of wholesale customers where withdrawals are not measured by revenue-quality real-time meters), until such time as revenue-quality real-time metering is available on a basis agreed upon by the unmetered wholesale customers. For purposes of the allocation of the ISO annual budgeted costs and the annual FERC fee pursuant to Rate Schedule 1 of this ISO OATT, withdrawals shall also include the absolute value of negative withdrawals by Load for behind the meter generation.

Advance Reservation: (1) A reservation of transmission service over the Cross-Sound Scheduled Line that is obtained in accordance with the applicable terms of Schedule 18 and the Schedule 18 Implementation Rule of the ISO New England Inc. Transmission, Markets and Services Tariff, or in accordance with any successors thereto; or (2) A right to schedule transmission service over the Neptune Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff; or (3) A right to schedule transmission service over the Linden VFT Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff; or (4) A right to schedule transmission service over the HTP Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff.

Affiliate: With respect to a person or entity, any individual, corporation, partnership, firm, joint venture, association, joint-stock company, trust or unincorporated organization, directly or indirectly controlling, controlled by, or under common control with, such person or entity. The term "control" shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Ancillary Services: Those services that are necessary to support the transmission of Capacity and Energy from resources to Loads while maintaining reliable operation of the NYS Transmission System in accordance with Good Utility Practice.

Annual Transmission Costs: The total annual cost of the Transmission System for purposes of Network Integration and Point-to-Point Transmission Services shall be the amount specified in Attachment H until amended by the Transmission Owners or modified by the Commission.

Annual Transmission Revenue Requirement: The total annual cost for each Transmission Owner (other than LIPA) to provide transmission service subject to review and acceptance by FERC or other authority.

Application: A request to receive Transmission Service by an Eligible Customer pursuant to the provisions of this Tariff that includes all information reasonably requested by the ISO.

Automatic Generation Control ("AGC"): The automatic regulation of the power output of electric generating facilities within a prescribed range in response to a change in system frequency, or tie-line loading, to maintain system frequency or scheduled interchange with other areas within predetermined limits.

Availability: A measure of time that a generating facility, transmission line or other facility is or was capable of providing service, whether or not it actually is in-service.

Available Generating Capacity: Generating Capacity that is on line to serve Load and/or provide Ancillary Services, or is capable of initiating start-up for the purpose of serving Transmission Customers or providing Ancillary Services, within thirty (30) minutes.

Available Operating Capacity: For purposes of determining a Scarcity Reserve Requirement, the capability of all Suppliers that are eligible to provide Operating Reserves and have submitted Energy Bids in the Real-Time Market representing the capability to provide Energy in greater than 30 minutes but less than or equal to 60 minutes; provided, however, that this value shall not include any quantity of Energy and Operating Reserves scheduled to be provided by all such Suppliers. The Available Operating Capacity value (in MW) shall be calculated by the RTD software for each normal RTD run. For purposes of calculating a Scarcity Reserve Requirement in accordance with Section 15.4.6.2 of Rate Schedule 4 of the NYISO Services Tariff, each RTD run shall utilize the value of Available Operating Capacity calculated during the immediately preceding normal RTD run and each RTC run shall utilize the value of Available Operating Capacity calculated during the most recently-completed normal RTD run prior to the RTC run.

Available Transfer Capability ("ATC"): A measure of the Transfer Capability remaining in the physical transmission network for further commercial activity, over and above already committed uses, calculated using the methodology described in Attachment C in the OATT.

1.2 Definitions - B

Back-Up Operation: The procedures for operating the NYCA in a safe and reliable manner when the ISO's normal communication or computer systems are not fully functional as set forth in Section 2.12 of this ISO OATT and Section 5.3 of the ISO Services Tariff.

Balance-of-Period Auction: An auction administered by the ISO in which Transmission Customers may purchase and sell TCCs valid for a future month or months in the same Capability Period in which the auction is conducted; provided, however, that the Balance-of-Period Auction conducted in the last month of a Capability Period will allow for the purchase and sale of TCCs valid for a future month or months in the next Capability Period.

Base Point Signals: Electronic signals sent from the ISO and ultimately received by Generators specifying the scheduled MW output for the Generator. Real-Time Dispatch ("RTD") Base Point Signals are typically sent to Generators on a nominal five (5) minute basis. AGC Base Point Signals are typically sent to Generators on a nominal six (6) second basis.

Basis Amount: As defined in the ISO Services Tariff.

Behind-the-Meter Net Generation Resource ("BTM:NG Resource"): As defined in the ISO Services Tariff.

Basis Month: As defined in the ISO Services Tariff.

Bid/Post System: An electronic information system used to allow the posting of proposed transmission schedules and Bids for Energy and Ancillary Services by Market Participants for use by the ISO and to allow the ISO to post Locational Based Marginal Prices and schedules.

Bid: Offer to sell or bid to purchase Energy, Demand Reductions or Transmission Congestion Contracts and an offer to sell Ancillary Services at a specified price that is duly submitted to the ISO pursuant to ISO Procedures. Bid shall mean mitigated Bid where appropriate.

Bid Price: The price at which the Customer offering the Bid is willing to provide the product or service, or is willing to pay to receive such product or service, as applicable. In the case of a CTS Interface Bid, the Bid Price is a dollar value that indicates the bidder's willingness to purchase Energy at a CTS Source and sell it at a CTS Sink across a CTS Enabled Interface if, at the time of scheduling, the forecasted CTS Sink Price minus the forecasted CTS Source Price is greater than, or equal to, the dollar value specified in the bid.

Bid Production Cost: Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running and Minimum Generation Bid, and Start-Up Bid).

Bidding Requirement: As defined in the ISO Services Tariff.

Bilateral Transaction: A Transaction between two or more parties for the purchase and/or sale of Capacity or Energy other than those in the ISO Administered Markets. A request to schedule a Bilateral Transaction in the Energy Market shall be considered a request to schedule Point-to-Point Transmission Service.

Billing Period: The period of time designated in Sections 2.7.3.2.1, or 2.7.3.2.2 of this ISO OATT over which the ISO will aggregate and settle a charge or a payment for services furnished under this ISO OATT or the ISO Services Tariff.

Board of Directors ("Board"): The governing body of the ISO which is comprised of ten (10) persons (Directors) that are unaffiliated with any Market Participants, as described in the ISO Agreement.

Business Issues Committee: A standing committee of the ISO created pursuant to the ISO Agreement to establish rules related to business issues and provide a forum for discussion of those rules and issues.

1.3 Definitions - C

Capability Period: Six-month periods which are established as follows: (1) from May 1 through October 31 of each year ("Summer Capability Period"); and (2) from November 1 of each year through April 30 of the following year ("Winter Capability Period"); or such other periods as may be determined by the Operating Committee of the ISO. A Summer Capability Period followed by a Winter Capability Period shall be referred to as a "Capability Year". Each Capability Period shall consist of On-Peak and Off-Peak periods.

Capacity: The capability to generate or transmit electrical power, or the ability to reduce demand at the direction of the ISO, measured in megawatts ("MW").

Capacity Benefit Margin ("CBM"): That amount of Total Transfer Capability reserved by the ISO on the NYS Transmission System to ensure access to generation from interconnected systems to meet generation reliability requirements.

Capacity Reservation Cap: The maximum percentage of transmission Capacity from a Transmission Owner's sets of ETCNL that may be converted into ETCNL TCCs or the maximum percentage of a Transmission Owner's RCRRs that may be converted into RCRR TCCs, as the case may be, as established by the ISO pursuant to Section 19.4.3 of Attachment M.

Centralized TCC Auction: The auction in which TCCs are released for sale for one or more Capability Periods through a bidding process administered by the ISO.

Code of Conduct: The rules, procedures and restrictions concerning the conduct of the ISO directors and employees, contained in Attachment F to the ISO Open Access Transmission Tariff.

Commenced Repair: As defined in the ISO Services Tariff.

Commission ("FERC"): The Federal Energy Regulatory Commission, or any successor agency.

Completed Application: An Application that satisfies all of the information and other requirements of the Tariff.

Confidential Information: Information and/or data which has been designated by a Transmission Customer to be proprietary and confidential, provided that such designation is consistent with the ISO Procedures and this Tariff, including the attached Code of Conduct.

Congestion: A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of Energy to serve the next increment of Load, exclusive of losses, at different locations on the Transmission System is unequal.

Congestion Component: The component of the LBMP measured at a location or the Transmission Usage Charge between two locations that is attributable to the cost of transmission Congestion as is more completely defined in Attachment B of the Services Tariff.

Congestion Rent: The opportunity costs of transmission Constraints on the NYS Transmission System. Congestion Rents are collected by the ISO through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions.

Congestion Rent Shortfall: A condition in which the Congestion Rent revenue collected by the ISO in the Day-Ahead Market for Energy is less than the amount of Congestion Rent revenue in the Day-Ahead Market for Energy that the ISO is obligated under the Tariff to pay out to the Primary Holders of TCCs.

Constraint: An upper or lower limit placed on a variable or set of variables that are used by the ISO in its SCUC, RTC or RTD programs to control and/or facilitate the operation of the NYS Transmission Systems.

Contingency: An actual or potential unexpected failure or outage of a system component, such as a Generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Contract Establishment Date: The date, listed in Attachment L, on which the listed existing agreements which are the source of Grandfathered Rights and Grandfathered TCCs were executed.

Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the Generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the Load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Credible Repair Plan: As defined in the ISO Services Tariff.

Credit Assessment: As defined in the ISO Services Tariff.

Cross-Sound Scheduled Line: A transmission facility that interconnects the NYCA to the New England Control Area at Shoreham, New York and terminates near New Haven, Connecticut.

CTS Enabled Interface: An External Interface at which the ISO has authorized the use of Coordinated Transaction Scheduling ("CTS") market rules and which includes a CTS Enabled

Proxy Generator Bus for New York and a CTS Enabled Proxy Generator Bus for the neighboring Control Area.

CTS Enabled Proxy Generator Bus: A Proxy Generator Bus at which the ISO either requires or permits the use of CTS Interface Bids for Import and Export Transactions in the Real-Time Market and requires the use of Decremental Bids for Wheels Through in the Real-Time Market. A CTS Enabled Proxy Generator Bus at which the ISO permits CTS Interface Bids will also permit Decremental and Sink Price Cap Bids.

CTS Interface Bid: A Real-Time Bid provided by an entity engaged in an External Transaction at a CTS Enabled Interface. CTS Interface Bids shall include a MW amount, a direction indicating whether the proposed Transaction is to Import Energy to, or Export Energy from, the New York Control Area, and a Bid Price.

CTS Sink: Representation of the location(s) within a Control Area where energy associated with a CTS Interface Bid is withdrawn. The NYCA CTS Sinks are Proxy Generator Buses.

CTS Sink Price: The price at a CTS Sink.

CTS Source: Representation of the location(s) within a Control Area where energy associated with a CTS Interface Bid is injected. The NYCA CTS Sources are Proxy Generator Buses.

CTS Source Price: The price at a CTS Source.

Curtailment or Curtail: A reduction in Transmission Service in response to a transmission capacity shortage as a result of system reliability conditions.

Customer: An entity which has complied with the requirements contained in the ISO Services Tariff, including having signed a Service Agreement, and is qualified to utilize the Market Services and the Control Area Services provided by the ISO under the ISO Services Tariff; provided, however, that a party taking services under the ISO Services Tariff pursuant to an unsigned Service Agreement filed with the Commission by the ISO shall be deemed a Customer.

1.4 Definitions - D

DADRP Component: As defined in the ISO Services Tariff.

Day-Ahead: Nominally, the twenty-four (24) hour period directly preceding the Dispatch Day, except when this period may be extended by the ISO to accommodate weekends and holidays.

Day-Ahead LBMP: The LBMPs calculated based upon the ISO's Day-Ahead Security Constrained Unit Commitment process.

Day-Ahead Market: The ISO Administered Market in which Capacity, Energy and/or Ancillary Services are scheduled and sold Day-Ahead consisting of the Day-Ahead scheduling process, price calculations and Settlements.

Day-Ahead Reliability Unit: A Day-Ahead committed Resource which would not have been committed but for the commitment request by a Transmission Owner in order to meet the reliability needs of the Transmission Owner's local system which request was made known to the ISO prior to the close of the Day-Ahead Market.

Decremental Bid: A monotonically increasing Bid Price curve provided by an entity engaged in a Bilateral Import, other than an entity submitting a CTS Interface Bid, or Internal Transaction to indicate the LBMP below which that entity is willing to reduce its Generator's output and purchase Energy in the LBMP Markets, or by an entity engaged in a Wheel Through transaction to indicate the Congestion Component cost at or below which that entity is willing to accept Transmission Service.

Demand Side Resource: As defined in the ISO Services Tariff.

Dennison Scheduled Line: A transmission facility that interconnects the NYCA to the Hydro Quebec Control Area at the Dennison substation, located near Massena, New York and extends through the province of Ontario, Canada (near the City of Cornwall) to the Cedars substation in Quebec, Canada.

Dependable Maximum Gross Capability ("DMGC"): As defined in the ISO Services Tariff.

Dependable Maximum Net Capability ("DMNC"): The sustained maximum net output of a Generator, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period as defined in the ISO Procedures.

Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Desired Net Interchange ("DNI"): A mechanism used to set and maintain the desired Energy interchange (or transfer) between two Control Areas; it is scheduled ahead of time and can be changed manually in real-time.

Developer: An Eligible Customer developing a generation project larger than 20 megawatts, or a merchant transmission project, proposing to interconnect to the New York State Transmission

System, in compliance with the NYISO Minimum Interconnection Standard and, depending on the Developer's interconnection service election, also in compliance with the NYISO Deliverability Interconnection Standard.

Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Owner(s) for the sole use/benefit of a particular Transmission Customer requesting service under the ISO OATT. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Sale: The sale of Original Residual TCCs, ETCNL, and Grandfathered TCCs directly to a buyer by the Transmission Owner that is the Primary Holder through a non-discriminatory auditable sale conducted on the ISO's OASIS, in compliance with the requirements and restrictions set forth in Commission Orders 888 et seq. and 889 et seq.

Dispatchable: A bidding mode in which Generators or Demand Side Resources indicate that they are willing to respond to real-time control from the ISO. Dispatchable Resources, not including the Generator of a BTM:NG Resource, may either be ISO-Committed Flexible or Self Committed Flexible. Dispatchable Generators that are the Generator serving a BTM:NG Resource must be Self-Committed Flexible. Dispatchable Demand Side Resources must be ISO Committed Flexible. Dispatchable Resources that are not providing Regulation Service will follow five-minute RTD Base Point Signals. Dispatchable Resources that are providing Regulation Service will follow six-second AGC Base Point Signals.

Dispatch Day: The twenty-four (24) hour (or, if appropriate, the twenty-three (23) or twenty-five (25) hour) period commencing at the beginning of each day (0000 hour).

DSASP Component: As defined in the ISO Services Tariff.

Dynamically Scheduled Proxy Generator Bus: A Proxy Generator Bus for which the ISO may schedule Transactions at 5 minute intervals in real time. Dynamically Scheduled Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

1.5 Definitions - E

East of Central-East: An electrical area comprised of Lead Zones F, G, H, I, J, and K, as identifies in the ISO Procedures.

East of Central-East Excluding Long Island: An electrical area comprised of Lead Zones F, G, H, I, and J, as identified in the ISO Procedures.

East of Central-East Excluding New York City and Long Island: An electrical area comprised of Land Zones F, G, H, I, as identifies in the ISO Procedures.

Economic Operating Point: The megawatt quantity which is a function of: i) the real-time LBMP at the Resource bus; and ii) the Supplier's real-time eleven constant cost step Energy Bid, for the Resource, such that (a) the offer price associated with Energy offers below that megawatt quantity (if that megawatt quantity is not that Resource's minimum output level) must be less than or equal to the real-time LBMP at the Resource bus, and (b) the offer price associated with Energy offers above that megawatt quantity (if that megawatt quantity is not that Resource's maximum output level) must be greater than or equal to the real-time LBMP at the Resource bus. In cases where multiple megawatt values meet conditions (a) and (b), the Economic Operating Point is the megawatt value meeting these conditions that is closest to the Resource's real-time scheduled Energy injection. In cases where the Economic Operating Point would be less than the minimum output level, the Economic Operating Point will be set equal to the MW value of the first point on the Energy Bid curve and in cases where the Economic Operating Point would be greater than the maximum output level, the Economic Operating Point will be set equal to the MW value of the last point on the Energy Bid curve. When evaluating the Economic Operating Point of a BTM:NG Resource, only Energy offers corresponding to quantities in excess of its Host Load will be considered.

Eligible Customer: (i) An entity that is engaged, or proposes to engage, in the wholesale or retail electric power business including any electric utility, power marketer, Federal power marketing agency, or any person generating Energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner offer the unbundled Transmission Service, or pursuant to a voluntary offer of such service by the Transmission Owner. (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Owner, is an Eligible Customer under the Tariff.

Emergency: Any abnormal system condition that requires immediate automatic or manual action to prevent or limit loss of transmission facilities or Generators that could adversely affect the reliability of an electric system.

Emergency State: The state that the NYS Power System is in when an abnormal condition occurs that requires automatic or immediate, manual action to prevent or limit loss of the NYS

Transmission System or Generators that could adversely affect the reliability of the NYS Power System.

End-State Centralized TCC Auction: A Centralized TCC Auction that the ISO will conduct after the ISO develops the necessary software.

Energy ("MWh"): A quantity of electricity that is Bid, produced, purchased, consumed, sold, or transmitted over a period of time, and measured or calculated in megawatt hours.

Energy and Ancillary Services Component: As defined in the ISO Services Tariff.

Equivalency Rating: As defined in the ISO Services Tariff.

ETA Agent: A Transmission Customer of the ISO that has been appointed by a Load Serving Entity and approved by the ISO in accordance with ISO Procedures for the purpose of enabling that Transmission Customer to hold all of the rights and obligations associated with Fixed Price TCCs, as provided for in Attachment M of this OATT.

ETCNL TCC: A TCC created when a Transmission Owner with ETCNL exercises its right to convert a megawatt of ETCNL into a TCC pursuant to Section 19.4.1 of Attachment M of this ISO OATT.

Excess Congestion Rents: Congestion revenues in the Day-Ahead Market for Energy collected by the ISO that are in excess of its Day-Ahead payment obligations. Excess Congestion Rents may arise if Congestion occurs in the Day- Ahead Market for Energy and if the Day-Ahead Transfer Capability of the Transmission System is not exhausted by the set of already-outstanding TCCs and Grandfathered Rights that are valid.

Existing Transmission Agreement ("ETA"): An agreement between two or more Transmission Owners, or between a Transmission Owner and another entity, in existence at the time of ISO start-up and providing for transmission service by a Transmission Owner to another Transmission Owner or another entity. Table 1A of Attachment L lists all ETAs. ETAs include Transmission Wheeling Agreements (including MWAs and Third Party TWAs) and Transmission Facility Agreements.

Existing Transmission Capacity for Native Load ("ETCNL"): Transmission capacity identified on a Transmission Owner's transmission system to serve the Native Load customers of the current Transmission Owners (as of the filing date of the original ISO Tariff-January 31, 1997) for the purposes of allocating revenues from the sale of TCCs related to that capacity. This includes transmission capacity required: (1) to deliver the output from Generators located out of a Transmission Owner's Transmission District; (2) to deliver power purchased under power supply contracts; and (3) to deliver power purchased under third party agreements (i.e., Non-Utility Generators). Existing Transmission Capacity for Native Load is listed in Attachment L, Table 3, "Existing Transmission Capacity Reservations for Native Load Table."

Expected EDRP/SCR MW: The aggregate Load reduction (in MW) expected to be realized from EDRP and/or SCRs during the real-time intervals that the ISO has called upon EDRP and/or SCRs to provide Load reduction in a Scarcity Reserve Region, as determined based on the

ISO's calculation of the historical performance of EDRP and SCRs. There will be separate values for voluntary and mandatory Load reductions. When determining the historical performance of SCRs, provision of Load reduction shall be deemed mandatory if the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of the NYISO Services Tariff as it relates to the SCRs in the applicable Load Zone, otherwise provision of such Load reduction shall be deemed voluntary. When determining the historical performance of the EDRP, provision of Load reduction by EDRP shall be deemed voluntary.

Expected Load Reduction: For purposes of determining the Real-Time Locational Based Marginal Price, the reduction in Load expected to be realized in real-time from activation of the Emergency Demand Response Program and from Load reductions requested from Special Case Resources, as established pursuant to ISO Procedures.

Export: A Bilateral Transaction or purchase from the LBMP Market where the Energy is delivered to an NYCA interconnection with another Control Area.

External: An entity (e.g., Supplier, Transmission Customer) or facility (e.g., Generator, Interface) located outside the Control Area being referenced or between two or more Control Areas. Where a specific Control Area is not referenced, the NYCA is the intended reference.

External Transactions: Purchases, sales or exchanges of Energy, Capacity or Ancillary Services for which either the Point of Injection ("POI") or Point of Withdrawal ("POW") or both are located outside the NYCA (i.e., Exports, Imports or Wheels Through).

1.6 Definitions - F

Federal Power Act ("FPA"): The Federal Power Act, as may be amended from time-to-time (See 16 U.S.C. § 796 et seq.)

Facilities Study: An engineering study conducted by the ISO and/or a Transmission Owner to determine the required modifications to the Transmission Owner's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested facilities.

Facility Flow-Based Methodology: The methodology, as described in Section 20.3.7 of Attachment N, used to allocate Net Auction Revenue among Transmission Owners.

Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff. Firm Point-To-Point Transmission Service is service for which the Transmission Customer has agreed to pay the Congestion associated with its service. A Transmission Customer may fix the price of Congestion associated with its Firm Point-To-Point Transmission Service by acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service.

Firm Transmission Service: Transmission Service requested by a Transmission Customer willing to pay Congestion Rent.

First Settlement: The process of establishing binding financial commitments on the part of Customers participating in the Day-Ahead Market based on Day-Ahead LBMP.

Fixed Block Unit: A unit that, due to operational characteristics, can only be dispatched in one of two states: either turned completely off, or turned on and run at a fixed capacity level.

Fixed Price TCC: TCCs obtained pursuant to Sections 19.2.1 or 19.2.2.of Attachment M of this OATT. If a TCC is obtained pursuant to Section 19.2.1 of Attachment M of this OATT, it is an Historic Fixed Price TCC. If a TCC is awarded to an LSE pursuant to the provisions of Section 19.2.2 of Attachment M of this OATT, it is a Non-Historic Fixed Price TCC.

Forced Outage: As defined in the ISO Services Tariff.

1.7 Definitions - G

Gap Solution: This term shall have the meaning given in Attachment Y to the OATT.

Generator: A facility, including the Generator of a BTM:NG Resource, capable of supplying Energy, Capacity and/or Ancillary Services that is accessible to the NYCA. A Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, and each unit within that group, shall be considered a Generator.

Generator Classes: The type of Generator (e.g., nuclear, gas turbine, fossil, hydro) which is used by the ISO to determine criteria that must be met for that Generator to qualify as a source of Installed Capacity.

Good Utility Practice: Any of the practices, methods or acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to delineate acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Government Bonds: Tax-exempt bonds issued by the New York Power Authority pursuant to Section 103 and related provisions of the Internal Revenue Code. 26 U.S.C. § 103.

Grandfathered Rights: The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements; and (3) Third Party Transmission Wheeling Agreements where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert them to Grandfathered TCCs.

Grandfathered TCCs: The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party TWAs where the party entitled to exercise the transmission rights associated with such agreements, has chosen, as provided for in the Tariff, to convert those rights to TCCs.

1.8 Definitions - H

Host Load: As defined in the ISO Services Tariff.

HTP Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection, L.L.C. Control Area at the West 49th Street Substation, New York, NY and terminates in Ridgefield, New Jersey.

1.9 Definitions - I

ICAP Ineligible Forced Outage: As defined in the ISO Services Tariff.

Import Curtailment Guarantee Payment: A payment made in accordance with Section 4.5.3.2 and Attachment J of the ISO Services Tariff to compensate a Supplier whose Import is Curtailed by the ISO.

Imports: A Bilateral Transaction or sale to the LBMP Market where Energy is delivered to a NYCA Interconnection from another Control Area.

Imputed Revenue: The Congestion Rents that owners of Grandfathered Rights do not have to pay due to their own use of those Grandfathered Rights.

Inactive Reserves: As defined in the ISO Services Tariff.

Inadvertent Energy Accounting: The accounting performed to track and reconcile the difference between net actual Energy interchange and scheduled Energy interchange of a Control Area with adjacent Control Areas.

Incremental Energy Bid: A series of monotonically increasing constant cost incremental Energy steps that indicate the quantities of Energy for a given price that an entity is willing to supply to the ISO Administered Markets.

Incremental TCC: A set of point-to-point Transmission Congestion Contract(s) that is awarded pursuant to Section 19.2.2 of Attachment M to this ISO OATT.

Independent System Operator, Inc. ("ISO"): The New York Independent System Operator, a not-for-profit corporation established pursuant to the ISO Agreement.

Independent System Operator Agreement ("ISO Agreement"): The agreement that establishes the New York ISO.

Independent System Operator/New York State Reliability Council ("ISO/NYSRC Agreement"): The agreement between the ISO and the New York State Reliability Council governing the relationship between the two organizations.

Independent System Operator/Transmission Owner Agreement ("ISO/TO Agreement"): The agreement that establishes the terms and conditions under which the Transmission Owners transferred to the ISO Operational Control over designated transmission facilities.

Injection Billing Units: A Transmission Customer's Actual Energy Injections (for all internal injections) or Scheduled Energy Injections (for all Import Energy injections) in the New York Control Area, including injections for Wheels Through. For purposes of Rate Schedule 1 and Rate Schedule 11 of this ISO OATT, (i) a Limited Energy Storage Resource shall be responsible for charges or eligible for payments on the basis only of its Actual Energy Injections and (ii) a Day-Ahead Demand Reduction Provider's Demand Reduction shall be included as Injection Billing Units. For purposes of recovering the ISO annual budgeted costs and the annual FERC fee pursuant to Rate Schedule 1 of this ISO OATT, Injection Billing Units shall include the absolute value of negative injections by pump storage facilities.

Injection Limit: As defined in the ISO Services Tariff.

Installed Capacity: A Generator or Load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for Energy in the NYCA for the purpose of ensuring that sufficient Energy and Capacity are available to meet the Reliability Rules. The Installed Capacity requirement, established by the NYSRC, includes a margin of reserve in accordance with the Reliability Rules.

Interconnection or Interconnection Points ("IP"): The point(s) at which the NYCA connects with a distribution system or adjacent Control Area. The IP may be a single tie line or several tie lines that are operated in parallel.

Interface: A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas.

Interface MW - Mile Methodology: The procedure used to allocate Original Residual TCCs determined prior to the first Centralized TCC Auction to Transmission Owners.

Interim Service Provider ("ISP"): As defined in Attachment FF to the OATT.

Intermittent Power Resource: A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. In New York, resources that depend upon wind, or solar energy or landfill gas for their fuel have been classified as Intermittent Power Resources. Each Intermittent Power Resource that depends on wind as its fuel shall include all turbines metered at a single scheduling point identifier (PTID).

Internal: An entity (*e.g.*, Supplier, Transmission Customer) or facility (*e.g.*, Generator, Interface) located within the Control Area being referenced. Where a specific Control Area is not referenced, internal means the NYCA.

Internal Transactions: Purchases, sales or exchanges of Energy, Capacity or Ancillary Services where the Generator and Load are located within the NYCA.

Investment Grade Customer: As defined in the ISO Services Tariff.

Investor-Owned Transmission Owners: At the present time these include: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

ISO Administered Markets: The Day-Ahead Market and the Real-Time Market (collectively the LBMP Markets) and any other market administered by the ISO.

ISO-Committed Fixed: In the Day-Ahead, a bidding mode in which a Generator requests that the ISO commit and schedule it. In the Real-Time Market, a bidding mode in which a Generator, with ISO approval, requests that the ISO schedule it no more frequently than every 15 minutes. A Generator scheduled in the Day-Ahead Market as ISO-Committed Fixed will participate as a Self-Committed Fixed Generator in the Real-Time Market unless it changes bidding mode, with ISO approval, to participate as an ISO-Committed Fixed Generator. A BTM:NG Resource is not permitted to utilize the ISO-Committed Fixed bidding mode.

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator Demand Side Resource follows Base Point Signals and is committed by the ISO. A BTM:NG Resource is not permitted to utilize the ISO-Committed Flexible bidding mode.

ISO Market Power Monitoring Program: The monitoring program approved by the Commission and administered by the ISO designed to monitor the possible exercise of market power in ISO Administered Markets.

ISO OATT (the "Tariff"): The ISO Open Access Transmission Tariff.

ISO Procedures: The procedures adopted by the ISO in order to fulfill its responsibilities under the ISO OATT, the ISO Services Tariff and the ISO Related Agreements.

ISO Related Agreements: Collectively, the ISO Agreement, the NYSRC Agreement, the ISO/NYSRC Agreement and the ISO/TO Agreement.

NYISO Services Tariff: The ISO Market Administration and Control Area Services Tariff.

ISO Tariffs: The ISO OATT and the ISO Services Tariff, collectively.

1.10 Definitions - J

1.11 Definitions - K

1.12 Definitions - L

LBMP Markets: A term that collectively refers to both the Real-Time Market and the Day-Ahead Market.

Linden VFT Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection, L.L.C. Control Area in Linden, New Jersey.

LIPA Tax-Exempt Bonds: Obligations issued by the Long Island Power Authority, the interest in which is not included in gross income under the Internal Revenue Code.

Load: A term that refers to either a consumer of Energy or the amount of Energy (MWh) or demand (MW) consumed by certain consumers.

Load Ratio Share: The ratio of an LSE's Load to Load within the NYCA during a specified time period.

Load Serving Entity ("LSE"): An entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail customers located within the NYCA, including an entity that takes service directly from the ISO to supply its own load in the NYCA.

Load Shedding: The systematic reduction of system demand by temporarily decreasing Load in response to Transmission System or area Capacity shortages, system instability, or voltage control considerations under Part 4 of the Tariff.

Load Zone: One (1) of eleven (11) geographical areas located within the NYCA that is bounded by one (1) or more of the fourteen (14) New York State Interfaces.

Local Furnishing Bonds: Tax-exempt bonds issued by a Transmissions Owner under an agreement between the Transmission Owner and the New York State Energy Research and Development Authority ("NYSERDA"), or its successor, or by a Transmission Owner itself, and pursuant to Section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).

Locality: Shall have the meaning set forth in §2.12 of the ISO Services Tariff.

Local Reliability Rule: A Reliability Rule established by a Transmission Owner and adopted by the NYSRC to meet specific reliability concerns in limited areas of the NYCA, including without limitation, special requirements and conditions that apply to nuclear plants and special requirements applicable to the New York City metropolitan area.

Locational Based Marginal Pricing ("LBMP"): The price of Energy at each location in the NYS Transmission System as calculated pursuant to Attachment J.

Locational Minimum Installed Capacity Requirement: The determination by the ISO in accordance with the ISO Services Tariff of that portion of the NYCA Minimum Installed

Capacity Requirement (as defined in the ISO Services Tariff) that must be electrically located within a Locality.

Long-Island ("L.I."): An electrical area comprised of Load Zone K, as identified in the ISO Procedures.

Long-Term Firm Point-To-Point Transmission Service: Firm Point-to-Point Service, the price of which is fixed for a long term by a Transmission Customer acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service.

Lost Opportunity Cost: The foregone profit associated with the provision of Ancillary Services, which is equal to the product of: (1) the difference between (a) the Energy that a Generator could have sold at the specific LBMP and (b) the Energy sold as a result of reducing the Generator's output to provide an Ancillary Service under the direction of the ISO; and (2) the LBMP existing at the time the Generator was instructed to provide the Ancillary Service, less the Generator's Energy bid for the same MW segment.

1.13 Definitions - M

Major Emergency State: An Emergency accompanied by abnormal frequency, abnormal voltage and/or equipment overloads that create a serious risk that the reliability of the NYS Power System could be adversely affected.

Manual Dispatch: A dispatch of the NYS Transmission System performed by the ISO when the ISO's RTD is unavailable.

Marginal Losses: The NYS Transmission System Real Power Losses associated with each additional MWh of consumption by Load, or each additional MWh transmitted under a Bilateral Transaction as measured at the Points of Withdrawal.

Marginal Losses Component: The component of LBMP at a bus that accounts for the Marginal Losses, as measured between that bus and the Reference Bus.

Market Participant: An entity, excluding the ISO, that produces, transmits, sells, and/or purchases for resale Capacity, Energy and Ancillary Services in the Wholesale Market. Market Participants include: Transmission Customers under the ISO OATT, Customers under the ISO Services Tariff, Power Exchanges, Transmission Owners, Primary Holders, LSEs, Suppliers and their designated agents. Market Participants also include entities buying or selling TCCs.

Market Services: Services provided by the ISO under the ISO Services Tariff related to the ISO Administered Markets for Energy, Capacity and Ancillary Services.

Member Systems: The eight Transmission Owners that comprise the membership of the New York Power Pool.

Minimum Generation Bid: A Bid parameter that identifies the payment a Supplier requires to operate a Generator at its specific minimum operating level or to provide a Demand Side Resource's specified minimum quantity of Demand Reduction. If the Supplier is a BTM:NG Resource, it shall not submit a Minimum Generation Bid.

Minimum Generation Level: For purposes of describing the eligibility of ten minute Resources to be committed by the Real Time Dispatch for pricing purposes pursuant to the Services Tariff, Section 4.4.3.3, an upper bound, established by the ISO, on the physical minimum generation limits specified by ten minute Resources. Ten minute Resources with physical minimum generation limits that exceed this upper bound will not be committed by the Real Time Dispatch for pricing purposes. The ISO shall establish a Minimum Generation Level based on its evaluation of the extent to which it is meeting its reliability criteria including Control Performance. The Minimum Generation Level, in megawatts, and the ISO's rationale for that level, shall be made available through the ISO's website or comparable means. If the Supplier is a BTM:NG Resource, it shall not submit a Minimum Generation Level.

Modified Wheeling Agreements ("MWA"): A Transmission Wheeling Agreement between Transmission Owners that was in existence at the time of ISO start-up, as amended and modified as described in Attachment K. Modified Wheeling Agreements are associated with Generators or power supply contracts existing at ISO start-up. All Modified Wheeling Agreements are listed in Attachment L, Table 1A, and are designated in the “Treatment” column of Table 1A, as “MWA.”

Mothball Outage: As defined in the ISO Services Tariff.

1.14 Definitions - N

Native Load Customers: The wholesale and retail power customers of the Transmission Owners on whose behalf the Transmission Owners, by statute, franchise, regulatory requirement, or contract, have undertaken an obligation to construct and operate the Transmission Owners' systems to meet the reliable electric needs of such customers.

Neptune Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection LLC Control Area at Levittown, Town of Hempstead, New York and terminates in Sayerville, New Jersey.

NERC: The North American Electric Reliability Council or, as applicable, the North American Electric Reliability Corporation.

NERC Transaction Priorities: The reservation and scheduling priority applied to a Transaction under the NERC Transmission Loading Relief Procedure.

NERC Transmission Loading Relief ("TLR") Procedure: "Standard IRO-006-3 – Reliability Coordination – Transmission Loading Relief" as approved in Docket No. ER06-1545, and any amendments thereto. See www.nerc.com for the current version of the NERC TLR Procedure.

Net Auction Revenue: The total amount, in dollars, as calculated pursuant to Section 20.3.1 of Attachment N, remaining after collection of all charges and allocation of all payments associated with a round of a Centralized TCC Auction or a Reconfiguration Auction. Net Auction Revenue takes into account: (i) revenues from and payments for the award of TCCs in a Centralized TCC Auction or Reconfiguration Auction, (ii) payments to Transmission Owners releasing ETCNL, (iii) payments or charges to Primary Holders selling TCCs, (iv) payments to Transmission Owners releasing Original Residual TCCs, (v) O/R-t-S Auction Revenue Surplus Payments and U/D Auction Revenue Surplus Payments, and (vi) O/R-t-S Auction Revenue Shortfall Charges and U/D Auction Revenue Shortfall Charges. Net Auction Revenue may be positive or negative.

Net Congestion Rent: The total amount, in dollars, as calculated pursuant to Section 20.2.1 of Attachment N, remaining after collection of all Congestion-related charges and allocation of all Congestion-related payments associated with the Day-Ahead Market. Net Congestion Rent takes into account: (i) charges and payments for Congestion Rents, (ii) settlements with TCC Primary Holders, (iii) O/R-t-S Congestion Rent Shortfall Charges and U/D Congestion Rent Shortfall Charges, and (iv) O/R-t-S Rent Congestion Surplus Payments and U/D Congestion Rent Surplus Payments. Net Congestion Rent may be positive or negative.

Net Installed Capacity ("Net-ICAP"): As defined in the ISO Services Tariff.

Net Unforced Capacity ("Net-UCAP"): As defined in the ISO Services Tariff.

Network Customer: An entity receiving Transmission Service pursuant to the terms of the ISO's Network Integration Transmission Service under Part 4 of the Tariff.

Network Integration Transmission Service: The Transmission Service provided under Part 4 of the Tariff.

Network Load: The Load that a Network Customer designates for Network Integration Transmission Service under Part 4 of the Tariff. The Network Customer's Network Load shall include all Load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total Load as Network Load but may not designate only part of the Load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular Load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part 3 of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated Load.

Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part 4 of the Tariff. For Eligible Customers that take service under the ISO Services Tariff, that Tariff shall function as their Network Operating Agreement.

Network Operating Committee: The ISO Operating Committee will serve this function.

Network Resource: Any generating resource that provides Installed Capacity to the NYCA designated under the Network Integration Transmission Service provisions of the Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Upgrades: Modifications or additions to transmission facilities that are integrated with and support the Transmission Owner's overall Transmission System for the general benefit of all users of such Transmission System.

Network Upgrade Agreement: An agreement entered into between a Transmission Customer and a Transmission Owner that identifies the rights and obligations of each party with respect to the Network Upgrade, as described in this Tariff.

New York City: The electrical area comprised of Load Zone J, as identified in the ISO Procedures.

New York Control Area ("NYCA"): The Control Area that is under the control of the ISO which includes transmission facilities listed in the ISO/TO Agreement Appendices A-1 and A-2, as amended from time-to-time, and Generation located outside the NYS Power System that is subject to protocols (e.g., telemetry signal biasing) which allow the ISO and other Control Area operator(s) to treat some or all of that Generation as though it were part of the NYS Power System.

New York Power Pool ("NYPP"): An organization established by agreement (the "New York Power Pool Agreement") made as of July 21, 1966, and amended as of July 16, 1991, by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and

Electric Corporation, and the Power Authority of the State of New York. LIPA became a Member of the NYPP on May 28, 1998 as a result of the acquisition of the Long Island Lighting Company by the Long Island Power Authority.

New York State Bulk Power Transmission Facility: This term shall have the meaning given in Attachment Y to the OATT.

New York State Power System ("NYS Power System"): All facilities of the NYS Transmission System, and all those Generators located within the NYCA or outside the NYCA, some of which may from time-to-time be subject to operational control by the ISO.

New York State Reliability Council ("NYSRC"): An organization established by agreement among the Member Systems of the New York Power Pool (the "NYSRC Agreement").

New York State Transmission System ("NYS Transmission System"): The entire New York State electric transmission system, which includes: (1) the Transmission Facilities Under ISO Operational Control; (2) the Transmission Facilities Requiring ISO Notification; and (3) all remaining transmission facilities within the NYCA.

Non-Competitive Proxy Generator Bus: A Proxy Generator Bus for an area outside of the New York Control Area that has been identified by the ISO as characterized by non-competitive Import or Export prices, and that has been approved by the Commission for designation as a Non-Competitive Proxy Generator Bus. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service for which a Transmission Customer is not willing to pay Congestion. Such service is not available in the markets that the NYISO administers.

Non-Investment Grade Customer: As defined in the ISO Services Tariff.

Non-Utility Generator ("NUG," "Independent Power Producer" or "IPP"): Any entity that owns or operates an electric generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other non-utility electricity producers, such as exempt wholesale generators that sell electricity.

Normal State: The condition that the NYS Power System is in when the Transmission Facilities Under ISO Operational Control are operated within the parameters listed for Normal State in the Reliability Rules. These parameters include, but are not limited to, thermal, voltage, stability, frequency, operating reserve and Pool Control Error limitations.

Northport-Norwalk Scheduled Line: A transmission facility that originates at the Northport substation in New York and interconnects the NYCA to the ISO New England Control Area at the Norwalk Harbor substation in Connecticut.

Notice of Intent to Return: As defined in the ISO Services Tariff.

Notification: Informing the ISO of all changes in status of the Transmission Facilities Requiring ISO Notification. Notification includes the Transmission Owners informing the ISO of all changes in the status of the designated transmission facilities.

Nuclear Regulatory Commission ("NRC"): Nuclear Regulatory Commission, or any successor thereto.

NYPA: The Power Authority of the State of New York.

NYPA Transmission Adjustment Charge ("NTAC"): A surcharge on all Energy Transactions designed to recover the Annual Transmission Revenue Requirement of NYPA which cannot be recovered through its TSC, TCCs, or other transmission revenues, including, but not limited to, its ETA revenues. This charge will be assessed to all Load statewide, as well as Transmission Customers in Wheels Through and Exports.

1.15 Definitions - O

Off-Peak: The hours between 11:00 p.m. and 7:00 a.m., prevailing Eastern Time, Monday through Friday, and all day Saturday and Sunday, and NERC-defined holidays, or as otherwise decided by ISO.

On-Peak: The hours between 7:00 a.m. and 11:00 p.m. inclusive, prevailing Eastern Time, Monday through Friday, except for NERC-defined holidays, or as otherwise decided by the ISO.

Open Access Same-Time Information System ("OASIS"): The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Operating Agreement: An agreement between the ISO and a non-incumbent owner of transmission facilities in the New York Control Area concerning the operation of the transmission facilities in the form of the agreement set forth in Appendix H (Section 31.11) of Attachment Y.

Operating Capacity: Capacity that is readily converted to Energy and is measured in MW.

Operating Committee: A standing committee of the ISO created pursuant to the ISO Agreement, which coordinates operations, develops procedures, evaluates proposed system expansions and acts as a liaison to the NYSRC.

Operating Requirement: As defined in the ISO Services Tariff.

Operating Reserves: Capacity that is available to supply Energy, or to reduce demand and that meets the requirements of the ISO. The ISO will administer Operating Reserves markets, in the manner described in Article 4 and Rate Schedule 4 of this ISO Services Tariff, to satisfy the various Operating Reserves requirements, including locational requirements, established by the Reliability rules and other applicable reliability standards. The basic Operating Reserves products that will be procured by the ISO on behalf of the market are classified as follows:

(1) Spinning Reserve: Operating Reserves provided by Generators and Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff that are already synchronized to the NYS Power System and can respond to instructions to change their output level, or reduce their Energy usage, within ten (10) minutes. Spinning Reserves may not be provided by Demand Side Resources that are Local Generators or by Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit;

(2) 10-Minute Non-Synchronized Reserve: Operating Reserve provided by Generators, Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit, or Demand Side Resources, including Demand Side Resources using Local Generators, that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can be started, synchronized and can change their output level within ten (10) minutes; and

(3) 30-Minute Reserve: Synchronized Operating Reserves provided by Generators, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, and Demand Side Resources that are not Local Generators; or non-synchronized Operating Reserves provided by Generators, Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, or Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can respond to instructions to change their output level within thirty (30) minutes, including starting and synchronizing to the NYS Power System.

Operating Reserve Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Operating Reserves meeting a particular Operating Reserve requirement corresponding to each possible quantity of Resources that the ISO's software may schedule to meet that requirement. A single Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for each of the ISO's twelve Operating Reserve requirements.

Operating Study Power Flow: A Power Flow analysis that is performed at least once before each Capability Period that is used to determine each Interface Transfer Capability for the Capability Period (See Attachment M).

Operational Control: Directing the operation of the Transmission Facilities Under ISO Operational Control to maintain these facilities in a reliable state, as defined by the Reliability Rules. The ISO shall approve operational decisions concerning these facilities, made by each Transmission Owner before the Transmission Owner implements those decisions. In accordance with ISO Procedures, the ISO shall direct each Transmission Owner to take certain actions to restore the system to the Normal State. Operational Control includes security monitoring, adjustment of generation and transmission resources, coordination and approval of changes in transmission status for maintenance, determination of changes in transmission status for reliability, coordination with other Control Areas, voltage reductions and Load Shedding, except that each Transmission Owner continues to physically operate and maintain its facilities.

Optimal Power Flow ("OPF"): The Power Flow analysis that is performed during the administration of the Centralized TCC Auction and Reconfiguration Auction to determine the most efficient simultaneously feasible allocation of TCCs to bidders.

Original Residual TCC: A TCC converted from Residual Transmission Capacity estimated prior to the first Centralized TCC Auction and allocated among the Transmission Owners utilizing the Interface MW-Mile Methodology prior to the first Centralized TCC Auction.

Order Nos. 888 et seq.: The Final Rule entitled Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, issued by the Commission on April 24, 1996, in Docket Nos. RM95-8-000 and RM94-7-001, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31,036 (1996) ("Order No. 888"), on reh'g, III FERC Stats. & Regs. ¶ 31,048 (1997) ("Order No. 888-A"), on reh'g, 81

FERC ¶ 61,248 (1997) (“Order No. 888-B”) (Order on reh’g 82 FERC ¶ 61,046 (1998) (“Order No. 888- C”).

Order Nos. 889 et seq.: The Final Rule entitled Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, issued by the Commission on April 24, 1996, in Docket No. RM95-9-000, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31,035 (1996) (“Order No. 889"), on reh’g, III FERC Stats. & Regs. ¶ 31,049 (1997) (“Order No. 889-A”), on reh’g, 81 FERC ¶ 61,253 (1997) (“Order No. 889-B”)).

Out-of-Merit Generation: Resources committed and/or dispatched by the ISO at specified output limits for specified time periods to meet Load and/or reliability requirements that differ from or supplement the ISO’s security constrained economic commitment and/or dispatch.

1.16 Definitions - P

Part 1: Tariff Section 1 pertaining to Definitions.

Part 2: Tariff Section 2 pertaining to Common Service Provisions.

Part 3: Tariff Section 3 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part 2 and appropriate Schedules and Attachments.

Part 4: Tariff Section 4 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part 2 and appropriate Schedules and Attachments.

Part 5: OATT Section 5 – Special Provisions for retail access and the Individual Retail Access Plans

Party or Parties: The ISO and the Transmission Customer receiving service under the Tariff.

Performance Tracking System: A system designed to report metrics for Generators and Loads which include but are not limited to actual output and schedules (See Rate Schedule 3 of the ISO Services Tariff). This system is used by the ISO to measure compliance with criteria associated with the provision of Energy and Ancillary Services.

Point(s) of Delivery: Point(s) on the NYS Transmission System or Proxy Generator Buses where Energy transmitted by the ISO will be made available to the Transmission Customer under the ISO Tariffs. The Point(s) of Delivery shall be specified in the Bid, Bilateral Transaction schedule, or similar entry.

Point(s) of Injection ("POI"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy and Ancillary Services will be made available to the ISO by the Customer or Transmission Customer under the ISO Tariffs. The Point(s) of Injection shall be specified in the Bid, Bilateral Transaction schedule, or similar entry. (May be referred to as "Point of Receipt" or similar in some Existing Transmission Agreements.)

Point(s) of Receipt: Point(s) of interconnection on the NYS Transmission System or Proxy Generator Buses where Energy will be made available to the ISO by the Transmission Customer under the ISO Tariffs. The Point(s) of Receipt shall be specified in the Bid, Bilateral Transaction schedule, or similar entry.

Point(s) of Withdrawal ("POW"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy will be made available to the Transmission Customer or Customer under the ISO Tariffs. The Point(s) of Withdrawal shall be specified in the Bid, Bilateral Transaction Schedule, or other similar entry. (May be referred to as "Point of Delivery" or similar in some Existing Transmission Agreements.)

Point-to-Point Transmission Service: The reservation and transmission of Capacity and Energy on a firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the ISO Tariffs.

Pool Control Error ("PCE"): The difference between the actual and scheduled interchange with other Control Areas, adjusted for frequency bias.

Post Contingency: Conditions existing on a system immediately following a Contingency.

Power Exchange ("PE"): A commercial entity meeting the requirements for service under the ISO OATT or the ISO Services Tariff that facilitates the purchase and/or sale of Energy, Capacity and/or Ancillary Services in the New York Wholesale Market. A PE may transact with the ISO on its own behalf or as an agent for others.

Power Factor: The ratio of real power to apparent power (the product of volts and amperes, expressed in megavolt-amperes, MVA).

Power Factor Criteria: Criteria to be established by the ISO to monitor a Load's use of Reactive Power.

Power Flow: A simulation which determines the Energy flows on the NYS Transmission System and adjacent transmission systems.

Power Purchaser: The entity that is purchasing the Capacity and Energy to be transmitted under the Tariff.

Primary Holder: The Transmission Customer that is the recognized holder of a TCC, as described in Attachment M of this ISO OATT.

Prior Equivalent Capability Period: The previous same-season Capability Period.

Proxy Generator Bus: A proxy bus located outside the NYCA that is selected by the ISO to represent a typical bus in an adjacent Control Area and at which LBMP prices are calculated. The ISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services available at the Interface.

PSC: The Public Service Commission of the State of New York or any successor agency thereto.

PSL: The New York Public Service Law, N.Y. Pub. Serv. Law § 1 et seq. (McKinney 1989 & Supp. 1997-98).

1.17 Definitions - Q

Qualified Non-Generator Voltage Support Resource: A resource that is neither a Generator nor a synchronous condenser but that is capable of providing the ISO with Reactive Power on a dynamic basis, that is energized and under the operational control of the ISO, or a Transmission Owner, that meets the resource-specific technical and testing criteria specified in the ISO Procedures, and that is ineligible to receive Reactive Power compensation other than as a Qualified Non-Generator Voltage Support Resource. The Cross-Sound Scheduled Line shall be a Qualified Non-Generator Voltage Support Resource, provided that it meets the technical and testing criteria specified in the ISO Procedures.

1.18 Definitions - R

RCRR TCC: A Load Zone-to-Load Zone TCC created when a Member System with a RCRR exercises its right to convert the RCRR into a TCC pursuant to Section 19.5.4 of Attachment M of this ISO OATT.

Reactive Power (MVAr): The product of voltage and the out-of-phase component of alternating current. Reactive Power, usually measured in MVAr, is produced by capacitors (synchronous condensers), over-excited Generators, and Qualified Non-Generator Voltage Support Resources, and absorbed by reactors or under-excited Generators and other inductive devices including the inductive portion of Loads.

Ramp Capacity: The amount of change in the Desired Net Interchange that generation located in the NYCA can support at any given time. Ramp Capacity may be calculated for all Interfaces between the NYCA and neighboring Control Areas as a whole or for any individual Interface between the NYCA and an adjoining Control Area.

Real Power Losses: The loss of Energy, resulting from transporting power over the NYS Transmission System, between the Point of Injection and Point of Withdrawal of that Energy.

Real-Time Bid: A Bid submitted into the Real-Time Commitment before the close of the Real-Time Scheduling Window. A Real-Time Bid shall also include a CTS Interface Bid.

Real-Time Commitment ("RTC"): A multi-period security constrained unit commitment and dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves and Regulation Service on a least as-bid production cost basis over a two hour and fifteen minute optimization period. The optimization evaluates the next ten points in time separated by fifteen minute intervals. Each RTC run within an hour shall have a designation indicating the time at which its results are posted: "RTC_{00}," RTC_{30}, and "RTC_{45}: post on the hour, and at fifteen, thirty, and forty-five minutes after the hour, respectively. Each RTC run will produce binding commitment instructions for the periods beginning fifteen and thirty minutes after its scheduled posting time and will produce advisory commitment guidance for the remainder of the optimization period, RTC_{15} will also establish hourly External Transaction schedules, while all RTC runs may establish 15 minute External Transaction schedules at Variably Scheduled Proxy Generator Buses. Additional information about RTC's functions is provided in Section 4.4.2 of the ISO Services Tariff.

Real-Time Dispatch ("RTD"): A multi-period security constrained dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least-as-bid production cost basis over a fifty, fifty-five or sixty-minute period (depending on when each RTD run covers within an hour). The Real-Time Dispatch dispatches, but does not commit, Resources, except that RTD may commit, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting in ten minutes. RTD may also establish 5-minute External Transaction schedules at Dynamically Scheduled Proxy Generator Buses. Real-Time Dispatch runs will normally occur every five minutes. Additional information about RTD's functions is provided in Section 4.4.3 of the ISO Services Tariff. Throughout the ISO

Services Tariff the term "RTD" will normally be used to refer to both the Real-Time Dispatch and to the specialized Real-Time Dispatch Corrective Action Mode software.

Real-Time Dispatch-Corrective Action Mode ("RTD-CAM"): A specialized version of the Real-Time Dispatch software that will be activated when it is needed to address unanticipated system conditions. RTD-CAM is described in Section 4.4.4 of the ISO Services Tariff.

Real-Time LBMP: The LBMPs established through the ISO Administered Real- Time Market.

Real-Time Market: The ISO Administered Markets for Energy and Ancillary Services resulting from the operation of the RTC and the RTD.

Real-Time Scheduling Window: The period of time within which the ISO accepts offers and Bids to sell and purchase Energy and Ancillary Services in the real-time market which period closes seventy-five (75) minutes before each hour, or eighty-five (85) minutes before each hour for Bids to schedule External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line.

Reconfiguration Auction: The monthly auction administered by the ISO which will either be: (i) a Balance-of-Period Auction; or (ii) an auction in which Transmission Customers may purchase and sell one-month TCCs; provided, however, that the ISO shall only conduct one Reconfiguration Auction type in a month.

Reference Bus: The location on the NYS Transmission System relative to which all mathematical quantities, including Shift Factors and penalty factors relating to physical operation, will be calculated. The NYPA Marcy 345 kV transmission substation is designated as the Reference Bus.

Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation Service Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Regulation Service corresponding to each possible quantity of Resources that the ISO's software may schedule to satisfy the ISO's Regulation Service constraint. A single Regulation Service Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for Regulation Service. The Shadow Price for Regulation Service shall be used to calculate Regulation Service payments under Rate Schedule 3 of the Service Tariff.

Reliability Rules: Those rules, standards, procedures and protocols developed and promulgated by the NYSRC, including Local Reliability Rules, in accordance with NERC, NPCC, FERC, PSC and NRC standards, rules and regulations, and other criteria and pursuant to the NYSRC Agreement.

Repair Plan: As defined in the ISO Services Tariff.

Required System Capability: Generation capability required to meet an LSE's peak Load plus Installed Capacity reserve obligation as defined in the Reliability Rules.

Reserved Capacity: The maximum amount of Capacity and Energy that the ISO agrees to transmit for the Transmission Customer over the NYS Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part 3 of this Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Residual Adjustment: The adjustment made to ISO costs that are recovered through Schedule 1. The Residual Adjustment is calculated pursuant to Schedule 1.

Residual Capacity Reservation Right ("RCRR"): A megawatt of transmission capacity from one Load Zone to an electrically contiguous Load Zone, each of which is internal to the NYCA, that may be converted into an RCRR TCC by a Member System allocated the RCRR pursuant to Section 19.5 of Attachment M.

Residual Transmission Capacity: The transmission capacity determined by the ISO before, during and after the Centralized TCC Auction which is conceptually equal to the following:

Residual Transmission Capacity = TTC - TRM - CBM - GTR - GTCC - ETCNL

The TCCs associated with Residual Transmission Capacity cannot be accurately determined until the Centralized TCC Auction is conducted.

TTC is the Total Transfer Capability that can only be determined after the Residual Transmission Capacity is known.

GTR is the transmission capacity associated with Grandfathered Rights.

GTCC is the transmission capacity associated with Grandfathered TCCs.

ETCNL is the transmission capacity associated with Existing Transmission Capacity for Native Load.

TRM is the Transmission Reliability Margin.

CBM is the Capacity Benefit Margin.

Retired: As defined in the ISO Services Tariff.

RMR Agreement: An agreement of limited duration that provides for the continued operation of one or more RMR Generator(s) to satisfy one or more Generator Deactivation Reliability Need(s) entered into between the ISO and an entity or entities that own or have operational control over the RMR Generator(s).

RMR Avoidable Costs: The (a) fixed costs of an Initiating Generator that would be avoided if it were to exit the ISO-Administered Markets in the manner specified in its Generator Deactivation Notice, (b) the fixed costs of a Generator already in a Mothball Outage, an ICAP Ineligible Forced Outage, or that has been mothballed since before May 1, 2015 that would be incurred if it were to re-enter the ISO-Administered Markets pursuant to an RMR Agreement that would be avoided if it remained in such state, or (c) the costs necessary for a new Generator proposed as a Generator Deactivation Solution to enter service. RMR Avoidable Costs include mandatory capital expenditures, fixed operating and maintenance costs, and forgone opportunity costs, determined by the ISO in accordance with Section 38.8 of Attachment FF, as modified by the Commission. RMR Avoidable Costs do not include variable costs or any other type of cost that are included in the Generator's Energy or Ancillary Services reference levels, or that are ordinarily included in Energy or Ancillary Services reference levels.

RMR Generator: The Generator or Generators operating under an RMR Agreement.

Rolling RTC: The RTC run that is used to schedule a given 15-minute External Transaction. The Rolling RTC may be an RTC_{00}, RTC_{15}, RTC_{30} or RTC_{45} run.

1.19 Definitions - S

Safe Operations: Actions which avoid placing personnel and equipment in peril with regard to the safety of life and equipment damage.

Scarcity Reserve Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Operating Reserves to meet a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(b) of Rate Schedule 4 of the NYISO Services Tariff apply corresponding to each possible quantity of Resources that the ISO's software may schedule to satisfy that requirement. A single Scarcity Reserve Demand Curve will apply to the Real-Time Market for each such Scarcity Reserve Requirement.

Scarcity Reserve Region: A Load Zone or group of Load Zones containing EDRP and/or SCRs that have been called by the ISO to address the same reliability need, as such reliability need is determined by the ISO.

Scarcity Reserve Requirement: A 30-Minute Reserve requirement established by the ISO for a Scarcity Reserve Region in accordance with Rate Schedule 4 of the NYISO Services Tariff.

Scheduled Energy Injection: Energy injections which are scheduled on a real-time basis by RTC.

Scheduled Energy Withdrawal: Energy Withdrawals which are scheduled on a real-time basis by RTC.

Scheduled Line: A transmission facility or set of transmission facilities: (a) that provide a distinct scheduling path interconnecting the ISO with an adjacent control area, (b) over which Customers are permitted to schedule External Transactions, (c) for which the NYISO separately posts TTC and ATC, and (d) for which there is the capability to maintain the Scheduled Line actual interchange at the DNI, or within the tolerances dictated by Good Utility Practice. Each Scheduled Line is associated with a distinct Proxy Generator Bus. Transmission facilities shall only become Scheduled Lines after the Commission accepts for filing revisions to the NYISO's tariffs that identify a specific set or group of transmission facilities as a Scheduled Line. The transmission facilities that are Scheduled Lines are identified in Section 4.4.4 of the Services Tariff.

SCUC: Security Constrained Unit Commitment, described in Attachment C of the Tariff.

Second Contingency Design and Operation: The planning, design and operation of a power system such that the loss of any two (2) facilities will not result in a service interruption to either native load customers or contracted firm Transmission Customers. Second Contingency Design and Operation criteria do not include the simultaneous loss of two (2) facilities, but rather consider the loss of one (1) facility and the restoration of the system to within acceptable operating parameters, prior to the loss of a second facility. These criteria apply to thermal, voltage and stability limits and are generally equal to or more stringent than NYPP, NPCC and NERC criteria.

Second Settlement: The process of: (1) identifying differences between Energy production, Energy consumption or NYS Transmission System usage scheduled in a First Settlement, and the actual production, consumption, or NYS Transmission System usage during the Dispatch Day; and (2) assigning financial responsibility for those differences to the appropriate Customers and Market Participants. Charges for Energy supplied (to replace Generation deficiencies or unscheduled consumption), and payments for Energy consumed (to absorb consumption deficiencies or excess Energy supply) or changes in transmission usage will be based on the Real-Time LBMPs.

Secondary Holder: Entities that purchase TCCs and have not been certified as a Primary Holder by the ISO.

Secondary Market: A market in which Primary and Secondary Holders sell TCCs by mechanisms other than through the Centralized TCC Auction, Reconfiguration Auction, or by Direct Sale.

Security Coordinator: An entity that provides the security assessment and Emergency operations coordination for a group of Control Areas. A Security Coordinator must not participate in the wholesale or retail merchant functions.

Self-Committed Fixed: A bidding mode in which a Generator is self-committed and opts not to be Dispatchable over any portion of its operating range.

Self-Committed Flexible: A bidding mode in which a dispatchable Generator follows Base Point Signals within a portion of its operating range, but self-commits.

Self-Supply: The provision of certain Ancillary Services, or the provision of Energy to replace Marginal Losses by a Transmission Customer using either the Transmission Customer's own Generators or generation obtained from an entity other than the ISO.

Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the ISO for service under the Tariff or any unexecuted Service Agreement, amendments on supplements thereto, that the ISO unilaterally files with the Commission.

Service Commencement Date: The date the ISO begins to provide service pursuant to the terms of an executed Service Agreement, or the date the ISO begins to provide service in accordance with Section 3.3.3 or Section 4.2.1 under the Tariff.

Settlement: The process of determining the charges to be paid to, or by a Transmission Customer to satisfy its obligations

Shadow Price: The marginal value of relieving a particular Constraint which is determined by the reduction in system cost that results from an incremental relaxation of that Constraint.

Shift Factor ("SF"): A ratio, calculated by the ISO, that compares the change in power flow through a transmission facility resulting from the incremental injection and withdrawal of power on the NYS Transmission System.

Short-Term Firm Point-To-Point Transmission Service: Firm Point-to-Point Service, the price of which is fixed for a short term by a Transmission Customer acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service.

Sink Price Cap Bid: A monotonically increasing Bid curve provided by an entity engaged in an Export to indicate the relevant Proxy Generator Bus LBMP below which that entity is willing to either purchase Energy in the LBMP Markets or, in the case of Bilateral Transactions, to accept Transmission Service, where the MW amounts on the Bid curve represent the desired increments of Energy that the entity is willing to purchase at various price points.

Southeastern New York ("SENY"): An electrical area comprised of Load Zones G, H, I, J, and K, as identified in the ISO Procedures.

Special Test Transactions: The revenues or costs from purchases and/or sales of Energy that may occur pursuant to virtual regional dispatch/intra-hour transaction pilot tests conducted by the ISO to analyze potential solutions for, or approaches to resolving inter-market "seams" issues with neighboring control area operators.

Start-Up Bid: A Bid parameter that may vary hourly and that identifies the payment a Supplier requires to bring a Generator up to its specified minimum operating level from an offline state or a Demand Side Resource from a level of no Demand Reduction to its specified minimum level of Demand Reduction. If the Supplier is a BTM:NG Resource, it shall not submit a Start-Up Bid.

Start-Up Bids submitted for a Generator that is not able to complete its specified minimum run time (of up to a maximum of 24 hours) within the Dispatch Day are expected to include expected net costs related to the hour(s) that a Generator needs to run on the day following the Dispatch Day in order to complete its minimum run time. The component of the Start-Up Bid that incorporates costs that the Generator expects to incur on the day following the Dispatch Day is expected to reflect the operating costs that the Supplier does not expect to be able to recover through LBMP revenues while operating to meet the Generator's minimum run time, at the minimum operating level Bid for that Generator for the hour of the Dispatch Day in which the Generator is scheduled to start-up. Settlement rules addressing Start-Up Bids that incorporates costs related to the hours that a Generator needs to run on the day following the Dispatch Day on which the Generator is committed are set forth in Attachment C to the ISO Services Tariff.

Storm Watch: Actual or anticipated severe weather conditions under which region-specific portions of the NYS Transmission System are operated in a more conservative manner by reducing transmission transfer limits.

Strandable Costs: Prudent and verifiable expenditures and commitments made pursuant to a Transmission Owner's legal obligations that are currently recovered in the Transmission Owner's retail or wholesale rate that could become unrecoverable as a result of a restructuring of the electric utility industry and/or electricity market, or as a result of retail-turned-wholesale customers, or customers switching generation or transmission service suppliers.

Stranded Investment Recovery Charge ("SIRC"): A charge established by a Transmission Owner to recover Strandable Costs.

Sub-Auctions: The set of rounds in a given Capability Period Auction in which TCCs of a given duration may be purchased.

Subzone: That portion of a Load Zone in a Transmission Owner's Transmission District.

Supplier: A Party that is supplying the Capacity, Energy and/or associated Ancillary Services to be made available under the ISO OATT or the ISO Services Tariff, including Generators, BTM:NG Resources, and Demand Side Resources that satisfy all applicable ISO requirements.

Supplemental Event Interval: Any RTD interval in which there is a maximum generation pickup or a large event reserve pickup or which is one of the three RTD intervals following the termination of the maximum generation pickup or the large event reserve pickup.

Supplemental Resource Evaluation ("SRE"): A determination of the least cost selection of additional Generators, which are to be committed, to meet: (i) changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to meet the reliability requirements of the Transmission Owner's local system or to meet Load or reliability requirements of the ISO; or (ii) forecast Load and reserve requirements over the six-day period that follows the Dispatch Day.

System Impact Study: An assessment by the ISO of (i) the adequacy of the NYS Transmission System to accommodate a request to build facilities in order to create incremental transfer capability, resulting in incremental TCCs, in connection with a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service; and (ii) the additional costs to be incurred in order to provide the incremental transfer capability.

1.20 Definitions - T

Tangible Net Worth: The value, determined by the ISO, of all of a Customer's assets less both: (i) the amount of the Customer's liabilities and (ii) all of the Customer's intangible assets, including, but not limited to, patents, trademarks, franchises, intellectual property, and goodwill.

Third Party Sale: Any sale for resale in interstate commerce to a power purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

Third Party Transmission Wheeling Agreements ("Third Party TWAs"): A Transmission Wheeling Agreement, as amended, between Transmission Owners or between a Transmission Owner and an entity that is not a Transmission Owner. Third Party TWAs are associated with the purchase (or sale) of Energy, Capacity, and/or Ancillary Services for the benefit of an entity that is not a Transmission Owner. All Third Party TWAs are listed in Attachment L, Table 1A, and are designated in the "Treatment "column of Table 1A, as "Third Party TWA."

Total Transfer Capability ("TTC"): The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner.

Trading Hub: A virtual location in a given Load Zone, modeled as a Generator bus and/or Load bus, for scheduling Bilateral Transactions in which both the POI and POW are located within the NYCA.

Trading Hub Energy Owner: A Customer who buys energy in a Bilateral Transaction in which the POW is a Trading Hub, or who sells energy in a Bilateral Transaction in which the POI is a Trading Hub.

Transaction: The purchase and/or sale of Energy or Capacity, or the sale of Ancillary Services. A Transaction bid into the Energy market to sell or purchase Energy or to schedule a Bilateral Transaction includes a Point of Injection and a Point of Withdrawal.

Transfer Capability: The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission facilities (or paths) between those areas under specified system conditions.

Transmission Congestion Contract Component ("TCC Component"): As defined in the ISO Services Tariff.

Transmission Congestion Contracts ("TCCs"): The right to collect or obligation to pay Congestion Rents in the Day-Ahead Market for Energy associated with a single MW of transmission between a specified POI and POW. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission.

Transmission Customer: Any Eligible Customer (or its designated agent) that (i) executes a Service Agreement, or (ii) requests in writing that the ISO file with the Commission a proposed unexecuted Service Agreement to receive Transmission Service under Part 3, 4 and/or 5 of the Tariff.

Transmission District: The geographic area served by the Investor-Owned Transmission Owners and LIPA, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York.

Transmission Facility Agreement ("TFA"): Agreements governing the use of specific or designated transmission facilities charges to cover all, or a portion, of the costs to install, own, operate, or maintain transmission facilities, to the customer under the agreement and that have provisions to provide Transmission Service utilizing said transmission facilities. All Transmission Facility Agreements are listed in Attachment L. Table 1A, and are designated in the "Treatment" column as "Facility Agmt. – MWA."

Transmission Facilities Under ISO Operational Control: The transmission facilities of the Transmission Owners listed in Appendix A-1 of the ISO/TO Agreement, ("Listing of Transmission Facilities Under ISO Operational Control,") that are subject to the Operational Control of the ISO. This listing may be amended from time-to-time as specified in the ISO/TO Agreement.

Transmission Facilities Requiring ISO Notification: The transmission facilities of the Transmission Owners listed in Appendix A-2 of the ISO/TO Agreement, "Listing of Transmission Facilities Requiring ISO Notification," whose status of operation must be provided to the ISO by the Transmission Owners (for the purposes stated in the ISO Tariffs and in accordance with the ISO OATT and ISO/TO Agreement) prior to the Transmission Owners making operational changes to the state of these facilities. This listing may be amended from time-to-time as specified in the ISO/TO Agreement.

Transmission Fund: The mechanism used under the current NYPP Agreement to compensate the Member Systems for providing Transmission Service for economy Energy Transactions over their transmission systems. Each Member System is allocated a share of the economy Energy savings in dollars assigned to the fund that is based on the ratio of their investment in transmission facilities to the sum of investments in transmission and generation facilities.

Transmission Owner: The public utility or authority (or its designated agent) that owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff.

Transmission Owner's Monthly Transmission System Peak: The maximum hourly firm usage as measured in megawatts (MW) of the Transmission Owner's transmission system in a calendar month.

Transmission Plan: A plan developed by the ISO staff with Transmission Owner's support that is a compilation of transmission projects proposed by the Transmission Owners and others, that are found to meet all applicable criteria.

Transmission Reliability Margin ("TRM"): The amount of TTC reserved by the ISO to ensure the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Transmission Service: Point-To-Point, Network Integration or Retail Access Transmission Service provided under Parts 3, 4 and 5 of the Tariff.

Transmission Service Charge (“TSC”): A charge designed to ensure recovery of the embedded cost of a Transmission Owner’s transmission system.

Transmission Shortage Cost: As defined in the NYISO Services Tariff.

Transmission System: The facilities operated by the ISO that are used to provide Transmission Services under Part 3, Part 4 or Part 5 of this Tariff.

Transmission Usage Charge (“TUC”): Payments made by the Transmission Customer to cover the cost of Marginal Losses and, during periods of time when the transmission system is Constrained, the marginal cost of Congestion. The TUC is equal to the product of: (1) the LBMP at the POW minus the LBMP at the POI (in $/MWh); and (2) the scheduled or delivered Energy (in MWh).

Transmission Wheeling Agreement (“TWA”): The agreements listed in Table 1A of Attachment L to the ISO OATT governing the use of specific or designated transmission facilities that are owned, controlled or operated by an entity for the transmission of Energy in interstate commerce. TWAs between Transmission Owners have been modified such that all TWAs between Transmission Owners are now MWAs.

1.21 Definitions - U

UCAP Component: As defined in the ISO Services Tariff.

Unrated Customer: As defined in the ISO Services Tariff.

Unsecured Credit: As defined in the ISO Services Tariff.

1.22 Definitions - V

Variably Scheduled Proxy Generator Bus: A Proxy Generator Bus for which the ISO may schedule Transactions at 15 minute intervals in real time. Variably Scheduled Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

Virtual Load: As defined in the ISO Services Tariff.

Virtual Supply: As defined in the ISO Services Tariff.

Virtual Transaction: As defined in the ISO Services Tariff.

Virtual Transaction Component: As defined in the ISO Services Tariff.

Voting Share: The method used in the ISO Agreement to allocate voting rights among the members of the Management Committee. The formula for calculating a Party's Voting Share is provided in the ISO Agreement.

1.23 Definitions - W

West of Central-East ("West" or "Western"): An electrical area comprised of Lead Zones A, B, C, D, and E, as identified in the ISO Procedures.

Wheels Through: Transmission Service, originating in another Control Area that is wheeled through the NYCA to another Control Area.

Wholesale Market: The sum of purchases and sales of Energy and Capacity for resale along with Ancillary Services needed to maintain reliability and power quality at the transmission level coordinated together through the ISO and Power Exchanges. A party who purchases Energy, Capacity or Ancillary Services in the Wholesale Market to serve its own Load is considered to be a participant in the Wholesale Market.

Wholesale Transmission Services Charges ("WTSC"): Those charges calculated pursuant to Attachment H of the OATT, incurred or declared overdue by a Transmission Owner pursuant to Section 26.11.2 of Attachment K to the ISO Services Tariff, after the effective date of these revisions; provided, however, that these provisions will not apply to pre-petition bankruptcy debts for a company that is currently in bankruptcy.

Wind Energy Forecast: The ISO's forecast of Energy that is expected to be supplied over a specified interval of time by an Intermittent Power Resource that depends on wind as its fuel and which is used in ISO's Energy market commitment and dispatch.

Withdrawal Billing Units: A Transmission Customer's Actual Energy Withdrawals (for all internal withdrawals) or Scheduled Energy Withdrawals (for all Export Energy withdrawals), including withdrawals for Wheels Through.

WTSC Component: As defined in the ISO Services Tariff.

1.24 Definitions - X

1.25 Definitions - Y

1.26 Definitions - Z

2 Common Service Provisions

2.1 Term and Effectiveness

2.1.1 Effectiveness:

This Tariff shall become effective on the latest of the following: (i) September 1, 1999; (ii) Commission approval of (a) this Tariff; (b) the ISO Services Tariff; (c) the ISO Agreement; (d) NYSRC Agreement; (e) the ISO/NYSRC Agreement; and (f) the ISO/TO Agreement (collectively, the "ISO Tariffs and ISO Related Agreements"); (iii) the date on which both the Commission and the PSC grant all necessary approvals to the Transmission Owners to transfer Operational Control of any facilities to the ISO or otherwise dispose of any of their property, including, without limitation, those approvals required under Section 70 of the New York Public Service Law ("PSL") and Section 203 of the Federal Power Act ("FPA"); (iv) the last date that any other approval or authorization is received, to the extent such additional approval or authorization is necessary; (v) execution of the ISO Related Agreements; or (vi) such later date specified by the Commission.

2.1.2 Term and Termination:

This Tariff shall remain in effect until: (i) canceled by the ISO upon sixty (60) days prior written notice in accordance with applicable Commission regulations; or (ii) the effective date of, any law, order, rule, regulation, or determination of a body of competent jurisdiction requiring termination or a material modification of this Tariff and/or Service Agreements related to this Tariff that would be inconsistent with any term or provision of the ISO/TO Agreement. Any Transmission Customer may withdraw from this Tariff on thirty (30) days prior written notice to the ISO.

2.2 Initial Allocation and Renewal Procedures

2.2.1 Initial Allocation of Available Transfer Capability:

Firm Transmission Service under this Tariff is obtained when the Transmission Customer agrees to pay the Congestion associated with its service. A Transmission Customer may fix the price of Congestion costs associated with its Firm Transmission Service through the purchase of a sufficient quantity of Transmission Congestion Contracts ("TCCs"), including Fixed Price TCCs that are obtained under Attachment M to this Tariff, with receipt and delivery points corresponding to its Transmission Service. TCCs are solely financial instruments that do not establish any rights to, or the availability of, Transmission Service. For purposes of determining whether existing capability on the NYS Transmission System is adequate to accommodate a request for Firm Transmission Service under this Tariff, the ISO shall employ Security Constrained Unit Commitment ("SCUC"), Real-Time Commitment ("RTC") and Real-Time Dispatch ("RTD") programs in accordance with Attachment C. The availability of TCCs will be determined as described in Attachment M.

2.2.2 Reservation Priority For Existing Firm Service:

Existing firm service customers (wholesale requirements and transmission-only, with a contract term of extending beyond the ISO implementation date), have the right to take Transmission Service from the ISO in accordance with the provisions of Attachment K. This transmission reservation priority is independent of whether the existing customer continues to purchase Capacity and Energy from a Transmission Owner or elects to purchase Capacity and Energy from another Supplier.

At the end of their contract terms, certain LSEs may have the right to obtain Historic Fixed Price TCCs in accordance with Attachment M to this Tariff.

All NYS Transmission Capacity associated with expired Grandfathered Rights and/or Grandfathered TCCs other than that needed to support Historic Fixed Price TCCs, shall be made available to support TCCs available for purchase in the next Centralized TCC auction facilitated by the ISO, pursuant to the provisions of Attachment M.

2.3 Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within and among the Control Areas affected by the Transmission Service. The ISO provides the following Ancillary Services: (i) Scheduling, System Control and Dispatch, (ii) Voltage Support Service, (iii) Regulation Service, (iv) Energy Imbalance; (v) Operating Reserves Service, and (vi) Black Start Service.

The specific Ancillary Services, prices and/or compensation methods are described on the schedules that are attached to and made a part of this Tariff. Sections 2.3.1 through 2.3.6 below list the six Ancillary Services.

2.3.1 Scheduling, System Control and Dispatch Service:

The costs for Scheduling, System Control, and Dispatch Service are included among those costs recovered through Schedule 1.

2.3.2 Voltage Support Service:

The rates and/or methodology are described in Schedule 2.

2.3.3 Regulation Service:

The rates and/or methodology are described in Schedule 3.

2.3.4 Energy Imbalance Service:

The rates and/or methodology are described in Schedule 4.

2.3.5 Operating Reserve Service:

The rates and/or methodology are described in Schedule 5.

2.3.6 ISO Black Start Capability:

The rates and/or methodology are described in Schedule 6.

2.4 Open-Access Same Time Information System ("OASIS")

Terms and conditions regarding Open Access Same-Time Information System and Standards of Conduct are set forth in Part 37 of the Commission's regulations ("Open Access Same-Time Information System and Standards of Conduct for Public Utilities") and 18 C.F.R. § 38 of the Commission's regulations (Business Practice Standards and Communication Protocols for Public Utilities). The ISO will maintain an OASIS, including a Bid/Post System, for purposes of scheduling Transmission Service.

The ISO shall post on OASIS and its public website an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of Transmission Service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The ISO shall post on OASIS and on its public website an electronic link to the NAESB website where any rules, standards and practices that are protected by copyright may be obtained. The ISO shall also post on OASIS and its public website an electronic link to a statement of the process by which the ISO shall add, delete or otherwise modify the rules, standards and practices that are not included in this tariff. Such process shall set forth the means by which the ISO shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the ISO deems appropriate.

2.5 Local Furnishing Bonds and Other Tax Exempt Financing

2.5.1 Tax Exempt Financing Pursuant to Section 142(f) of the Internal Revenue Code:

This provision is applicable only to Transmission Owners that have financed facilities for the local furnishing of Energy with Local Furnishing Bonds, as described in Section 142(f) of the Internal Revenue Code ("Local Furnishing Bonds"). Notwithstanding any other provision of this Tariff, neither the ISO nor the Transmission Owner shall be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any Local Furnishing Bond(s) used to finance the Transmission Owner's facilities.

2.5.2 Section 211 Order:

The provision of transmission service under this Tariff shall also constitute provision of transmission service pursuant to an Order by the Commission under Section 211 of the FPA with respect to the transmission of electricity on Consolidated Edison's transmission system.

2.5.3 Alternative Procedures for Requesting Transmission Service:

(i) If a Transmission Owner other than LIPA determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any Local Furnishing Bond(s), the Transmission Owner shall advise the ISO within thirty (30) days of receipt of the Completed Application from an Eligible Customer requesting such service, or on the date on which this Tariff becomes effective, whichever is applicable. If LIPA determines that the provision of Transmission Service requested by an Eligible Customer would jeopardize the tax-exempt status of any Local Furnishing Bond(s) or LIPA Tax-Exempt Bonds, LIPA shall promptly advise the ISO.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the FPA, the Transmission Owner, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the FPA and to the issuance of a proposed order under Section 211 of the FPA. The Commission, upon receipt of the Transmission Owner's waiver of its rights to a request for service under Section 213(a) of the FPA and to the issuance of a proposed order under Section 211 of the FPA, shall issue an order under Section 211 of the FPA. Upon issuance of the order under Section 211 of the FPA, the ISO and the Transmission Owner shall be required to provide the requested Transmission Service in accordance with the terms and conditions of this Tariff.

2.5.4 Tax Exempt Financing Pursuant to Section 103 and Related Provision of the Internal Revenue Code:

This provision is applicable only to NYPA which has financed transmission facilities with the proceeds of bonds issued pursuant to Section 103 and related provisions of the Internal Revenue Code ("Government Bonds"). Notwithstanding any other provision of this Tariff, neither the ISO nor NYPA shall be required to provide Transmission Service to any Eligible Customer pursuant to this Tariff if provision of such transmission service would result in loss of the tax-exempt status of any government bonds or impair NYPA's ability to issue future tax-exempt obligations.

2.5.5 Transmission Service Effects on Use of Tax-Exempt Financing by LIPA:

This provision is applicable only to LIPA Tax-Exempt Bonds. Notwithstanding any other provisions of this Tariff, neither the ISO nor LIPA shall be required to provide Transmission Service to any Eligible Customer pursuant to this Tariff if the provision of such

Transmission Service would result in the loss of tax-exempt status of any of LIPA Tax-Exempt Bonds or impair the Long Island Power Authority's ability to issue future tax-exempt obligations.

2.5.6 Responsibility for Costs Associated With Loss of Tax-Exempt Status:

If by virtue of an order issued by the Commission pursuant to Section 211 of the FPA, the ISO or a Transmission Owner is required to provide Transmission Service that would adversely affect the tax-exempt status of a Transmission Owner's Local Furnishing Bonds, Government Bonds, LIPA Tax-Exempt Bonds, or any other tax-exempt debt obligations then the Eligible Customer receiving such Transmission Service will compensate the Transmission Owner for all costs, if any, associated with the loss of tax-exempt status plus the costs of Transmission Service.

2.5.7 Use of LIPA's Facilities:

All categories of Transmission Service into and out of the Long Island Transmission District shall require pre-approval by LIPA to ensure compliance with Sections 2.5.1 and 2.5.5, above. LIPA shall promptly inform the ISO of those categories of Transmission Service that are preapproved. Customers seeking Transmission Service into and out of the Long Island Transmission District shall submit requests for service to the ISO pursuant to the terms of its Tariffs. If a Customer requests a category of Transmission Service that is not pre-approved, the ISO shall reject the schedule and advise the Customer that such Transmission Service must first be reviewed by LIPA and determined to be capable of being provided in a manner that is consistent with Sections 2.5.1 and 2.5.5, above. The ISO shall schedule Transmission Service into and out of the Long Island Transmission District, including External Transactions, in accordance with its Tariffs. The ISO also shall adopt procedures for coordination of scheduling Transmission Service into and out of the Long Island Transmission District, including External

Transactions, consistent with the requirements of this Section and Section 11.02 of the ISO Agreement which shall be implemented on a nondiscriminatory basis.

2.6 Reciprocity

A Transmission Customer receiving Transmission Service under this Tariff agrees to provide comparable Transmission Service that it is capable of providing to each Transmission Owner on similar terms and conditions over facilities used for the transmission of Energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of Energy owned, controlled or operated by the Transmission Customer’s corporate Affiliates. A Transmission Customer that takes Transmission Service from a power pool or Regional Transmission Group, Regional Transmission Organization (RTO), Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the transmission-owning members of such power pool and Regional Transmission Group, RTO, ISO, or other transmission organization on similar terms and conditions over facilities used for the transmission of Energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of Energy owned, controlled or operated by the Transmission Customer’s corporate Affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains Transmission Service under this Tariff, but also to all parties to a Transaction that involves the use of Transmission Service under this Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request Transmission Service under this Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

2.7 Billing and Payment

2.7.1 ISO as Counterparty; Right to Net or Set Off; ISO Clearing Account

2.7.1.1 ISO as Counterparty

The ISO shall be for all purposes the contracting counterparty, in its own name and right, to each Transmission Customer for any purchase or sale of any product or service, or for any other transaction, that is financially settled by the ISO under the ISO Tariffs.

2.7.1.2 Right to Net or Set Off Obligations Owed

Unless otherwise specifically set forth in this ISO OATT, if for any settlement period the ISO is required to pay any amount to the Transmission Customer and the Transmission Customer is required to pay any amount to the ISO under this ISO OATT or the ISO Services Tariff, such amounts shall be netted, and the party owing the greater aggregate amount shall pay to the other party the difference between the amounts owed. Additionally, all outstanding payment obligations under this ISO OATT and the ISO Services Tariff between the ISO and the Transmission Customer may be netted, offset, set off, or recouped, and payment shall be owed as set forth above.

2.7.1.3 ISO Clearing Account

The ISO will establish one or more accounts (the "ISO Clearing Account") at a bank or other financial institution, and Transmission Customers shall make payments to the ISO or receive payments from the ISO through the ISO Clearing Account in accordance with their settlement information provided by the ISO as described in Section 2.7.3 of this ISO OATT.

The funds held by the ISO in the ISO Clearing Account shall not be commingled with funds held by the ISO in any other ISO accounts.

2.7.1.4 ISO Liability for Payment

The obligation of the ISO to pay Transmission Customers for monies owed for a given settlement period shall be limited so that the aggregate liability of the ISO for such payments does not exceed the sum of (i) the aggregate amount paid to or recovered by the ISO from Transmission Customers (including by applying a defaulting Transmission Customer's financial security) for that settlement period, and (ii) the amount of funds held by the ISO in the Working Capital Fund. The process for declaring and recovering bad debt losses is set forth in Attachment U to this ISO OATT.

2.7.2 Determination and Payment of Charges Associated with Transmission Service

This Section 2.7.2 applies to all Transmission Services except Transmission Service pursuant to Grandfathered Agreements listed in Attachment L. Charges applicable to Grandfathered Agreements are described in Attachment K.

2.7.2.1 Transmission Service Charge - General Applicability

The TSC charge is applied to all Actual Energy Withdrawals from the NYS Power System under Part 3 or Part 4 of this Tariff, except for withdrawals by a Transmission Owner to provide bundled retail service or scheduled withdrawals associated with grandfathered transactions as specified in Attachments K and L. The TSC charge also is applied to Transactions to destinations outside the NYCA (Export or Wheel-Through Transactions), except as provided for in Section 2.7.2.1.4 of this Tariff.

Subject to the foregoing, the TSC applies to all Actual Energy Withdrawals regardless of whether the withdrawals occur in conjunction with a Bilateral Transaction or through the purchase of Energy from an LBMP Market. The TSC is payable under this Section regardless of whether the withdrawal is scheduled under Part 3 or Part 4 of this Tariff. Customers buying Energy from a Transmission Owner as part of a bundled retail rate will pay a portion of the Transmission Owner's transmission revenue requirement as part of their retail rates. Sales to these customers will be included in the billing units used to calculate each Transmission Owner's TSC under this Tariff in accordance with Attachment H.

Transmission Customers who are parties to grandfathered agreements specified in Attachment L will pay the applicable contract rate in those agreements. Revenues from these agreements will be credited against the Transmission Owners' individual revenue requirements in calculating the TSC.

2.7.2.1.1 Payable to Transmission Owners: The TSC will be payable to Transmission Owners, in the manner described below in the remainder of Section 2.7.2.1.

2.7.2.1.2 Payable by Retail Access Customers: Retail access customers or LSEs scheduling on their behalf will pay a TSC to their respective Transmission Owners under the provisions described in Part 5 of this Tariff. The TSC is payable under Part 5 (Retail Access Service) regardless of whether the LSE takes service under Part 3 (Point-to-Point Service) or Part 4 (Network Integration Service) of this Tariff.

2.7.2.1.3 Payable by LSEs Serving Non-Retail Access Load in NYCA: LSEs serving NYCA Load that is not part of a retail access program, such as customers of municipal electric systems, will pay a TSC to the Transmission Owner in whose Transmission District the Load is located. The TSC shall apply to Actual Energy Withdrawals by the Load, regardless of whether such withdrawals are associated with Transmission Service under Part 3 or Part 4 of this Tariff or purchases from an LBMP Market, whether the withdrawals are scheduled or unscheduled, and regardless of whether the withdrawals were made on the Load's behalf by the LSE or by another Transmission Customer.

2.7.2.1.4 Payable by Transmission Customers Scheduling Export or Wheel-Through Transactions: Transmission Customers scheduling Transactions to destinations outside the NYCA (Export or Wheel-Through Transactions) are subject to a TSC as calculated in Attachment H. The TSC charge shall be eliminated on all Exports and Wheel-Through Transactions scheduled with the ISO to destinations within the New England Control Area; provided that the following conditions shall continue to be met: (1) a Commission approved tariff provision is in effect that provides for unconditional reciprocal elimination of charges on Exports and Wheel-Through Transactions from the New England Control Area to the New York Control Area; (2) no change in the provisions in this Tariff related to Local Furnishing Bonds and Other Tax Exempt Financing shall be required for the reciprocal elimination of charges on Export and Wheel-Through Transactions to the New York Control Area; and (3) the New York Transmission Owners have the ability to fully recover the revenues related to the charges on Export and Wheel-Through Transactions that are eliminated. The ISO and the New York Transmission Owners, jointly or separately, shall have the right to make a Section 205 filing with the Commission to reimpose the charge on Exports and Wheel-Through Transactions if at any time any of the foregoing conditions is no longer satisfied. The ISO will perform the requisite calculation and inform the Transmission Customer of the applicable Transmission Owner(s) of the TSC charge. The TSC will be payable by the Transmission Customer directly to the Transmission Owner(s).

2.7.2.2 Transmission Usage Charge (TUC)

2.7.2.2.1 Payable to the ISO: Transmission Usage Charges include Congestion Rents and charges for Marginal Losses. They are payable directly to the ISO. Attachment J explains the calculation of the TUC.

2.7.2.2.2 Payable by Transmission Customers Scheduling Transmission Service: All Transmission Customers scheduling Transmission Service under Part 3 or Part 4 of this Tariff shall pay the applicable TUC charge as calculated in the Attachment J hereto.

2.7.2.2.3 Payable by Transmission Owners Scheduling Bilateral Transactions on Behalf of Bundled Retail Customers: Transmission Owners scheduling Transmission Service to supply bundled retail customers shall pay the applicable TUC charge.

2.7.2.2.4 Payable by Customers Scheduling Direct LBMP Purchases from the LBMP Market: Any Customer purchasing from the LBMP Market to supply bundled retail customers, will pay the Congestion Rent and Marginal Losses charge applicable to its location. These Congestion Rent and Marginal Losses charges will be included in the calculation of the LBMP charged by the ISO for the purchase of Energy from the LBMP Market.

2.7.2.3 Ancillary Services

2.7.2.3.1 Payable to the ISO: All Ancillary Services charges are payable directly to the ISO.

2.7.2.3.2 Payable by LSEs: All LSEs scheduling Transmission Service under Part 3 or Part 4 or purchases from the LMBP Market to supply Load in the NYCA shall pay Ancillary Services charges as described in Schedules 1 through 6. The charges will be assessed on the basis of all Actual Energy Withdrawals by the Load, regardless of whether such withdrawals are scheduled or unscheduled, and regardless of whether they are scheduled on the Load's behalf by the LSE or by another Transmission Customer. As explained in Schedule 1, in certain circumstances the Schedule 1 charge may vary depending upon the Transmission District in which the Load is located.

2.7.2.3.3 Payable by Customers Scheduling External Transactions: Transmission Customers scheduling Export or Wheel-Through Transactions to destinations outside the NYCA, or purchases from the LBMP Market to serve Load outside the NYCA shall pay Ancillary Services charges under Schedules 1, 2, 4, and 5 of this Tariff. The charges will be assessed on the basis of all Scheduled Energy Withdrawals from the NYCA.

2.7.2.3.4 Payable by Transmission Owners Serving Bundled Retail Customers: Transmission Owners scheduling Transmission Service or purchases from the LBMP Market to serve of bundled retail customers shall pay the ISO Ancillary Services charges as described in Schedules 1 to 6 based on Actual Energy Withdrawals.

2.7.2.4 NYPA Transmission Adjustment Charge (NTAC)

2.7.2.4.1 Payable to the ISO: NTAC charges are calculated in Attachment H. All NTAC charges are payable to the ISO.

2.7.2.4.2 Payable by LSEs Serving Load in the NYCA: Each LSE serving Load in the NYCA shall pay an NTAC to the ISO based on the LSE's Actual Energy Withdrawals.

2.7.2.4.3 Payable by Transmission Customers Scheduling Export or Wheel-Through Transactions: Transmission Customers scheduling Export or Wheel-Through Transactions shall pay an NTAC based on their Transaction schedules. The NTAC charge shall not apply to Exports and Wheel-Through Transactions scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

2.7.2.5 Reliability Facilities Charge ("RFC") and LIPA RFC

2.7.2.5.1 Payable through the ISO: All RFC and LIPA RFC charges are calculated, collected and payable to the ISO pursuant to Rate Schedule 10.

2.7.3 Billing and Payment Procedures

For purposes of this Section 2.7.3:

(i) the term "Complete Week Settlement Period" shall mean the seven day period between Saturday and Friday for which all of the days are in the same month; and

(ii) the term "Stub Week Settlement Period" shall mean the six or fewer day period between Saturday and Friday for which all of the days are in the same month.

2.7.3.1 Billing and Settlement Information

The ISO shall provide settlement and billing information to Transmission Customers. The ISO shall inform each Transmission Customer that provides or is provided services furnished under this ISO OATT or the ISO Services Tariff of the payments due for such service. Such information shall be made electronically available to the Transmission Customer.

2.7.3.2 Invoicing and Payment

2.7.3.2.1 Weekly Invoice

On or about each Wednesday, as set forth in ISO Procedures, the ISO shall submit an invoice to a Transmission Customer that indicates the net amount owed by or owed to the Transmission Customer for those services furnished under this ISO OATT or the ISO Services Tariff for the previous Complete Week Settlement Period or Stub Week Settlement Period that are designated as Weekly Invoice Components in ISO Procedures; *provided, however,* that the net amount owed by or owed to the Transmission Customer for those services furnished for a Stub Week Settlement Period that concludes a month shall be included in the next monthly invoice issued in accordance with Section 2.7.3.2.2 of this ISO OATT.

2.7.3.2.2 Monthly Invoice

Within five (5) business days after the first day of each month, the ISO shall submit an invoice to a Transmission Customer that indicates the net amount owed by or owed to the Transmission Customer:

(i) for those services furnished under this ISO OATT or the ISO Services Tariff for a Stub Week Settlement Period that concludes the previous month that are designated as Weekly Invoice Components in ISO Procedures;

(ii) for any adjustments to amounts contained in the weekly invoices issued in the previous month pursuant to Section 2.7.3.2.1 of this ISO OATT;

(iii) for those services furnished under this ISO OATT or the ISO Services Tariff in the previous month that are designated as Monthly Invoice Components in ISO Procedures;

(iv) for any adjustments to amounts contained in a previously issued monthly invoice that was issued on or about one hundred twenty (120) days prior to the issuance of this invoice; and

(v) for any adjustments to amounts contained in a previously issued monthly invoice as part of the Close-Out Settlement of that monthly invoice pursuant to Section 2.7.4.2.2 of this ISO OATT.

2.7.3.2.3 Payment by the Transmission Customer

A Transmission Customer owing payments on net in its weekly invoice or its monthly invoice shall make those payments to the ISO through the ISO Clearing Account by the second business day after the date on which the weekly invoice or monthly invoice is rendered by the ISO unless otherwise specified in ISO Procedures. In accordance with Section 2.7.1.2 of this ISO OATT, the ISO may net any overpayment by the Transmission Customer for past estimated charges against current amounts due from the Transmission Customer or, if the Transmission

Customer has no outstanding amounts due, the ISO may pay to the Transmission Customer an amount equal to the overpayment.

2.7.3.2.4 Payment by the ISO

Except as provided in Section 2.7.1.4 of this ISO OATT, the ISO shall pay all net monies owed to a Transmission Customer in its weekly invoice or its monthly invoice from the ISO Clearing Account by the second business day after the due date for Transmission Customer payments set forth in Section 2.7.3.2.3 of this ISO OATT unless otherwise specified in ISO Procedures.

2.7.3.3 Use of Estimated Data and Meter Data

The ISO may use estimates, including estimated meter data, in whole or in part to settle a weekly or monthly invoice in accordance with ISO Procedures. The ISO shall use meter data submitted to the ISO in accordance with Section 3.16 of this ISO OATT. Any charges based on estimates shall be subject to true-up in invoices subsequently issued by the ISO after the ISO has obtained the requisite actual information, provided that the ISO shall only true-up charges based on meter data prior to the deadline for finalizing the meter data established in Section 2.7.4.2 of this ISO OATT. A trued-up charge shall include interest amounts calculated at the rate set forth in Section 2.7.4 of this ISO OATT from the weekly or monthly due date for the charge until the date of payment of the trued-up amount for that charge.

2.7.3.4 Method of Payment

All payments by the Transmission Customer shall be made by either (i) wire transfer in immediately available funds payable to the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures. All payments by the ISO shall be made either (i) by wire transfer in immediately available funds payable to the Transmission Customer by the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures.

2.7.3.5 Verification of Payments

The ISO shall verify that all payments owed by Transmission Customers in accordance with this ISO OATT and the ISO Services Tariff have been paid to the ISO in a timely manner. If a Transmission Customer fails to make a payment within the time period established in Sections 2.7.3.2.1, 2.7.3.2.2, and 2.7.3.6 of this ISO OATT or pays less than the amount due, the ISO shall take measures pursuant to Section 2.7.5 of this ISO OATT. Except as provided in Section 2.7.1.4 of this ISO OATT, the ISO shall also ensure that monies owed to Transmission Customers in accordance with this ISO OATT and the ISO Services Tariff are paid through the ISO Clearing Account in a timely manner.

2.7.3.6 TCC Auction Settlements

Notwithstanding Sections 2.7.3.2.1 and 2.7.3.2.2 of this ISO OATT, the ISO shall make settlements related to the Centralized TCC Auction and the Reconfiguration Auction as set forth in this Section 2.7.3.6.

2.7.3.6.1 The ISO shall submit invoices to, and make settlements with, Transmission Owners in connection with the allocation of Net Auction Revenues in accordance with the timeline set forth in ISO Procedures.

2.7.3.6.2 Transmission Customers owing payments to the ISO as a result of their activity in or related to a Centralized TCC Auction or Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, shall make those payments to the ISO through the ISO Clearing Account in accordance with the timeline set forth in ISO Procedures.

2.7.3.6.3 Except as provided in Section 2.7.1.4 of this ISO OATT, the ISO shall pay all net monies owed to Transmission Customers as a result of their activity in or related to a Centralized TCC Auction or a Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, from the ISO Clearing Account in accordance with ISO Procedures.

2.7.3.6.4 Sections 2.7.3.1, 2.7.3.3, 2.7.3.4 and 2.7.3.5 of this ISO OATT and Section 19.9.6 of Attachment M of this ISO OATT shall apply to settlements calculated in accordance with this Section 2.7.3.6.

2.7.3.7 Settlement Information and Billing Procedures for TSCs

The ISO shall provide each Transmission Owner with information to facilitate TSC billing. Settlement information and billing procedures for payments of the TSC by retail access customers or LSEs serving retail access customers in accordance with Section 5 of this ISO OATT shall be separately issued, paid and collected in accordance with Section 5 of this ISO OATT. Settlement information and billing procedures for payments for TSCs for customers other than retail access customers and LSEs serving retail access customers shall be separately issued, paid and collected in accordance with the terms and conditions set forth in Attachment H of this ISO OATT in accordance with Section 5 of this ISO OATT.

2.7.3.8 Billing Procedures for Retail Access Programs

The billing procedures for customers participating in retail access programs shall be in accordance with Section 5 of this ISO OATT.

2.7.4 Interest on Unpaid Balances:

Interest on any unpaid amount whether owed to a Transmission Customer or to the ISO (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a (a)-(2)(iii). Interest on unpaid amounts shall be calculated from the due date of the bill to the date of payment. Invoices shall be considered as having been paid on the date of receipt of payment by the ISO.

If the ISO is unable to provide settlement information on time due to the actions or inactions of the Transmission Customer, in addition to any other remedies the ISO may have at law or in equity, the Transmission Customer shall pay interest on amounts due, as calculated above, from the first day of the Billing Period following the Billing Period in which charges are accrued, to the time of payment of those charges.

2.7.4.1 Billing Disputes:

This Section 2.7.4.1 establishes the process and timeframe for review, challenge, and correction of Transmission Customer invoices. For purposes of this Section 2.7.4.1, any deadline that falls on a Saturday, Sunday, or holiday for which the ISO is closed shall be observed on the ISO's next business day.

For purposes of this Section 2.7.4.1, "finalized" data and invoices shall not be subject to further correction, including by the ISO, except as ordered by the Commission or a court of competent jurisdiction; *provided, however,* that nothing herein shall be construed to restrict any stakeholder's right to seek redress from the Commission in accordance with the Federal Power Act.

2.7.4.2 Settlement Cycle for Services Furnished On and After January 1, 2009

2.7.4.2.1 ISO Corrections or Adjustments and Transmission Customer Challenges to the Accuracy of Settlement Information

Settlement information for services furnished beginning January 1, 2009, and thereafter shall be subject to review, comment, and challenge by a Transmission Customer and correction or adjustment by the ISO for errors at any time for up to five (5) months from the date of the initial invoice for the month in which service is rendered as set forth in Section 2.7.3.2.2 of this ISO OATT and as further provided in Section 2.7.4.2.2, subject to the following requirements and limitations:

(i) A Supplier or meter authority may review, comment on, and challenge Generator, tie-line, and sub-zone Load metering data for fifty-five (55) days from the date of the initial invoice for the month in which service is rendered. Following this review period, the ISO shall then have five (5) days to process and correct Generator, tie-line, and sub-zone Load metering data, after which time it shall be finalized.

(ii) The meter authority shall provide to the ISO all LSE bus metering data then available within seventy (70) days from the date of the initial invoice and shall provide any necessary updates to the LSE bus metering data as soon as possible thereafter. The ISO shall post all available LSE bus metering data within approximately seventy-five (75) days from the date of the initial invoice and shall continue to post incoming LSE bus metering data as soon as practicable after it is received.

(iii) The ISO shall post advisory settlement information, including available LSE bus metering data, within ninety (90) days from the date of the initial invoice. Transmission Customers may review, comment on, and challenge this settlement information, except for Generator, tie-line, and sub-zone Load metering data, after which the ISO shall process and correct the data and issue a corrected invoice with the regular monthly invoice issued on or about one hundred twenty (120) days from the date of the initial invoice. Following the ISO's issuance of a corrected invoice, Transmission Customers may continue to review, comment on, and challenge their settlement information, excepting Generator, tie-line, and sub-zone Load metering data, until the end of the five-month review period.

(iv) The meter authority shall provide to the ISO any final updates or corrections to LSE bus metering data within one hundred thirty (130) days from the date of the initial invoice. The ISO shall then post any updated and corrected LSE bus metering data within one hundred thirty-five (135) days from the date of the initial invoice. Transmission Customers may then review, comment on, and challenge the LSE bus metering data for an additional ten (10) days. Following this review period, the ISO shall have five (5) days to process and correct the LSE bus metering data, after which it shall be finalized.

The ISO shall use reasonable means to post metering revisions for review by Transmission Customers and to notify Transmission Customers of the approaching expiration of review periods. To challenge settlement information contained in an invoice, a Transmission Customer shall first make payment in full, including any amounts in dispute. Transmission Customer challenges to settlement information shall: (i) be submitted to the ISO in writing, (ii) be clearly identified as a settlement challenge, (iii) state the basis for the Transmission Customer's challenge, and (iv) include supporting documentation, if applicable. The ISO shall notify all Transmission Customers of errors identified and the details of corrections or adjustments made pursuant to this Section 2.7.4.2.1.

2.7.4.2.2 Review and Correction of Challenged Invoices

The ISO shall evaluate a settlement challenge as soon as possible within two (2) months following the conclusion of the challenge period specified in Section 2.7.4.2.1; *provided, however,* the ISO may, upon notice to Transmission Customers within this time of extraordinary circumstances requiring a longer evaluation period, take up to six (6) months to evaluate a settlement challenge. The ISO shall not be limited to the scope of Transmission Customer challenges in its review of a challenged invoice and may, at its discretion, review and correct any other elements and intervals of a challenged invoice, except Load and meter data as specified in Section 2.7.4.2.1. Corrections to a challenged invoice shall be applied to all Transmission Customers that were or should have been affected by the original settlement and shall not be limited to the Transmission Customer challenging the invoice; *provided, however,* that the ISO may recover *de minimis* amounts or amounts that the ISO is unable to collect from individual Transmission Customers through Rate Schedule 1 of this ISO OATT.

Upon completing its evaluation, the ISO shall provide written notice to the challenging Transmission Customer of the ISO's final determination regarding the Transmission Customer's settlement challenge. If the ISO determines that corrections or adjustments to a challenged invoice are necessary and can quantify them with reasonable certainty, the ISO shall provide all Transmission Customers with the details of the corrections or adjustments within the timeframe established in this Section 2.7.4.2.2. The ISO shall then provide a period of twenty-five (25) days for Transmission Customers to review the corrected settlement information and provide comments to the ISO regarding the implementation of those corrections or adjustments; *provided, however,* that in the event of a dispute resolution proceeding conducted in accordance with Section 2.7.4.3 of this ISO OATT, this twenty-five (25) day period shall not start or, if it has already started, shall be suspended until the conclusion of the dispute resolution proceeding. Following the conclusion of the dispute resolution proceeding, the ISO shall make any corrections to Transmission Customers' settlement invoices that it determines to be necessary and shall then start or re-start the twenty-five (25) day Transmission Customer comment period.

If no errors in the implementation of corrections or adjustments are identified during the twenty-five (25) day Transmission Customer comment period, the ISO shall issue a finalized close-out settlement ("Close-Out Settlement"), clearly identified as such, in the next regular monthly billing invoice. If an error in the implementation of a correction or adjustment is identified during the twenty-five (25) day Transmission Customer comment period, the ISO shall have one (1) month to make such further corrections as are necessary to address the error and provide Transmission Customers with one additional period of twenty-five (25) days to review and comment on the implementation of those further corrections. If an error in the implementation of those further corrections is identified, the ISO shall then have one (1) month to make any final corrections that are necessary and shall issue a finalized Close-Out Settlement in the next regular monthly billing invoice.

2.7.4.3 Expedited Dispute Resolution Procedures for Unresolved Settlement Challenges

2.7.4.3.1 Applicability of Expedited Dispute Resolution Procedures

This Section 2.7.4.3 establishes expedited dispute resolution procedures applicable to address any dispute between a Transmission Customer and the ISO regarding a Transmission Customer settlement that was not resolved in the ordinary settlement review, challenge, and correction process; *provided, however*, that nothing herein shall restrict a Transmission Customer or the ISO from seeking redress from the Commission in accordance with the Federal Power Act.

A Transmission Customer may request expedited dispute resolution if it has previously presented a settlement challenge consistent with the requirements of Section 2.7.4.2.1 of this ISO OATT and has received from the ISO a final, written determination regarding the settlement challenge pursuant to Section 2.7.4.2.2 of this ISO OATT. The scope of an expedited dispute resolution proceeding shall be limited to the subject matter of the Transmission Customer's prior settlement challenge. Transmission Customer challenges regarding Generator, tie-line, sub-zone Load, and LSE bus metering data shall not be eligible for formal dispute resolution proceedings under this ISO OATT. To ensure consistent treatment of disputes, separate requests for expedited dispute resolution regarding the same issue and the same service month or months may be resolved on a consolidated basis, consistent with applicable confidentiality requirements.

2.7.4.3.2 Initiation of Expedited Dispute Resolution Proceeding

To initiate an expedited dispute resolution proceeding, a Transmission Customer shall submit a written request to the ISO Chief Financial Officer within eleven (11) business days from the date that the ISO issues a final, written determination regarding a Transmission Customer settlement challenge pursuant to Section 2.7.4.2.2 of this ISO OATT. A Transmission Customer's written request for expedited dispute resolution shall contain: (i) the name of the Transmission Customer making the request, (ii) an indication of other potentially affected parties, to the extent known, (iii) an estimate of the amount in controversy, (iv) a description of the Transmission Customer's claim with sufficient detail to enable the ISO to determine whether the claim is within the subject matter of a settlement challenge previously submitted by the Transmission Customer, (v) copies of the settlement challenge materials previously submitted by the Transmission Customer to the ISO, and (vi) citations to the ISO Tariffs and other relevant materials upon which the Transmission Customer's settlement challenge relies.

The ISO Chief Financial Officer shall acknowledge in writing receipt of the Transmission Customer's request to initiate an expedited dispute resolution proceeding. If the ISO determines that the proceeding would be likely to aid in the resolution of the dispute, the ISO shall accept the Transmission Customer's request and provide written notice of the proceeding to all Transmission Customers through the ordinary means of communication for settlement issues. The ISO shall provide written notice to the Transmission Customer in the event that the ISO declines its request for expedited dispute resolution.

2.7.4.3.3 Participation by Other Interested Transmission Customers

Any Transmission Customer with rights or interests that would be materially affected by the outcome of an expedited dispute resolution proceeding may participate; *provided, however*, that a Transmission Customer seeking or supporting a change to the NYISO's determination regarding a Transmission Customer settlement challenge must have previously raised the issue in a settlement challenge consistent with the requirements of Section 2.7.4.2.1 of this ISO OATT. To participate, such Transmission Customer shall submit to the ISO Chief Financial Officer a written request to participate that meets the requirements for an initiating request for expedited dispute resolution within eleven (11) business days from the date that the ISO issues notice of the expedited dispute resolution proceeding. If the ISO determines that the Transmission Customer has met the requirements of this Section 2.7.4.3.3, the ISO will accept the Transmission Customer's request to participate in the dispute resolution proceeding.

2.7.4.3.4 Selection of a Neutral

As soon as reasonably possible following the ISO's acceptance of a Transmission Customer's request for expedited dispute resolution under Section 2.7.4.3.2, the ISO shall appoint a neutral to preside over the proceeding by randomly selecting from a list (i) provided to the ISO by the American Arbitration Association or (ii) developed by the ISO with input from the appropriate stakeholder committee, until an available neutral is found. To the extent possible, the neutral shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues and the financial settlement of electric markets.

No person shall be eligible to act as a neutral who is a past or present officer, employee, or consultant to any of the disputing parties, or of an entity related to or affiliated with any of the disputing parties, or is otherwise interested in the matter in dispute except upon the express written consent of the parties. Any individual appointed as a neutral shall make known to the disputing parties any such disqualifying relationship or interest and a new neutral shall be appointed, unless express written consent is provided by each party.

2.7.4.3.5 Conduct of the Expedited Dispute Resolution Proceeding

The neutral shall schedule the initial meeting of the disputing parties within five (5) business days of appointment. Except as otherwise provided in this Section 2.7.4.3, the neutral shall have discretion over the conduct of the dispute resolution process including, but not limited to: (i) requiring the disputing parties to meet for discussion, (ii) allowing or requiring written submissions, (iii) establishing guidelines for such written submissions, and (iv) allowing the participation of Transmission Customers that have requested an opportunity to be heard.

Within sixty (60) days of the appointment of the neutral, if the dispute has not been resolved, the neutral shall provide the disputing parties with a written, confidential, and non-binding recommendation for resolving the dispute. The disputing parties shall then meet in an attempt to resolve the dispute in light of the neutral's recommendation. If the disputing parties have not resolved the dispute within ten (10) days of receipt of the neutral's recommendation, the dispute resolution process will be concluded.

Neither the recommendation of the neutral, nor statements made by the neutral or any party, including the ISO, or their representatives, nor written submissions prepared for the dispute resolution process, shall be admissible for any purpose in any proceeding.

2.7.4.3.6 Allocation of Costs

Each party to a dispute resolution proceeding shall be responsible for its own costs incurred during the process and for a pro rata share of the costs of a neutral.

2.7.5 Customer Default

2.7.5.1 Events of Default

A Transmission Customer shall be in default, upon written notice from the ISO, in the event that: (i) the Transmission Customer fails to timely make a payment due to the ISO, regardless of whether such payment obligation is in dispute, (ii) the Transmission Customer fails to comply with the ISO's creditworthiness requirements, or (iii) the Transmission Customer fails to cure its default in another independent system operator/regional transmission organization market. In the event of a billing dispute between the ISO and the Transmission Customer, the ISO will continue to provide service under the Service Agreement as long as the Transmission Customer continues to make all payments.

2.7.5.2 Cure

Unless otherwise provided in Attachment W to this OATT, a Transmission Customer shall have one (1) business day to cure a default resulting from its failure to timely make a payment due to the ISO. A Transmission Customer shall have two (2) business days to cure a default resulting from its failure to comply with the ISO's creditworthiness requirements; *provided, however,* that a Transmission Customer shall have one (1) business day to cure a default resulting from its failure to comply with the ISO's creditworthiness requirements following termination of a Prepayment Agreement.

2.7.5.3 ISO Remedies

In addition to any and all other remedies available under the ISO Tariffs or pursuant to law or equity, the ISO shall have the following remedies:

(i) **Event of Default.** Upon an event of default and expiration of the relevant cure period, the ISO may terminate service to a Transmission Customer immediately upon notice to the Commission. In addition, in the event of a payment default, the ISO shall have the sole and exclusive right to initiate debt collection procedures against a Transmission Customer on account of any such default. The process for declaring and recovering bad debt losses is set forth in Attachment U to this OATT.

(ii) **Financial Distress.** In the event of a reduction in the amount of a Transmission Customer's Unsecured Credit (a) by fifty percent (50%) or more as determined in accordance with Section 26.5 of Attachment K to the ISO Services Tariff, or (b) as a result of a material adverse change as determined in accordance with Section 26.14 of Attachment K to the ISO Services Tariff, then the ISO shall have the right to: (1) immediately issue an invoice to such Transmission Customer requiring payment within two (2) business days from the invoice date for initial settlements representing the sum of that Billing Period's daily billing data available as of the invoice date, and/or (2) require such Transmission Customer to prepay estimated charges weekly for up to twelve months in accordance with ISO Procedures.

(iii) **Default in Another ISO/RTO.** In the event a Transmission Customer fails to cure its default in another independent system operator/regional transmission organization market, then the ISO shall have the right to: (1) demand immediate payment by the Transmission Customer to the ISO for any amounts owed as of the date of the demand, and/or (2) require the Transmission Customer to prepay estimated charges weekly for a minimum of twelve months in accordance with ISO Procedures, and/or (3) reduce or eliminate the amount of the Transmission Customer's Unsecured Credit.

(iv) **Two Late Payments.** In the event a Transmission Customer fails to pay its invoice when due on two occasions within a rolling twelve (12) month period, then the ISO shall have the right to: (1) require the Transmission Customer to prepay estimated charges weekly, based on the charges incurred by the Transmission Customer in the previous week, for up to twelve months, and/or (2) reduce or eliminate the amount of the Transmission Customer's Unsecured Credit for up to twelve (12) months.

2.7.5.4 Notice to Transmission Customers

The ISO shall notify all Transmission Customers in the event that a Transmission Customer is in default and shall also notify all Transmission Customers in the event that the Transmission Customer subsequently cures the default or the ISO terminates the Transmission Customer due to the default. In the event of a payment default or creditworthiness default, the ISO will disclose in its notice to Transmission Customers the approximate amount of the default as follows:

Default Amount	Type of Default	
Range	Payment	Creditworthiness
$0 to $100,000		
$100,001 to $500,000		
$500,001 to $1,000,000		
$1,000,001 to $5,000,000		
$5,000,001 to $10,000,000		
> $10,000,000		

In addition, in the event of a payment default, unless otherwise precluded, the ISO will also disclose the amount and type of collateral, if any, held by the ISO to secure the defaulting Transmission Customer's obligations to the ISO.

2.7.6 Stranded Costs

The Transmission Owners other than NYPA may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in Commission Order No. 888. However, the Transmission Owners must separately file any proposal to recover stranded costs under Section 205 of the FPA. This provision shall not supersede or otherwise affect a Transmission Owner's right to recover stranded costs under other authority. To the extent that LIPA's rates for service are established by LIPA's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s and are not subject to Commission and/or PSC jurisdiction, LIPA's recovery of stranded costs will not be subject to the foregoing requirements.

Upon filing of a proposal to recover stranded costs under the FPA, the Transmission Owner shall immediately provide the ISO with a copy of the appropriate rate schedule which will be incorporated as a new Stranded Service and Point-to-Point Service Customers and remit the collected amounts to the applicable Transmission Owner(s). Any SIRC rate schedule developed by LIPA under this Tariff will be effective upon receipt by the ISO, subject to any applicable laws and orders.

2.8 Accounting for the Transmission Owner’s Use of the Tariff

The Transmission Owners shall record the following amounts, as outlined below.

2.8.1 Transmission Revenue:

Transmission Owner shall include in a separate operating revenue account or subaccount, the revenues it receives from Transmission Service when making Third-Party Sales under Part 3 of this Tariff.

2.8.2 Study Costs and Revenues:

A Transmission Owner shall include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred by the Transmission Owner to perform any System Impact Study or Facilities Study to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under this Tariff; and include in a separate operating revenue account or subaccount the revenues received by the Transmission Owner for a System Impact Study or Facilities Study performed when such amounts are separately stated and identified in the Transmission Customer’s billing under this Tariff.

2.9 Regulatory Filings

Subject to Section 2.10, nothing contained in the Tariff, any Service Agreement, or any Network Operating Agreement shall be construed as affecting in any way the right of the ISO, or any Transmission Owner, with respect to a change in its revenue requirement, to unilaterally make an application to the Commission, pursuant to Section 205 of the FPA, for a change in rates, terms and conditions, charges, classification of service, a Service Agreement or a Network Operating Agreement.

Subject to Section 2.10, nothing contained in this Tariff or any Service Agreement shall be construed as affecting in any way the ability of any party receiving service under this Tariff to exercise its rights under the FPA and pursuant to the Commission's rules and regulations promulgated thereunder.

2.10 Tariff Modifications

Notwithstanding any other provision in this Tariff, this Tariff may be modified only as follows: any proposed amendment to this Tariff must be submitted to both the ISO Management Committee and the ISO Board; if both the ISO Board and the ISO Management Committee agree to an amendment of this Tariff, the ISO shall file the proposed amendment with the Commission pursuant to Section 205 of the FPA; if the ISO Board and the ISO Management Committee do not agree on a proposed amendment of this Tariff, this Tariff shall not be subject to change pursuant to Section 205 of the FPA. Nothing herein is intended to limit the rights of the ISO or any person under Section 206 of the FPA.

2.11 Force Majeure and Indemnification and Liability Limitation

2.11.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. The ISO, each Transmission Owner and each Transmission Customer will not be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

2.11.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save the ISO and each Transmission Owner harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the ISO's or the Transmission Owner's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of gross negligence or intentional wrongdoing by the ISO and except in the case of gross negligence or negligence consistent with the limitation of liability standards in Section 2.11.3(a), or intentional wrongdoing by the Transmission Owner. The ISO will procure insurance or other alternative risk financing arrangements sufficient to cover the risks associated with the carrying out of its responsibilities under this Tariff. The proceeds from such insurance shall be used prior to the invocation by the ISO of its right to indemnification under this Section, through the Rate Schedule 1 charge. Except to the extent that indemnification of the ISO is required from a particular Transmission Customer because of the acts or omissions of the Transmission Customer, indemnification of or by the ISO shall be effected through the Rate Schedule 1 charge.

Nothing in this section shall preclude the ISO from seeking indemnification of penalty costs against Customers and Market Participants, including Transmission Owners, as provided in Schedule 11 of this Tariff, except that the ISO shall not be indemnified in instances of its gross negligence or intentional misconduct.

2.11.3 Limitation of Liability

(a) The Transmission Owner shall not be liable, whether based on contract, indemnification, warranty, equity, tort, strict liability or otherwise, to any Transmission Customer, Market Participant, User, Interconnection Customer, Interconnecting Transmission Owner or any third party or other person for any damages whatsoever, including, without limitation, direct, incidental, consequential (including, without limitation, attorneys' fees and litigation costs), punitive, special, multiple, exemplary or indirect damages arising or resulting from any act or omission in any way associated with service provided under this Tariff, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, except to the extent that the Transmission Owner is found liable for gross negligence or intentional misconduct, in which case the Transmission Owner will only be liable for direct damages. Nothing in this section, however, is intended to affect obligations otherwise provided in agreements between the ISO and Transmission Owner. Except with respect to an interruption of service or when a Transmission Owner is acting in good faith to implement or comply with the directives of the ISO, the forgoing provisions shall not limit the liability of the Transmission Owner for damages resulting from its own negligence in connection with property owned, installed or maintained by a retail or wholesale customer of the Transmission Owner or leased by the customer from a third party, or for any damages to a retail or wholesale customer resulting from the negligence of the Transmission Owner in connection with the Transmission Owner's operation of the transmission system or from the presence or operation of the Transmission Owner's structures, equipment, wires, pipes, appliances or devices on the customer's premises.

(b) The ISO shall not be liable, whether based on contract, indemnification, warranty, equity, tort, strict liability or otherwise, to any Transmission Customer, Market Participant, User, Interconnection Customer, Interconnecting Transmission Owner or any third party or other person for any damages whatsoever, including, without limitation, direct, incidental, consequential (including, without limitation, attorneys' fees and litigation costs), punitive, special, multiple, exemplary or indirect damages arising or resulting from any act or omission in any way associated with service provided under this Tariff, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, except to the extent that the ISO is found liable for gross negligence or intentional misconduct, in which case the ISO will only be liable for direct damages. Nothing in this section, however, is intended to affect obligations otherwise provided in agreements between the ISO and Transmission Owner.

(c) Neither the Transmission Owner nor the ISO shall be liable for damages arising out of services provided under this Tariff, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, occurring as a result of conditions or circumstances beyond the control of the Transmission Owner or ISO, as applicable, or resulting from electric system design common to the domestic electric utility industry or electric system operation practices or conditions common to the domestic electric utility industry. The Transmission Owner shall not be liable for acts or omissions done in compliance or good faith attempts to comply with directives of the ISO.

2.11.4 Applicability to Generators:

The provisions on limitation of liability and damages, and on indemnification, set forth in Sections 2.11.2 and 2.11.3 shall be applicable to Generators acting in good faith to implement or comply with the directives of the Transmission Owner or the ISO.

2.11.5 ISO Cost Recovery:

To the extent that the ISO is required to pay any money damages or compensation or pay amounts due to its indemnification of any other party, the ISO shall be allowed to recover any such amounts under Schedule 1 of this ISO OATT as part of the Administrative Charges.

2.11.6 Reliability Compliance and Penalty Cost Recovery

(a) Customer Compliance with Reliability Standards: In accordance with applicable requirements in this Tariff and the ISO Procedures, all Customers shall conform to all applicable reliability criteria, policies, standards, rules, regulations and other requirements of NERC, NPCC, NYSRC, or any applicable regional council, or their successors, the ISO's specific reliability requirements and ISO Procedures, and operating guidelines and all applicable requirements of federal and state regulatory authorities. Failure to conform to these requirements may subject a Customer to direct assignment of penalties assessed against the ISO by FERC, NERC, NPCC or any other federal or state regulatory authority as a result of such Customer's failure to conform.

(b) Direct Assignment of Penalty Costs: The ISO's compliance with applicable reliability criteria, policies, standards, rules, regulations and other requirements is sometimes dependent on timely, accurate and adequate information and/or action on the part of a Customer. If the ISO is found to be non-compliant with respect to any applicable reliability criteria, policies, standards, rules, regulations and other requirements as a result of a Customer's actions or failure to act in violation of an obligation imposed by the ISO Tariffs, ISO Procedures, or ISO Related Agreements, the ISO may seek to directly assign to the Customer the cost of a penalty imposed on the ISO as a consequence of the Customer's non-compliance. If the Customer is found to be non-compliant with respect to any applicable reliability criteria, policies, standards, rules, regulations and other requirements as a result of the ISO's actions or failure to act in violation of an obligation imposed by the ISO Tariffs, ISO Procedures, or ISO Related Agreements, the Customer may seek to directly assign to the ISO the cost of a penalty imposed on the Customer as a consequence of the ISO's non-compliance. Any direct assignment of penalty costs must first be approved by FERC, as provided in Schedule 11 of this Tariff.

(c) ISO's Recovery of Penalty Costs Through Schedule 11: If direct assignment to a particular Customer is not possible or if the ISO is directly responsible for a violation because of its own action or inaction, the ISO may seek to recover such penalty costs in Schedule 11 Section 6.11.3 of this Tariff. Any inclusion of penalty costs in Schedule 11 must first be approved by FERC on a case-by-case basis, as provided in Schedule 11. Prior to seeking FERC authorization for recovery of a penalty in Schedule 11 Section 6.11.3 of this Tariff, the ISO shall consult with the Management Committee and any appropriate subcommittee or working groups designated by the Management Committee, regarding the recovery and allocation of such penalty before filing at FERC. Any recommendation by the Management Committee regarding a proposed penalty recovery shall be reported by the ISO to FERC in any ISO filing seeking penalty recovery.

(d) As used in this section, the term "Customer" shall include Transmission Owners.

2.12 Back-Up Operation

2.12.1 Back-Up Operation Procedures:

The ISO shall maintain Back-Up Operation procedures that will carry out the intent and purposes of this ISO OATT, to the extent practical, in circumstances under which the normal communications or computer systems of the ISO are not fully functional. Such procedures shall include testing requirements and training for the ISO staff, and Transmission Owners. If a communication or computer system malfunction results in the ISO's inability to operate the NYCA in accordance with ISO Procedures or under approved testing procedures, the ISO will direct the Transmission Owners to assume the responsibility to operate their respective systems in accordance with Good Utility Practice to facilitate the operation of the NYCA in a safe and reliable manner.

The Transmission Owners will continue to operate their respective systems until such time that the ISO is ready to resume control. During Back-Up Operation, the Transmission Owner control centers will operate to maintain the Desired Net Interchange ("DNI") within each Transmission District. Generator Bid curves will be provided by the ISO to the individual Transmission Owners in order to permit dispatch by the Transmission Owners subject to the Transmission Owner code of conduct. Normal Day-Ahead Market and Real-Time Market operations may be halted if required.

2.12.2 Market Participant and Transmission Customer Obligations:

During Back-Up Operation, Transmission Customers and other Market Participants shall comply with any and all instructions and orders issued by the ISO or the Transmission Owners.

2.12.3 Billing and Settlement:

In the event that Back-Up Operation is implemented, the billing and settlement procedures contained in Section 2.7 of this ISO OATT shall apply only to the extent they can be implemented by the Back-Up Operation procedures. The ISO will develop and apply as necessary modified billing and settlement procedures for use under the specific circumstances that required Back-Up Operation. The ISO shall gather necessary information, manually reconstruct the billing information as soon as practical, and submit invoices to Transmission Customers. The ISO shall be under no obligation to comply with the billing procedure time limits specified in Article 2.7. Neither the ISO nor the Transmission Owners shall be liable, under any circumstances, for any economic losses suffered by any Transmission Customer, Market Participant, or third party, resulting from the implementation by the ISO of Back-Up Operation or from compliance with orders issued by the ISO or Transmission Owners that were necessary to operate the NYCA in a safe and reliable manner. Such orders may include, without limitation, instructions to generation facilities to increase or decrease output, and instructions to Load to reduce or interrupt service.

2.13 Emergency Notification:

The ISO shall notify the Commission and the PSC one business day after declaring a Major Emergency.

2.14 Creditworthiness

All Transmission Customers and applicants seeking to become Transmission Customers shall be subject to the creditworthiness requirements contained in Attachment K to the ISO Services Tariff, including the minimum participation criteria set forth in Section 26.1 of Attachment K. "Customer," as used in Attachment K to the ISO Services Tariff, shall also mean "Transmission Customer" and an applicant seeking to become a Transmission Customer.

2.15 List of Affiliates and/or Parent Company

A Transmission Customer taking service under the Tariff shall provide the ISO, upon application for service, with a list identifying its parent company as well as any Affiliates. The Transmission Customer shall notify the ISO within 30 days of the effective date of any change to the original list. Any Transmission Customer shall respond within 10 days, to a request by the ISO to update the list of Affiliates and/or parent company. In addition, a Transmission Customer and an applicant seeking to become a Transmission Customer shall inform the ISO of any Affiliates that are currently taking service or applying to take service under the Tariffs.

2.16 Dispute Resolution Procedures

The dispute resolution procedures in the ISO Market Administration and Control Area Services Tariff shall apply to any dispute arising under this Tariff, except as otherwise indicated.

2.17 Incorporation of Certain Business Practice Standards

Pursuant to Commission Order No. 676-H, the ISO incorporates by reference the following business practice standards developed by the North American Energy Standards Board's Wholesale Electric Quadrant:

- WEQ-000, Abbreviations, Acronyms, and Definition of Terms, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Oct. 4, 2012, Nov. 28, 2012 and Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);
- WEQ-001, Open Access Same-Time Information Systems (OASIS), OASIS Version 2.0 ,WEQ Version 003, July 31, 2012 as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied November 26, 2013) excluding Standards WEQ-001-9.5, WEQ-001-10.5, WEQ-001-14.1.3, WEQ-001-15.1.2 and WEQ-001-106.2.5, except as provided in section 2.17.1 below;
- WEQ-004, Coordinate Interchange, WEQ Version 003, July 31, 2012 (with Final Action ratified on December 28, 2012), except as provided in section 2.17.1 below;
- WEQ-005, Area Control Error (ACE) Equation Special Cases, WEQ Version 003, July 31, 2012;
- WEQ-006, Manual Time Error Correction, WEQ Version 003, July 31, 2012;
- WEQ-007, Inadvertent Interchange Payback, WEQ Version 003, July 31, 2012;
- WEQ-008, Transmission Loading Relief - Eastern Interconnection, WEQ Version 003, July 31, 2012 (with minor corrections applied November 28, 2012);
- WEQ-011, Gas/Electric Coordination, WEQ Version 003, July 31, 2012;
- WEQ-012 Public Key Infrastructure (PKI), WEQ Version 003, July 31, 2012, (as modified by NAESB final actions ratified on Oct. 4, 2012), except as provided in section 2.17.1 below (NYISO compliance to begin May 15, 2017, pursuant to *New York Independent System Operator, Inc.*, FERC Docket No. ER-15-550-000, Notice Granting Extension (April 15, 2015);
- WEQ-015, Measurement and Verification of Wholesale Electricity Demand Response, WEQ Version 003, July 31, 2012 (with minor corrections applied November 26, 2013); and
- WEQ-021, Measurement and Verification of Energy Efficiency Products, WEQ Version 003, July 31, 2012.

2.17.1 The ISO is not required to comply with the following Standards:

- WEQ-001 Open Access Same-Time Information Systems (OASIS), OASIS Version 2.0, WEQ Version 003, July 31, 2012 (with minor corrections applied November 26, 2013): Standards 001-2, 001-3, 001-4, 001-5, 001-6, 001-7, 001-8, 001-9, 001-10, 001-011, 001-012, 001-13.1.2, 001-13.1.3(b) and (c), 001-014, 001-015, 001-016, 001-017, 001-018, 001-019, 001-020, 001-021, 001-022, 001-23, 001-101 through 001-107.3.1, 001-Appendix A, 001-Appendix B, and 001-Appendix D, pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015);

- WEQ-002, Open Access Same-Time Information System (OASIS) Business Practice Standards and Communication Protocols (S&CP), OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Nov. 28, 2012 and Dec. 28, 2012 (with minor corrections applied November 26, 2013), pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015);
- WEQ-003, Open Access Same-Time Information Systems (OASIS) Data Dictionary Business Practice Standards, OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Nov. 28, 2012 and Dec. 28, 2012 (with minor corrections applied November 26, 2013), pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015);
- WEQ-004, Coordinate Interchange, WEQ Version 003, July 31, 2012 (with Final Action ratified on December 28, 2012): Standards 004-3, 004-18, and 004-Appendix A and 004-Appendix C, pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015); and
- WEQ-013, Open Access Same-Time Information Systems (OASIS) Implementation Guide, OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied November 26, 2013), pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015).

3 Point-To-Point Transmission Service

Preamble

The ISO will provide Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff over the NYS Transmission System. Point-To-Point Transmission Service is for the receipt of Energy at designated Point(s) of Receipt and the transfer of such Energy to designated Point(s) of Delivery. Firm Point-To-Point Transmission Service is service for which the Transmission Customer has agreed to pay the Congestion Rent associated with its service. A Transmission Customer may fix the price of Day-Ahead Congestion Rent associated with its Firm Point-To-Point Transmission Service by acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service. Notwithstanding any provision in this Part to the contrary, External Transactions scheduled at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line shall be subject to the requirements of Attachment N to the ISO Services Tariff. Each Transmission Customer also utilizes Market Services and shall take service under the ISO Market Services Administration and Control Area Services Tariff.

3.1 Nature of Firm Point-To-Point Transmission Service

3.1.1 Term:

The minimum term of Firm Point-To-Point Transmission Service shall be provided in nominal one hour increments and the maximum term shall not exceed the maximum permissible term as specified in ISO Procedures.

3.1.2. Reservation Priority:

All requests for Firm Point-to-Point Transmission Service will be deemed to have the same reservation priority. Firm Point-to-Point Transmission Service will have the same priority as Network Service subject to Section 3.1.6.

3.1.3 Use of Firm Transmission Service by the Transmission Owner(s):

The Transmission Owner will be subject to the rates, terms and conditions of Part 3 of the Tariff when making Third-Party Sales under (i) agreements executed on or after the effective date of ISO, or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Owners will maintain separate accounting, pursuant to Section 2.8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

3.1.4 Service Agreements:

The ISO shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Firm Point-To-Point Transmission Service. Executed Service Agreements that contain the information required under this Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

3.1.5 Transmission Customer Obligation for Facility Additions or Redispatch Cost:

The ISO continuously redispatches all resources subject to its control in order to meet Load and to accommodate requests for a Firm Transmission Service through the use of SCUC, RTC, and RTD. Firm Point-To-Point Transmission Customers are charged for these redispatch costs in accordance with Attachment J. Transmission Owner(s) will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 3.7. The Transmission Customer or Eligible Customer must agree to compensate the Transmission Owner(s) for any necessary transmission facility additions pursuant to Section 3.7.

3.1.6 Curtailment of Firm Transmission Service:

In the event that a Curtailment on the NYS Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the Transaction(s) that effectively relieve the Constraint. When applicable, the ISO will follow the Lake Erie Emergency Redispatch ("LEER") Procedure filed on February 26, 1999, in Docket No. EL99-52-000 which is incorporated by reference herein. The LEER Procedure is intended to prevent the necessity of implementing the Curtailment procedures contained in the Commission and NERC tariffs and policies. To the extent possible, Curtailments of External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line shall be based on the transmission priority of the associated Advance Reservation for use of the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line (as appropriate). The ISO reserves the right to Curtail Firm Transmission Service provided under this Tariff for reliability reasons, in whole or in part, when, in the ISO's sole discretion, an Emergency or other unforeseen condition threatens to or does impair or degrade the reliability of the NYS Power System. The ISO will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. If the ISO declares a Major Emergency State, Transmission Customers shall comply with all directions issued by the ISO concerning the avoidance, management, and alleviation of the Major Emergency and shall comply with all procedures concerning a Major Emergency set forth in the ISO Procedures and the Reliability Rules. If the ISO is required to Curtail Transmission Service as a result of a Transmission Loading Relief ("TLR") event, the ISO will perform such Curtailment in accordance with the NERC TLR Procedure.

3.1.7 Classification of Firm Transmission Service:

3.1.7.1 The Transmission Customer taking Firm Point-To-Point Transmission Service may request a modification of the Points of Receipt or Delivery pursuant to the terms of Section 3.15.

3.1.7.2 The ISO shall provide firm Transmission Service for the delivery of Energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt shall be set forth in the Firm Point-To-Point Service schedule submitted by the Transmission Customer.

3.1.8 Scheduling of Firm Point-To-Point Transmission Service:

3.1.8.1 In the Day-Ahead Market: Schedules for the Transmission Customer's Firm Point-to-Point Transmission Service Day-Ahead must be submitted to the ISO no later than 5:00 a.m. of the day prior to commencement of the Dispatch Day or 4:50 a.m. for Transmission Service over the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line. Schedules involving the use of LIPA's facilities shall be treated in accordance with Section 2.5.7. Schedules submitted after 5:00 a.m., or 4:50 a.m. as appropriate, will not be accepted in the Day-Ahead schedule. Schedules of Energy to be delivered must be stated in increments of 1,000 kWh per hour between each Point of Receipt and corresponding Point of Delivery. For Firm Transmission Service requests between a Point of Receipt and Point of Delivery that are internal to the NYCA, and between a Point of Receipt at the Proxy Generator Bus designated for Imports and a Point of Delivery that is a Load Bus internal to the NYCA, the ISO will furnish to the Transmission Customer hour-to-hour schedules equal to those requested and shall deliver the Energy provided by such schedules. Energy shall be provided from the Point of Receipt if economic, and from the LBMP Market otherwise. For Firm Transmission Service requests between a Point of Delivery at the Proxy Generator Bus designated for Exports and a Point of Receipt that is a Generator Bus internal to the NYCA the ISO will furnish to the Transmission Customer, hour-to-hour schedules equal to the Export Transaction schedule and shall deliver the Energy provided by such schedules. For Firm Transmission Service requests between a Point of Receipt at the Proxy Generator Bus designated for Imports and a Point of Delivery at the Proxy Generator Bus designated for Exports, the ISO will furnish to the Transmission Customer hour-to-hour schedules equal to the Wheel-Through Transaction schedule and shall deliver the Energy provided by such schedules. Should the Transmission Customer revise or terminate any schedule, such party shall notify the ISO prior to the close of the Real-Time Scheduling Window, and the ISO shall have the right to adjust accordingly the schedule for Energy to be received and to be delivered.

3.1.8.2 In the Real-Time Market: Schedules for the Transmission Customer's Firm Point-to-Point Transmission Service in Real-Time must be submitted to the ISO no later than the close of the Real-Time Scheduling Window.

Schedules involving the use of LIPA's facilities shall be treated in accordance with Section 2.5.7. Schedules submitted after the close of the Real-Time Scheduling Window shall not be accepted in the Real-Time schedule. Schedules of any Energy that is to be delivered must be stated in increments of 1,000 kWh per hour between each Point of Receipt and corresponding Point of Delivery. For Firm Transmission Service requests between a Point of Receipt and Point of Delivery that are internal to the NYCA, or between a Point of Receipt at the Proxy Generator Bus designated for Imports and a Point of Delivery that is a Load Bus internal to the NYCA, the ISO will furnish to the Transmission Customer schedules equal to those requested and shall deliver the Energy provided by such schedules. Energy shall be provided from the Point of Receipt if economic, and from the LBMP Market otherwise. For Firm Transmission Service requests between a Point of Delivery at the Proxy Generator Bus designated for Exports and a Point of Receipt that is a Generator Bus internal to the NYCA, the ISO will furnish to the Transmission Customer schedules equal to the Export Transaction schedule and shall deliver the Energy provided by such schedules. For Firm Transmission Service requests between a Point of Receipt at the Proxy Generator Bus designated for Imports and a Point of Delivery at the Proxy Generator Bus designated for Exports, the ISO will furnish to the Transmission

Customer hour-to-hour schedules equal to the Wheel-Through Transaction schedule and shall deliver the Energy provided by such schedules. Should the Transmission Customer revise or terminate any schedule, such party shall notify the ISO prior to the close of the Real-Time Scheduling Window and the ISO shall have the right to adjust accordingly the schedule for Energy to be received and to be delivered.

3.2 Nature of Non-Firm Point-To-Point Transmission Service:

Non-Firm Point-To-Point Transmission Service is not available in the markets that the NYISO administers.

3.3 Service Availability

3.3.1 General Conditions:

The ISO will provide Firm Point-To-Point Transmission Service over the NYS Transmission System pursuant to ISO designated Points of Receipt and Points of Delivery, to any Transmission Customer that has met the requirements of Section 3.4. Non-Firm Point-To-Point Transmission Service is not available in the markets that the NYISO administers.

3.3.2 Available Transfer Capability:

The ISO continuously redispatches all resources subject to its control in order to meet Load and to accommodate requests for Firm Transmission Service through the use of SCUC, RTC and RTD. The ISO will post information regarding ATC and TTC availability on the OASIS.

3.3.3 Initiating Service in the Absence of an Executed Service Agreement:

If the ISO and the Transmission Customer requesting Firm Point-To-Point Transmission Service cannot agree on all terms and conditions of the Point-To-Point Service Agreement, ISO shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the ISO to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the ISO for such requested Transmission Service. The ISO shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the ISO in accordance with the terms and conditions of the unexecuted filed Service Agreement, subject to true-up at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Tariff.

3.3.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System:

If a Transmission Customer requests that the NYS Transmission System be expanded or modified, the Transmission Owner(s), at the ISO's request, will use due diligence to expand or modify its applicable portion of the NYS Transmission System to increase Transfer Capability, provided the Transmission Customer agrees to compensate the applicable Transmission Owner(s) for such costs pursuant to the terms of Section 3.19. The Transmission Owner(s) will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Owner has the right to expand or modify.

3.3.5 Deferral of Service:

Any increase in TCCs associated with new facilities is subject to completion of construction of those transmission facilities or upgrades.

3.3.6 Real Power Losses:

Real Power Losses are associated with all Transmission Service. The Transmission Customer is responsible for losses associated with all Transmission Service in accordance with Schedules 7-8 and as calculated in Attachment J.

3.4 Transmission Customer Responsibilities

3.4.1 Conditions Required of Transmission Customers:

Point-To-Point Transmission Service shall be provided by the ISO only if the following conditions are satisfied by the Transmission Customer:

a. The Transmission Customer has pending a Completed Application for service;

b. The Transmission Customer meets the creditworthiness criteria set forth in Attachment W;

c. The Transmission Customer provides an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff in an amount calculated by the ISO;

d. The Transmission Customer has arrangements in place for any other Transmission Service necessary to effect the delivery from the generating source to the ISO prior to the time when service under Part 3 of the Tariff commences;

e. The Transmission Customer provides the information required by the ISO’s planning process established in Attachment Y;

f. The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part 3 of the Tariff, whether or not the Transmission Customer takes service;

g. The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 3.3.3;

h. The Transmission Customer has satisfied the communication requirements and the metering requirements established by the ISO; and

i. If the Point-to-Point Transmission Service involves the use of LIPA's transmission facilities, approval of such transactions has been granted pursuant to Section 2.5.7.

3.4.2 Transmission Customer Responsibility for Third-Party Arrangements:

Any scheduling arrangements that may be required by other Control Areas shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the ISO, notification to the ISO identifying such systems and authorizing them to schedule Energy to be transmitted by the ISO pursuant to Section 3 of this Tariff on behalf of the Transmission Customer at the Point of Delivery or the Point of Receipt. The ISO will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other Control Area consistent with Good Utility Practice.

3.5 Procedures for Arranging Firm Point-To-Point Transmission Service

3.5.1 Application:

A request for Firm Point-To-Point Transmission Service must contain a written Application at least sixty (60) days in advance of the calendar month in which service is to commence. The ISO will consider a request for such firm service on shorter notice when feasible.

A Transmission Customer may fix the price of Congestion Costs associated with its service by acquiring sufficient TCCs with the same Point(s) of Receipt and Point(s) of Delivery as its Transmission Service.

3.5.2 Completed Application:

A Completed Application shall provide all of the information included in 18 CFR **§** 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under this Tariff;

(iii) The Service Commencement Date and the term of the requested Transmission Service; and

(iv) Any additional information required by the ISO pursuant to its planning process established in Attachment Y or otherwise.

The ISO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations and the Code of Conduct in Attachment F.

3.5.3 Deposit:

No deposit is required for service under this Tariff.

3.5.4 Notice of Deficient Application:

If an Application fails to meet the requirements of this Tariff, the ISO shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The ISO will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application.

3.5.5 Response to a Completed Application:

The Transmission Customer may request a System Impact Study pursuant to Section 19 of this ISO OATT at the point in time when its Application is complete.

3.5.6 Execution of Service Agreement:

If a System Impact Study is not requested and the service can be provided, the ISO shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is requested, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the ISO will be deemed a withdrawal and termination of the request for a Service Agreement. Nothing herein limits the right of an Eligible Customer to file another Service Agreement after such withdrawal and termination.

3.5.7 Extension for Commencement of Service.

3.6 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service is not available in the markets that the NYISO administers.

3.7 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

The FERC Order No. 888 provisions for initiating a transmission system expansion are contained in Section 3.7 and Sections 3.13 through 3.14.2. Additional ISO responsibilities for transmission system expansion are contained in Section 3.8. Study procedures associated with new interconnections to the NYS Power System are contained in Section 3.9. Section 19C addresses prioritization of network and point-to-point transmission expansion and interconnection studies. Nothing in this Tariff shall preclude the Transmission Owner from proposing and constructing transmission facilities in the public interest in accordance with all applicable regulatory requirements.

3.7.1 Notice of Request for System Impact Study:

Firm Transmission Service is available to an Eligible Customer, including a Transmission Owner, willing to pay Congestion Rent as described in this Tariff. A request for Firm Point-To-Point Transmission Service would not normally require a System Impact Study unless the Eligible Customer specifically requests that the ISO conduct such a study of facilities that could be constructed (for example, if the Eligible Customer requesting Firm Transmission Service determines that Congestion Rent or the cost of TCCs is too high and the customer is considering constructing new facilities to create incremental transfer capability resulting in incremental TCCs, or, if an Eligible Customer requests that transmission facilities be constructed to address reliability or other operational concerns) (a “Study Request”). When an Eligible Customer submits a Study Request it must give the ISO written notice of whether it intends to conduct all or part of the System Impact Study itself. After receiving a complete Study Request, the ISO shall, within thirty (30) days of the date that the Operating Committee approves the scope of the System Impact Study, or such other time as is agreed upon by the ISO and the

Eligible Customer, tender a System Impact Study agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO, for performing the required System Impact Study. The ISO shall coordinate with all affected Transmission Owners in performing the System Impact Study. A description of the ISO's methodology for completing a System Impact Study is provided in Attachment D. Before a Study Request is evaluated, the Eligible Customer shall execute the System Impact Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study agreement, its Study Request shall be deemed withdrawn.

3.7.2 System Impact Study Agreement and Cost Reimbursement:

The System Impact Study agreement will clearly specify the ISO's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the ISO shall rely, to the extent reasonably practicable, on existing transmission planning studies including applicable studies submitted by the Eligible Customer. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's Study Request.

For System Impact Studies that a Transmission Owner or the ISO conducts on its own behalf, the Transmission Owner or ISO shall record the cost of the System Impact Studies pursuant to Section 2.8.

If a Transmission Owner, on behalf of the ISO, performs all or part of a System Impact Study, the ISO shall reimburse the Transmission Owner for any costs that the Transmission Owner incurred.

3.7.3 System Impact Study Procedures:

The ISO shall coordinate with all affected Transmission Owners in performing the System Impact Study.

Upon receipt of an executed System Impact Study agreement, the ISO will complete the required System Impact Study as follows:

3.7.3.1 if the Study Request specified that the Eligible Customer would not perform any part of the study then the ISO shall use due diligence to complete the study, and to obtain all necessary stakeholder approvals, within a one hundred and twenty (120) day period, or a different period agreed to by the Eligible Customer and the ISO, starting on the date that the ISO receives the executed System Impact Study Agreement, or an alternative starting date agreed to by the Eligible Customer and the ISO; or

3.7.3.2 if the Study Request specified that the Eligible Customer would perform all or part of the System Impact Study itself, then:

3.7.3.2.1 the ISO shall use due diligence to complete those portion(s) of the study that the Eligible Customer is not performing, and to obtain all necessary stakeholder approvals of those portions, within a one hundred and twenty (120) day period, or a different period agreed to by the Eligible Customer and the ISO, starting on the date that the ISO receives the executed System Impact Study Agreement, or an alternative starting date agreed to by the Eligible Customer and the ISO; and

3.7.3.2.2 the ISO shall use due diligence to review any portion(s) of a study performed by an Eligible Customer within a thirty (30) day period or a different period agreed to by the Eligible Customer and the ISO, starting on the date that the ISO receives a complete draft from the Eligible Customer of its portion(s) of the study, or an alternative starting date agreed to by the Eligible Customer and the ISO. If the ISO determines that the portion(s) of the study performed by the Eligible Customer are incomplete or that changes are required, the Eligible Customer shall make any necessary changes. The ISO shall then use due diligence to review a revised complete draft of the Eligible Customer's portion(s) of the study within thirty days, or a different period agreed to by the Eligible Customer and the ISO, starting on the date that the ISO receives a revised complete draft, or an alternative starting date agreed to by the Eligible Customer and the ISO.

Upon the ISO's issuance of a final draft study report, the Eligible Customer must proceed with its study report to the Transmission Planning Advisory Subcommittee ("TPAS") of the ISO Operating Committee within three (3) months and to the next Operating Committee meeting following the TPAS review; provided, however, if the TPAS recommends revisions or supplements to the study report, the revised report must proceed to the next TPAS meeting following completion of such revisions, and to the next Operating Committee following the TPAS review of the revised study report. Failure to proceed with its study report to the TPAS and Operating Committee within these time frames will result in withdrawal of the Study Request.

If the Operating Committee directs the ISO to modify a System Impact Study or to perform other study-related work before granting its approval, then the deadline for completing the study will be extended for an additional time agreed upon by the ISO and the Eligible Customer. If the ISO and the Eligible

Customer are unable to agree on an additional time the deadline for completing the study will be extended for another sixty (60) days.

The System Impact Study shall identify any additional Direct Assignment Facilities or Network Upgrades required to comply with a Eligible Customer's or Transmission Owner's request. In the event that the ISO is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The ISO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself or a Transmission Owner. The ISO shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Study Request can be completed at no additional cost (*e.g.*, if the ISO is currently studying requests to construct similar facilities).

3.7.4 Facilities Study Procedures:

After a System Impact Study indicates that additions or upgrades to the Transmission System could be constructed in response to the Eligible Customer's Study Request, the Transmission Owner(s) whose facilities may be modified in performing the upgrade or addition (the "affected" Transmission Owners) shall, within thirty (30) days of the later of: (i) the completion of the System Impact Study; (ii) the date on which the Eligible Customer provides the affected Transmission Owner(s) with written notice of whether it intends to perform all or part of the Facilities Study itself; or (iii) such other time as is agreed upon by the Transmission

Owner(s) and the Eligible Customer, tender to the Eligible Customer a Facilities Study agreement. The ISO shall cooperate with the affected Transmission Owner(s) in performing any subsequent Facilities Studies. In the Facilities Study agreement, the Eligible Customer shall agree to reimburse the Transmission Owner(s) for performing the required Facilities Study and the ISO for its associated costs. If the Eligible Customer wants the Transmission Owner(s) to undertake the Facilities Study, the Eligible Customer shall execute the Facilities Study agreement and return it to the Transmission Owner(s) within fifteen (15) days.

Upon receipt of an executed Facilities Study agreement, the affected Transmission Owner(s) will complete the required Facilities Study as follows:

3.7.4.1 if the Eligible Customer gave written notice that it would not perform any part of the study then the affected Transmission Owners(s) shall use due diligence to complete the study within a one hundred and twenty (120) day period, or a different period agreed to by the Eligible Customer and the affected Transmission Owner(s), starting on the date that the affected Transmission Owner(s) receive the executed Facilities Study Agreement, or an alternative starting date agreed to by the Eligible Customer and the affected Transmission Owner(s); or

3.7.4.2 if the Eligible Customer gave written notice that it would perform all or part of the Facilities Study itself, then:

3.7.4.2.1 the affected Transmission Owner(s) shall use due diligence to complete those portion(s) of the study that the Eligible Customer is not performing within a one hundred and twenty (120) day period, or a different period agreed to by the Eligible Customer and the affected Transmission Owner(s), starting on the date that the affected Transmission Owner(s) receive the executed Facilities Study

Agreement, or an alternative starting date agreed to by the Eligible Customer and the affected Transmission Owner(s); and

3.7.4.2.2 the affected Transmission Owner(s) shall use due diligence to review any portion(s) of a study performed by an Eligible Customer within a thirty (30) day period or a different period agreed to by the Eligible Customer and the affected Transmission Owner(s), starting on the date that the affected Transmission Owner(s) receive a complete draft from the Eligible Customer of its portion(s) of the study, or an alternative starting date agreed to by the Eligible Customer and the affected Transmission Owner(s). If the affected Transmission Owner(s) determine that the portion(s) of the study performed by the Eligible Customer are incomplete or that changes are required, the Eligible Customer shall make any necessary changes. The affected Transmission Owner(s) shall then use due diligence to review a revised complete draft of the Eligible Customer's portion(s) of the study within thirty days, or a different period agreed to by the Eligible Customer and the affected Transmission Owner(s), starting on the date that the affected Transmission Owner(s) receive a revised complete draft, or an alternative starting date agreed to by the Eligible Customer and the affected Transmission Owner(s).

If the Transmission Owner(s) are unable to complete the Facilities Study in the allotted time period, the Transmission Owner(s) shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of this Tariff, and (iii) the time required to complete such construction. The Facilities Study shall contain a non-binding estimate as to the feasible TCCs resulting from the construction of the new facilities. If the Eligible Customer decides to proceed with the construction of the facilities described in the Facilities Study, the Eligible Customer shall (1) enter into a construction contract with the Transmission Owner(s) whose system(s) will be directly modified, and with the entity that will construct the facilities under the supervision of the Transmission Owner(s) (if other than the Transmission Owner(s)), and guarantee to compensate the Transmission Owner(s) and constructing entity (if other than the Transmission Owner(s)) for all costs incurred associated with the construction, and (2) provide each Transmission Owner with a letter of credit or other reasonable form of security acceptable to the Transmission Owner equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The construction contract shall contain terms and obligations of the Transmission Customer to pay for the facilities modifications or additions pursuant to the contract.

3.7.5 Facilities Study Modifications:

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the ISO or Transmission Owner that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part 3 of this Tariff.

3.7.6 Due Diligence in Completing New Facilities:

The Transmission Owner(s), in coordination with the ISO, shall use due diligence to add necessary facilities or upgrade their transmission systems within a reasonable time. The Transmission Owner(s) will not upgrade their existing or planned system if doing so would impair system reliability.

3.7.7 Partial Interim Service:

If the ISO, in cooperation with the Transmission Owner(s), determines that it can satisfy a portion of the Eligible Customers request based on the existing transmission system configuration, the ISO will provide that information to the Eligible Customer. The awarding of such TCCs will be subject to the results of the TCC auction process.

3.7.8 Expedited Procedures for New Facilities:

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the ISO to coordinate with the Transmission Owner(s) to tender at one time, together with the results of required studies, an "Expedited Request" pursuant to which the Eligible Customer would agree to compensate the Transmission Owner(s) and ISO for all costs incurred pursuant to the terms of this Tariff. In order to exercise this option, the Eligible Customer shall request in writing an Expedited Request covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in order to address the Transmission Customer's request. While the Transmission Owner(s) agree to provide the Eligible Customer with their best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Owner(s) for all costs incurred pursuant to the provisions of this

Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a completed application and will be deemed terminated and withdrawn.

3.7.9 Penalties for Failure to Meet Study Deadlines:

Sections 3.7.3 and 3.7.4 require the ISO, or the affected Transmission Owner, to use due diligence to meet the completion deadlines for System Impact Studies and Facilities Studies, respectively.

(i) The ISO, or a Transmission Owner as appropriate, is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and non-Affiliates' Facilities Studies that it completes in any two consecutive calendar quarters are not completed within the study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of System Impact Studies and non-Affiliates' Facilities Studies processed outside of the study completion deadlines, the ISO and the Transmission Owner(s) shall consider the total number of System Impact Studies and Facilities Studies for *non-Affiliates* that they collectively completed during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are not completed on time by the total number of completed studies. The ISO or Transmission Owner may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the study completion deadlines.

(iii) The ISO or Transmission Provider is subject to an operational penalty if it completes ten (10) percent or more of System Impact Studies and non-Affiliates' Facilities Studies outside of the study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the ISO's or Transmission Owner's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the ISO or Transmission Owner, as applicable, completes at least ninety (90) percent of all System Impact Studies and non-Affiliates' Facilities Studies within the deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day that the ISO or Transmission Owner takes to complete that study beyond the deadline.

3.7.10 Clustering of Point-to-Point Studies

The Eligible Customer may request that the ISO or affected Transmission Owner(s), as applicable, cluster the System Impact Studies and/or Facilities Studies. The Eligible Customer shall notify the ISO or affected Transmission Owner(s), as applicable, prior to signing a study agreement if the Eligible Customer requests its System Impact Study or Facilities Study to be clustered with another Eligible Customer's System Impact Study or Facilities Study. In this notification, the Eligible Customer shall identify the other Eligible Customer request(s) with which it would like to be clustered, and shall indicate whether the other Eligible Customer(s) with which it requests clustering support(s) the clustering request. The ISO or affected Transmission Owner(s) may, in their discretion, notify Eligible Customers who have requested studies about potential clustering opportunities. The ISO or affected Transmission Owner(s), as applicable, will accommodate any reasonable clustering request; however, the ISO or affected Transmission Owner(s) will not consider a clustering request to be reasonable if:

(i) The cluster is not supported by all Eligible Customers proposed to be in the cluster; or

(ii) The ISO or affected Transmission Owner(s) determine that the requests should be studied individually rather than in a cluster (*e.g.*, studies are geographically diverse or otherwise impact the transmission system in diverse ways such that clustering is not reasonable).

All Eligible Customers involved in a cluster study will be required to execute the System Impact Study Agreement and/or Facilities Study Agreement which provides that the System Impact Study or Facilities Study will be performed as a cluster study. The study will be performed in accordance with the procedures set forth in section 3.7.3, 3.7.4, 4.5.3 and 4.5.4 with the exception that the timeline for performing the System Impact Study or Facilities Study will begin to run after all Eligible Customers who have notified the ISO or Transmission Owner of their intent to participate in a cluster study have executed a System Impact Study Agreement or Facilities Study Agreement, or on a later date authorized under those provisions.

Once Eligible Customers agree to have the ISO or a Transmission Owner cluster their System Impact Studies or Facilities Studies, the Eligible Customers may not opt out of the cluster unless the ISO or affected Transmission Owner(s), respectively, agree(s), in its or their sole discretion, to allow it.

Eligible Customers that have agreed to cluster their System Impact Study or Facilities Study shall be responsible for reimbursing the ISO or affected Transmission Owner for performing the clustered System Impact Study or Facilities Study in equal shares, unless the Eligible Customers in the cluster independently agree to an alternate cost-sharing structure, in which case the Eligible Customers shall provide the ISO or affected Transmission Owner(s) with a copy of that alternate agreement, as executed. If the ISO or an affected Transmission Owner allows a participating Eligible Customer to opt out of a cluster, the Eligible Customer shall remain liable for its share of the ISO or affected Transmission Owner(s)' costs in performing the cluster study..

3.8 Development of Transmission Reinforcement Options

3.8.1 At the request of the NYPSC, the ISO shall, within its available resources and modeling capabilities, evaluate options, and develop associated cost estimates to address potential Reliability Needs, congestion, or transmission needs driven by Public Policy Requirements identified by the NYPSC. Such evaluation shall be made available to all customers or potential customers for the purpose of evaluating the economic costs and benefits of new facilities. Eligible Customers, including Transmission Owners, may then request a System Impact Study for a specific expansion project in accordance with Section 3.7.1 through 3.7.3. Development of the transmission reinforcement options will not reflect the impacts of alternatives that may be proposed by other Eligible Customers, including generation projects, which could increase or decrease transmission interface transfer capability or Congestion Rents or both. Cost estimates provided will be based on readily available data and shall in no way be binding on the ISO. The ISO will not charge the PSC for this service.

3.8.2 Subject to the Eligible Customer's obligation to compensate the ISO, at the request of an Eligible Customer, the ISO will develop illustrative transmission reinforcement options as described in Section 3.8.1 above. The Eligible Customer shall comply with the provisions of Sections 3.7.1 through 3.7.3 that require the customer to enter into a System Impact Study agreement and agree to compensate the ISO for all costs incurred to conduct the study.

3.8.3 Requests to proceed with a system expansion shall be subject to the provisions of Sections 3.7.4 through 3.7.8, and Sections 3.13 through 3.15.

3.9 Study Procedures For New Interconnections To The NYS Power System

3.9.1 Request for Interconnection Study:

Any Eligible Customer proposing to interconnect its Load or Large Facility with the NYS Power System shall submit its interconnection proposal to the ISO. The ISO, in cooperation with the Transmission Owner with whose system the Eligible Customer proposes to interconnect, shall perform technical studies to determine whether the proposed interconnection may degrade system reliability or adversely affect the operation of the NYS Power System. The technical studies shall be conducted in accordance with the procedures specified in Section 3.9.2. The proposed interconnection shall not proceed if the ISO concludes in the study that the proposed interconnection may degrade system reliability or adversely affect the operation of the NYS Power System. If the proposal is rejected, the ISO shall provide in writing the reasons why the proposal was rejected.

3.9.2 Study Procedures:

Upon receipt of the interconnection proposal and a written guarantee by the Eligible Customer to pay all costs incurred by the ISO and Transmission Owner(s) conducting the technical studies, the ISO, in cooperation with the Transmission Owner with whose system the Eligible Customer proposes to interconnect shall perform the technical studies of the proposed interconnection. The ISO shall evaluate each Large Facility using the Interconnection Studies specified in the Large Facility Interconnection Procedures in Attachment X. The technical studies shall address the following:

3.9.2.1 An evaluation of the potential significant impacts of the proposed interconnection on NYS Power System reliability, at a level of detail that reflects the magnitude of the impacts and the reasonable likelihood of their occurrence;

3.9.2.2 An evaluation of impacts of the proposed interconnection on system voltage, stability and thermal limitations, as prescribed in the Reliability Rules;

3.9.2.3 An evaluation as to whether modifications to the NYS Power System would be required to maintain Interface transfer capability or comply with the voltage, stability and thermal limitations, as prescribed in the Reliability Rules. The ISO will apply the criteria established by NERC, NPCC and the NYSRC;

3.9.2.4 An evaluation of alternatives that would eliminate adverse reliability impacts, if any, resulting from the proposed interconnection; and

3.9.2.5 An estimate of the increase or decrease in the Total Transfer Capability across each affected Interface.

3.9.3 Operating Committee Approval

Upon the ISO's issuance of a final draft study report, the Eligible Customer must proceed with its study report to the Transmission Planning Advisory Subcommittee ("TPAS") of the ISO Operating Committee within three (3) months and to the next Operating Committee meeting following the TPAS review; provided, however, if the TPAS recommends revisions or supplements to the study report, the revised report must proceed to the next TPAS meeting following completion of such revisions, and to the next Operating Committee following the TPAS review of the revised study report. Failure to proceed with its study report to the TPAS and Operating Committee within these time frames will result in withdrawal of the Study Request.

3.9.4 Interconnection Agreements:

After receiving the approval of the proposed interconnection, and after the Eligible Customer makes payment to the ISO and Transmission Owner for the cost of the technical studies, the Eligible Customer may elect to continue with the proposed interconnection by entering into an interconnection agreement with the Transmission Owner with whose system the Eligible Customer proposes to interconnect. After completion of the Interconnection Facilities Study and Attachment S cost allocation process, the Developer of a Large Generating Facility may elect, in accordance with the Large Facility Interconnection Procedures in Attachment X, to continue with its proposed interconnection by entering into a Standard Large Generator Interconnection Agreement with the ISO and the Transmission Owner with whose system the Developer proposes to interconnect.

3.9.5 Interconnection Facilities Cost:

The Developer of the proposed Large Facility shall be responsible for the cost of the facilities needed for its project to reliably interconnect to the New York State Power System, in accordance with the interconnection facilities cost allocation rules set out in Attachment S.

3.10 Prioritizing Transmission and Interconnection Studies

For the purposes of determining the priority for: (i) Interconnection proposals submitted by an Eligible Customer, in writing, and currently pending with one or more Transmission Owner(s) prior to the effective date of this Tariff; (ii) transmission studies requested pursuant to the provisions of a Transmission Owner's Open Access Tariff prior to the date of ISO OATT Tariff implementation or transmission studies requested pursuant to Sections 3.7.4, 3.7.8 and 4.5.4 of this Tariff; (iii) transmission studies requested by Eligible Customers pursuant to Sections 3.8.2 and 4.5.7.2 of this Tariff; (iv) proposals submitted pursuant to Section 3.6.2 of the ISO Agreement; and (v) interconnection proposals submitted pursuant to 3.9 and 4.5.8 of this Tariff; the ISO shall give priority to each transmission study or Interconnection proposal on the basis of its date of submittal to the ISO or Transmission Owner. Before the effective date of this Tariff, the date of submittal of each transmission study or Interconnection proposal shall be determined by the application procedures of each Transmission Owner. New transmission studies or Interconnection proposals submitted after the effective date of this Tariff shall be subject to the same prioritization procedures, unless such procedures are modified by the ISO. In the event of different submission dates before one or more Transmission Owners or the ISO, the earliest submittal date shall be used for prioritization. After an effective date to be determined by the Commission, Large Facility Interconnection Requests shall be subject to the prioritization process included in the Large Facility Interconnection Procedures in Attachment X. The ISO may determine the priority of transmission studies under Section 3.6.3 of the ISO Agreement and studies requested by the PSC under Section 3.8.1 of this Tariff according to procedures to be developed by the ISO. Notwithstanding this provision and Section 3.8.1, the ISO shall give priority within its available resources to any requests by the NYPSC to evaluate transmission reinforcement options, and non-transmission options, as part of the Public Policy Requirements planning process contained in Attachment Y of the OATT.

3.11 Small Generator Interconnections

The interconnection procedures, and standard interconnection agreement, to be used for the interconnection of generating facilities no larger than 20 MWs, are set forth in Attachment Z to this ISO OATT.

3.12 The Comprehensive Reliability Planning Process

The ISO shall conduct the Comprehensive Reliability Planning Process in accordance with Attachment Y to this Tariff and ISO Procedures. To the extent practicable, the ISO shall coordinate the performance of the studies required under Attachment Y with any transmission and interconnection studies that may be requested under sections 3.7, 3.8, 3.9, 4.5, 4.5.7, and 4.5.8 of this Tariff.

3.13 Procedures if The Transmission Owner is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

3.13.1 Delays in Construction of New Facilities:

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Owner(s) constructing the facilities shall promptly notify the Transmission Customer. In such circumstances, the Transmission Owner(s) shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Owner also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Owner(s) that is reasonably needed by the Transmission Customer to evaluate any alternatives.

3.13.2 Alternatives to the Original Facility Additions:

When the review process of Section 3.13.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Owner shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires that one of the alternative facilities be constructed, it may request the Transmission Owner(s) to submit a revised construction contract between the Transmission Customer and the Transmission Owner(s) constructing the alternative facilities. In the event the Transmission Owner concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the Dispute Resolution Process under Section 2.16 or it may refer the dispute to the Commission for resolution.

3.13.3 Refund Obligation for Unfinished Facility Additions:

If the Transmission Owner and the Transmission Customer mutually agree that no other reasonable alternatives exist, the obligation to provide the requested construction of additional facilities shall terminate. However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Owner(s) through the time construction was suspended.

3.14 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

3.14.1 Responsibility for Third-Party System Additions:

The ISO and Transmission Owner(s) shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The ISO will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

3.14.2 Coordination of Third-Party System Additions:

The Transmission Owner(s) shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Owner(s), after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Owner(s) shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Owner of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 2.16 or it may refer the dispute to the Commission for resolution.

3.15 Changes in Service Specifications

Customers eligible for Transmission Service may designate their Point of Receipt and Point of Delivery by submitting a schedule with the ISO in accordance with Section 3.1.8 of this ISO OATT.

3.16 Metering and Power Factor Correction at Receipt and Delivery Point(s)

3.16.1 Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the Capacity and Energy being transmitted under Part 3 of this Tariff and to communicate the information to the Transmission Owner and the ISO. Such equipment shall remain the property of the Transmission Customer.

3.16.2 Access to Metering Data:

The ISO and Transmission Owner shall have access to metering data, which may reasonably be required to maintain reliability and to facilitate measurements and billing under the Service Agreement.

3.16.3 Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Owner pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

3.17 Compensation for Transmission Service

Rates for Firm Point-To-Point Transmission Service are provided in Schedule 7 appended to the Tariff. The Transmission Owner shall use Part 3 of this Tariff to make its Third-Party Sales. The Transmission Owner shall account for such use at the applicable Tariff rates, pursuant to Section 2.8 of this Tariff.

The billing of these charges will be performed pursuant to Section 2.7 of this Tariff.

3.18 Stranded Cost Recovery

The Transmission Owners other than NYPA may seek to recover stranded costs from the Point-to-Point Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Owners must separately file any proposal to recover stranded costs under Section 205 of the FPA. This provision shall not supersede or otherwise affect a Transmission Owner's right to recover stranded costs under other authority. To the extent that LIPA's rates for service are established by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s and are not subject to Commission and/or PSC jurisdiction, LIPA's recovery of stranded costs will not be subject to the foregoing requirements.

Upon filing of a proposal to recover stranded costs under the FPA, the Transmission Owner shall immediately provide the ISO with a copy of the appropriate rate schedule which will be incorporated as a new SIRC rate schedule under this Tariff, subject to refund as may be required by the Commission. The ISO shall collect such SIRC from Network Service Customers and remit the collected amounts to the applicable Transmission Owner(s). Any SIRC rate schedule developed by LIPA under this Tariff will be effective upon receipt by the ISO, subject to any applicable laws and orders.

3.19 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the ISO in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy.

4 Network Integration Transmission Service

Preamble

The ISO will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in this Tariff and Service Agreement over the transmission facilities of the parties to the ISO/TO Agreement. Network Integration Transmission Service will be provided when the Network Customer agrees to pay the Congestion Rent associated with its requested service. The Network Customer may fix the price of its Network Integration Transmission Service by purchasing TCCs corresponding with designated Network Resources and its Network Load. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the individual Transmission Owner utilizes their respective transmission systems to serve their Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy Energy purchases to its Network Load from non-designated resources on an as-available basis (i.e. when there is no Congestion) without additional charge. Transmission Service for sales to non-designated Loads will be provided pursuant to the applicable terms and conditions of Part 3 of this Tariff.

4.1 Nature of Network Integration Transmission Service

4.1.1 Scope of Service:

Network Integration Transmission Service is a Transmission Service that allows Network Customers to efficiently and economically utilize Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the NYCA and any additional Load that may be designated pursuant to Section 4.4.3 of this Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 2.3.

4.1.2 Transmission Owner Responsibilities:

Each Transmission Owner will plan, construct, operate and maintain their respective transmission systems in accordance with Good Utility Practice and its planning obligations in Attachment Y, in order to provide the Network Customer with Network Integration Transmission Service over the NYS Transmission System. The Transmission Owner, on behalf of its Native Load Customers, shall be required to designate resources and Loads in the same manner as any Network Customer under Part 4 of this Tariff. This information must be consistent with the information used by the ISO to calculate ATC. The Transmission Owners and the ISO shall include the Network Customer's Network Load in transmission system planning and shall, consistent with Good Utility Practice and Attachment Y, endeavor to construct and place into service sufficient transmission capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Owner’s delivery of its own generating and purchased resources to its Native Load Customers.

4.1.3 Network Integration Transmission Service:

The ISO will provide Firm Transmission Service over the NYS Transmission System to the Network Customer for the delivery of Energy from its designated Network Resources to serve its Network Loads on a basis that is comparable to the Transmission Owner's use of the NYS Transmission System to reliably serve its Native Load Customers.

4.1.4 Secondary Service:

The Network Customer may use the NYS Transmission System to deliver Energy to its Network Loads from resources that have not been designated as Network Resources. Such Energy shall be transmitted, on an as-available basis (i.e., when there is no Congestion between the non-Network Resource and the Network Load), at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff.

4.1.5 Real Power Losses:

Real Power Losses are associated with all Transmission Service. The Network Customer is responsible for losses associated with all Transmission Service in accordance with Schedule 9 and as calculated in Attachment J.

4.1.6 Restrictions on Use of Service:

The Network Customer shall not use Network Integration Transmission Service for (i) sales of Capacity and Energy to non-designated Loads or (ii) direct or indirect provisions of this Transmission Service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part 3 of this Tariff for any Third-Party Sale which requires use of the NYS Transmission

System. The ISO shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 4.2.4 to facilitate a wholesale sale that does not serve a Network Load.

4.2 Initiating Service

4.2.1 Condition Precedent for Receiving Service:

Subject to the terms and conditions of Part 4 of this Tariff, the ISO will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part 4 of this Tariff; (ii) the Eligible Customer, ISO and the Transmission Owner(s) complete the technical arrangements set forth in Sections 4.2.3 and 4.2.4; (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment D for service under Part 4 of this Tariff or requests in writing that the ISO file a proposed unexecuted Service Agreement with the Commission; (iv) the Eligible Customer executes a Network Operating Agreement with the ISO pursuant to Attachment G; and (v) if the Network Service involves the use of LIPA's, transmission facilities, approval of such transaction has occurred pursuant to Section 2.5.7.

4.2.2 Application Procedures:

An Eligible Customer requesting service under Part 4 of this Tariff must submit an Application to the ISO as far as possible in advance of the month in which service is to commence. Applications should be submitted by entering the information listed below on the ISO's OASIS. Prior to implementation of the ISO's OASIS, a Completed Application for Network Integration Transmission Service will be dated and time-stamped. Applications should be submitted by entering the information listed below on the ISO's OASIS. Prior to implementation of the ISO's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the ISO by telefax, or (ii) providing the information by telephone over the ISO's time recorded telephone line.

A Completed Application shall provide all of the information included in 18 C.F.R. §

2.20 including, but not limited to, the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under this Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total Loads to be served at each transmission voltage level, and the Loads to be served from each Transmission Owner substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter Load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible Loads included in the Network Load. This shall include the summer and winter Capacity requirements for each interruptible Load (had such load not been interruptible), that portion of the Load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer Load (if any) included in the 10-year Load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of Capacity from unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all Generators

- Operating restrictions
  - Any periods of restricted operations throughout the year
  - Maintenance schedules
  - Minimum loading level of unit
  - Normal operating level of unit
- Minimum Generation and Start-Up Bid and variable Energy Bid information for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the New York Control Area, where only a portion of unit output is designated as a Network Resource
- For each off-system Network Resource, such description shall include:
  - Identification of the Network Resource as an off-system resource
  - Amount of power to which the customer has rights
  - Identification of the control area from which the power will originate
  - Delivery point(s) to the New York State Transmission System
  - Transmission arrangements on the external transmission system(s)
  - Operating restrictions, if any
  - Any periods of restricted operations throughout the year
  - Maintenance schedules
  - Minimum loading level of unit
  - Normal operating level of unit
  - Any must-run unit designations required for system reliability or contract reasons

- Approximate variable generating cost ($/MWH) for redispatch computations;

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the Load, lines, transformers, reactive devices and Load type, including normal and emergency ratings of all transmission equipment in a Load flow format compatible with that used by the ISO and the Transmission Owners
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- Transmission system maps that include any proposed expansions or upgrades
  10 year projection of system expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas; and

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one hour.

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 4.2.2(v) do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program; and

(ix) Any additional information required of the Transmission Customer as specified in the ISO's planning process established in Attachment Y.

Unless the parties agree to a different time frame, the ISO must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this Section, the ISO shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the ISO will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application, without prejudice, to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this Section. The Eligible Customer will be assigned a new time-stamp consistent with the date of the new or revised Application. The ISO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations and the Code of Conduct in Attachment F.

4.2.3 Technical Arrangements to be Completed Prior to Commencement of Service:

Network Integration Transmission Service shall not commence until the ISO, Transmission Owners and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the NYS Transmission System. The ISO shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

4.2.4 Network Customer Facilities:

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and Energy from the NYS Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or Interconnection. To the extent that a Network Customer is serving retail customers in a Transmission Owner’s retail access program, the Network Customer shall procure retail distribution services in accordance with Part 5 or this Tariff and the Transmission Owner’s retail access tariff as filed with the PSC, or in the case of LIPA, as established under state law.

4.2.5 Filing of Service Agreement:

The ISO will file Service Agreements with the Commission in compliance with applicable Commission regulations.

4.3 Network Resources

4.3.1 Designation of Network Resources:

Network Resources shall include all resources designated as Installed Capacity suppliers in the NYCA. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party Load outside of the NYCA or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. Any owned or purchased resources that were serving the Network Customer's Loads under firm agreements entered into on or before the Service Commencement Date shall also be designated as Network Resources until the Network Customer terminates the designation of such resources.

4.3.2 Designation of New Network Resources:

The Network Customer may designate a new Network Resource by providing the ISO with as much advance notice as practicable. A designation of a new Network Resource must be made by a request for modification of service pursuant to an Application under Section 4.2. This request must include a statement that the new Network Resource, or any portion thereof, is not committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. The Network Customer's request will be deemed deficient if it does not include this statement and the ISO will follow the procedures for a deficient application as described in Section 4.2.2 of the Tariff.

4.3.3 Termination of Network Resources:

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the ISO as soon as reasonably practicable, but no later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 4.3.2; and

(v) Identification of any related Transmission Service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related Transmission Service requests must be approved or denied as a single request. The evaluation of these related Transmission Service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing Transmission Service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the ISO will follow the procedures for a deficient application as described in Section 4.2.2 of the Tariff.

4.3.4 Operation of Network Resources:

The Network Customer shall not operate its designated Network Resources located in the Network Customer's Control Area or NYCA such that the output of those facilities exceeds its designated Network Load, plus net sales of Energy through the LBMP Market established under the ISO Services Tariff, plus losses, plus power sales under a reserve sharing program, plus sales that permit curtailment without penalty to serve its designated Network Load. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the ISO to respond to an Emergency or other unforeseen condition which may impair or degrade the reliability of the NYS Transmission System. For all Network Resources not physically connected with the New York State Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource’s capacity, as specified in the Network Customer’s Application pursuant to Section 4.2, unless the Network Customer supports such delivery within the New York State Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 4.1.4.

4.3.5 Network Customer Redispatch Obligation:

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to allow the ISO to redispatch its Network Resources. The redispatch of resources pursuant to this Section shall be on a least cost, non-discriminatory basis.

4.3.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The NYS Transmission System:

The Network Customer shall be responsible for any arrangements necessary to deliver

Capacity and Energy from a Network Resource not physically interconnected with the NYS Transmission System. The ISO will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

4.3.7 Limitation on Designation of Network Resources:

Network Resources must be directly interconnected with the NYCA or demonstrate that Firm Transmission Service has been obtained from the Network Resource to the NYCA boundary.

4.3.8 Use of Interface Capacity by the Network Customer:

There is no limitation upon a Network Customer's use of the NYS Transmission System at any particular Interface with another transmission system to integrate Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the total Interface capacity of the NYS Transmission System with other transmission systems may not exceed the Network Customer's Load.

4.3.9 Network Customer Owned Transmission Facilities:

The Network Customer that owns existing transmission facilities that are integrated with the NYS Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the ISO to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the effective date of a Final Rule in RM05-25-000, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Owner’s facilities; provided however, the Network Customer’s transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Owner, would be eligible for inclusion in the Transmission Owner’s annual transmission revenue requirement as specified in Attachment H. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the parties.

4.4 Designation of Network Load

4.4.1 Network Load:

The Network Customer must designate the individual Network Loads on whose behalf the ISO will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

4.4.2 New Network Loads Connected With the Transmission Owners:

The Network Customer shall provide the ISO and the Transmission Owners with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to the NYS Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The ISO and the Transmission Owners will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 4.5 and shall be charged to the Network Customer in accordance with Commission policies.

4.4.3 Network Load Not Physically Interconnected with the NYS Transmission System:

This Section applies to both initial designation pursuant to Section 4.4 and the subsequent addition of new Network Load not physically interconnected with the NYS Transmission System. To the extent that the Network Customer desires to obtain Transmission Service for a load outside the NYS Transmission System, the Network Customer shall exclude that entire Load from its Network Load and purchase Point-To-Point Transmission Service under Part 3 of this Tariff. To the extent that the Network Customer gives notice of its intent to add a new

Network Load as part of its Network Load pursuant to this Section the request must be made through a modification of service pursuant to a new Application.

4.4.4 New Interconnection Points:

To the extent the Network Customer desires to add a new Delivery Point or Interconnection point between the NYS Transmission System and a Network Load, the Network Customer shall provide the ISO with as much advance notice as reasonably practicable.

4.4.5 Changes in Service Requests:

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g., the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by a Transmission Owner and charged to the Network Customer as reflected in the Service Agreement. However, the ISO must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

4.4.6 Annual Load and Resource Information Updates:

The Network Customer shall provide the ISO with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part 4 of this Tariff including, but not limited to, any information provided under section 4.2.2(ix) pursuant to the ISO's planning process under Attachment Y. The Network Customer also shall provide the ISO with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the ISO's ability to provide reliable service.

4.5 Additional Study Procedures For Network Integration Transmission Service Requests

The FERC Order No. 888 provisions for initiating a Network Integration Transmission System expansion are contained in this Section. Additional ISO responsibilities for Transmission System expansion are contained in Section 4.5.7. Study procedures associated with new Interconnections to the NYS Power System are contained in Section 4.5.8. Section 3.10 addresses prioritization of network and point-to-point transmission expansion and interconnection studies. Nothing in this Tariff shall preclude the Transmission Owners from proposing or constructing transmission facilities in the public interest in accordance with all applicable regulatory requirements.

4.5.1 Notice of Request for System Impact Study:

Network Integration Transmission Service is available to an Eligible Customer, including a Transmission Owner, willing to pay Congestion Rent as described in this Tariff. A request for Network Integration Transmission Service would not normally require a System Impact Study unless the Eligible Customer specifically requests that the ISO conduct such a study of facilities that could be constructed (for example, if the Eligible Customer requesting Network Integration Transmission Service determines that Congestion Rent or the cost of TCCs is too high and that customer is considering constructing new facilities to create incremental transfer capability resulting in incremental TCCs, or, if an Eligible Customer requests that transmission facilities be constructed to address reliability or other operational concerns) (a “Study Request”). When an Eligible Customer submits a Study Request it must give the ISO written notice of whether it intends to conduct all or part of theSystem Impact Study itself. After receiving a complete Study Request, the ISO shall, within thirty (30) days of the date that the Operating Committee approves the scope of the System Impact Study, or such other time as is agreed upon by the ISO and the Eligible Customer, tender a System Impact Study agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO for performing the required System Impact Study. The ISO shall coordinate with the affected Transmission Owners in performing the System Impact Study. A description of the ISO's methodology for completing a System Impact Study is provided in Attachment D. Before a System Impact Study Request is evaluated, the Eligible Customer shall execute the System Impact Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study agreement, its Study Request shall be deemed withdrawn.

4.5.2 System Impact Study Agreement and Cost Reimbursement:

The System Impact Study agreement will clearly specify the ISO's estimate of the actual cost, and time for completion of the System Impact Study.

The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the ISO shall rely, to the extent reasonably practicable, on existing transmission planning studies including applicable studies submitted by the Eligible Customer. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's Study Request.

For System Impact Studies that a Transmission Owner or the ISO conducts on its own behalf, the Transmission Owner or ISO shall record the cost of the System Impact Studies pursuant to Section 8.

If a Transmission Owner, on behalf of the ISO, performs all or part of a System Impact Study, the ISO shall reimburse the Transmission Owner for any costs that the Transmission

Owner incurred.

4.5.3 System Impact Study Procedures:

The ISO shall coordinate with all affected Transmission Owners in performing the System Impact Study.

Upon receipt of an executed System Impact Study agreement, the ISO will complete the required System Impact Study as follows:

4.5.3.1 if the Study Request specified that the Eligible Customer would not perform any part of the study then the ISO shall use due diligence to complete the study, and to obtain all necessary stakeholder approvals, within a one hundred and twenty (120) day period, or a different period agreed to by the Eligible Customer and the ISO, starting on the date that the ISO receives the executed System Impact Study Agreement, or an alternative starting date agreed to by the Eligible Customer and the ISO; or

4.5.3.2 if the Study Request specified that the Eligible Customer would perform all or part of the System Impact Study itself, then:

4.5.3.2.1 the ISO shall use due diligence to complete those portion(s) of the study that the Eligible Customer is not performing, and to obtain all necessary stakeholder approvals of those portions, within a one hundred and twenty (120) day period, or a different period agreed to by the Eligible Customer and the ISO, starting on the date that the ISO receives the executed System Impact Study Agreement, or an alternative starting date agreed to by the Eligible Customer and the ISO; and

4.5.3.2.2 the ISO shall use due diligence to review any portion(s) of a study performed by an Eligible Customer within a thirty (30) day period or a different period agreed to by the Eligible Customer and the ISO, starting on the date that the ISO receives a complete draft from the Eligible Customer of its portion(s) of the study, or an alternative starting date agreed to by the Eligible Customer and the ISO. If the ISO determines that the portion(s) of the study performed by the Eligible Customer are incomplete or that changes are required, the Eligible Customer shall make any necessary changes. The ISO shall then use due diligence to review a revised complete draft of the Eligible Customer's portion(s) of the study within thirty days, or a different period agreed to by the Eligible Customer and the ISO, starting on the date that the ISO receives a revised complete draft, or an alternative starting date agreed to by the Eligible Customer and the ISO.

Upon the ISO's issuance of a final draft study report, the Eligible Customer must proceed with its study report to the Transmission Planning Advisory Subcommittee ("TPAS") of the ISO Operating Committee within three (3) months and to the next Operating Committee meeting following the TPAS review; provided, however, if the TPAS recommends revisions or supplements to the study report, the revised report must proceed to the next TPAS meeting following completion of such revisions, and to the next Operating Committee following the TPAS review of the revised study report. Failure to proceed with its study report to the TPAS and Operating Committee within these time frames will result in withdrawal of the Study Request.

If the Operating Committee directs the ISO to modify a Network

Integration Transmission Service Study or to perform other study-related work before granting its approval, then the deadline for completing the study will be extended for an additional time agreed upon by the ISO and the Eligible Customer. If the ISO and the Eligible Customer are unable to agree on an additional time the deadline for completing the study will be extended for another sixty (60) days.

The System Impact Study shall identify any additional Direct Assignment Facilities or Network Upgrades required to comply with an Eligible Customer's or Transmission Owner's request. In the event that the ISO is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The ISO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself or a Transmission Owner. The ISO shall notify the Eligible Customer immediately upon completion of the System Impact Study if the System Impact Study Request can be completed at no additional cost (e.g., if the ISO is currently studying requests to construct similar facilities).

4.5.4 Facilities Study Procedures

After a Study indicates that additions or upgrades to the Transmission System could be constructed in response to the Eligible Customer's Study Request, the Transmission Owner(s) whose facilities may be modified in performing the upgrade or addition (the "affected" Transmission Owner(s)), shall, within thirty (30) days of the later of: (i) the completion of the System Impact Study; (ii) the date on which the Eligible Customer provides the affected Transmission Owner(s) with written notice of whether it intends to perform all or part of the Facilities Study itself, or (iii) such other time as is agreed upon by the Transmission Owner(s) and the Eligible Customer, tender to the Eligible Customer a Facilities Study agreement. The ISO shall cooperate with the affected Transmission Owners in performing any subsequent Facilities Studies. In the Facilities Study agreement, the Eligible Customer shall agree to reimburse the Transmission Owner(s) for performing the required Facilities Study and the ISO for its associated costs. If the Eligible Customer wants the affected Transmission Owner(s) to undertake the Facilities Study, the Eligible Customer shall execute the Facilities Study agreement and return it to the affected Transmission Owner(s) within fifteen (15) days.

Upon receipt of an executed Facilities Study agreement, the affected Transmission Owner(s) will complete the required Facilities Study as follows:

4.5.4.1 if the Eligible Customer gave written notice that it would not perform any part of the study then the affected Transmission Owners(s) shall use due diligence to complete the study within a one hundred and twenty (120) day period, or a different period agreed to by the Eligible Customer and the affected Transmission Owner(s), starting on the date that the affected Transmission Owner(s) receive the executed Facilities Study Agreement, or an alternative starting date agreed to by the Eligible Customer and the affected Transmission Owner(s); or

4.5.4.2 if the Eligible Customer gave written notice that it would perform all or part of the Facilities Study itself, then:

4.5.4.2.1 the affected Transmission Owner(s) shall use due diligence to complete those portion(s) of the study that the Eligible Customer is not performing within a one hundred and twenty (120) day period, or a different period agreed to by the Eligible Customer and the affected Transmission Owner(s), starting on the date that the affected Transmission Owner(s) receive the executed Facilities Study Agreement, or an alternative starting date agreed to by the Eligible Customer and the affected Transmission Owner(s); and

4.5.4.2.2 the affected Transmission Owner(s) shall use due diligence to review any portion(s) of a study performed by an Eligible Customer within a thirty (30) day period or a different period agreed to by the Eligible Customer and the affected Transmission Owner(s), starting on the date that the affected Transmission Owner(s) receive a complete draft from the Eligible Customer of its portion(s) of the study, or an alternative starting date agreed to by the Eligible Customer and the affected Transmission Owner(s). If the affected Transmission Owner(s) determine that the portion(s) of the study performed by the Eligible Customer are incomplete or that changes are required, the Eligible Customer shall make any necessary changes. The affected Transmission Owner(s) shall then use due diligence to review a revised complete draft of the Eligible Customer's portion(s) of the study within thirty days, or a different period agreed to by the Eligible Customer and the affected Transmission Owner(s), starting on the date that the affected Transmission Owner(s) receive a revised complete draft, or an alternative starting date agreed to by the Eligible Customer and the affected Transmission Owner(s).

If the Transmission Owner(s) are unable to complete the Facilities Study in the allotted time period, the Transmission Owner(s) shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study.

When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, as determined pursuant to the provisions of Part Section 4 of this Tariff, and (iii) the time required to complete such construction. The Facilities Study shall contain a non-binding estimate as to the feasible TCCs resulting from the construction of the new facilities. If the Eligible Customer decides to proceed with the construction of the facilities described in the Facilities Study, the Eligible Customer shall (1) enter into a construction contract with the Transmission Owner(s) whose system(s) will be directly modified, and with the entity that will construct the facilities under the supervision of the Transmission Owner (if other than the Transmission Owner(s)), and guarantee to compensate the Transmission Owner(s) and constructing entity (if other than the Transmission Owner(s)) for all costs incurred associated with the construction, and (2) provide each Transmission Owner with a letter of credit or other reasonable form of security acceptable to the Transmission Owner equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The construction contract shall contain terms and obligations of the Transmission Customer to pay for the facilities modifications or addition pursuant to the contract.

4.5.5 Penalties for Failure to Meet Study Deadlines:

Section 3.7.9 defines penalties that apply for failure to meet the due diligence deadlines for System Impact Studies and Facilities Studies under Part 3 of the Tariff. These same requirements and penalties apply to service under Part 4 of the Tariff.

4.5.6 Clustering of Network Integration Transmission Service Studies:

Section 3.7.10 specifies the procedures that shall govern the clustering of System Impact Studies conducted by the ISO and Facilities Studies conducted by affected Transmission Owners.

4.5.7 Development of Transmission Reinforcement Options

4.5.7.1 At the request of the PSC, the ISO shall develop a limited number of illustrative transmission reinforcement options, and associated cost estimates, to increase transfer capability limits on Interfaces identified by the PSC as having significant Congestion. Such reinforcement option results shall be made available to all Customers or potential Customers for the purpose of evaluating the economic costs and benefits of new facilities. Eligible Customers, including Transmission Owners, may then request a System Impact Study for a specific expansion project in accordance with Sections 4.5.1 through 4.5.3. Development of the transmission reinforcement options will not reflect the impacts of alternatives that may be proposed by other Eligible Customers, including generation projects, which could increase or decrease transmission Interface Transfer Capability or Congestion Rents or both. Cost estimates provided will be based on readily available data and shall in no way be binding on the ISO. The ISO will not charge the PSC for this service.

4.5.7.2 Subject to the Eligible Customer’s obligation to compensate the ISO, at the request of an Eligible Customer, the ISO will develop illustrative transmission reinforcement options as described in Section 4.5.7.1 above. The Eligible Customer shall comply with the provisions of Sections 4.5.1 through 4.5.3 that require the customer to enter into a System Impact Study agreement and agree to compensate the ISO for all costs incurred to conduct the study.

4.5.7.3 Requests to proceed with a system expansion shall be subject to the provisions of Section 4.5.

4.5.8 Study Procedures for New Interconnections to the NYS Power System

4.5.8.1 Request for Interconnection Study:

Any Eligible Customer proposing to interconnect its Load or Large Facility with the NYS Power System shall submit its interconnection proposal to the ISO. The ISO, in cooperation with the Transmission Owner with whose system the Eligible Customer proposes to interconnect, shall perform technical studies to determine whether the proposed interconnection may degrade system reliability or adversely affect the operation of the NYS Power System. The technical studies shall be conducted in accordance with the procedures specified in Section 4.5.8.2. The proposed interconnection shall not proceed if the ISO concludes in the study that the proposed interconnection may degrade system reliability or adversely affect the operation of the NYS Power System. If the proposal is rejected, the ISO shall provide in writing the reasons why the proposal was rejected.

4.5.8.2 Study Procedures:

Upon receipt of the interconnection proposal and a written guarantee by the Eligible Customer to pay all costs incurred by the ISO and Transmission Owner(s) conducting the technical studies, the ISO, in cooperation with the Transmission Owner with whose system the Eligible Customer proposes to interconnect, shall perform the technical studies of the proposed interconnection. The ISO shall evaluate each Large Facility using the Interconnection Studies specified in the Large Facility Interconnection Procedures in Attachment X. The technical studies shall address the following:

(i) An evaluation of the potential significant impacts of the proposed interconnection on NYS Power System reliability, at a level of detail that reflects the magnitude of the impacts and the reasonable likelihood of their occurrence;

(ii) An evaluation of impacts of the proposed interconnection on system voltage, stability and thermal limitations, as prescribed in the Reliability Rules;

(iii) An evaluation as to whether modifications to the NYS Power System would be required to maintain Interface transfer capability or comply with the voltage, stability and thermal limitations, as prescribed in the Reliability Rules. The ISO will apply the criteria established by NERC, NPCC and the NYSRC;

(iv) An evaluation of alternatives that would eliminate adverse reliability impacts, if any, resulting from the proposed interconnection; and

(v) An estimate of the increase or decrease in the Total Transfer Capability across each affected Interface.

4.5.8.3 Interconnection Agreements:

After receiving the approval of the proposed interconnection, and after the Eligible Customer makes payment to the ISO and Transmission Owner for the cost of the technical studies, the Eligible Customer may elect to continue with the proposed interconnection by entering into an interconnection agreement with the Transmission Owner with whose system the Eligible Customer proposes to interconnect. After completion of the Interconnection Facilities Study and Attachment S cost allocation process, the Developer of a Large Generating Facility may elect, in accordance with the Large Facility Interconnection Procedures in Attachment X, to continue with its proposed interconnection by entering into a Standard Large Generator Interconnection Agreement with the ISO and the Transmission Owner with whose system the Developer proposes to interconnect.

4.5.8.4 Interconnection Facilities Cost:

The Developer of the proposed Large Facility shall be responsible for the cost of the facilities needed for its project to reliably interconnect to the New York State Power System, in accordance with the interconnection facilities cost allocation rules set out in Attachment S.

4.5.9 Small Generator Interconnections:

The interconnection procedures, and standard interconnection agreement, to be used for the interconnection of generating facilities no larger than 20 MW, are set forth in Attachment Z to this ISO OATT..

4.6 Load Shedding and Curtailments

4.6.1 Procedures:

The ISO and the Transmission Owners shall maintain Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the NYS Transmission System. The parties will implement such programs during any period when the ISO determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The ISO will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

4.6.2 Transmission Constraints:

During any period when the ISO determines that a transmission Constraint exists on the NYS Transmission System, and such Constraint may impair the reliability of the NYS Transmission System, the ISO will dispatch generation resources on a least-cost basis in accordance with the provisions of Attachment J. When applicable, the ISO will follow the LEER Procedure, referenced in Section 3.1.6, which is incorporated by reference herein. If the ISO is required to Curtail Transmission Service as a result of a TLR event, the ISO will perform such Curtailment in accordance with the NERC TLR Procedure. Any redispatch under this Section may not unduly discriminate between the Transmission Owner's use of the NYS Transmission System on behalf of its Native Load Customers and any Network Customer's use of the NYS Transmission System to serve its designated Network Load.

4.6.3 Cost Responsibility for Relieving Transmission Constraints:

Whenever the ISO implements least-cost redispatch procedures in response to a transmission Constraint, all Transmission Customers and Network Customers will bear the costs of such redispatch in accordance with Attachment J.

4.6.4 Curtailments of Scheduled Deliveries:

If a transmission Constraint on the NYS Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the ISO determines that it is necessary to Curtail scheduled deliveries, the parties shall Curtail such schedules in accordance with the Network Operating Agreement.

4.6.5 Allocation of Curtailments:

The ISO shall, on a non-discriminatory basis, Curtail the Transaction(s) that effectively relieve the Constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Owners and Network Customers in proportion to their respective Load Ratio Shares. The ISO shall not direct Network Customers to Curtail schedules to an extent greater than the ISO would Curtail the Transmission Owners' schedules under similar circumstances.

4.6.6 Load Shedding:

To the extent that a system contingency exists on the NYS Transmission System and the ISO determines that it is necessary to shed load, the parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

4.6.7 System Reliability:

Notwithstanding any other provisions of this Tariff, the ISO reserves the right, consistent with Good Utility Practice and on a non-discriminatory basis, to Curtail Network Integration Transmission Service without liability on the ISO's and/or Transmission Owner's part for the purpose of the Transmission Owners making necessary adjustments to, changes in, or repairs on their lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the NYS Transmission System or on any other system(s) directly or indirectly interconnected with the NYS Transmission System, the ISO, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The ISO will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Owners' use of the NYS Transmission System on behalf of its Native Load Customers. The ISO shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

4.7 Rates and Charges

Rates for Network Transmission Integration Service are provided for in Schedule 9 of this ISO OATT. The billing of these charges will be performed pursuant to Article 2.7 of this ISO OATT.

4.7.1 Monthly Demand Charge:

4.7.2 Redispatch Charge:

The Network Customer shall pay redispatch costs in accordance with the provisions of Attachment J.

4.7.3 Stranded Cost Recovery:

The Transmission Owners other than NYPA may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Owners must separately file any proposal to recover stranded costs under Section 205 of the FPA. This provision shall not supersede or otherwise affect a Transmission Owner's right to recover stranded costs under other authority. To the extent that LIPA's rates for service are established by Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s and are not subject to FERC and/or PSC jurisdiction, LIPA's recovery of stranded costs will not be subject to the foregoing requirements.

Upon filing of a proposal to recover stranded costs under the FPA, the Transmission Owner shall immediately provide the ISO with a copy of the appropriate rate schedule which will be incorporated as a new SIRC rate schedule under this ISO OATT, subject to refund as may be required by the Commission. The ISO shall collect such SIRC from Network Service Customers and remit the collected amounts to the applicable Transmission Owner(s). Any SIRC rate schedule developed by LIPA under this ISO OATT will be effective upon receipt by the ISO, subject to any applicable laws and orders.

4.8 Operating Arrangements

4.8.1 Operation Under The Network Operating Agreement:

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

4.8.2 Network Operating Agreement:

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part 4 of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the NYS Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the ISO, Transmission Owners and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the NYS Transmission System, interchange schedules, unit outputs for redispatch required under Section 4.6, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted Loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part 4 of this Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 C.F.R. § 39.1 and the Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the ISO, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and the NPCC requirements. The ISO shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services to the extent that such arrangements comply with the provisions for Self-Supply of Ancillary Services as described in Schedules 3 and 5. For Network Customers that are also taking service under the ISO Services Tariff, the Service Agreement under that Tariff will function as the Network Operating Agreement. All other Network Customers will negotiate a Network Operating Agreement with the ISO. A list of requirements for such Network Operating Agreement is included in Attachment G.

4.8.3 Network Operating Committee:

The ISO Operating Committee will serve as the Network Operating Committee and will coordinate operating criteria for the parties' respective responsibilities under the Network Operating Agreement. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

5 Special Provisions for Retail Access

Preamble

All retail Transmission Service over the transmission facilities of the Parties to the ISO/TO Agreement shall be pursuant to this Section. This Section applies only to Eligible Customers taking service under retail access tariffs filed with the PSC and the Commission; or under otherwise lawfully established rates and terms of the following Transmission Owners ("Retail Access Tariffs"): Central Hudson, Consolidated Edison, LIPA, NYSEG, Niagara Mohawk, Orange and Rockland and RG&E. LSEs applying for service under this portion of this Tariff must certify to the ISO that they are participating as an LSE in one of the enumerated retail access programs.

The ISO will provide retail access services under this Tariff to Eligible Customers taking unbundled Transmission Service pursuant to a state requirement that a Transmission Owner offer the Transmission Service, or pursuant to a voluntary offer of such service by a Transmission Owner. Retail access customers are individual end-use customers eligible for retail access under the Transmission Owner's retail access plans as filed with the PSC or, in the case of LIPA, established under State law, or pursuant to a voluntary offer of such service by a Transmission Owner. All retail access customers participating in the retail access programs of Central Hudson, Consolidated Edison, LIPA, NYSEG, Niagara Mohawk and Orange and Rockland are Eligible Customers under this Tariff. Retail access customers will take service under Part 5 of this Tariff. All Sections of this Tariff apply to LSEs serving such customers. Eligible Customers, such as electric utilities, are not required to offer retail access to their customers as a condition of service under this Tariff. All retail access customers serving as their own LSE must take Transmission Service under either Part 3 or 4 of this Tariff in addition to taking service under Part IV. The common service provisions of Part 2 apply to retail access customers including LSEs.

5.1 Rights and Responsibilities of Eligible Customers and LSEs

5.1.1 Eligible Customers:

Subject to Section 5.1.2, each Eligible Customer taking service under a retail access tariff of a Transmission Owner may, but need not, select an LSE to serve its needs for Energy and related services, according to the provisions of the applicable retail access tariff or retail access operating procedures. Such Eligible Customer must become a Transmission Customer under this Tariff. Each retail access customer shall be responsible for paying the retail Transmission Service Charge to the affected Transmission Owner, as provided for in the individual Transmission Owner's retail access tariffs. If an Eligible Customer selects an LSE to serve as its agent in procuring Transmission Service from the ISO, that LSE shall be responsible for all Transmission Usage Charges and other charges associated with the Transmission Service received, and billed in accordance with Section 2.7 of this Tariff. If accommodated by the applicable retail access program, an Eligible Customer may become the customer of an LSE, with that LSE serving not as an agent, but as a Transmission Customer of the ISO who procures and resells Transmission Service to the Eligible Customer. Eligible Customers using the services of an LSE, either as an agent or a reseller of Transmission Service, need not individually enter into a Service Agreement with the ISO.

5.1.2 Load Serving Entities

5.1.2.1 General Requirements:

LSEs (including Eligible Customers serving as their own LSE) shall be responsible for scheduling Transmission Service and providing forecasts and other information applicable to the Eligible Customers they serve or for whom they act as agents, as required by ISO Procedures. All LSEs must satisfy the ISO's requirements, including a requirement that LSEs schedule transactions in whole increments of 1 MW or greater in each hour at each Point of Receipt and each Point of Delivery. LSEs may provide this information aggregated to reflect the combined requirements of the Eligible Customers they serve or for whom they act as agents, to the extent permitted by ISO Procedures. All LSEs must execute a Service Agreement with the ISO pursuant to this Tariff.

5.1.2.2 RG&E's Retail Access Plan:

LSEs participating in RG&E's retail access program are considered Eligible Customers for purposes of service under this Tariff. Such LSEs will take service under all Parts of this Tariff and will pay a wholesale TSC to RG&E.

5.1.2.3 Retail Access Programs:

Each LSE participating in one or more of the retail access programs of Central Hudson, Consolidated Edison, LIPA, NYSEG, Niagara Mohawk and Orange and Rockland will sign Service Agreements under this Tariff as both a Transmission Customer and as an agent for retail access customers. Each LSE participating in such programs will certify to the ISO that they are the duly authorized agent of the retail access customers they are representing and have met all relevant PSC and individual Transmission Owner criteria. Each LSE will be responsible for paying the Transmission Usage Charges, and all other charges due here under, except the retail access customer, not the LSE, will be responsible for paying the TSC to the affected Transmission Owner.

5.1.3 Transmission Service Charges:

The TSC calculated under the terms of this Tariff may be collected by the Transmission Owners in one of the following ways: (a) for retail access customers participating in Central

Hudson's, Consolidated Edison's, LIPA's, New York State Electric & Gas's, Niagara Mohawk Power Corporation's, or Orange and Rockland's retail access programs, the Transmission Owner may collect its TSC directly from each Customer in its service territory that takes service under its retail access tariffs, or (b) for retail access customers participating in the RG&E's retail access program, the Transmission Owner may collect its TSC directly from the LSEs serving Load in its service territory, commensurate with each LSE's utilization of its system. The rates charged for retail access Transmission Service and the terms and condition for such service shall be in accordance with the provisions of the Transmission Owner's retail access tariff. In addition, the manner in which these charges are collected and the billing procedures shall be determined by the Transmission Owner in accordance with its filed retail access tariff and retail access plans and procedures.

5.1.4 Settlement Procedures:

Consistent with each Transmission Owner's retail access plan, the ISO shall initially utilize the services of the Transmission Owners to assist in the data collection and processing necessary to provide for financial Settlement for the services provided under this Tariff, consistent with the ISO's Settlement procedures. Any LSE whose Load is not adequately metered to allow the ISO to implement its Settlement procedures, will have its Load determined by the Transmission Owner in whose Load Zone it is located in accordance with the Transmission Owner's retail access plan on file with the PSC, or in the case of LIPA, its lawfully established rates and terms. The ISO shall use this data in developing its Settlement information and charges under this Part IV of this Tariff. The ISO's Settlement procedures shall be designed to coordinate with the retail access tariffs of each Transmission Owner, and shall accommodate the allocation of cost responsibility for unaccounted-for Energy, theft, and losses on delivery facilities not explicitly included in the ISO's loss calculation model among all LSEs serving Load pursuant to that Transmission Owner's retail access program.

5.2 The Individual Retail Access Plans

Each Transmission Owner reserves the right to unilaterally modify its retail access tariff subject to any necessary regulatory filing. Each Transmission Owner also reserves the right to unilaterally modify its retail transmission charges subject to any filing required to be made with the Commission pursuant to Section 205 of the FPA or in the case of LIPA, approval by the Long Island Power Authority's Board of Trustees. The ISO shall implement any tariff changes necessary to implement the changes to the retail transmission charge. Ongoing proceedings before the PSC may impact rates, terms and conditions for retail access programs covered under this Section.

5.2.1 Central Hudson

Customers taking part in Central Hudson's retail access program shall take service under Parts I and IV of this Tariff and under Central Hudson's PSC and FERC approved retail access tariff, FERC Rate Schedule No. ER 98-3602 as amended from time to time. Pursuant to Central Hudson's retail access tariff and this Tariff all retail access customers will receive a bill from Central Hudson for the transmission component of their retail access service. Such customers shall pay this bill directly to Central Hudson.

5.2.2 Consolidated Edison

Retail access customers participating in the Consolidated Edison's retail access plan shall take retail access service under Parts 2 and 5 of this Tariff and under Consolidated Edison's PSC and FERC approved retail access tariff, Consolidated Edison's Rate Schedule FERC No. 1, Attachments K and L and Consolidated Edison Company of New York, Inc. PSC No. 2 - Retail Access, as amended from time to time. Pursuant to Consolidated Edison's retail access tariff and this Tariff, retail access customers will receive a bill from Consolidated Edison for the transmission component of their retail access service. Such customers shall pay this bill to Consolidated Edison in accordance with the terms of Consolidated Edison's Rate Schedule FERC No. 1, Attachments K and L and Consolidated Edison Company of New York, Inc. PSC No. 2 - Retail Access, as amended from time to time.

5.2.3 LIPA

Retail access customers participating in the LIPA retail access plan shall receive retail Transmission Service pursuant to Parts 2 and 5 of this Tariff and the "Long Island Choice" portions of approved "Long Island Power Authority Tariff For Electric Service." Retail Transmission Service customers will be billed and shall pay for such service as part of their bundled retail delivery service rate pursuant to the Long Island Choice portion of the Long Island Power Authority Tariff for Electric Service.

5.2.4 NYSEG

Retail customers participating in NYSEG's retail access program, known as Customer Advantage, shall receive Transmission Service pursuant to Parts 2 and 5 of this Tariff and pursuant to the provisions to NYSEG's retail access tariffs PSC Nos. 90, 115 and 118, as amended or their successors, that relate to its Customer Advantage Program. LSEs are referred to as "Energy Service Companies" or "ESCOs" in NYSEG's retail access tariffs. ESCOs eligible to participate in NYSEG's Customer Advantage Program will act as agents for retail customers for the purpose of obtaining the necessary service under this Tariff when a retail customer contracts with the ESCO for Electric Power Supply pursuant to the Customer Advantage Program. Retail customers that are eligible to participate in NYSEG's Customer Advantage Program that meet the requirements of the ISO and NYSEG's retail access tariffs (referred to as "Self Supply Customers" or "SSCs" under the retail access tariffs) shall also be required to obtain the necessary service under this Tariff but solely for their own use. Retail customers participating in NYSEG's Program will be billed and shall pay for the Transmission Service Charge as part of their retail service rate pursuant to the retail access tariffs.

NYSEG is currently a party to proceedings before the PSC, which could impact the terms and conditions of its Customer Advantage Program. It is the Company's intent to file changes to this Tariff as necessary and appropriate to reflect Orders issued by the PSC relating to the program.

5.2.5 Niagara Mohawk

Retail access is provided to Niagara Mohawk's customers through the company's PSC #207 tariff, Rule 39, as amended from time to time. Customers under this program will take retail Transmission Service under Parts I and IV of this Tariff. They will be billed by, and make payments directly to Niagara Mohawk for the applicable Transmission Service Charge.

5.2.6 Orange and Rockland

Retail access customers participating in the Orange and Rockland retail access plan shall take retail access service under Parts 2 and 5 of this Tariff and under Orange and Rockland Utilities, Inc., FERC Electric Tariff, Volume No. 3, as amended from time to time. Pursuant to Orange and Rockland's PSC approved retail access tariff and this Tariff all retail access customers will receive a bill from Orange and Rockland for the transmission component of their retail service. Such customers shall pay this bill directly to Orange and Rockland in accordance with the terms of Orange and Rockland Utilities, Inc. FERC Electric Tariff, Volume No. 3, as amended from time to time.

5.2.7 Rochester Gas and Electric Corporation

Under Rochester Gas and Electric Corporation's retail access program, 10% of the Load became eligible to choose their own supplier of electricity on July 1, 1998. (PSC No. 15 - Electricity, Rochester Gas and Electric Corporation, Schedule for Electric Distribution Service.) Twenty percent of the Load will became eligible to participate in the choice program on July 1, 1999, while 50% of the Load may elect their supplier by July 1, 2000. All customers will be eligible to choose their supplier of electricity beginning July 1, 2001.

6 Schedules

6.1 Schedule 1 - ISO Annual Budget Charge and Other Non-Budget Charges and Payments

6.1.1 Introduction

The ISO shall bill each Transmission Customer each Billing Period to recover the ISO's annual budgeted costs as set forth in Section 6.1.2 of this Rate Schedule 1.

The ISO shall separately bill each Transmission Customer under this Rate Schedule 1 for certain other charges and payments not related to the ISO annual budget charge. Specifically, the ISO shall bill each Transmission Customer on a quarterly basis to recover NERC and NPCC charges and on a Billing Period basis to recover FERC charges as set forth in Sections 6.1.3 and 6.1.15 respectively of this Rate Schedule 1. The ISO shall also bill each Transmission Customer each Billing Period to recover the following costs or allocate the following received payments under this Rate Schedule 1:

(i) bad debt loss charges as set forth in Section 6.1.4;

(ii) Working Capital Fund charges as set forth in Section 6.1.5;

(iii) non-ISO facilities payment charges as set forth in Section 6.1.6;

(iv) charges to recover costs for payments made to Suppliers pursuant to incremental cost recovery for units that responded to Local Reliability Rules I-R3 and I-R5 as set forth in Section 6.1.7;

(v) charges to recover and payments to allocate residual costs as set forth in Section 6.1.8;

(vi) charges for Special Case Resources and Curtailment Service Providers called to meet reliability needs as set forth in Section 6.1.9;

(vii) charges to recover DAMAP costs as set forth in Section 6.1.10;

(viii) charges to recover Import Curtailment Guarantee Payment costs as set forth in Section 6.1.11;

(ix) charges to recover Bid Production Cost guarantee payment costs as set forth in Section 6.1.12;

(x) charges to recover and payments to allocate settlements of disputes as set forth in Section 6.1.13; and

(xi) payments to allocate financial penalties collected by the ISO as set forth in Section 6.1.14.

Transmission Customers who are retail access customers being served by an LSE shall not pay these charges to the ISO; the LSE shall pay these charges.

6.1.2 ISO Annual Budget Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the ISO's recovery of its annual budgeted costs. The ISO annual budgeted costs that are recoverable through this Rate Schedule 1 are set forth in Section 6.1.2.1 of this Rate Schedule 1. The ISO shall calculate the charge for the recovery of these ISO annual budgeted costs from each Transmission Customer on the basis of its participation in physical market activity as indicated in Section 6.1.2.2 of this Rate Schedule 1. The ISO shall calculate this charge for each Transmission Customer on the basis of its participation in non-physical market activity, the Special Case Resource program, and the Emergency Demand Response program as indicated in Section 6.1.2.4 of this Rate Schedule 1. The ISO shall use the revenue collected through Section 6.1.2.4 of this Rate Schedule 1 to recover any of its annual budgeted costs for the immediately preceding calendar year that it has not already recovered under Section 6.1.2.2 of this Rate Schedule for that year. The ISO shall credit any additional revenue collected through Section

6.1.2.4 of this Rate Schedule 1 for the remainder of the calendar year to each Transmission Customer on the basis of its physical market activity as indicated in Section 6.1.2.5 of this Rate Schedule 1.

6.1.2.1 ISO Annual Budgeted Costs

The ISO annual budgeted costs to be recovered through Section 6.1.2 of this Rate Schedule 1 include, but are not limited to, the following costs associated with the operation of the NYS Transmission System by the ISO and the administration of the ISO Tariffs and ISO Related Agreements by the ISO:

- Processing and implementing requests for Transmission Service including support of the ISO OASIS node;
- Coordination of Transmission System operation and implementation of necessary control actions by the ISO and support for these functions;
- Performing centralized security constrained dispatch to optimally re-dispatch the NYS Power System to mitigate transmission Interface overloads and provide balancing services;
- Costs related to the ISO’s administration and operation of the LBMP market and all other markets administered by the ISO;
- Costs related to the ISO’s administration of Control Area Services;
- Costs related to the ISO’s administration of the ISO’s Market Power Mitigation Measures and the ISO’s Market Monitoring Plan;
- Costs related to the maintenance of reliability in the NYCA;
- Costs related to the provision of Transmission Service;
- Preparation of settlement statements;
- NYS Transmission System studies, when the costs of the studies are not recoverable from a Transmission Customer;
- Engineering services and operations planning;
- Data and voice communications network service coordination;
- Metering maintenance and calibration scheduling;
- Record keeping and auditing;
- Training of ISO personnel;

- Development and maintenance of information, communication and control systems;
- Professional services;
- Carrying costs on ISO assets, capital requirements and debts;
- Tax expenses, if any;
- Administrative and general expenses;
- Insurance premiums and deductibles related to ISO operations;
- Any indemnification of or by the ISO pursuant to Section 2.11.2 of this ISO OATT or Section 12.4 of the Services Tariff;
- Regulatory fees; and
- The ISO's share of the expenses of Northeast Power Coordinating Council, Inc. or its successor.

6.1.2.2 Calculation of the ISO Annual Budget Charge for Transmission Customers Participating in Physical Market Activity

The ISO shall charge, and each Transmission Customer that participates in physical market activity shall pay, an ISO annual budget charge each Billing Period as calculated according to the following formula.

$$ISO\ Annual\ Budget\ Charge_{c,P}$$

$$= \left(InjectionUnits_{c,P} * \left(0.28 * \frac{ISOCosts_{Annual}}{TotalEstWithdrawalUnits_{Annual}} \right) \right)$$

$$+ \left(WithdrawalUnits_{c,P} * \left(0.72 * \frac{ISOCosts_{Annual}}{TotalEstWithdrawalUnits_{Annual}} \right) \right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$ISO\ Annual\ Budget\ Charge_{c,P}$ = The amount, in \$, of the ISO annual budgeted costs for which Transmission Customer c is responsible for Billing Period P.

$ISOCosts_{Annual}$ = The sum, in \$, of the ISO's annual budgeted costs for the current calendar year.

$InjectionUnits_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Injections at a CTS Enabled Interface with ISO New England resulting from Imports that are not associated with wheels through New England.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalEstWithdrawalUnits_{Annual}$ = The sum, in MWh, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the ISO in the summer prior to the current calendar year, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.2.3 Review and Modification of the ISO Annual Budget Charge Allocation Methodology

The current 72%/28% cost allocation methodology between Withdrawal Billing Units and Injection Billing Units for the ISO annual budget charge shall remain unchanged through at least December 31, 2016 and shall continue to remain unchanged until such point in time that a study is conducted and the results of the study warrant changing the 72%/28% cost allocation. The following provisions prescribe the process and timeline for the review and, if warranted by the results of a future study, modification of the 72%/28% cost allocation on a going forward basis:

(i) A vote of the Management Committee will be taken in the third calendar quarter of 2015 on whether a new study should be conducted during late-2015 and 2016 to allow modification of the 72%/28% cost allocation, if warranted by the results of the study, to be implemented by January 1, 2017. A positive vote by 58% of the Management Committee will be required to go forward with the study, but there will no longer be a "material change" standard as was historically applied to the determination of whether a study should be conducted.

(ii) If the Management Committee vote discussed in (i) above determines that a study should not be conducted, the 72%/28% cost allocation between Withdrawal Billing Units and Injection Billing Units shall be extended through at least December 31, 2017. In the third calendar quarter of 2016, a vote will be taken on whether a new study should be conducted during late-2016 and 2017 to allow modification of the percentage allocation, if warranted by the results of the study, to be implemented by January 1, 2018. Unless a 58% vote of the Management Committee is registered in favor of declining to go forward with the study, the study will be conducted.

(iii) If the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above determines that a study should not be conducted, the current 72%/28% cost allocation shall remain unchanged until such point in time as the Management Committee determines that a study shall be conducted and the results of that study warrant changing the percentage allocation between Withdrawal Billing Units and Injection Billing Units. If the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above determines that a study should not be conducted, the Management Committee will revisit the issue of conducting a study annually in the third calendar quarter of each year using the same voting standard (*i.e.* the study shall be performed unless 58% of the Management Committee votes not to commission the study) that was applied to the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above.

(iv) If, and when, the Management Committee determines a study shall be conducted:

(a) Such study shall be completed, and the results thereof shared with Market Participants, before the end of the second calendar quarter of the year prior to the date on which a possible change to the then current allocation may become effective; and

(b) The ISO will present a draft study scope to Market Participants for consideration and comment before the ISO issues the study scope as part of its Request For Proposal process to retain a consultant to perform the study. A meeting shall be held with Market Participants to discuss the components (*e.g.*, categories of costs considered, allocation of benefits, unbundling, etc.) that should be included in the draft study scope before the draft is issued by the ISO.

6.1.2.4 Calculation of the ISO Annual Budget Charge for Transmission Customers Participating in Non-Physical Market Activity, the Special Case Resource Program, or the Emergency Demand Response Program

6.1.2.4.1 Charge for Transmission Customers Engaging in Virtual Transactions

The ISO shall charge, and each Transmission Customer that has its virtual bids accepted and thereby engages in Virtual Transactions shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$VTCharge_{c,P} = VTRate * VTCleared_{c,P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$VTCharge_{c,P}$ = The amount, in \$, for which Transmission Customer *c* is responsible for Billing Period *P*.

VTRate = For calendar year 2012, the applicable rate shall be \$0.0871 per cleared MWh of Virtual Transactions, based on a \$2.6 million projected 2012 annual revenue requirement. For calendar years following 2012, the applicable rate shall be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of this Rate Schedule 1.

$VTCleared_{c,P}$ = The total cleared Virtual Transactions, in MWh, for Transmission Customer *c* in Billing Period *P*.

6.1.2.4.2 Charge for Transmission Customers Purchasing Transmission Congestion Contracts

The ISO shall charge, and each Transmission Customer that purchases Transmission Congestion Contracts - excluding Transmission Congestion Contracts that are created prior to January 1, 2010 - shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$TCCCharge_{c,P} = TCCRate * TCCSettled_{c,P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$TCCCharge_{c,P}$ = The amount, in \$, for which Transmission Customer *c* is responsible for Billing Period *P*.

TCCRate = For calendar year 2012, the applicable rate shall be \$0.0372 per settled MWh of Transmission Congestion Contracts, based on a \$4.9 million projected 2012 annual revenue requirement. For calendar years following 2012, the applicable rate shall be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of this Rate Schedule 1.

$TCCSettled_{c,P}$ = The total settled Transmission Congestion Contracts, excluding Transmission Congestion Contracts created prior to January 1, 2010, in MWh, for Transmission Customer *c* in Billing Period *P*.

6.1.2.4.3 Charge for Transmission Customers Participating in the Special Case Resource Program or Emergency Demand Response Program

The ISO shall charge, and each Transmission Customer that participates in the ISO's Special Case Resources program or its Emergency Demand Response program shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$SCR\ and\ EDR\ Charge_{c,P} = DRInjections_{c,P} * \left(0.28 * \frac{ISOCosts_{Annual}}{TotalEstWithdrawalUnits_{Annual}}\right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$SCR\ and\ EDR\ Charge_{c,P}$ = The amount, in $, for which Transmission Customer c is responsible for Billing Period P.

$DRInjections_{c,P}$ = The total Load reduction, in MWh, measured and compensated during testing or an actual event for Transmission Customer c in Billing Period P.

$ISOCosts_{Annual}$ = The sum, in $, of the ISO's annual budgeted costs in the current calendar year.

$TotalEstWithdrawalUnits_{Annual}$ = The sum, in MWh, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the ISO in the summer prior to the current calendar year, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.2.4.4 Re-setting of Rate for Virtual Transaction and Transmission Congestion Contracts Related Charges

For each calendar year after calendar year 2012, the ISO shall use the following formula to calculate (i) the rate for the charge to Transmission Customers engaging in Virtual Transactions as determined in Section 6.1.2.4.1 of this Rate Schedule 1, and (ii) the rate for the charge to Transmission Customers purchasing Transmission Congestion Contracts as determined in Section 6.1.2.4.2 of this Rate Schedule 1.

$$ResetRate = \frac{AnnRevRequirement - Over/UnderCollection}{3YearRollingAvgBillUnits}$$

Where:

ResetRate = For each calendar year after calendar year 2012, this rate will be used for either (i) the VTRate in the formula in Section 6.1.2.4.1 of this Rate Schedule 1, or (ii) the TCCRate in the formula in Section 6.1.2.4.2 of this Rate Schedule 1.

AnnRevRequirement = The product, in $, of (i) the prior year's annual revenue requirement for either (A) Virtual Transaction market activity or (B) Transmission Congestion Contract market activity, and (ii) an escalation factor. The ISO shall calculate the escalation factor as the percentage change in the ISO budget between (i) the ISO budget for the calendar year two years prior to the current calendar year ("Calendar Year Minus 2") and (ii) the ISO budget for the calendar year one year prior to the current calendar year ("Calendar Year Minus 1").

Over/Under Collection = The ISO shall calculate the amount, in $, that it has over or under collected for the prior year's annual revenue requirement for either (A) Virtual Transaction market activity or (B) Transmission Congestion Contract market activity, as the case may be, as follows: (i) The ISO shall divide the annual revenue requirements for the applicable market activity for Calendar Year Minus 2 and for Calendar Year Minus 1 into twelve equal monthly revenue requirements for each of these calendar years. (ii) The ISO shall then calculate the amount of revenue, in $, that it over or under collected for each of the months from July of Calendar Year Minus 2 through June of Calendar Year Minus 1, which shall be calculated as (a) the revenue amount, in $, that the ISO collected for each month for the applicable market activity, minus (b) the monthly revenue requirement, in $, for that month as determined above. If the result of this calculation is positive, then the ISO overcollected for that month. If the result of this calculation is negative, then the ISO undercollected for that month. (iii) The ISO shall then calculate the total over or under collection amount, in $, for the period of July of Calendar Year Minus 2 through June of Calendar Year Minus 1, which shall be equal to (a) the sum, in $, of the revenue that the ISO overcollected for each month during this period (i.e., the sum of the positive monthly results determined above), minus (b) the sum, in $, of the absolute value of the revenue that the ISO undercollected for each month during this period (i.e., the sum of the absolute value of the negative monthly results determined above).

3YearRollingAvgBillUnits = The ISO shall calculate the three year rolling average of billing units, in MWh, using twelve-month averages of the appropriate billing units for the period between July of the calendar year four years prior to the current calendar year ("Calendar Year Minus 4") and June of Calendar Year Minus 1.

The annual rate computed through the formula in this Section 6.1.2.4.4 shall be subject to a 25% maximum increase or decrease for each year.

6.1.2.5 Credit for Transmission Customers Participating in Physical Market Activity After Recovery of ISO Annual Budgeted Costs or Actual Costs for the Preceding Year

The ISO shall use the revenue collected each Billing Period pursuant to Section 6.1.2.4 of this Rate Schedule 1 to recover the lower of: (i) its annual budgeted costs for the immediately preceding calendar year; or (ii) its actual costs for the immediately preceding calendar year, which it has not already recovered under Section 6.1.2 of this Rate Schedule for that year. Once it has recovered its annual budgeted costs or actual costs for the immediately preceding calendar year, the ISO shall distribute each Billing Period for the remainder of the calendar year any additional revenue collected pursuant to Section 6.1.2.4 of this Rate Schedule to each Transmission Customer that participates in physical market activity as calculated according to the following formula.

$$ISO\ Annual\ Budget\ Credit_{c,P} = \left(NonPhysicalActivityRevenue_P * \left(0.28 * \frac{InjectionUnits_{c,P}}{TotalInjectionUnits_P}\right)\right) + \left(NonPhysicalActivityRevenue_p * \left(0.72 * \frac{WithdrawalUnits_{c,P}}{TotalWithdrawalUnits_P}\right)\right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$ISO\ Annual\ Budget\ Credit_{c,P}$ = The amount, in \$, that Transmission Customer *c* will receive for Billing Period *P*.

$NonPhysicalActivityRevenue_P$= The sum, in \$, of the revenue collected by the ISO for Billing Period *P* through the charges to Transmission Customers for non-physical market activity as calculated in Section 6.1.2.4 of this Rate Schedule 1, less the amount the ISO is using to recover the annual budgeted costs or actual costs for the immediately preceding calendar year that it did not recover 1) under Section 6.1.2.2 of this Rate Schedule for that year or 2) through NonPhysicalActivityRevenue previously used for this purpose in the current calendar year provided, however, $NonPhysicalActivityRevenue_P$ shall not be less than zero

$InjectionUnits_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Injections at a CTS Enabled Interface with ISO New England resulting from Imports that are not associated with wheels through New England.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalInjectionUnits_P$ = The sum, in MWh, of Injection Billing Units for all Transmission Customers in Billing Period P, except for Scheduled Energy Injections at a CTS Enabled Interface with ISO New England resulting from Imports that are not associated with wheels through New England.

$TotalWithdrawalUnits_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England

Following the end of calendar year 2017, the ISO shall review the credits that have been made to Transmission Customers participating in physical market activity pursuant to this Section 6.1.2.5 and shall present the results of its review to Market Participants for comment.

6.1.3 NERC and NPCC Charges

The ISO receives an invoice from NERC and NPCC (as defined below) on a quarterly basis for the recovery of the upcoming calendar quarter's costs related to the dues, fees, and related charges of:

(i) the NERC for its service as the Electric Reliability Organization for the United States ("ERO"), recovered pursuant to FERC Docket Nos. RM05-30-000, RR06-1-000 and RR06-3-000 and related dockets, and

(ii) the Northeast Power Coordinating Council: Cross-Border Regional Entity, Inc. ("NPCC"), or its successors, incurred to carry out functions that are delegated by the NERC and that are related to ERO matters pursuant to Section 215 of the FPA.

The ISO shall charge on a quarterly basis, and each Transmission Customer taking service under the ISO Tariffs shall pay, a charge for the recovery of the NERC and NPCC costs in accordance with Section 6.1.3.1 of this Rate Schedule 1.

Notwithstanding any applicable provisions of this ISO OATT or of the ISO Services Tariff, the ISO may supply to NERC the name of any LSE failing to pay any amounts due to NERC and the amounts not paid.

6.1.3.1 Calculation of NERC and NPCC Charges

The ISO shall charge, and each Transmission Customer shall pay, a charge on a quarterly basis to recover the NERC and NPCC costs invoiced to the NYISO by NERC and NPCC for the upcoming calendar quarter. This charge shall be calculated according to the following formula.

$$NERC\&NPCC\ Charge_{c,Q} = NERC\&NPCCCosts_{Q} * \frac{TUWithdrawalUnits_{c,M}}{TUTotalWithdrawalUnits_{M}}$$

Where:

c = Transmission Customer.

Q = The relevant calendar quarter, for which the NERC and NPCC costs apply.

$NERC\&NPCC\ Charge_{c,Q}$ = The amount of the NERC and NPCC costs invoiced to the ISO, in $, for which Transmission Customer c is responsible for calendar quarter Q.

$NERC\&NPCCCosts_{Q}$ = The NERC and NPCC costs, in $, invoiced to the ISO for calendar quarter Q.

M = The month in which the ISO charges Transmission Customers to recover NERC and NPCC costs for calendar quarter Q.

$TUWithdrawalUnits_{c,M}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in its four-month true-up invoice that is issued with its regular monthly invoice in month M, except for Withdrawal Billing Units for Wheels Through and Exports.

$TUTotalWithdrawalUnits_M$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in their four-month true-up invoices that are issued with their regular monthly invoices in month M, except for Withdrawal Billing Units for Wheels Through and Exports.

In calculating the Withdrawal Billing Units for this NERC and NPCC charge, the ISO shall use the LSE bus meter data that have been submitted by the meter authorities for use in the calculation of the four-month true-up of the Transmission Customer's monthly invoice pursuant to Sections 7.4.1.1.2 and 7.4.1.1.3 of the ISO Services Tariff and Sections 2.7.4.2.1(ii) and 2.7.4.2.1(iii) of this ISO OATT. This calculation of the NERC and NPCC charge shall not be subject to correction or adjustment.

6.1.4 Bad Debt Loss Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of bad debt losses in accordance with the methodology established in Attachment U of this ISO OATT.

6.1.5 Working Capital Fund Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the collection and maintenance of the Working Capital Fund in accordance with the methodology established in Attachment V of this ISO OATT.

6.1.6 Non-ISO Facilities Payment Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge in accordance with Section 6.1.6.5 of this Rate Schedule 1 for the recovery of the costs of the ISO's monthly payments to the owners of facilities that are needed for the economic and reliable operation of the NYS Transmission System. At present, the ISO makes such payments to:

(i) Consolidated Edison Co. of New York, Inc. for the purchase, installation, operation, and maintenance of phase angle regulators at the Hopatcong-Ramapo Interconnection between the ISO and PJM Interconnection, LLC (the "Ramapo PARs Charge"), and

(ii) Rochester Gas & Electric Corporation for the installation of a 135 MVAR Capacitor Bank at Rochester Station 80 on the cross-state 345 kV system.

6.1.6.1 Calculation of the Ramapo PARs Charge

The Ramapo PARs Charge is the Consolidated Edison Co. of New York ("Con Edison") component of the *NonISOFacilitiesCosts* defined in Section 6.1.6.5 below. Con Edison shall calculate the Ramapo PARs Charge using the procedures described in the 1993 PARs Facilities Agreement that was accepted for filing by FERC in Docket No. ER93-640-000 on May 10, 1993 (the "1993 Agreement"), irrespective of the effectiveness of the 1993 Agreement. The costs Con Edison may include in the Ramapo PARs Charge are limited to the categories of costs that are eligible for recovery under the 1993 Agreement, and by the rules in this Section.

In order to permit the replacement of the Ramapo 3500 PAR that failed in June of 2016 without further delay, commencing on July 1, 2017 Transmission Customers will begin reimbursing Con Edison for up to 100% of the costs Con Edison incurred or incurs to purchase and install a replacement for the 3500 PAR, and up to 100% of the going-forward costs Con Edison incurs to operate and maintain the 3500 PAR.

With regard to the Ramapo PAR installed in and in service since 2013 ("Installed PAR"), Con Edison shall not submit a Ramapo PARs Charge that would cause Transmission Customers to pay more than 50% of the costs Con Edison submitted for inclusion in the *Non-ISO Facilities Payment Charge* for the Installed PAR prior to July 1, 2017. Subject to the foregoing restriction, in order to permit the continued operation of the Ramapo Installed PAR, commencing on July 1, 2017, Transmission Customers will reimburse Con Edison for up to 100% of Con Edison's going-forward cost of purchasing, installing, operating and maintaining the Installed PAR.

If PJM Interconnection, LLC ("PJM"), on behalf of some or all of its customers, assumes an obligation to pay a portion of the Ramapo PARs Charge, then the obligation of Transmission Customers to pay the Ramapo PARs Charge shall be reduced consistent with the obligation that PJM Interconnection, LLC assumes.

6.1.6.2 Transparency of the Ramapo PARs Charge

The ISO shall post on its web site the itemized monthly bill (for the preceding month) that Con Edison develops and submits to the ISO in accordance with Section 2.4 of the 1993 Agreement. The itemized monthly bill determines the Ramapo PARs Charge.

No later than August 1 of each year Con Edison shall prepare and the ISO shall post on is website an estimate of the monthly costs and expenses associated with the Ramapo PARs for the next calendar year and for each of the four subsequent years.

Con Edison shall maintain books and records related to its calculation of Ramapo PARs Charge, including costs incurred. Such books and records shall be subject to review by any New York Transmission Customer at reasonable intervals during normal business hours.

6.1.6.3 Refund of the Ramapo PARs Charge to Transmission Customers

To the extent Transmission Customers paid more than 50% of the Ramapo PARs Charge for a Billing Period, they shall be eligible to receive a refund if and to the extent Con Edison's cost recovery exceeds 100% of the Ramapo PARs Charge for that Billing Period.

If PJM, or one or more PJM transmission owners, submit(s) a payment to the ISO covering Ramapo PARs Charges assessed by Con Edison for a past period that is on or after July

1, 2017, and the conditions set forth in the first paragraph of this Section 6.1.6.3 are satisfied, then appropriate refunds shall be paid to Transmission Customers in accordance with the rules set forth below.

If PJM or any of the PJM transmission owners submit payments to Con Edison covering Ramapo PARs Charges assessed by Con Edison on or after July 1, 2017 and the conditions set forth in the first paragraph of this Section 6.1.6.3 are satisfied, then Con Edison shall refund to the ISO any amounts it received in excess of 100% of the Ramapo PARs Charge for a Billing Period and the ISO shall distribute the refund it receives from Con Edison in accordance with the rules set forth below.

If the ISO receives a refund from Con Edison, or a payment from PJM or from one or more PJM transmission owners related to the Ramapo PARs Charge, then the ISO shall refund the amount received to its Transmission Customers as soon as practicable. Refunds shall be allocated to each Transmission Customer based on its market participation in the Billing Period during which refunds are issued, using the same load ratio share basis that the ISO uses to allocate the *NonISOFacilitiesCosts* charges to Transmission Customers. Interest paid to the ISO shall be allocated to each Transmission Customer in the same manner as refunds are allocated.

6.1.6.4 Retirement and Replacement of the Ramapo PARs

If either of the Ramapo PARs described in Section 6.1.6.1 fail and are not reparable, or are retired with the consent of the ISO, then the original cost of the facilities retired shall be deducted from the gross plant in service and any unrecovered book cost shall be increased by the cost of removal and reduced by any salvage value, tax benefits, and insurance proceeds. The net balance shall be billed to the ISO for payment to Con Edison in a lump sum in accordance with the calculation, transparency, and cost allocation provisions applicable to the Ramapo PARs Charge.

If either of the Ramapo PARs described in Section 6.1.6.1 are damaged or condemned, the ISO may direct Con Edison to repair or replace them, provided that: (1) the costs of such repair or replacement net any insurance proceeds shall be recovered by Con Edison in accordance with the calculation, transparency, and cost allocation provisions applicable to the Ramapo PARs Charge; (2) Con Edison shall be the sole party responsible for determining whether a repair or replacement is in accordance with good utility practice; and (3) the schedule for any such repair or replacement shall be determined by Con Edison based on reliability considerations.

6.1.6.5 Calculation of Non-ISO Facilities Payment Charge

6.1.6.5.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a non-ISO facilities payment charge for each Billing Period. This charge shall be equal to the sum of the hourly non-ISO facilities payment charges for the Transmission Customer, as calculated according to the following formula, for each hour in the relevant Billing Period.

$$Non\text{-}ISO\ Facilities\ Payment\ Charge_{c,h} = \frac{NonISOFacilitiesCost_M}{N} * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

M = The relevant month.

h = A given hour in the relevant Billing Period in month M.

N = Total number of hours h in month M.

$Non\text{-}ISO\ Facilities\ Payment\ Charge_{c,h}$ = The amount, in \$, for which Transmission Customer c is responsible for hour h.

$NonISOFacilitiesCosts_M$ = The sum, in \$, of the ISO's bills for month M for the non-ISO facilities from (i) Consolidated Edison Co. of New York (less the portion, if any, of such bill paid by PJM Interconnection, LLC) and (ii) Rochester Gas and Electric Corporation.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.6.5.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT.

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a non-ISO facilities payment charge for each Billing Period. This charge shall be equal to the sum of the daily non-ISO facilities payment charges for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

$$Non\text{-}ISO\ Facilities\ Payment\ Charge_{c,d} = \frac{NonISOFacilitiesCosts_M}{N} * \frac{StationPower_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period in month M.

N = Number of days d in month M.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.6.5.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.5.2 shall be determined for day *d*.

6.1.6.5.3 Non-ISO Facilities Payment Credit

The ISO shall credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the non-ISO facilities payment charge under Section 6.1.6.5.2 of this Rate Schedule 1 for each Billing Period. This credit shall be equal to the sum of daily payments for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

$$Non\text{-}ISO\ Facilities\ Payment\ Credit_{c,d} = NonISOFacPayCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period.

$Non\text{-}ISO\ Facilities\ Payment\ Credit_{c,d}$ = The amount, in \$, that Transmission Customer c will receive for day d.

$NonISOFacPayCharge_d$ = The sum of non-ISO facilities payment charges, in \$, for all Transmission Customers as calculated in Section 6.1.6.5.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.6.5.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.5.3 shall be determined for day *d*.

6.1.7 Charge to Recover Payments Made to Suppliers Pursuant to Incremental Cost Recovery for Units Responding to Local Reliability Rules I-R3 and I-R5

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge for the recovery of the costs of payments to Suppliers pursuant to the incremental cost recovery for units that responded to either (i) Local Reliability Rule I-R3 or (ii) Local Reliability Rule I-R5, as applicable, for each Billing Period. This charge shall be equal to the sum of the daily charges for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period. The ISO shall perform this calculation separately to recover as applicable either (i) the payment costs related to Local Reliability I-R3, or (ii) the payment costs related to Local Reliability Rule I-R5.

$$Local\ Reliability\ Rules\ Payment\ Recovery\ Charge_{c,d} = LRRPayment_d * \frac{TDWithdrawal_{c,d}}{TDTotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Local\ Reliability\ Rules\ Payment\ Recovery\ Charge_{c,d}$ = The amount, in $, for which Transmission Customer c is responsible for day d.

$LRRPayment_d$ - The amount, in $, paid in day d to Suppliers pursuant to the incremental cost recovery for units that responded, as applicable, to either (i) Local Reliability Rule I-R3 in the Consolidated Edison Transmission District or (ii) Local Reliability Rule I-R5 in the LIPA Transmission District.

$TDWithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

$TDTotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as third-party providers.

6.1.8 Residual Costs Payment/Charge

The ISO's payments for market transactions by Transmission Customers will not equal the ISO's payments to Suppliers for market transactions. Part of the difference consists of Day-Ahead Congestion Rent. The remainder comprises a residual adjustment, which the ISO shall calculate and each Transmission Customer shall receive or pay on the basis of its Withdrawal Billing Units. The most significant component of the residual adjustment is the residual costs payment or charge calculated in accordance with Section 6.1.8.1 of this Rate Schedule 1.

6.1.8.1 Calculation of Residual Costs Payment/Charge

6.1.8.1.1 Transmission Customers Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each Billing Period. The payment or charge for the relevant Billing Period shall be equal to (i) the sum of the hourly residual costs payments for the Transmission Customer as calculated according to the following formula for each hour in the relevant Billing Period, minus (ii) the sum of the hourly residual costs charges for the Transmission Customer as calculated in the following formula for each hour in the relevant Billing Period. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant Billing Period. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant Billing Period.

$$Residual\ Costs\ Payment/Charge_{c,h} = (CustomerPayments_h - ISOPayments_h) * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Residual\ Costs\ Payment/Charge_{c,h}$ = The amount, in $, for hour h that Transmission Customer c will receive (if positive) or for which Transmission Customer c is responsible (if negative).

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_{h}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$CustomerPayments_{h}$ = The ISO's receipts, in $, for each hour h from Transmission Customers that equal the sum of the following components, which could be either positive or negative amounts:

(i) payments of the Energy component and Marginal Losses Component of LBMP for Energy scheduled in the LBMP Market in hour h in the Day-Ahead Market;

(ii) payments of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy purchased in the Real-Time LBMP Market for hour h that was not scheduled Day-Ahead;

(iii) payments of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy by Suppliers that provided less Energy in the real-time dispatch for hour h than they were scheduled Day-Ahead to provide in hour h for the LBMP Market;

(iv) the Marginal Losses Component of the TUC payments made in accordance with this ISO OATT for Bilateral Transactions that were scheduled in hour h in the Day-Ahead Market; and

(v) the Marginal Losses Component and Congestion Component of the real-time TUC payments made in accordance with this ISO OATT for Bilateral Transactions that were not scheduled in hour h in the Day-Ahead Market.

(vi) the M2M settlement between the ISO and PJM Interconnection, L.L.C. for hour h, determined in accordance with Section 8 of Schedule D to Attachment CC to this ISO OATT.

$ISOPayments_h$ = The ISO's payments, in \$, in each hour h to Suppliers that equal the sum of the following components, which could be either positive or negative amounts:

(i) payments of the Energy component and Marginal Losses Components of LBMP for Energy to Suppliers that were scheduled to provide in the LBMP Market in hour h in the Day-Ahead Market;

(ii) payments to Suppliers of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy provided to the ISO in the Real-Time Dispatch for hour h that those Suppliers were not scheduled to provide Energy in hour h in the Day-Ahead Market;

(iii) payments of the Energy component and Marginal Losses Component of LBMP for Energy to LSEs that consumed less Energy in the real-time dispatch than those LSEs were scheduled Day-Ahead to consume in hour h; and

(iv) payments of the Marginal Losses Component and Congestion Component of the real-time TUC to Transmission Customers that reduced their Bilateral Transaction schedules for hour h after the Day-Ahead Market.

6.1.8.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT.

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each Billing Period. The payment or charge for the relevant Billing Period shall be equal to (i) the sum of the daily residual costs payments for the Transmission Customer as calculated according to the following formula for each day in the relevant Billing Period, minus (ii) the sum of the daily residual costs charges for the Transmission Customer as calculated in the following formula for each day in the relevant Billing Period. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant Billing Period. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant Billing Period.

$$Residual\ Costs\ Payment/Charge_{c,d} = \frac{(CustomerPayments_d - ISOPayments_d)}{TotalWithdrawalUnits_d} * StationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* that it used to supply Station Power as a third-party provider for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.8.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.8.1.2 shall be determined for day d.

6.1.8.1.3 Residual Costs Adjustment

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs adjustment for each Billing Period. This adjustment shall be equal to the sum of the daily adjustments (positive and negative) for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period. If the summed amount is positive for the Billing Period, the ISO shall pay the Transmission Customer the adjustment amount. If the summed amount is negative for the Billing Period, the ISO shall charge the Transmission Customer the adjustment amount.

$$Residual\ Costs\ Adjustment_{c,d} = ResidCharge/PaymentCosts_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period.

$Residual\ Costs\ Adjustment_{c,d}$ = The amount, in $, for day *d* that Transmission Customer *c* will receive (if positive) or for which Transmission Customer *c* is responsible (if negative).

$ResidCharge/PaymentCosts_d$ = (i) If Transmission Customers were responsible for a residual costs charge for day *d* pursuant to Section 6.1.8.1.2 of this Rate Schedule 1, the (positive) amount, in $, of the costs that the ISO has collected through the residual costs charges for all Transmission Customers for day *d*. (ii) If Transmission Customers received a residual costs payment for day *d* pursuant to Section 6.1.8.1.2 of this Rate Schedule 1, the (negative) amount, in $, of the revenue that the ISO has paid through the residual costs payments to all Transmission Customers for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.8.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.8.1.3 shall be determined for day *d*.

6.1.9 Recovery of Special Case Resources and Curtailment Services Providers Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of Special Case Resources and Curtailment Service Providers costs for each Billing Period. This charge shall be equal to the sum of the hourly charges for the Transmission Customer, as calculated in Sections 6.1.9.1 and 6.1.9.2 of this Rate Schedule 1, for each hour in the relevant Billing Period and, where applicable, for each Subzone.

6.1.9.1 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.9.1, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers that were called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone for which the reliability services of the Special Case Resources and Curtailment Service Providers were called shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ SCR\ and\ CSP\ Charge_{c,h} = LocalReliabilityCosts_h * \frac{SZWithdrawalUnits_{c,h}}{SZTotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Local\ Reliability\ SCR\ and\ CSP\ Charge_{c,h}$ = The amount, in \$, for which Transmission Customer c is responsible for hour h for the relevant Subzone.

$LocalReliabilityCosts_h$ = The payments, in \$, for hour h in the relevant Subzone made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of that Subzone.

$SZWithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_{h}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.9.2 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.9.2, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units except for Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

$$NYCA\ Reliability\ SCR\ and\ CSP\ Charge_{c,h} = NYCAReliabilityCosts_{h} * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_{h}}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$NYCA\ Reliability\ SCR\ and\ CSP\ Charge_{c,h}$ = The amount, in $, for which Transmission Customer *c* is responsible for hour *h*.

$NYCAReliabilityCosts_{h}$ = The payments, in $, for hour *h* made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h*, except for the Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as third-party providers.

6.1.10. Recovery of Day-Ahead Margin Assurance Payment Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of DAMAP costs for each Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.10.1 and 6.1.10.2 of this Rate Schedule 1, for each hour or each day, as applicable, in the relevant Billing Period and for each Subzone, where applicable.

6.1.10.1 Recovery of Costs of DAMAPs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.10.1, the ISO shall recover the costs for DAMAPs incurred to compensate Resources for meeting the reliability needs of a local system.

6.1.10.1.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ DAMAP\ Charge_{c,h} = DAMAPCosts_h * \frac{SZWithdrawalUnits_{c,h}}{SZTotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Local\ Reliability\ DAMAP\ Charge_{c,h}$ = The amount, in $, for which Transmission Customer c is responsible for hour h for the relevant Subzone.

$DAMAPCosts_h$ = The DAMAP costs, in $, for hour *h* in the relevant Subzone incurred to compensate Resources meeting the reliability needs of that Subzone.

$SZWithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.10.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ DAMAP\ Charge_{c,d} = \frac{DAMAPCosts_d}{SZTotalWithdrawalUnits_d} * \ SZStationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$SZStationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* in day *d* in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.2 shall be determined for day *d*.

6.1.10.1.3 Local Reliability DAMAP Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.1.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Local\ Reliability\ DAMAP\ Credit_{c,d} = LocRelDAMAPCharge_d * \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period.

$Local\ Reliability\ DAMAP\ Credit_{c,d}$ = The amount, in $, that Transmission Customer *c* will receive for day *d* for the relevant Subzone.

$LocRelDAMAPCharge_d$ = The sum of charges, in $, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.10.1.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.3 shall be determined for day *d*.

6.1.10.2 Recovery of Costs of All Remaining DAMAPs

Pursuant to this Section 6.1.10.2, the ISO shall recover the costs of all DAMAPs not recovered through Section 6.1.10.1 of this Rate Schedule 1 from all Transmission Customers.

6.1.10.2.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

$$Remaining\ DAMAP\ Charge_{c,h} = RemainingDAMAPCosts_h * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Remaining\ DAMAP\ Charge_{c,h}$ = The amount, in $, for which Transmission Customer *c* is responsible for hour *h*.

$RemainingDAMAPCosts_h$ = The DAMAP costs, in $, for hour *h* not recovered by the ISO through Section 6.1.10.1 of this Rate Schedule 1.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h*, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h*, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.10.2.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$Remaining\ DAMAP\ Charge_{c,d} = \frac{RemainingDAMAPCosts_d}{TotalWithdrawalUnits_d} * \ StationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* used to supply Station Power as a third-party provider for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.2 shall be determined for day *d*.

6.1.10.2.3 Remaining DAMAP Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.2.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Remaining\ DAMAP\ Credit_{c,d} = RemainingDAMAPCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_{c,d}}$$

Where:

d = A given day in the relevant Billing Period.

$Remaining\ DAMAP\ Credit_{c,d}$ = The amount, in \$, that Transmission Customer c will receive for day d.

$RemainingDAMAPCharge_d$ = The sum of charges, in \$, for all Transmission Customers as calculated in Section 6.1.10.2.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.3 shall be determined for day d.

6.1.11 Recovery of Import Curtailment Guarantee Payment Costs

6.1.11.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the hourly charges for the Transmission Customer, as calculated in accordance with the following formula, for each hour in the relevant Billing Period.

$$Import\ Curtailment\ Guarantee\ Charge_{c,h} = ImportCurtGuarCosts_h * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Import\ Curtailment\ Guarantee\ Charge_{c,h}$= The amount, in $, for which Transmission Customer c is responsible for hour h.

$ImportCurtGuarCosts_h$ = The costs, in $, for the Import Curtailment Guarantee Payments to Import Suppliers for hour h.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.11.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a charge for each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the daily charges for the Transmission Customer, as calculated in accordance with the following formula, for each day in the relevant Billing Period.

$$Import\ Curtailment\ Guarantee\ Charge_{c,d} = \frac{ImportCurtGuarCosts_d}{TotalWithdrawalUnits_d} * \ StationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* used to supply Station Power as a third-party provider for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.2 shall be determined for day *d*.

6.1.11.3 Import Curtailment Guarantee Credit

The ISO shall credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.11.2 of this Rate Schedule 1 above for each Billing Period. This credit shall be equal to the sum of daily payments for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

$$Import\ Curtailment\ Guarantee\ Credit_{c,d} = ImpCurtGuarCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period.

$Import\ Curtailment\ Guarantee\ Credit_{c,d}$ = The amount, in $, that Transmission Customer *c* will receive for day *d*.

$ImpCurtGuarCharge_d$ = The sum of charges, in $, for all Transmission Customers as calculated in Section 6.1.11.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.3 shall be determined for day *d*.

6.1.12 Recovery of Bid Production Cost Guarantee Payment and Demand Reduction Incentive Payment Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of BPCG and Demand Reduction Incentive Payment costs for each Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.12.1 through 6.1.12.6 of this Rate Schedule 1, for each day in the relevant Billing Period and for each Subzone, where applicable.

6.1.12.1 Costs of Demand Reduction BPCGs and Demand Reduction Incentive Payments

After accounting for imbalance charges paid by Demand Reduction Providers, the ISO shall recover the costs associated with Demand Reduction Bid Production Cost guarantee payments and Demand Reduction Incentive Payments from Transmission Customers pursuant to the methodology established in Attachment R of this ISO OATT.

6.1.12.2 Costs of BPCGs for Additional Generating Units Committed to Meet Forecast Load

If the sum of all Bilateral Transaction schedules, excluding schedules of Bilateral Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO may commit Resources in addition to the reserves that it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load. The ISO shall recover a portion of the costs associated with Bid Production Cost guarantee payments for the additional Resources committed Day-Ahead to meet the Day-Ahead forecast of Load from Transmission Customers pursuant to the methodology established in Attachment T of this ISO OATT. The ISO shall recover the residual costs of such Bid Production Cost guarantee payments not recovered through the methodology in Attachment T of the ISO OATT pursuant to Section 6.1.12.6 of this Rate Schedule 1.

6.1.12.3 Costs of BPCGs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.3, the ISO shall recover the costs for Bid Production Cost guarantee payments incurred to compensate Suppliers for their Resources, other than Special Case Resources, that are committed or dispatched to meet the reliability needs of a local system.

6.1.12.3.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ BPCG\ Charge_{c,d} = BPCGCosts_d * \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Local\ Reliability\ BPCG\ Charge_{c,d}$ = The amount, in \$, for which Transmission Customer *c* is responsible for day *d* for the relevant Subzone.

$BPCGCosts_d$ = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Resources for day *d* in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone, except for the Bid Production Cost guarantee payments made to Suppliers for Special Case Resources.

$SZWithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.3.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ BPCG\ Charge_{c,d} = \frac{BPCGCosts_d}{SZTotalWithdrawalUnits_d} * \ SZStationPower_{c,d}$$

Where:

$SZStationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* in day *d* in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.3.1 above,

6.1.12.3.3 Local Reliability BPCG Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.3.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Local\ Reliability\ BPCG\ Credit_{c,d} = \ LocRelBPCGCharge_d * \frac{SZWithdrawalUnits_{c,d}}{SZWithdrawalUnits_{c,d}}$$

Where:

$Local\ Reliability\ BPCG\ Credit_{c,d}$ = The amount, in \$, that Transmission Customer *c* will receive for day *d* for the relevant Subzone.

$LocRelBPCGCharge_d$ = The sum of charges, in \$, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.12.3.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.3.1 above.

6.1.12.4 Cost of BPCGs for Special Case Resources Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.4, the ISO shall recover the costs of Bid Production Cost guarantee payments incurred to compensate Special Case Resources called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Special Case Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ SCR\ BPCG\ Charge_{c,d} = BPCGCosts_d * \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Local\ Reliability\ SCR\ BPCG\ Charge_{c,d}$ = The amount, in \$, for which Transmission Customer c is responsible for day d for the relevant Subzone.

$BPCGCosts_d$ = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Special Case Resources for day *d* in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone.

$SZWithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.5 Cost of BPCG for Special Case Resources Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.12.5, the ISO shall recover the costs for Bid Production Cost guarantee payments to compensate Special Case Resources called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used except for Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$NYCA\ Reliability\ SCR\ BPCG_{c,d} = BPCGCost_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$NYCA\ Reliability\ SCR\ BPCG\ Charge_{c,d}$ = The amount, in $, for which Transmission Customer *c* is responsible for day *d*.

$BPCGCosts_d$ = The Bid Production Cost guarantee payments, in $, made to Suppliers for Special Case Resources called to meet the reliability needs of the NYCA for day *d*.

$WithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d*, except for the Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider.

$TotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d*, except for the Withdrawal Billing Units for Wheels-Through, Exports or to supply Station Power as third-party providers.

6.1.12.6 Costs of All Remaining BPCGs

Pursuant to this Section 6.1.12.6, the ISO shall recover the costs of all Bid Production Cost guarantee payments not recovered through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, 6.1.12.4, and 6.1.12.5 of this Rate Schedule 1, including the residual costs of Bid Production Cost guarantee payments for additional Resources not recovered through the methodology in Attachment T of this ISO OATT, from all Transmission Customers.

6.1.12.6.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$Remaining\ BPCG\ Charge_{c,d} = RemainingBPCGCosts_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Remaining\ BPCG\ Charge_{c,d}$ = The amount, in \$, for which Transmission Customer *c* is responsible for day *d*.

$RemainingBPCGCosts_d$ = The BPCG costs, in \$, for day *d* not recovered by the ISO through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, 6.1.12.4, and 6.1.12.5 of this Rate Schedule 1.

$WithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d*, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d*, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a

CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.12.6.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$Remaining\ BPCG\ Charge_{c,d} = \frac{RemainingBPCGCosts_d}{TotalWithdrawalUnits_d} * StationPower_{c,d}$$

Where:

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* used to supply Station Power as a third-party provider for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.6.1 of this Rate Schedule 1 above.

6.1.12.6.3 Remaining BPCG Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.6.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Remaining\ BPCG\ Credit_{c,d} = RemainingBPCGCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_{c,d}}$$

Where:

$Remaining\ BPCG\ Credit_{c,d}$ = The amount, in \$, that Transmission Customer *c* will receive for day *d*.

$RemainingBPCGCharge_d$ = The sum of charges, in \$, for all Transmission Customers as calculated in Section 6.1.12.6.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.6.1 of this Rate Schedule 1 above.

6.1.13 Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or charge in accordance with Section 6.1.13.1 of this Rate Schedule 1 for the distribution of funds received by the ISO or the recovery of funds incurred by the ISO in the settlement of a dispute.

6.1.13.1 Calculation of the Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or a dispute resolution charge for each Billing Period as calculated according to the following formula.

$$Dispute\ Resolution\ Payment/Charge_{c,P} = DisputeResolutionCosts_P * \frac{WithdrawalUnits_{c,P}}{TotalWithdrawalUnits_P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$Dispute\ Resolution\ Payment/Charge_{c,P}$ = The amount, in \$, for Billing Period P that (i) Transmission Customer c will receive if the ISO is distributing funds that it has collected in the settlement of a dispute, or (ii) Transmission Customer c will be responsible for if the ISO is recovering funds that it has incurred in the settlement of a dispute.

$DisputeResolutionCosts_P$ = The amount, in \$, for Billing Period P that (i) the ISO has collected in the settlement of a dispute or (ii) the ISO has incurred in the settlement of a dispute.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.14 Credit for Financial Penalties

The ISO shall distribute to each Transmission Customer each Billing Period in accordance with the following formula any payments that it has collected from Transmission Customers to satisfy: (i) Financial Impact Charges issued pursuant to Sections 4.5.3.2 and 4.5.4.2 of the ISO Services Tariff; (ii) ICAP sanctions issued pursuant to Section 5.12.12 of the ISO Services Tariff; (iii) ICAP deficiency charges pursuant to Section 5.14.3.1 of the ISO Services Tariff, except as provided in Section 5.14.3.2 of the ISO Services Tariff; (iv) market power mitigation financial penalties pursuant to Section 23.4.3.6 of Attachment H of the ISO Services Tariff, except as provided in Section 23.4.4.3.2 of Attachment H of the ISO Services Tariff; and (v) any other financial penalties set forth in the ISO Services Tariff or this ISO OATT. The ISO will perform this calculation separately for the allocation of the revenue from each financial penalty.

$$Financial\ Penalties\ Credit_{c,P} = PenaltyRevenue_P * \frac{WithdrawalUnits_{c,P}}{TotalWithdrawalUnits_P}$$

Where:

c = Transmission Customer.

P = A given day in the relevant Billing Period.

$Financial\ Penalties\ Credit_{c,P}$ = The amount, in \$, that Transmission Customer c will receive for Billing Period P.

$PenaltyRevenue_P$ = The sum, in \$, of revenue that the ISO has collected for Billing Period P from a Transmission Customer for one of the financial penalties indicated in Section 6.1.14 of this Rate Schedule 1.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c for Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers for Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.15 Calculation of FERC Fee Charges

As a public utility the transmission provider under this Tariff is subject to annual charges assessed by the Commission in accordance with Part 382 of the Commission's regulations (annual FERC fee). The ISO shall charge, and each Transmission Customer taking service under the ISO Tariffs shall pay, a charge for the recovery of the annual FERC fee, on the basis of its participation in physical market activity, and on the basis of its participation in non-physical market activity in accordance with Sections 6.1.15.1 and 6.1.15.2 respectively. The annual FERC fee shall be allocated ninety-four (94%) to physical market activity and six (6%) to non-physical market activity respectively. Pursuant to ISO Procedures, the six (6%) of the annual FERC fee allocated to non-physical market activity shall be further allocated approximately four percent (4%) to Transmission Congestion Contracts and approximately two percent (2%) to Virtual Transactions. The total charge to each Transmission Customer for recovery of the annual FERC fee shall be the sum of the Transmission Customer's Physical FERC Fee Charge and the Transmission Customer's Non-Physical FERC Fee Charge.

An estimated annual FERC fee shall be recovered over the twelve months of each federal fiscal year. The ISO will publish the estimated annual FERC fee for each federal fiscal year no less than one month in advance of the start of that federal fiscal year. Upon receiving the invoice for the annual FERC fee, the ISO will implement a true-up, a credit or charge, equal to the difference between the estimated annual FERC fee for the fiscal year and the invoiced amount, in the first Billing Period following receipt of the invoiced annual FERC fee, as is practicable. The ISO shall recover or refund the true-up amount over a six month period.

All funds collected by the ISO for the annual FERC fee shall be deposited in the annual FERC fee account. The annual FERC fee account shall be an interest-bearing account separate from all other accounts maintained by the ISO. The ISO shall disburse funds from the annual FERC fee account in order to pay the FERC any and all annual FERC fee charges assessed against the ISO.

6.1.15.1 Calculation of Physical FERC Fee Charge for Transmission Customers Participating in Physical Market Activity

The ISO shall charge, and each Transmission Customer that participates in physical market activity shall pay, a charge for the recovery of the annual FERC fee as calculated according to the following formula:

$$
\begin{aligned}
&Physical\ FERC\ Fee\ Charge_{c,P} \\
&\quad = \left(Injection\ Units_{c,P} * \left(0.28 * PRatio * \frac{(Est\ FERC\ Fee_P + True\text{-}Up\ Costs_P)}{TotalInjectionUnits_P}\right)\right) \\
&\quad + \left(Withdrawal\ Units_{c,P} * \left(0.72 * \ PRatio * \frac{(Est\ FERC\ Fee_P + True\text{-}Up\ Costs_P)}{TotalWithdrawalUnits_P}\right)\right)
\end{aligned}
$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$Physical\ FERC\ Fee\ Charge_{c,P}$ = The amount, in \$, of the annual FERC fee for which Transmission Customer c is responsible for Billing Period P.

$Injection\ Units_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P.

$PRatio$ = Ninety-four percent (94%).

$Est\ FERC\ Fee_P$ = Billing Period P's proportional allocation of the estimated annual FERC fee for the current FERC fiscal year.

$True\text{-}up\ Costs_P$ = Billing Period P's proportional allocation of the difference between the invoiced annual FERC fee and the estimated annual FERC fee.

$TotalInjectionUnits_P$ = The sum, in MWh, of Injection Billing Units for all Transmission Customers in Billing Period P.

$Withdrawal\ Units_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in the Billing Period P.

$TotalWithdrawalUnits_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in the Billing Period P.

6.1.15.2 Calculation of the FERC Fee Charge for Transmission Customers Participating in Non-Physical Market Activity

The ISO shall charge, and each Transmission Customer that has its virtual bids accepted and thereby engages in Virtual Transactions or that purchases Transmission Congestion Contracts shall pay, a charge for the recovery of the annual FERC fee as calculated according to the following formula: $Non\text{-}Physical\ FERC\ Fee\ Charge_{c,P} = \left(VTCleared_{c,P} * \left(\left(\frac{VTRatio * Est\ FERC\ Fee_P}{Total\ VT\ Cleared_P}\right) + \left(\frac{VTRatio * True\text{-}Up\ Costs_P}{Total\ VT\ Cleared_P}\right)\right)\right) + \left(TCC\ Settled_{c,P} * \left(\left(\frac{TCCRatio * Est\ FERC\ Fee_P}{Total\ TCC\ Settled_P}\right) + \left(\frac{TCCRatio * True\text{-}Up\ Costs_P}{Total\ TCC\ Settled_P}\right)\right)\right)$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$Non - Physical\ FERC\ Fee\ Charge_{c,P}$ = The amount, in \$, of the annual FERC fee for which Transmission Customer c is responsible for Billing Period P.

$VT\ Cleared_{c,P}$ = The total cleared Virtual Transactions, in MWh, for Transmission Customer c in Billing Period P.

$Est\ FERC\ Fee_P$ = Billing Period P's proportional allocation of the estimated annual FERC fee for the current FERC fiscal year.

$True - up\ Costs_P$ = Billing Period P's proportional allocation of the difference between the invoiced annual FERC fee and the estimated annual FERC fee.

$VTRatio$ = Approximately two percent (2%).

$Total\ VT\ Cleared_P$ = The sum, in MWh, of cleared Virtual Transactions for all Transmission Customers in Billing Period P.

$TCCSettled_{c,P}$ = The total settled Transmission Congestion Contracts, in MWh, for Transmission Customer c in Billing Period P.

$TCCRatio$ = Approximately four percent (4%).

$Total\ TCC\ Settled_P$ = The sum of settled Transmission Congestion Contracts, in MWh, for all Transmission Customers in Billing Period P.

6.2 Schedule 2 - Charges for Voltage Support Service

In order to maintain transmission voltages on the NYS Transmission System within acceptable limits, generation facilities under the control of the ISO, synchronous condensers, and Qualified Non-Generator Voltage Support Resources, are operated to produce (or absorb) reactive power. Thus, Voltage Support Service must be provided for each Transaction on the NYS Transmission System. The amount of Voltage Support Service that must be supplied will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the ISO.

Voltage Support Service is to be provided directly by the ISO. The methodologies that the ISO will use to obtain Voltage Support Service and the associated charges for such service are set forth below.

6.2.1 Responsibilities

The ISO shall coordinate the Voltage Support Service provided by generation facilities, synchronous condensers, and Qualified Non-Generator Voltage Support Resources that qualify to provide such services as described in Section 15.2.1.1 of Rate Schedule 2 of the ISO Services Tariff.

6.2.1.1 Wheels Through, Exports and Purchases from the LBMP Market

Transmission Customers engaging in Wheels Through, and Transmission Customers or Customers engaged in Export Transactions, except for Export Transactions at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England, shall purchase Voltage Support Service from the ISO at the rates described in the formula contained in Section 6.2.2.1 of this Rate Schedule.

6.2.1.2 Load-Serving Entities

LSEs serving Load in the NYCA shall purchase Voltage Support Service from the ISO at the rates described in the formula contained in Section 6.2.2.1 of this Rate Schedule.

6.2.2 Payments

6.2.2.1 Payments made by Transmission Customers and LSEs

Transmission Customers, Customers, and LSEs shall pay the ISO for Voltage Support Service. The ISO shall compute the Voltage Support Service Rate based on forecast data using the following equation

$$Rate_{VSS} = \frac{\sum NYISO_{VSSPmts} + PYA_{VSS}}{Energy_{NYISO}}$$

Where:

$Rate_{VSS}$ = Voltage Support Service Rate ($/MWh)

$Energy_{ISO}$ = The annual forecasted transmission usage for the year as projected by the ISO including Load within the NYCA, Exports and Wheels Through (MWh).

$\Sigma\ NYISO_{VSSPmts}$ = The sum of the projected ISO payments to generation facilities, synchronous condensers, and Qualified Non-Generator Voltage Support Resources providing Voltage Support Service based on Sections 15.2.2.1, 15.2.2.2 and 15.2.2.3 of Rate Schedule 2 of the ISO Services Tariff ($).

PYA_{VSS} = "Prior year adjustment" for Voltage Support Service which is the total of prior year payments to generation facilities, synchronous condensers, and Qualified Non-Generator Voltage Support Resources supplying Voltage Support Service as defined in the ISO Services Tariff less the total of payments received by the ISO from Transmission Customers , Customers and LSEs in the prior year for Voltage Support Service (including all payments for penalties) ($).

Transmission Customers engaging in Wheels Through and Transmission Customers or Customers engaged in Export Transactions, except for Export Transactions at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England, shall pay to the ISO a charge for this service equal to the rate as determined in Section 6.2.1 of this Rate Schedule multiplied by their Energy scheduled in the hour. LSEs shall pay to the ISO a charge for this service equal to the rate as determined in Section 6.2.1 of this Rate Schedule multiplied by the Energy consumed by the LSE’s Load located in the NYCA in the hour provided, however, LSEs taking service under Section 5 of the OATT to supply Station Power as a third-party provider shall pay to the ISO a charge for this service equal to the rate as determined in Section 6.2.1 of this Rate Schedule multiplied by the LSE’s Station Power provided under Section 5 of the OATT. For LSEs and all Wheels Through and Exports, the ISO shall calculate the payment hourly. The ISO shall bill each Transmission Customer or LSE each Billing Period.

6.2.3 Self-Supply

All Voltage Support Service shall be purchased from the ISO.

6.3 Schedule 3 - Charges for Regulation Service

Regulation Service is necessary to provide for the continuous balance of resources (generation and interchange) with Load. The obligation to maintain this balance between Resources and Load lies with the ISO. The ISO must offer this service when the Transmission Service is used to serve Load within the NYCA and when LSEs use Energy from the LBMP Market to service Load within the NYCA. The charges for Regulation Service are set forth below.

6.3.1 Customer Obligations and Responsibilities

LSEs shall purchase this service from the ISO.

6.3.2 Charges to LSEs

6.3.2.1 For all Actual Energy Withdrawals for Load located in the NYCA, LSE taking service under the OATT or buying Energy from the LBMP Market shall pay a charge for this service on all withdrawals to serve Load in the NYCA in accordance with this Rate Schedule.

6.3.2.2 The ISO shall charge LSEs serving Load in the NYCA for Regulation Service for each hour. The ISO shall charge LSEs taking service under Section 5 of the ISO OATT to supply Station Power as third-party providers for Service for each day. The charge shall be calculated as the Regulation Service Rate, determined as an hourly or a daily rate as appropriate, multiplied by the LSE's Load for the hour or by the LSE's withdrawals to provide Station Power as a third party provider for the day. The ISO shall calculate the Regulation Service Rate, for an hour or for a day as appropriate, as follows:

$$Rate_{Reg} = \frac{(Supplier\ Payment - Supplier\ Charge - Generator\ Charge)}{Load_{NYCA}}$$

where: $Rate_{Reg}$ is the hourly or daily rate for Regulation Service ($/MWh);

Supplier Payment is the aggregate of all Day-Ahead Market and Real-Time Market payments (including Regulation Revenue Adjustment Payments) made by the ISO to all Suppliers of this Regulation Service as described in Rate Schedule 3 of the ISO Services Tariff for the hour or for the day;

Supplier Charge is the aggregate of: (i) charges paid by all Suppliers for poor Regulation Service performance, as described in Section 15.3.5.4; (ii) all real-time imbalance charges paid by Suppliers under Section 15.3.5.2(a) of that Rate Schedule; and (iii) all Regulation Revenue Adjustment Charges assessed pursuant to Section 15.3.6 of that Rate Schedule for the hour or for the day;

Generator Charge is the aggregate of charges paid by all Generators that do not provide Regulation Service and do not follow their RTD Base Points sufficiently accurately, as described in Rate Schedule 3A of the ISO Services Tariff for the hour or for the day; and

$Load_{NYCA}$ is the total Load in the NYCA for the hour or for the day, as appropriate.

6.3.2.3 In any hour where the charges paid by Generators and Suppliers, as described in the ISO Services Tariff, exceed the payments made to Suppliers of this service (i) the ISO shall not assess a charge against any LSE, and (ii) the surplus will be applied to the following hour as an offset to subsequent payments.

6.3.2.4 Charges to be paid by LSEs for this service shall be aggregated to render a monthly charge. The ISO shall credit charges paid for Regulation Service by LSEs taking service under Section 5 of the ISO OATT to supply Station Power as third-party providers for the day on a Load ratio share basis to LSEs serving Load in the NYCA for the day.

6.4 Schedule 4 - Energy Imbalance Service

Energy Imbalance Service is provided Day-Ahead when a difference occurs between: (1) scheduled Transmission Service and scheduled delivery of Energy to a Load located within the NYCA from a POI located within the NYCA over a single hour, (2) scheduled Transmission Service and scheduled delivery of Energy to a Load located within the NYCA from a POI located external to the NYCA over the scheduling interval, and (3) scheduled Transmission Service and scheduled delivery of Energy from a POI within the NYCA to a neighboring control area over the scheduling interval.

Energy Imbalance Service is provided in real-time when a difference occurs between: (1) scheduled Transmission Service and scheduled delivery of Energy to a Load located within the NYCA from a POI located within the NYCA over the scheduling interval, (2) scheduled Transmission Service and scheduled delivery of Energy to a Load located within the NYCA from a POI located external to the NYCA over the scheduling interval, and (3) scheduled Transmission Service and scheduled delivery of Energy from a POI within the NYCA to a neighboring control area in the scheduling interval.

Differences between scheduled Transmission Service in the Day-Ahead Market and scheduled Transmission Service in the Real-Time Market for the same transaction are governed by Attachment J of the OATT, not by this Rate Schedule 4. Differences between the scheduled delivery of Energy in the Day-Ahead Market and the scheduled delivery of Energy in the Real-Time Market for the same transaction are governed by Section 4.5 of the Services Tariff, not by this Rate Schedule 4.

The ISO must offer this service when the Transmission Service is used to serve Load within the NYCA, or for an Export Transaction when the generation source is a Generator located in the NYCA. The Transmission Customer, or Generator as appropriate, must purchase this service from the ISO. The charges for Energy Imbalance Service are set forth below.

6.4.1 Energy Imbalance Service Charges

Each Transmission Customer that has executed a Service Agreement under the ISO Services Tariff, whose scheduled Energy delivery in the Day-Ahead Market is less than its scheduled Transmission Service in the Day-Ahead Market, will be charged an amount equal to the product of the Day-Ahead LBMP determined pursuant to Attachment B of the Services Tariff, at the Point of Delivery (Point of Injection) and the difference between the scheduled Energy delivery in the Day-Ahead Market and the scheduled Transmission Service in the Day-Ahead Market, provided however, when the Energy delivery scheduled in the Day-Ahead Market is from a POI within the NYCA, Energy Imbalance Service is charged to the Generator associated with the POI.

Each Transmission Customer that has not executed a Service Agreement under the ISO Services Tariff, whose scheduled Energy delivery in the Day-Ahead Market is less than its scheduled Transmission Service in the Day-Ahead Market, will be charged an amount equal to the product of: (i) the higher of: (a) 150 percent of the Day-Ahead LBMP determined pursuant to Attachment B of the Services Tariff, at the Point of Delivery (Point of Injection); and (b) $100 per MWh, and (ii) the difference between the scheduled Energy delivery in the Day-Ahead Market and the scheduled Transmission Service in the Day-Ahead Market, provided however, when the scheduled delivery of Energy is from a POI within the NYCA, Energy Imbalance Service is charged to the Generator associated with the POI.

Each Transmission Customer that has executed a Service Agreement under the ISO Services Tariff whose scheduled Energy delivery in the Real-Time Market is less than its scheduled Transmission Service in the Real-Time Market, will be charged an amount equal to the product of the Real-Time LBMP price determined pursuant to Attachment B of the Services Tariff, at the Point of Delivery (Point of Injection) and the difference between the scheduled Energy delivery in the Real-Time Market and the scheduled Transmission Service in the Real-Time Market, provided however, when the scheduled delivery of Energy is from a POI within the NYCA, Energy Imbalance Service is charged to the Generator associated with the POI.

Each Transmission Customer that has not executed a Service Agreement under the ISO Services Tariff, whose scheduled Energy delivery in the Real-Time Market is less than its Transmission Service scheduled in the Real-Time Market, will be charged an amount equal to the product of (i) the higher of (a) 150 percent of the real-time LBMP determined pursuant to Attachment J, at the Point of Delivery (Point of Injection), and (b)$100 per MWh, and (ii) the difference between the scheduled Energy delivery in the Real-Time Market and the scheduled transmission service in the Real-Time Market, provided however, when the scheduled delivery of Energy is from a POI within the NYCA, Energy Imbalance Service is charged to the Generator associated with the POI.

Settlements when Actual Energy delivery exceeds Actual Energy Withdrawals are governed by Services Tariff Section 4.5.

Energy imbalances resulting from inadvertent interchange between Control Areas will continue to be addressed by ISO procedures and in accordance with NERC and NPCC policies. Any increase or decrease in costs resulting from pay back of accumulated inadvertent interchange will be included in the residual costs payment or the residual costs charge as calculated in Section 6.1.8 of Rate Schedule 1 of this ISO OATT.

6.4.2 Inadvertent Energy Management Requirements

6.4.2.1 Facilities on Boundaries with Neighboring Control Areas

The correction required for external Inadvertent Energy Accounting facilities on Interfaces between the NYCA and other Control Areas will be done using Inadvertent Energy Accounting techniques established by the ISO in accordance with NERC and other established reliability criteria.

6.4.3 Self-Supply

All Energy Imbalance Services shall be purchased from the ISO.

6.5 Schedule 5 - Charges for Operating Reserve Service

The ISO must offer this service when Transmission Service is used to serve Load within the NYCA. Transmission Customers and LSEs must either purchase this service from the ISO. The charges for Operating Reserve Service are set forth below.

The NYSRC shall be responsible for evaluating the adequacy of the criteria for determining the required level of Operating Reserves and shall modify such criteria from time to time as required. The ISO shall establish additional categories of Operating Reserves if necessary to ensure reliability.

The ISO will ensure that Suppliers that are compensated for using Capacity to provide one Operating Reserve product are not simultaneously compensated for providing another Operating Reserve product, or Regulation Service, using the same Capacity (consistent with the additive nature of the market clearing price calculation formulae in Sections 15.4.5.1 and 15.4.6.1 of Rate Schedule 4 of the ISO Services Tariff).

6.5.1 Operating Reserves Charges

Transmission Customers and Customers engaging in Export Transactions, except for Export Transactions at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England, and LSEs shall pay an hourly charge equal to the product of (A) the cost to the ISO of providing all Operating Reserves for a given hour; and (B) the ratio of (i) the LSE's hourly Load or the Transmission Customer's hourly scheduled Export Transactions, except for Export Transactions at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England, to (ii) the sum of all Load in the NYCA and all scheduled Export Transactions, except for Export Transactions at a CTS Enabled Interface with ISO New England resulting from

Exports that are not associated with wheels through New England, for a given hour. The cost to the ISO of providing Operating Reserves in each hour will equal the total amount that the ISO pays to procure Operating Reserves on behalf of the market in the Day-Ahead Market and the Real-Time Market, less payments collected from entities that are scheduled to provide less Operating Reserves in the Real-Time Market than in the Day-Ahead Market during that hour, under Rate Schedule 4 of the ISO Services Tariff. The ISO shall aggregate the hourly charges to produce a total charge for a given Dispatch Day.

LSEs taking service under Section 5 of the OATT to supply Station Power as third-party providers shall pay to the ISO a daily charge for this service equal to the product of (A) the cost to the ISO of providing all Operating Reserves for the day and (B) the ratio of (i) the LSE's Station Power supplied under Section 5 of the OATT for the day to (ii) the sum of all Load in the NYCA and all scheduled Exports, except for Export Transactions at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England, for the day. The ISO shall credit the daily charges paid for Operating Reserves by LSEs taking service under Section 5 of the OATT to supply Station Power as third-party providers on a Load ratio share basis to the Load in the NYCA for that day and all scheduled Exports for the day except for Export Transactions at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.5.2 Self-Supply

Transmission Customers, including LSEs, may provide for Self-Supply of Operating Reserve by placing Resources supplying any one of the Operating Reserves under ISO Operational Control. The Resources must meet ISO rules for acceptability, pursuant to Rate Schedule 4 of the Services Tariff. The specified Resources will receive the market value of the

Operating Reserves services provided by the specified Resource as determined in the ISO Services Tariff. In addition, Transmission Customers, including LSEs, may enter into Day-Ahead bilateral financial transactions, *e.g.*, contracts-for-differences, in order to hedge against price volatility in the Operating Reserves markets.

6.6 Schedule 6 - Black Start and System Restoration Services

The terms of Rate Schedule 5 of the ISO Services Tariff are hereby incorporated by reference into this Tariff. In applying the terms of Rate Schedule 5 of the ISO Services Tariff in connection with this Tariff, all terms in Rate Schedule 5 that are applicable to "Customers" shall be similarly applicable to "Transmission Customers," and the ISO shall interpret all other defined terms and cross-references in Rate Schedule 5 that are specific to the ISO Services Tariff consistent with similar terms and provisions of this Tariff, unless otherwise specified.

6.7 Schedule 7 - Firm Point-To-Point Transmission Service

The charges for Firm Point-To-Point Transmission Service are described below. Section 2.7 of this Tariff contains the billing and settlement terms and identifies which customers are responsible for paying each of the charges. Charges are based on actual transmission use with billing units measured in MWh.

6.7.1 Transmission Usage Charge ("TUC")

The TUC (in $) for each Billing Period shall be the sum of the hourly values for each hour in that Billing Period of (i) the hourly Day-Ahead TUCs for Firm Point-To-Point Transmission Service scheduled in the Day-Ahead Market, and (ii) the hourly Real-Time TUCs for Firm Point-To-Point Transmission Service scheduled before the close of the Real-Time Scheduling Window.

6.7.1.1 The hourly Day-Ahead TUC shall be calculated as follows:

Hourly Day-Ahead TUC = Scheduled Amount x ($DALBMP_{DP}$ - $DALBMP_{RP}$)

Where:

Scheduled Amount is the quantity of MWh scheduled for Firm Point-To-Point Transmission Service in the Day-Ahead Market by the Transmission Customer for that hour.

$DALBMP_{DP}$ is the Day-Ahead LBMP price of Energy (in $/MWh) in that hour measured at the Point of Delivery (or withdrawal) as specified in the Transmission Service schedule. The method used to calculate Day-Ahead LBMP is described in Attachment B of the Services Tariff.

DALBMP$_{RP}$ is the Day-Ahead LBMP price of Energy (in $/MWh) in that hour measured at the Point of Receipt (or injection) as specified in the Transmission Service schedule. The method used to calculate Day-Ahead LBMP is described in Attachment B of the Services Tariff.

6.7.1.2 The hourly Real-Time TUC shall be calculated as follows:

$$TUC\ for\ hour\ k\ for\ transaction\ j = \frac{1}{3600}\sum_{i=1}^{n} MW_{ij} * t_i * \left(LBMP_{ij}^{r} - LBMP_{ij}^{s}\right)$$

where:

MW_{ij} = MW of the Transmission Service for RTD execution interval i, for transaction j

n = Number of RTD intervals in an hour

t_i = Number of seconds in interval i which are part of hour k

$LBMP_{ij}^{r}$ = LBMP at withdrawal location r for RTD execution interval i, for transaction j

$LBMP_{ij}^{s}$= LBMP at injection locations for RTD execution interval i, for transaction j

3600 = number of seconds in each hour

6.7.1.2.1 A Transmission Customer that submits a real-time Transmission Service schedule prior to the close of the Real-Time Scheduling Window, for an amount that is less than the Scheduled Amount, shall be credited for the difference at the Real-Time TUC.

6.7.1.2.2 A Transmission Customer that submits a Transmission Service schedule prior to the close of the Real-Time Scheduling Window, for an amount that is greater than the Scheduled Amount, shall be charged for the difference at the Real-Time TUC.

6.7.1.3 Exceptions

6.7.1.3.1 A Transmission Customer's Transmission Service schedule associated with an Export Bilateral Transaction shall be set equal to the physical schedule of the Export Bilateral Transaction for any hour in which the ISO physically curtails the customer's scheduled Transmission Service.

6.7.1.3.2 Transmission Customers with Grandfathered Rights that take Transmission Service in the Day-Ahead Market that corresponds to that customer's Grandfathered Rights shall pay for Marginal Losses associated with the hourly Day-Ahead LBMP in lieu of the TUC in accordance with Attachment K.

6.7.2 Marginal Losses

Payments for Marginal Losses (the "Marginal Losses Cost") shall equal the sum of the Hourly Day-Ahead Marginal Losses Cost and any adjustment to that cost as a result of subsequent schedule changes in the Real-Time Market (the "Hourly Real-Time Marginal Losses Cost")

6.7.2.1 Hourly Day-Ahead Marginal Losses Cost is calculated as follows:

Hourly Day-Ahead Marginal Losses Cost = Scheduled Amount x ($DAMLC_{DP}$ - $DAMLC_{RP}$)

Where:

$DAMLC_{DP}$ is the Marginal Losses Component of the Day-Ahead LBMP measured at the Delivery Point identified in the Transmission Customer's schedule. The Day-Ahead LBMP is calculated in accordance with Attachment B of the Services Tariff.

$DAMLC_{RP}$ is the Marginal Losses Component of the Day-Ahead LBMP measured at the Receipt Point identified in the Transmission Customer's schedule. The Day-Ahead LBMP is calculated in accordance with Attachment B of the Services Tariff.

6.7.2.2 Hourly Real-Time Marginal Losses Cost is calculated as follows:

Hourly Real-Time Marginal Losses Cost = Scheduled Amount x ($RTMLC_{DP}$ - $RTMLC_{RP}$)

Where:

$RTMLC_{DP}$ is the Marginal Losses Component of the Real-Time LBMP measured at the Delivery Point identified in the Transmission Service schedule. The Real-Time LBMP is calculated in accordance with Attachment B of the Services Tariff.

$RTMLC_{RP}$ is the Marginal Losses Component of the Real-Time LBMP measured at the Receipt Point identified in the Transmission Service schedule. The Real-Time LBMP is calculated in accordance with Attachment B of the Services Tariff.

6.7.2.2.1 If the Transmission Customer submits a Transmission Service schedule prior to the close of the Real-Time Scheduling Window, for an amount that is less than the Scheduled Amount in the Day-Ahead Market, the ISO shall credit that Transmission Customer for the difference in Marginal Losses Cost using the Real-Time LBMP Marginal Losses Component.

6.7.2.2.2 If the Transmission Customer submits a Transmission Service schedule prior to the close of the Real-Time Scheduling Window, for an amount that is greater than the Scheduled Amount in the Day-Ahead Market, the ISO shall charge that Transmission Customer for the difference in Marginal Losses Cost using the Real-Time LBMP Marginal Losses Component.

6.7.3 Wholesale Transmission Service Charge ("WTSC")

The Wholesale Transmission Service Charge (in $) is calculated as follows:

6.7.3.1 For Exports and Wheels Through

WTSC = Schedule Amount x WTSC Rate

Where:

Scheduled Amount is the quantity of MWh scheduled in each hour for that month for Firm Point-To-Point Transmission Service by the Transmission Customer.

WTSC Rate is the Wholesale Transmission Service Charge Rate or combination of rates that applies to the Transmission Customer's Transmission Service as determined in Attachment H.

6.7.3.2 For Imports and Internal Wheels

WTSC = Actual Energy Withdrawals x WTSC Rate

6.7.4 Retail Transmission Service Charge ("RTSC")

The rates and charges for retail transmission service are described in Part 5 of this Tariff.

6.7.5 NYPA Transmission Adjustment Charge ("NTAC")

LSEs serving retail access Load will be charged an NTAC consistent with each Transmission Owner's retail access program pursuant to Section 2.7 of this Tariff. The Transmission Customer shall pay to the ISO each Billing Period the NTAC. NTAC (in $) is calculated as follows:

6.7.5.1 For Exports and Wheels Through

NTAC = Scheduled Amount x NTAC Rate

Where:

NTAC Rate is the rate listed and described in Attachment H.

Scheduled Amount is the amount of MWh scheduled in each hour for that Billing Period for Firm Point-To-Point Transmission Service by the Transmission Customer.

6.7.5.2 For Imports and Internal Wheels

NTAC = Actual MWh Withdrawals x NTAC Rate

Where:

NTAC Rate is the rate listed and described in Attachment H.

6.8 Schedule 8 - Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service is not available in the markets that the NYISO administers.

6.9 Schedule 9 - Network Integration Transmission Service

The charges for Network Integration Transmission Service are described below. Article 2.7 of this Tariff contains the billing and settlement terms and identifies which customers are responsible for paying each of the charges. Charges are based on actual transmission use with billing units measured in MWh.

6.9.1 Transmission Usage Charge ("TUC")

The TUC (in $) for each Billing Period shall be the sum of the hourly values for each hour in that Billing Period of (i) the hourly Day-Ahead TUCs for Network Integration Transmission Service scheduled in the Day-Ahead Market, and (ii) the hourly Real-Time TUCs for Network Integration Transmission Service scheduled no later than ninety (90) minutes prior to such hour in the Dispatch Day.

6.9.1.1 The hourly Day-Ahead TUC shall be calculated as follows:

Hourly Day-Ahead TUC = Scheduled Amount x ($DALBMP_{DP}$ - $DALBMP_{RP}$)

Where:

Scheduled Amount is the quantity of MWh scheduled for Network Integration Transmission Service in the Day-Ahead Market by the Transmission Customer for that hour.

$DALBMP_{DP}$ is the Day-Ahead LBMP price of energy (in $/MWh) in that hour measured at the Point of Delivery (or withdrawal) as specified in the Transmission Service schedule. The method used to calculate Day-Ahead LBMP is described in Attachment B of the Services Tariff.

$DALBMP_{RP}$ is the Day-Ahead LBMP price of energy (in $/MWh) in that hour measured at the Point of Receipt (or injection) as specified in the Transmission Service schedule. The method used to calculate Day-Ahead LBMP is described in Attachment B of the Services Tariff.

6.9.1.2 The hourly Real-Time TUC shall be calculated as follows:

$$TUC\ for\ hour\ k\ For\ transaction\ j = \frac{1}{3600}\sum_{i=1}^{n} MW_{ij} * t_i * \left(LBMP_{ij}^{r} - LBMP_{ij}^{s}\right)$$

Where:

Mw_{ij} = MW of the transaction for SCD execution interval i, for transaction j

n = Number of SCD intervals in an hour

t_i = Number of seconds in interval i which are part of hour k

$LBMP_{ij}^{r}$ = LBMP at withdrawal location r for SCD execution interval i, for transaction j

$LBMP_{ij}^{s}$ = LBMP at injection locations for SCD execution interval i, for transaction j

3600 = number of seconds in each hour

6.9.1.2.1 If the Transmission Customer submits a Transmission Service schedule, after the close of the Day-Ahead Market schedule but no later then ninety (90) minutes prior to such hour in the Dispatch Day, for an amount that is less than the Scheduled Amount, the ISO shall credit that Transmission Customer for the difference at the Real-Time TUC.

6.9.1.2.2 If the Transmission Customer submits a Transmission Service schedule, after the close of the Day-Ahead Market schedule but no later then ninety (90) minutes prior to such hour in the Dispatch Day, for an amount that is greater than the Scheduled Amount, the ISO shall charge that Transmission Customer for the difference at the Real-Time TUC.

6.9.1.3 Exceptions to the requirement to pay the hourly TUC.

6.9.1.3.1 The hourly TUC shall not apply in any hour in which the ISO physically and financially Curtails the customer’s scheduled Transmission Service during the Dispatch Day.

6.9.1.3.2 Transmission Customers with Grandfathered Rights that take Transmission Service in the Day-Ahead Market that corresponds to that customer’s Grandfathered Rights shall, subject to a Section 205 filing under the Federal Power Act, pay for Marginal Losses associated with the hourly Day-Ahead LBMP in lieu of the TUC.

6.9.2 Marginal Losses

Payments for Marginal Losses (the “Marginal Losses Cost”) shall equal the sum of the Hourly Day-Ahead Marginal Losses Cost and any adjustment to that cost as a result of subsequent schedule changes in the Real-Time Market (the “Hourly Real-Time Marginal Losses Cost”)

6.9.2.1 Hourly Day-Ahead Marginal Losses Cost is calculated as follows:

Hourly Day-Ahead Marginal Losses Cost = Scheduled Amount x ($DAMLC_{DP}$ - $DAMLC_{RP}$)

Where:

$DAMLC_{DP}$ is the Marginal Losses Component of the Day-Ahead LBMP measured at the Delivery Point identified in the Transmission Customer's schedule. The Day-Ahead LBMP is calculated in accordance with Attachment B of the Services Tariff.

$DAMLC_{RP}$ is the Marginal Losses Component of the Day-Ahead LBMP measured at the Receipt Point identified in the Transmission Customer's schedule. The Day-Ahead LBMP is calculated in accordance with Attachment B of the Services Tariff.

6.9.2.2 Hourly Real-Time Marginal Losses Cost is calculated as follows:

Hourly Real-Time Marginal Losses Cost = Scheduled Amount x ($RTMLC_{DP}$ - $RTMLC_{RP}$)

Where:

$RTMLC_{DP}$ is the Marginal Losses Component of the Real-Time LBMP measured at the Delivery Point identified in the Transmission Service schedule. The Real-Time LBMP is calculated in accordance with Attachment B of the Services Tariff.

$RTMLC_{RP}$ is the Marginal Losses Component of the Real-Time LBMP measured at the Receipt Point identified in the Transmission Service schedule. The Real-Time LBMP is calculated in accordance with Attachment B of the Services Tariff.

6.9.2.2.1 If the Transmission Customer submits a Transmission Service schedule, after the close of the Day-Ahead Market schedule but no later than ninety (90) minutes prior to such hour in the Dispatch Day, for an amount that is less than the Scheduled Amount in the Day-Ahead Market, the ISO shall credit that Transmission Customer for the difference in Marginal Losses Cost using the Real-Time LBMP Marginal Losses Component.

6.9.2.2.2 If the Transmission Customer submits a Transmission Service schedule, after the close of the Day-Ahead Market schedule but no later than ninety (90) minutes prior to such hour in the Dispatch Day, for an amount that is greater than the Scheduled Amount in the Day-Ahead Market, the ISO shall charge that Transmission Customer for the difference in Marginal Losses Cost using the Real-Time LBMP Marginal Losses Component.

6.9.3 Wholesale Transmission Service Charge ("WTSC")

The Wholesale Transmission Service Charge (in $) is calculated as follows:

6.9.3.1. For Exports and Wheels Through

WTSC = Schedule Amount x WTSC Rate

Where:

Scheduled Amount is the quantity of MWh scheduled in each hour for that month for Network Integration Transmission Service by the Transmission Customer.

WTSC Rate is the Wholesale Transmission Service Charge Rate or combination of rates that applies to the Transmission Customer's Transmission Service as determined in Attachment H.

6.9.3.2. For Imports and Internal Wheels

WTSC = Actual Energy Withdrawals x WTSC Rate

Where:

Actual MWh Withdrawal is the quantity of MWh withdrawn at the Point of Delivery identified in the Transmission Customer's Transmission Service schedule, in an hour. The amount shall be determined by: (1) measurement with a revenue-quality meter; (2) assessment in accordance with a Transmission Owner's PSC-approved retail access program or LIPA's lawfully established retail access program where the customer's demand is not measured by a revenue-quality meter; or (3) using a method agreed to by the customer and the applicable Transmission Owner until such time as a revenue-quality meter is available.

6.9.4 Retail Transmission Service Charge ("RTSC")

The rates and charges for retail transmission service are described in Section 5 of this Tariff.

6.9.5 NYPA Transmission Adjustment Charge ("NTAC")

LSEs serving retail access Load will be charged an NTAC consistent with each Transmission Owner's retail access program pursuant to Section 2.7 of this Tariff. The Transmission Customer shall pay to the ISO each Billing Period the NTAC. NTAC (in $) is calculated as follows:

6.9.5.1 For Exports and Wheels Through

NTAC = Scheduled Amount x NTAC Rate

Where:

NTAC Rate is the rate listed and described in Attachment H.

Scheduled Amount is the amount of MWh scheduled in each hour for that Billing Period for Network Integration Transmission Service by the Transmission Customer.

6.9.5.2 For Imports and Internals Wheels

NTAC = Actual MWh Withdrawals x NTAC Rate

Where:

NTAC Rate is the rate listed and described in Attachment H.

Actual MWh Withdrawal is the quantity of MWh withdrawn at the Point of Delivery identified in the Transmission Customer's Transmission Service schedule, in an hour. The amount shall be determined by: (1) measurement with a revenue-quality meter; (2) assessment in accordance with a Transmission Owner's PSC-approved retail access program or LIPA's lawfully established retail access program where the customer's demand is not measured by a revenue-quality meter; or (3) using a method agreed to by the customer and the applicable Transmission Owner until such time as a revenue-quality meter is available.

6.10 Schedule 10 - Rate Mechanism for the Recovery of the Regulated Transmission Facilities Charge ("RTFC")

6.10.1 Applicability

6.10.1.1 Eligible Projects

This Schedule establishes the Regulated Transmission Facilities Charge ("RTFC") for the recovery of the costs of a regulated transmission project that is eligible for cost recovery in accordance with the Comprehensive System Planning Process requirements set forth in Attachment Y of the ISO OATT.[1] A Transmission Owner, Unregulated Transmitting Utility,[2] or Other Developer may recover through the RTFC the costs that it is eligible to recover pursuant to Attachment Y of the ISO OATT related to: (i) a regulated backstop transmission solution proposed by a Responsible Transmission Owner pursuant to Section 31.2.4.3.1 of Attachment Y of the ISO OATT and the ISO/TO Reliability Agreement; (ii) an alternative regulated transmission solution that the ISO has selected pursuant to Section 31.2.6.5.2 of Attachment Y of the ISO OATT as the more efficient or cost-effective solution to a Reliability Need; or (iii) a regulated transmission Gap Solution proposed by a Responsible Transmission Owner pursuant to Section 31.2.11.4 of Attachment Y of the ISO OATT; (iv) an alternative regulated Transmission Gap Solution that has been determined by the appropriate state regulatory agency(ies) as the preferred solution to a Reliability Need pursuant to Section 31.2.11.5 of Attachment Y of the ISO OATT; (v) a regulated economic transmission project that has been approved pursuant to Section 31.5.4.6 of Attachment Y of the ISO OATT; (vi) a Public Policy Transmission Project that the ISO has selected pursuant to Section 31.4.8.2 of Attachment Y of the ISO OATT as the more efficient or cost-effective solution to a Public Policy Transmission Need; (vii) a Public Policy Transmission Project proposed by a Developer in response to a request by the NYPSC or Long Island Power Authority in accordance with Section 31.4.3.2 of Attachment Y of the ISO

OATT; or (viii) the portion of an Interregional Transmission Project selected by the ISO in the CSPP that is allocated to the NYISO region pursuant to Section 31.5.7 of Attachment Y of the ISO OATT. For purposes of this Schedule, such a transmission project is referred to as an "Eligible Project." The costs incurred for an Eligible Project by LIPA or NYPA will be billed and collected under a separate LIPA RTFC or NYPA RTFC, as applicable, as described in Section 6.10.5.

[1]Capitalized terms used in this Schedule that are not defined in this Schedule shall have the meaning set forth in Section 31.1.1 of Attachment Y of the ISO OATT and, if not therein, in Section 1 of the OATT.

[2]An "Unregulated Transmitting Utility" is a Transmission Owner, such as LIPA and NYPA, that, pursuant to Section 201(f) of the Federal Power Act, is not subject to the Commission's jurisdiction under Sections 205 and 206(a) of the Federal Power Act.

6.10.1.2 Projects Not Eligible for Cost Recovery Through the RTFC

This Schedule does not apply to projects that are not eligible pursuant to Attachment Y of the ISO OATT for cost allocation and recovery under the ISO OATT, including, but not limited to: (i) projects undertaken by Transmission Owners through the Local Transmission Owner Planning Processes pursuant to Section 31.1.3 and Section 31.2.1 of Attachment Y of the ISO OATT; (ii) market-based solutions to transmission needs identified in the CSPP; (iii) any non-transmission components of an Eligible Project (*e.g.*, generation, energy efficiency, or demand response resources); (iv) transmission Generator Deactivation Solutions selected in the Generator Deactivation Process pursuant to Attachment FF of the ISO OATT and eligible for cost recovery through Schedule 16 (Section 6.16) of the ISO OATT; (v) transmission facilities eligible for cost recovery through another rate schedule of the ISO OATT; and (vi) facilities for which costs are recovered through the Transmission Service Charge ("TSC") or the NYPA Transmission Adjustment Charge ("NTAC") determined in accordance with Attachment H of the ISO OATT.

6.10.2 Revenue Requirement for RTFC

The RTFC (including a LIPA RTFC or NYPA RTFC, as applicable) shall be calculated in accordance with the formula set forth in Section 6.10.3 using the revenue requirement of the Transmission Owner, Unregulated Transmitting Utility, or Other Developer, as applicable, necessary to recover the costs of an Eligible Project. The revenue requirement to be used in the calculation and recovery of the RTFC for a Transmission Owner or Other Developer, other than an Unregulated Transmitting Utility, is described in Section 6.10.4. The development of a revenue requirement and recovery of costs for an Eligible Project by an Unregulated Transmitting Utility through a NYPA RTFC or a LIPA RTFC, as applicable, is described in Section 6.10.5.

If an Eligible Project involves the construction of a facility identified as a Highway System Deliverability Upgrade in a completed Class Year Interconnection Facilities Study, the Project Cost Allocation for which has been accepted and Security posted by at least one Class Year Developer, the project cost and resulting revenue requirement will be reduced to the extent permitted by Section 25.7.12.3.3 of Attachment S of the ISO OATT.

6.10.3 Calculation and Recovery of RTFC and Payment of Recovered Revenue

6.10.3.1 The ISO will calculate and bill an RTFC (or a LIPA RTFC or NYPA RTFC, as applicable) separately for each Eligible Project in accordance with this Section 6.10.3. The ISO shall collect the RTFC from LSEs. The LSEs, including Transmission Owners, competitive LSEs, municipal systems, and any other LSEs, serving Load in the Load Zones and/or Subzones to which the costs of the Eligible Project have been allocated (each a “Responsible LSE”) shall pay the RTFC. The cost of each Eligible Project shall be allocated as follows: (i) the costs of an Eligible Project that is eligible for cost allocation and recovery through the reliability planning process shall be allocated in accordance with Section 31.5.3 of Attachment Y of the ISO OATT; (ii) the costs of an Eligible Project that is eligible for cost allocation and recovery through the CARIS process shall be allocated in accordance with Section 31.5.4 of Attachment Y of the ISO OATT; (iii) the costs of an Eligible Project that is eligible for cost allocation and recovery through the Public Policy Transmission Planning Process shall be allocated in accordance with Section 31.5.5 of Attachment Y of the ISO OATT; and (iv) the costs of an Eligible Project that is eligible for cost allocation and recovery as an Interregional Transmission Project shall be allocated in accordance with Section 31.5.7 of Attachment Y of the ISO OATT.

6.10.3.2 The revenue requirement established by the Transmission Owner or Other Developer pursuant to Section 6.10.4 and an Unregulated Transmitting Utility pursuant to Section 6.10.5 will be the basis for the applicable RTFC Rate ($/MWh) that shall be charged by the ISO to each Responsible LSE based on its Actual Energy Withdrawals as set forth in Section 6.10.3.5.

6.10.3.3 The Developer shall request Incremental TCCs with respect to the Eligible Project in accordance with the requirements of Section 19.2.4 of Attachment M of the ISO OATT and receive any Incremental TCCs to the extent awarded by the ISO pursuant to such request. As it relates solely to the Eligible Project, the Developer shall not be a “Transmission Owner” for purposes of Section 20.2.5 or Section 20.3.7 of Attachment N of the ISO OATT and accordingly shall not receive an allocation of Net Congestion Rents under Section 20.2.5 of Attachment

N of the ISO OATT or Net Auction Revenues under Section 20.3.7 of Attachment N of the ISO OATT.

The Developer shall in relation to any Eligible Project exercise its right to obtain and maintain in effect all Incremental TCCs, including temporary Incremental TCCs, to which it has rights under Section 19.2.4 of Attachment M of the ISO OATT and shall take the actions required to do so in accordance with the procedures specified therein. Notwithstanding Sections 19.2.4.7 and 19.2.4.8 of Attachment M of the ISO OATT, Incremental TCCs created and awarded to the Developer as a result of implementation of an Eligible Project shall not be eligible for sale in Secondary Markets. Incremental TCCs that may be created and awarded to the Developer as a result of the implementation of an Eligible Project, shall be offered by the Developer in all rounds of the six month Sub-Auction of each Centralized TCC Auction conducted by the ISO. The ISO shall disburse the associated auction revenues to the Developer. The total amount of the auction revenues disbursed to the Developer pursuant to this Section 6.10.3.3 shall be used in the calculation of the RTFC Rate, as set forth in Section 6.10.3.5. Incremental TCCs associated with an Eligible Project shall continue to be offered for the duration of the Incremental TCCs, established pursuant to the terms of Attachment M of the ISO OATT.

The revenue offset discussed in this Section 6.10.3.3 shall commence upon the first payment of revenues related to Incremental TCCs associated with the implementation of an Eligible Project on or after the date the RTFC is implemented. The RTFC and the revenue offset related to Incremental TCCs associated with the implementation of an Eligible Project shall not require and shall not be dependent upon a reopening or review of: (i) the Developer's revenue requirements for the RTFC of another Eligible Project pursuant to this Section 6.10 of the ISO OATT, (ii) the Developer's revenue requirement for charges set forth in another rate schedule of the ISO OATT, or (iii) the Transmission Owners' revenue requirements for the TSCs or NTAC set forth in Attachment H of the ISO OATT.

6.10.3.3.1 With respect to the Eligible Project only, the Developer shall receive the outage charges described herein and shall not be charged O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Auction Revenue Shortfall Charges or U/D Auction Revenue Shortfall Charges or be paid O/R-t-S Congestion Rent Surplus Payments, U/D Congestion Rent Surplus Payments, O/R-t-S Auction Revenue Surplus Payments or U/D Auction Revenue Surplus Payments under Section 20.2.4 and Section 20.3.6 of Attachment N of the ISO OATT. Outage charges related to any Incremental TCCs awarded by the ISO for an Eligible Project shall be assessed to the Developer, and payable by the Developer to the ISO, pursuant to Section 19.2.4 of Attachment M of the ISO OATT for an Expander not subject to Section 20.2.5 of Attachment N of the ISO OATT for any hour in the Day-Ahead Market during which an Expansion, associated with an Eligible Project, is modeled to be wholly or partially out of service.

6.10.3.4 The billing units for the RTFC Rate for the Billing Period shall be based on the Actual Energy Withdrawals available for the current Billing Period for those Load Zones and/or Subzones allocated the costs of the project in the manner described in Section 6.10.3.1.

6.10.3.5 Cost Recovery Methodology

The ISO shall calculate the RTFC for each Eligible Project for each Responsible LSE as follows:

Step 1: Calculate the $ assigned to each Load Zone or Subzone (as applicable)

$$\mathrm{RTFC}_{p,z,B} = \left(\mathrm{AnnualRR}_{p,B} - \mathrm{IncrementalTransmissionRightsRevenue}_{p,B} + \mathrm{OutageCostAdjustment}_{p,B}\right) \times \left(\mathrm{ZonalCostAllocation}_{z,p}\right)$$

Step 2: Calculate a per-MWh Rate for each Load Zone or Subzone (as applicable)

$$\mathrm{RTFCRate}_{p,z,B} = \mathrm{RTFC}_{p,z,B} / \mathrm{MWh}_{z,B}$$

Step 3: Calculate charge for each Billing Period for each Responsible LSE in each Load Zone or Subzone (as applicable)

$$\mathrm{Charge}_{B,l,z,p} = \mathrm{RTFCRate}_{p,z,B} * \mathrm{MWh}_{l,z,B}$$

Step 4: Calculate charge for each Billing Period for each Responsible LSE across all Load Zones or Subzones (as applicable)

$$\mathrm{Charge}_{B,l,p} = \sum_{z \in Z} \left(\mathrm{Charge}_{B,l,z,p}\right)$$

Where,

l = the relevant Responsible LSE;

p = an individual Eligible Project;

z = an individual Load Zone or Subzone, as applicable;

Z = set of ISO Load Zones or Subzones as applicable;
B = the relevant Billing Period;

$MWh_{\mathbf{z,B}}$ = Actual Energy Withdrawals in Load Zone or Subzone, as applicable, z aggregated across all hours in Billing Period B;

$MWh_{l,z,B}$ = Actual Energy Withdrawals for Responsible LSE l in Load Zone or Subzone, as applicable, z aggregated across all hours in Billing Period B;

$AnnualRR_{p,B}$ = the pro rata share of the annual revenue requirement for each Eligible Project p as discussed in Section 6.10.2 above, allocated for Billing Period B;

$IncrementalTransmissionRightsRevenue_{p,B}$ = the auction revenue derived from the sale of Incremental TCCs plus Incremental TCC payments received by the Developer pursuant to Section 20.2.3 of Attachment N of the ISO OATT for each Eligible Project p, as discussed in Section 6.10.3.3 above, allocated for Billing Period B. The revenues from the sale of Incremental TCCs in the ISO's six month Sub-Auctions of each Centralized TCC Auction shall be allocated uniformly across all hours of the Billing Period;

$OutageCostAdjustment_{p,B}$ = the Outage charges determined pursuant to Section 6.10.3.3.1 above for any hour in the Day-Ahead Market during which the Eligible Project p is modeled to be wholly or partially out of service aggregated across all hours in Billing Period B; and

$ZonalCostAllocation_{z,p}$ = the proportion of the cost of Eligible Project p allocated to Load Zone or Subzone, as applicable, z, in the manner described in Section 6.10.3.1 above;

6.10.3.6 The NYISO will collect the appropriate RTFC revenues each Billing Period and remit those revenues to the appropriate Transmission Owner, Unregulated Transmitting Utility, or Other Developer in accordance with the NYISO's billing and settlement procedures; *provided, however*, that LIPA will be responsible for billing and collecting the costs of an Eligible Project undertaken by LIPA that are allocated to customers within the Long Island Transmission District in accordance with Section 6.10.5.2.1.

6.10.4 Recovery of Costs Incurred by Transmission Owner or Other Developer

6.10.4.1 The RTFC shall be used as the cost recovery mechanism for the recovery of the costs of an Eligible Project undertaken by a Transmission Owner or Other Developer, other than an Unregulated Transmitting Utility, which project is authorized by the Commission to recover costs under this rate mechanism; *provided*, *however*, nothing in this cost recovery mechanism shall be deemed to create any additional rights for a Transmission Owner or Other Developer to proceed with a regulated transmission project that it does not otherwise have at law. The costs that may be included in the revenue requirement for calculating the RTFC pursuant to Section 6.10.3 include all reasonably incurred costs, as determined by the Commission, related to the preparation of proposals for, and the development, financing, construction, operation, and maintenance of, an Eligible Project, including those costs explicitly permitted for recovery pursuant to Attachment Y of the ISO OATT. These costs include, but are not limited to, a reasonable return on investment and any incentives for the construction of transmission projects approved under Section 205 or Section 219 of the Federal Power Act and the Commission's regulations implementing those sections.

6.10.4.2 The period for cost recovery will be determined by the Commission and will begin if and when the Eligible Project enters into service, is halted, or as otherwise determined by the Commission, including for the recovery of CWIP or other permissible cost recovery. The Transmission Owner/Other Developer, or, at its request, the ISO, shall either make a Section 205 filing with the Commission or make an informational filing under a formula rate to provide for the Commission's review and approval or acceptance of the project cost and resulting revenue requirement to be recovered through the RTFC. The filing may include all reasonably incurred costs specified in Section 6.10.4.1 of this Schedule that are related to the Transmission Owner's or the Other Developer's undertaking an

Eligible Project. The filing must be consistent with the Transmission Owner's or the Other Developer's project proposal made to and evaluated by the ISO pursuant to Attachment Y. The Transmission Owner or Other Developer shall bear the burden of resolving all concerns about the contents of the filing that might be raised in such proceeding. The ISO will begin to calculate and bill the RTFC in accordance with the period for cost recovery determined by the Commission after the Commission has accepted or approved the filing or otherwise allowed the filing to go into effect pursuant to a formula rate.

6.10.5 Recovery of Costs by an Unregulated Transmitting Utility

6.10.5.1 The costs that may be included in the revenue requirement for an Eligible Project undertaken by an Unregulated Transmitting Utility include all reasonably incurred costs related to the preparation of proposals for, and the development, financing, construction, operation, and maintenance of, an Eligible Project, including those costs explicitly permitted for recovery pursuant to Attachment Y of the ISO OATT, as well as a reasonable return on investment. Except as otherwise provided in Section 6.10.5.2.1, for any recovery of a revenue requirement by an Unregulated Transmitting Utility under the RTFC, the period of cost recovery will be determined by the Commission and will begin if and when the Eligible Project enters into service, is halted, or as otherwise determined by the Commission, including for the recovery of CWIP or other permissible cost recovery. Except as otherwise provided in Section 6.10.5.2.1, the ISO will begin to calculate and bill the RTFC for an Unregulated Transmitting Utility pursuant to Section 6.10.3 in accordance with the period for cost recovery determined by the

Commission after the Commission has accepted or approved the filing of its revenue requirement or otherwise allowed the filing to go into effect pursuant to a formula rate.

6.10.5.2 Cost Recovery for LIPA

Any costs incurred for an Eligible Project undertaken by LIPA, as an Unregulated Transmitting Utility, that are eligible for recovery under Section 6.10.5.1 under a LIPA RTFC shall be recovered over the period established by Long Island Power Authority's Board of Trustees as follows:

6.10.5.2.1 For costs to LIPA customers: Cost will be recovered pursuant to a rate recovery mechanism approved by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Upon approval of the rate recovery mechanism, LIPA shall provide to the ISO, for purposes of inclusion within the ISO OATT and filing with the Commission on an informational basis only, a description of the rate recovery mechanism, the costs of the Eligible Project, and the rate that LIPA will charge and collect from responsible entities within the Long Island Transmission District in accordance with the ISO cost allocation methodology pursuant to Section 31.5 of Attachment Y of the ISO OATT.

6.10.5.2.2 For Costs to Other Transmission Districts, As Applicable: Where the ISO determines that there are Responsible LSEs serving Load outside of the Long Island Transmission District that should be allocated a portion of the costs of the Eligible Project undertaken by LIPA, LIPA shall coordinate with and inform the ISO of the amount of such costs. Such costs will be an allocable amount of the cost base recovered through the recovery mechanism described in Section 6.10.5.2.1 in accordance with the formula set forth in Section 6.10.3.5. Such costs of the Eligible Project allocable to Responsible LSEs serving Load outside of the Long Island Transmission District shall constitute the "revenue requirement." The ISO shall file the revenue requirement with the Commission if requested to do so by LIPA, for Commission review under the same "comparability" standard as is applied to review of changes in LIPA's TSC under Attachment H of the ISO OATT. The filing must be consistent with LIPA's project proposal made to and evaluated by the ISO pursuant to Attachment Y. LIPA shall intervene in support of such filing at the Commission and shall bear the burden of resolving all concerns about the contents of the filing that might be raised in such proceeding. Upon the Commission's acceptance for filing of LIPA's revenue requirement and using the procedures described in Sections 6.10.3.1 through 6.10.3.5 of this Schedule, the ISO shall calculate a separate LIPA RTFC based on the revenue requirement and shall bill for LIPA the LIPA RTFC as a separate line item to the Responsible LSEs serving Load in Transmission Districts located outside of the Long Island Transmission District. The ISO shall remit the revenues collected to LIPA in accordance with the ISO's billing and settlement procedures.

6.10.5.3 Cost Recovery for NYPA

Any costs incurred for an Eligible Project undertaken by NYPA, as an Unregulated Transmitting Utility, that are eligible for recovery under Section 6.10.5.1 shall be recovered under a NYPA RTFC as described herein. A reasonable return on investment for an Eligible

Project undertaken by NYPA may include any incentives for construction of transmission projects available under Section 205 or Section 219 of the Federal Power Act and the Commission's regulations implementing those sections, as determined by the Commission.

6.10.5.3.1 NYPA shall coordinate with and inform the ISO of the amount of the costs it incurred in undertaking an Eligible Project. Such costs shall constitute the revenue requirement. Either the ISO shall make a Section 205 filing with the Commission on behalf of NYPA or NYPA shall make an informational filing under a formula rate with the Commission, of the revenue requirement. The filing must be consistent with NYPA's project proposal made to and evaluated by the ISO pursuant to Attachment Y. NYPA shall intervene in support of such filing at the Commission and shall bear the burden of resolving all concerns about the contents of the filing that might be raised in such proceeding, including being solely responsible for making any arguments or reservations regarding its status as a non-Commission-jurisdictional utility and the appropriate standard for Commission review of its revenue requirement. After the Commission has accepted or approved the filing or otherwise allowed the filing to go into effect pursuant to a formula rate, the ISO shall calculate in accordance with Sections 6.10.3.1 through 6.10.3.5 of this Schedule a separate NYPA RTFC based on the revenue requirement and bill for NYPA the NYPA RTFC to the Responsible LSEs. The ISO shall remit the revenues collected to NYPA in accordance with the ISO's billing and settlement procedures.

6.10.5.4 Savings Clause. The inclusion in the ISO OATT or in a filing with the Commission pursuant to Section 6.10.5 of the revenue requirement for recovery of costs incurred by an Unregulated Transmitting Utility, including LIPA or NYPA, related to an Eligible Project undertaken pursuant to Attachment Y of the ISO OATT, as provided for in this Section 6.10.5, or the inclusion of such revenue requirement in the LIPA RTFC or NYPA RTFC, shall not be deemed to modify the treatment of such rates as non-jurisdictional pursuant to Section 201(f) of the FPA.

6.11 Schedule 11 - Penalty Cost Recovery

6.11.1 Direct Allocation of Costs Associated With NERC Penalty Assessments

6.11.1.1 Purpose and Objectives

Under the NERC Functional Model and the NERC Rules of Procedure, Registered Entities within a specific function may be assessed penalties by FERC, NERC, and/or NPCC for violations of NERC Reliability Standards. Pursuant to the terms and conditions of the Tariff and the ISO Procedures, certain tasks associated with Reliability Standards compliance may be performed either by the ISO and/or the Customers even when they are not the Registered Entity. This Schedule furnishes a mechanism by which either the ISO or a Customer may directly allocate, with FERC approval, monetary penalties imposed by FERC, NERC and/or NPCC on the Registered Entity to entity or entities whose conduct is determined by NERC or the Regional Entity to have led to a Reliability Standard violation. For purposes of this rate schedule, the terms "Customer" and "Market Participant" shall include Transmission Owners. The purpose of this schedule is to allow for cost allocation; nothing in this schedule is intended to affect the obligations of Registered Entities for compliance with NERC Reliability Standards. Penalties that are assessed against the ISO on or after the effective date of this Section shall be recoverable as provided in this Section regardless of the date of the violation(s) for which the penalty is assessed. Notwithstanding any provisions of the ISO's Tariffs or ISO Related Agreements, including those provisions requiring stakeholder approval for Section 205 filings in certain instances, the ISO has the independent authority to make Section 205 filings in accordance with the provisions of this Schedule 11 after consultation with the Management Committee as provided in Section 5.1.1(c) of the Services Tariff or Section 2.11.6(c) of the ISO OATT.

6.11.1.2 Definitions

All defined terms in this Schedule shall have the meaning given to them in the Tariff and the ISO Procedures unless otherwise stated below.

Compliance Monitoring and Enforcement Program (CMEP) - The program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

NERC Functional Model - Defines the set of functions that must be performed to ensure the reliability of the bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

NERC Reliability Standards - Those standards that have been developed by NERC and approved by FERC to ensure the reliability of the bulk power system.

NERC Rules of Procedure - The rules and procedures developed by NERC and approved by **the** FERC. These rules include the process by which a responsible entity, which is to perform a set of functions to ensure the reliability of the bulk power system, must register as the Registered Entity.

Registered Entity - The entity registered under the NERC Functional Model and NERC Rules of Procedures for the purpose of compliance with NERC Reliability Standards and responsible **for** carrying out the tasks within a NERC function without regard to whether a task or tasks are performed by another entity pursuant to the terms of the ISO's Tariffs and ISO Related Agreements.

Regional Entity - An entity to whom NERC has delegated Electric Reliability Organization (ERO) functions in a particular geographic region. For the ISO region, the applicable Regional Entity is the Northeast Power Coordinating Council (NPCC).

6.11.1.3 Allocation of Costs When the ISO is the Registered Entity

6.11.1.3.1 If FERC, NERC and/or NPCC assesses a monetary penalty against the ISO as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of a Customer or Customers contributed to the Reliability Standard violation(s) at issue, then the ISO may directly allocate such penalty costs or a portion thereof to the Customer or Customers whose conduct contributed to the Reliability Standards violation(s), provided that all of the following conditions have been satisfied:

(1) Pursuant to the CMEP, the Customer or Customers received notice and an opportunity to fully participate in the underlying CMEP proceeding;

(2) This CMEP proceeding produced a root cause finding, subsequently filed with FERC, that the Customer contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and

(3) A NERC filing of the root cause finding identifying the Customer's or Customers' conduct as causing or contributing to the Reliability Standards violation charged against the ISO as the Registered Entity is made at FERC.

6.11.1.3.2 The ISO will notify the Customer or Customers found to have contributed to a violation, either in whole or in part, in the CMEP proceedings. Such notification shall set forth in writing the ISO's intent to invoke this Section 6.11.1.3 and directly assign the costs associated with a monetary penalty to the Customer or Customers. Such notification shall (i) state that the ISO believes the criteria for direct assignment and allocation of costs under this Schedule have been satisfied; and (ii) describe the underlying factual basis supporting a penalty cost assignment, including a description of the conduct contributing to the violation and the nature of the violation of the ISO Tariffs or ISO Related Agreement requirements.

6.11.1.3.3 A failure by a Customer or Customers to participate in the CMEP proceedings will not prevent the ISO from directly assigning the costs associated with a monetary penalty to the responsible Customer or Customers provided all other conditions set forth herein have been satisfied.

6.11.1.3.4 Where the Regional Entity's and/or NERC's root cause analysis finds that more than one party's conduct contributed to the Reliability Standards violation(s), the ISO shall inform all involved Customers and shall make an initial apportionment for purposes of the cost allocation on a basis reasonably proportional to the parties' relative fault consistent with NERC's root cause analysis.

6.11.1.3.5 If the ISO and the involved Customer(s) agree on the proportion of penalty cost allocation, such agreement shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act for approval.

6.11.1.3.6 Should the Customer(s) disagree with the ISO's initial apportionment of the penalty based on each party's relative fault, then the parties shall meet in an attempt to informally resolve the penalty allocation. If the parties cannot agree informally, the matter shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

6.11.1.3.7 Once there is a final order by FERC regarding the ISO's ability to directly assign the penalty amounts, the ISO shall include such amounts in the appropriate Customer's or Customers' invoice for the next Billing Period. Such payment amount shall be due with interest calculated at the FERC authorized refund rate from the date of payment of the penalty by the ISO, provided however, nothing precludes the Customer or Customers from paying such penalty when it becomes due for the ISO to avoid paying interest costs. If the Customer pays such penalty under protest when it becomes due and prior to a final order by FERC and such Customer is thereafter found not liable, the Customer is entitled to a refund of the penalty amount from the ISO, with interest calculated at the FERC authorized refund rate from the date the Customer pays the penalty.

6.11.1.4 Allocation of Costs When a Customer is the Registered Entity

6.11.1.4.1 If FERC, NERC and/or NPCC assesses a monetary penalty against a Customer as the Registered Entity for a violation of a NERC Reliability Standard(s), and the conduct of the ISO contributed to the Reliability Standard violation(s) at issue, then such Customer may directly allocate such penalty costs or portion thereof to the ISO to the extent the ISO's conduct contributed to the Reliability Standards violation(s), provided that the following conditions have been satisfied:

6.11.1.4.1.1 Pursuant to the CMEP, the ISO received notice and an opportunity to fully participate in the underlying CMEP proceeding;

6.11.1.4.1.2 This CMEP proceeding produced a root cause finding, subsequently filed with FERC, that the ISO contributed, either in whole or in part, to the NERC Reliability Standards violation(s); and

6.11.1.4.1.3 A NERC filing of the root cause finding identifying the ISO's conduct as causing or contributing to the Reliability Standards violation charged against the Customer as the Registered Entity is made at FERC.

6.11.1.4.2 The Customer shall notify the ISO if the ISO is found to have contributed to a violation, either in whole or in part in the CMEP proceedings. Such notification shall set forth in writing the Customer's intent to invoke this Section 6.11.1.4 and directly assign the costs associated with a monetary penalty to the ISO. Such notification shall (i) state that the Customer believes the criteria for direct assignment and allocation of costs under this Schedule have been satisfied; and (ii) describe the underlying factual basis supporting a penalty cost assignment, including a description of the conduct contributing to the violation and, where applicable, the nature of the violation of the ISO Tariffs or ISO Related Agreement requirements.

6.11.1.4.3 A failure by the ISO to participate in the CMEP proceedings will not prevent the Customer from directly assigning the costs associated with a monetary penalty to the ISO provided all other conditions set forth herein have been satisfied.

6.11.1.4.4 Where the Regional Entity's and/or NERC's root cause analysis finds that the ISO's conduct contributed to the Reliability Standards violation(s), the Customer shall inform the ISO and shall make an initial apportionment for purposes of the cost allocation on a basis reasonably proportional to the parties' relative fault consistent with NERC's root cause analysis.

6.11.1.4.5 If the ISO and the involved Customer agree on a proportion of penalty cost allocation, such agreement shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

6.11.1.4.6 Should the ISO disagree with the Customer's initial apportionment of the penalty based on each party's relative fault, then the parties shall meet in an attempt to informally resolve the penalty allocation. If the parties cannot agree informally, the matter shall be submitted to the FERC pursuant to Section 205 of the Federal Power Act.

6.11.1.4.7 Once there is a final order by FERC regarding the Customer's direct assignment of costs to the ISO, the ISO shall pay such amount with interest calculated at the FERC authorized refund rate from the date of payment of the penalty by the Registered Entity. The ISO shall thereafter pursue the recovery of such costs in accordance with Section 6.11.3 of this Schedule 11. Nothing precludes the ISO from paying such penalty when it becomes due for the Registered Entity to avoid paying interest costs. If the ISO pays such penalty under protest when it becomes due and prior to a final order by FERC and the ISO thereafter is found not liable, the ISO is entitled to a refund of the penalty amount from the Customer with interest calculated at the FERC authorized refund rate from the date of payment of the penalty by the ISO. The ISO shall thereafter refund any amounts that were collected from all Customers pursuant to Section 6.11.3 of this Schedule 11.

6.11.2 Allocation of Costs Associated With Other Reliability **Penalty Assessments**

6.11.2.1 Purpose and Objectives

The ISO is responsible for performing specific functions under other applicable state and federal regulatory requirements and may be assessed penalties by other regulatory bodies for violations of applicable regulatory requirements. Section 6.11.3 of this Schedule furnishes a mechanism by which the ISO may seek to recover monetary penalties imposed by such regulatory authorities. Penalties that are assessed against the ISO on or after the effective date of this Section shall be recoverable as provided in this Section regardless of the date of the violation(s) for which the penalty is assessed. Notwithstanding any provisions of the ISO's Tariffs or ISO Related Agreements, including those provisions requiring stakeholder approval for Section 205 filings in certain instances, the ISO has the independent authority to make Section 205 filings in accordance with the provisions of this Schedule 11 after consultation with the Management Committee as provided in Section 5.1.1(c) of the Services Tariff and in Section 2.11.6(c) of the ISO OATT.

6.11.3 Allocation of Costs Associated With Penalty Assessments

6.11.3.1

Where a particular Customer or Customers cannot be identified as the root cause of a penalty assessment against the ISO or if the ISO is assessed a penalty because of its own action or inaction that resulted in a reliability standard violation or a violation of applicable state or federal regulatory requirements, or if the ISO is allocated a penalty under Section 6.11.1.4 of this Schedule 11, the ISO may seek to recover such penalty costs in accordance with this Schedule 11. Any inclusion of penalty assessments in this Schedule 11 must first be approved by FERC on a case-by-case basis, as provided in *Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators*, Docket No. AD07-12-000, 122 FERC ¶ 61,247 (2008), or any successor policy. Notwithstanding any provisions of the ISO's Tariffs or ISO Related Agreements, including those provisions requiring stakeholder approval for Section 205 filings in certain instances, the ISO has the independent authority to make Section 205 filings in accordance with the provisions of this Schedule 11 after consultation with the Management Committee as provided in Section 5.1.1(c) of the Services Tariff or Section 2.11.6(c) of the ISO OATT.

6.11.3.2

Any and all costs associated with the imposition of NERC Reliability Standards penalties or penalties assessed by other regulatory authorities that may be assessed against the ISO either directly by NERC, other regulatory authority or allocated by a Customer or Customers under this Schedule shall be (i) paid by the ISO notwithstanding the limitation of liability provisions in this Tariff or the Services Tariff; and (ii) recovered as set forth in this Schedule 11, after consultation with the Management Committee as provided in Section 5.1.1(c) of the Services Tariff or Section 2.11.6(c) of the ISO OATT, or as otherwise approved by the FERC.

6.11.3.3

Penalties that are assessed against the ISO on or after the effective date of this section shall be recoverable as provided in this section regardless of the date of the violation(s) for which the penalty is assessed.

6.11.3.4 Allocation Basis and Invoicing

6.11.3.4.1 Allocation Basis. Any penalties that are permitted recovery under Section 6.11.3.0 of this Schedule 11 shall be allocated 50% to all Injection Billing Units and 50% to all Withdrawal Billing Units in the following manner. The rate to be applied to Injection Billing Units shall be the quotient of (i) 50% of (ii) the penalty costs to be recovered in the Billing Period divided by the total Injection Billing Units for the Billing Period. The rate to be applied to the Withdrawal Billing Units shall be the quotient of (i) 50% of (ii) the penalty costs to be recovered in the Billing Period divided by the total Withdrawal Billing Units for that Billing Period. The Injection Billing Unit rate shall then be multiplied by each Transmission Customer's aggregate Injection Billing Units for the Billing Period, and the Withdrawal Billing Unit rate shall be multiplied by each Transmission Customer's aggregate Withdrawal Billing Units for the Billing Period.

6.11.3.4.2 Invoicing. Once there is a final order by FERC regarding the ISO's ability to recover penalty amounts, the ISO shall include such amounts in the invoice for the next Billing Period utilizing the billing units for the Billing Period of infraction. For purposes of this calculation, the "Billing Period of infraction" shall be the Billing Period in which the violation occurred. Should the penalty be assessed for a violation occurring over multiple Billing Periods, the penalty to be recovered for each Billing Period shall be the total penalty to be recovered through Section 6.11.3 of this Schedule divided by the number of Billing Periods over which the violation occurred. Whenever practicable, the ISO shall recover this Rate Schedule 11 charge in the invoice issued in the Billing Period following the Billing Period in which the NYISO incurs the penalty charge. The ISO may recover penalty charges over several Billing Periods if, in its discretion, the ISO determines such method of recovery to be a prudent course of action. In the event that one or more entities who otherwise would have been apportioned a share of the penalty are no longer Customers, the ISO shall adjust the remaining Customers' shares of the penalty costs, on a proportional basis, if necessary to fully recover the penalty charge.

6.12 Schedule 12 - Rate Mechanism for the Recovery of the Highway Facilities Charge ("HFC")

6.12.1 Applicability

6.12.1.1 This Schedule establishes the Highway Facilities Charge ("HFC") for the recovery of that portion of the costs related to Highway System Deliverability Upgrades ("Highway SDUs") required for deliverability under Section 25.7.12 of Attachment S of the ISO OATT that are allocated to Load Serving Entities ("LSEs"). This Schedule shall not apply to: (i) the extent that a Highway SDU is addressed and funded as part of a transmission project undertaken in accordance with the Comprehensive System Planning Process pursuant to Attachment Y of the ISO OATT; (ii) costs for System Upgrade Facilities or System Deliverability Upgrades that are allocated to Developers or Interconnection Customers in accordance with Attachments S, X or Z of the ISO OATT; (iii) costs of transmission expansion projects undertaken in connection with an individual request for Transmission Service under Sections 3.7 or 4.5 of the ISO OATT; (iv) transmission facilities eligible for cost recovery pursuant to another rate schedule of the ISO OATT; and (v) transmission facilities for which costs are recovered through the Transmission Service Charge ("TSC") or the NYPA Transmission Adjustment Charge ("NTAC") determined in accordance with Attachment H of the ISO OATT.

6.12.1.2 The HFC shall be calculated in accordance with the formula in Section 6.12.3 using the revenue requirement related to each Highway SDU filed with the Commission by a Transmission Owner pursuant to Section 6.12.2 and approved or accepted by the Commission. The costs that may be included in the revenue requirement for calculating the HFC include all reasonably incurred costs, as determined by the Commission, related to the development, construction, operation and maintenance of any Highway SDU undertaken pursuant to Attachment S of this tariff (including costs for a Highway SDU that is subsequently halted through no fault of the constructing Transmission Owner) that are allocated to LSEs. These costs include, but are not limited to, a reasonable return on investment and any incentives for the construction of transmission projects approved under Section 205 or Section 219 of the Federal Power Act and the Commission's regulations implementing those sections. The HFC established under this Schedule shall be separate from the TSC and the NTAC determined in accordance with Attachment H of the ISO OATT, and any charge for transmission facilities eligible for cost recovery through another rate schedule of the ISO OATT.

6.12.2 Recovery of Transmission Owner's Costs Related to Highway SDUs

Each Transmission Owner shall file with the Commission the rate treatment, prior to the implementation of any HFC, that will be used to derive and determine the revenue requirement to be included in the HFC for Highway SDUs undertaken pursuant to a Class Year Deliverability Study and allocated to LSEs in accordance with Section 25.7.12 of Attachment S of the ISO OATT. The rate treatment will provide for the recovery of the full revenue requirement for that portion of a Highway SDU that is allocated to LSEs consistent with the provisions of Attachment S and this Rate Schedule. Pursuant to a determination by the ISO that the threshold for construction of a Highway SDU has been crossed in accordance with Section 25.7.12.3.1 of Attachment S of the ISO OATT, the Transmission Owner(s) responsible for constructing the

Highway SDU will proceed with the approval process for all necessary federal, state and local authorizations for the requested project to which this HFC applies.

6.12.2.1 Upon receipt of all necessary federal, state, and local authorizations, including Commission approval or acceptance of the rate treatment, the Transmission Owner(s) shall commence construction of the project.

6.12.2.2 The portion of the cost of the Highway SDU to be allocated to LSEs will be reduced by any Headroom payments made to the constructing Transmission Owner by a subsequent Developer or Interconnection Customer prior to the completion of the project.

6.12.2.3 The period for cost recovery will be determined by the Commission and will begin if and when the Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12 enters service, is halted, or as otherwise determined by the Commission. The Transmission Owner(s) will make a filing with the Commission to provide for its review and approval or acceptance of the final project cost and resulting revenue requirement to be recovered through the HFC pursuant to this Rate Schedule 12. The Transmission Owner(s) shall bear the burden of resolving all concerns about the content of the filing that might be raised in such proceeding. The ISO will begin to calculate and bill the HFC in accordance with the period for cost recovery determined by the Commission after the Commission has accepted or approved the filing.

6.12.3 Calculation and Recovery of HFC and Payment of Recovered Revenue

The HFC is to be invoiced by the ISO separately for each Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12 and paid by the LSEs allocated in accordance with Section 25.7.12.3.2 of Attachment S of the ISO OATT. The ISO shall collect the HFC from LSEs. The LSEs,, including Transmission Owners, non-Transmission Owner LSEs, municipal systems, competitive LSEs and any other LSE, to which the costs of the Highway SDU have been allocated (each a "Responsible LSE") will be invoiced by the ISO and shall pay the HFC.

6.12.3.1 The revenue requirement filed by the Transmission Owner pursuant to this Schedule and approved or accepted by the Commission, as may be subsequently adjusted in accordance with Section 6.12.4.1.3 below, will be the basis for the HFC that shall be charged by the ISO to each Responsible LSE for the Billing Period based on the Responsible LSE's proportionate share of the ICAP requirement in the statewide capacity market, adjusted to subtract locational capacity requirements, as set forth in Section 25.7.12.3.2 of Attachment S of the ISO OATT.

6.12.3.2 The HFC for the Billing Period shall include operation and maintenance costs for the proportionate share of the Highway SDU funded by LSEs.

6.12.3.3 LSEs will not be responsible for actual costs in excess of their share of the final Class Year estimated cost of the Highway SDU if the excess results from causes within the control of a Transmission Owner(s) responsible for constructing the Highway SDU as described in Section 25.8.6.4 of Attachment S of the ISO OATT.

6.12.3.4 As described in Section 25.7.2.2 of Attachment S of the ISO OATT, the Transmission Owner(s) responsible for constructing a Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12 shall request Incremental TCCs with respect to the Highway SDU in accordance with the requirements of Section 19.2.4 of Attachment M. As it relates solely to a Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12, the Transmission Owner(s) responsible for constructing the Highway SDU shall not be a "Transmission Owner" for purposes of Section 20.2.5 or Section 20.3.7 of Attachment N of the ISO OATT. Accordingly, the Transmission Owner(s) responsible for constructing the Highway SDU shall not receive Net Congestion Rents pursuant to Section 20.2.5 of Attachment N of the ISO OATT or Net Auction Revenues pursuant to Section 20.3.7 of Attachment N of the ISO OATT as it relates to a Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12.

6.12.3.4.1 The Transmission Owner(s) responsible for constructing a Highway SDU shall exercise its right to obtain and maintain in effect all Incremental TCCs they are awarded with respect to the Highway SDU, as further described in Section 25.7.2.2 of Attachment S of the ISO OATT. The Incremental TCCs awarded with respect to a Highway SDU may not be sold or transferred through a Centralized TCC Auction, Reconfiguration Auction or the Secondary Market. The Transmission Owner(s) responsible for constructing a Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12 shall receive congestion payments pursuant to Section 20.2.3 of Attachment N of the ISO OATT for any Incremental TCCs related to the Highway SDU for which it is the Primary Holder. The congestion payments received by the Transmission Owner(s) responsible for constructing a Highway SDU from any Incremental

TCCs it holds related to the Highway SDU will be used in the calculation of the HFC. The HFC and adjustments related to Incremental TCCs shall not require and shall not be dependent upon any reopening or any review of : (i) the Transmission Owner's revenue requirements for the HFC for another Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12; (ii) the Transmission Owner's revenue requirements for the TSCs and NTAC set forth in Attachment H of the ISO OATT; or (iii) the Transmission Owner's revenue requirements for the charge for a transmission facility eligible for cost recovery pursuant to another rate schedule of the ISO OATT.

6.12.3.4.2 As it relates solely to a Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12, the Transmission Owner(s) responsible for constructing the Highway SDU shall receive outage charges for any Incremental TCCs related to the Highway SDU it holds pursuant to Section 19.2.4.10 of Attachment M of the ISO OATT for any hour in the Day-Ahead Market during which the Highway SDU is modeled to be wholly or partially out of service as an entity not subject to Section 20.2.5 of Attachment N of the ISO OATT with respect to the Highway SDU. Accordingly, the Transmission Owner(s) responsible for constructing the Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12 shall not be charged or paid O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Auction Revenue Shortfall Charges, U/D Auction Revenue Shortfall Charges, O/R-t-S Congestion Rent Surplus Payments, U/D Congestion Rent Surplus Payments, O/R-t-S Auction Revenue

Surplus Payments or U/D Auction Revenue Surplus Payments pursuant to Attachment N of the ISO OATT.

6.12.3.5 **Cost Recovery Methodology**

The HFC for the Billing Period shall be based on the ICAP requirement in the statewide capacity market, adjusted to subtract locational capacity requirements for those LSEs determined to be allocated the costs of the project in accordance with Section 25.7.12 of Attachment S of the ISO OATT.

6.12.3.5.1 The ISO shall calculate each LSE's share of the HFC for each Billing Period (*i.e.*, LSE HFC $\text{Allocation}_{p,l,B}$) as follows:

LSE HFC $\text{Allocation}_{p,l,B}$ = (Billing Period $\text{HFC}_{p,B}$ - $\text{IncrementalTransmissionRightsRevenue}_{p,B}$+ Outage Cost $\text{Adjustment}_{p,B}$) x (LSE ICAP Allocation $\%_{l,B}$)

Where:

l = the relevant Responsible LSE;

p = an individual Highway SDU for which a portion of the costs thereof are recovered pursuant to this Rate Schedule 12;

B= the relevant Billing Period;

Billing Period $\text{HFC}_{p, B}$ = the pro-rata share of the annual HFC for Highway SDU p, as discussed in Section 6.12.2 above and as may be adjusted in accordance with Section 6.12.4.1.3 below, allocated for Billing Period B;

LSE ICAP Allocation $\%_{l,B}$ = the LSE's proportionate share of the NYCA ICAP requirement for Billing Period B, adjusted to subtract Locational ICAP requirements for Billing Period B, which shall be calculated as:

> (LSE total ICAP Requirement – Sum of LSE Locational ICAP Requirements for any Locality not located within another Locality)/(NYCA Minimum Installed Capacity Requirement – Sum of Locational Minimum Installed Capacity Requirements for any Locality not located within another Locality)

Such ICAP requirements shall be the ICAP equivalent of the LSE's UCAP requirements prior to any reduction for Locality Exchange MW;

$\text{IncrementalTransmissionRightsRevenue}_{p,B}$ = Congestion payments received by the applicable

Transmission Owner for Billing Period B pursuant to Section 20.2.3 of Attachment N of the ISO OATT for any Incremental TCCs held by the Transmission Owner related to the Highway SDU p, as discussed in Section 6.12.3.4.1 above; and

Outage Cost Adjustment$_{p,B}$ = the Outage charges for any Incremental TCCs held by the Transmission Owner related to the Highway SDU p determined pursuant to Section 6.12.3.4.2 above for any hour in the Day-Ahead Market during which the Highway SDU p is modeled to be wholly or partially out of service aggregated across all hours of Billing Period B.

6.12.3.5.2 The ISO will collect the appropriate HFC revenues each Billing Period and remit those revenues to the appropriate Transmission Owner(s) in accordance with the ISO's billing and settlement procedures.

6.12.3.5.3 Billing true-ups to account for load shifting between LSEs will be based upon the existing ICAP methodology, as appropriate. These true-ups will occur on a monthly basis pursuant to ISO procedures.

6.12.4 Headroom Accounting

As new generators and merchant transmission facilities come on line and use the Headroom created by a prior Highway SDU, the Developers or Interconnection Customers of those new facilities will reimburse prior Developers or Interconnection Customers or will compensate the LSEs who funded the Highway SDU Headroom in accordance with Sections 25.8.7 and 25.8.8 of Attachment S of the ISO OATT.

6.12.4.1 The Developer or Interconnection Customer of the subsequent project shall make a lump sum payment to the constructing Transmission Owner(s) proportional to the electrical use of the Headroom in the account by the Developer's or Interconnection Customer's project.

6.12.4.1.1 Payment shall be made as soon as the cost responsibilities of the subsequent Developer or Interconnection Customer are determined in accordance with Attachment S of the ISO OATT.

6.12.4.1.2 Payment to the constructing Transmission Owner(s) will be based upon the depreciated amount of the Highway SDU in the constructing Transmission Owner's accounting records.

6.12.4.1.3 The constructing Transmission Owner(s) will adjust their revenue requirement under this Rate Schedule 12 to account for any payments received from subsequent Developers or Interconnection Customers to lower the HFC charged to LSEs going forward and notify the ISO of the adjusted revenue requirement.

6.13 Schedule 13 – Rate Mechanism for the Recovery of the Transco Facilities Charge ("TFC")

6.13.1 Applicability

This Schedule establishes the Transco Facilities Charge ("TFC") for the recovery of costs related to the following New York Transco LLC ("NY Transco") projects, each of which is hereinafter referred to as an "Approved NYTP" and each of which has been approved by the New York Public Service Commission ("NYPSC") on November 4, 2013, in Case No. 12-E-0503 (the "Transmission Owner Transmission Solutions" or "TOTS" projects): (1) the Ramapo-to-Rock Tavern Project; (2) the Marcy South Series Compensation Fraser-to-Coopers Corner Reconductoring Project; and (3) the Staten Island Unbottling Project.[1] NY Transco may undertake an Approved NYTP and seek cost recovery through a TFC under this Schedule.[2]

The TFC shall be separate from the Transmission Service Charge ("TSC") and the NYPA Transmission Adjustment Charge ("NTAC") determined in accordance with Section 14 of Attachment H of the ISO OATT, and any Reliability Facilities Charge ("RFC") determined pursuant to Section 6.10 of the ISO OATT.

In addition, NY Transco shall receive the outage charges described herein and shall not be charged O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Auction Revenue Shortfall Charges or U/D Auction Revenue Shortfall Charges or be paid O/R-t-S Congestion Rent Surplus Payments, U/D Congestion Rent Surplus Payments, O/R-t-S Auction Revenue Surplus Payments or U/D Auction Revenue Surplus Payments under

[1] Any costs incurred on the forced cooling portion of the Staten Island Unbottling Project after the date of the Commission's order approving the offer of partial settlement in Docket No. ER15-572, issued on March 17, 2016, shall not be recovered through the TFC without further order of the Commission.

[2] Capitalized terms used in this Schedule that are not defined in this Schedule shall have the same meaning set forth in Section 31.1.1 of Attachment Y of the ISO OATT.

Section 20.2.4 and Section 20.3.6 of the ISO OATT; and NY Transco shall receive Incremental TCCs as described in Section 19.2.4 of the ISO OATT, but NY Transco shall not be a "Transmission Owner" for purposes of Section 20.2.5 or Section 20.3.7 of the ISO OATT and accordingly shall not receive an allocation of Net Congestion Rents under Section 20.2.5 of the ISO OATT or Net Auction Revenues under Section 20.3.7 of the ISO OATT.

6.13.2 Revenue Requirement for TFC

The TFC shall be calculated in accordance with the formula set forth in Section 6.13.3 using the revenue requirement of NY Transco necessary to recover the costs of an Approved NYTP. The revenue requirement to be used in the calculation of the TFC is described in Section 6.13.4. The costs that may be included in the revenue requirement include all reasonably incurred costs related to the preparation of proposals for, and the development, financing, construction, operation, and maintenance of, an Approved NYTP, including, but not limited to, a reasonable return on investment and any incentives for the construction of transmission projects approved under Section 205 or Section 219 of the Federal Power Act and the Commission's regulations implementing those sections, as determined by the Commission.

6.13.3 Calculation and Recovery of TFC and Payment of Recovered Revenue

The ISO will calculate and bill the TFC for each Approved NYTP in accordance with this Section 6.13.3. The ISO shall collect the TFC from the LSEs. The LSEs, including Transmission Owners, competitive LSEs, and municipal systems, serving Load located in Transmission Districts to which the costs of the Approved NYTP have been allocated (each a "Responsible LSE") shall pay the TFC. The costs of each Approved NYTP shall be allocated as set forth in the appropriate allocation table in Section 36.2 of Attachment 1 to Attachment DD; *provided, however*, that the portion of the costs of the Approved NYTP allocated to Responsible

LSEs located in the NYPA North Subzone shall be calculated as part of the allocation percentage for Niagara Mohawk Power Corporation d/b/a National Grid set forth in Section 36.2.

6.13.3.1 The revenue requirement filed pursuant to this Schedule by NY Transco will be the basis for the TFC Rate ($/MWh) for the Billing Period that shall be charged by the ISO to each Responsible LSE based on its Actual Energy Withdrawals as set forth in Section 6.13.3.4. The revenue requirement of the NY Transco will be calculated according to the formula rate set forth in Section 36.3.1. of Attachment DD of the ISO OATT.

6.13.3.2 NY Transco shall in relation to any Approved NYTP reasonably exercise its right to obtain and maintain in effect all Incremental TCCs, including temporary Incremental TCCs, to which it has rights under Section 19.2.4 of the ISO OATT and shall take the actions required to do so in accordance with the procedures specified therein. Notwithstanding Section 19.2.4.7 and 19.2.4.8 of the ISO OATT, Incremental TCCs created and awarded to NY Transco as a result of implementation of an Approved NYTP shall not be eligible for sale in Secondary Markets. Incremental TCCs that may be created and awarded to NY Transco as a result of the implementation of an Approved NYTP, shall be offered by the ISO in all rounds of the six month Sub-Auction of each Centralized TCC Auction conducted by the ISO. The ISO shall disburse the associated auction revenues to NY Transco. The total amount of the auction revenues disbursed to the NY Transco pursuant to this Section 6.13.3.2 shall be used in the calculation of the TFC Rate, as set forth in Section 6.13.3.4. Incremental TCCs associated with an Approved NYTP shall continue to be offered for the duration of the

Incremental TCCs, established pursuant to the terms of Attachment M.

The revenue offset discussed in this Section 6.13.3.2 shall commence upon the first payment of revenues related to Incremental TCCs associated with the implementation of an Approved NYTP on or after the date the TFC is implemented. The TFC and the revenue offset related to Incremental TCCs associated with the implementation of an Approved NYTP shall not require and shall not be dependent upon a reopening or review of NY Transco's revenue requirements for an RFC pursuant to Section 6.10 of the ISO OATT.

6.13.3.2.1 Outage Charges related to Incremental TCCs. Outage charges developed pursuant to the provisions of OATT Section 19 applicable to Expanders (as that term is defined in OATT Section 19) not subject to OATT Section 20.2.5, shall be payable to the ISO for any hour in the Day-Ahead Market during which an Expansion, associated with an Approved NYTP, is modeled to be wholly or partially out of service.

6.13.3.3 The billing units for the TFC Rate for the Billing Period shall be based on the Actual Energy Withdrawals available for the current Billing Period for those Transmission Districts allocated the costs of the Approved NYTP in accordance with Attachment DD of the ISO OATT.

6.13.3.4 Cost Recovery Methodology

6.13.3.4.1 Cost Recovery Methodology for All Responsible LSEs Except NYPA

The ISO shall calculate the TFC for each Responsible LSE as follows:

Step 1: Calculate the $ assigned to each Transmission District

$$\mathrm{TFC}_{t,B} = \sum_{p \in P} \Big(\big(\mathrm{AnnualRR}_{p,B} - \mathrm{Incremental\ TCC\ Revenue}_{p,B} + \mathrm{Outage\ Cost\ Adjustment}_{p,B}\big) \times \big(\mathrm{TransmissionDistrictCostAllocation}_{t,p}\big)\Big)$$

Step 2: Calculate a per-MWh Rate for each Transmission District

$$\mathrm{TFCRate}_{t,B} = \mathrm{TFC}_{t,B} / \mathrm{MWh}_{t,B}$$

Step 3: Calculate charge for each Billing Period for each Responsible LSE in each Transmission District

$$\mathrm{Charge}_{B,l,t} = \mathrm{TFCRate}_{t,B} \times \mathrm{MWh}_{l,t,B}$$

Step 4: Calculate charge for each Billing Period for each Responsible LSE across all Transmission Districts

$$\mathrm{Charge}_{B,l} = \sum_{t \in T} \big(\mathrm{Charge}_{B,l,t}\big)$$

Where,

l = the relevant Responsible LSE;

P = set of projects;

T = set of ISO Transmission Districts;

t = an individual Transmission District

B = the relevant Billing Period;

$\mathrm{MWh}_{t,B}$ = Actual Energy Withdrawals in Transmission District t aggregated across all hours in Billing Period B;

$\mathrm{MWh}_{l,t,B}$= Actual Energy Withdrawals for Responsible LSE l in Transmission District t aggregated across all hours in Billing Period B;

Annual $RR_{p,B}$ = the pro rata share of the annual revenue requirement for each project p as discussed in Section 6.13.2 above allocated for Billing Period B;

Incremental TCC $Revenue_{p,B}$ = the auction revenue derived from the sale of Incremental TCCs plus Incremental TCC payments received by NY Transco pursuant to Section 20.2.3 of the ISO OATT for each project p as discussed in Section 6.13.3.2 above allocated for Billing Period B. The revenues from the sale of Incremental TCCs in the ISO's six month Sub-Auctions of each Centralized TCC Auction shall be allocated uniformly across all hours of the Billing Period;

Outage Cost $Adjustment_{p,B}$ = the Outage Charges determined pursuant to OATT Section 6.13.3.2.1 for any hour in the Day-Ahead Market during which the project p is modeled to be wholly or partially out of service aggregated across all hours in Billing Period B;

Transmission District Cost $Allocation_{t,p}$ = the proportion of the cost of project p allocated to Transmission District t, as set forth in Section 36.2 of Attachment 1 to Attachment DD; *provided*, *however*, that the proportion of the cost of project p allocated to the NYPA North Subzone shall be included in the percentage for Niagara Mohawk Power Corporation d/b/a National Grid set forth in Section 36.2.

6.13.3.5 For the initial Rate Year 2016, the ISO may begin billing and collecting NY Transco's projected TFC subsequent to January 1, 2016; however, once billing commences in 2016, the ISO shall bill and collect NY Transco's projected TFC in equal installments for each Billing Period over the balance of 2016.

6.13.3.6 The ISO will collect the appropriate TFC revenues each Billing Period and remit those revenues to NY Transco in accordance with the ISO's billing and settlement procedures.

6.13.4 Recovery of Costs Incurred by NY Transco

6.13.4.1 The TFC shall be used as the cost recovery mechanism for the recovery of the costs of an Approved NYTP that is proposed, developed, or constructed by NY Transco under applicable federal, state and local law and authorized by the Commission to recover costs under this rate mechanism; *provided*, *however*, nothing in this cost recovery mechanism shall be deemed to create any additional rights for NY Transco to proceed with a regulated transmission project that NY

Transco does not otherwise have at law.

6.13.4.2 The period for cost recovery will be determined by the Commission and will begin if and when the Approved NYTP is completed, or as otherwise determined by the Commission. NY Transco and/or the ISO, as applicable, will make a filing with the Commission to provide for its review and approval or acceptance, as appropriate, of the final project cost and resulting revenue requirement to be recovered through the TFC, which shall be reproduced in the form of Section 36.3 of Attachment 2 to Attachment DD of the ISO OATT. The filing may include all reasonably incurred costs related to NY Transco's undertaking an Approved NYTP as specified in Section 6.13.2 of this Schedule. NY Transco shall bear the burden of resolving all concerns about the contents of the filing that might be raised in such proceeding.

6.14 Schedule 14 – Rate Mechanism for Recovery of RMR Generator and Interim Service Provider Related Charges from and Payment of RMR Generator and Interim Service Provider Related Credits to RMR LSEs

6.14.1 Applicability

The ISO will apply this Schedule separately for each RMR Generator operating under an RMR Agreement and to each Generator operating as an Interim Service Provider. For purposes of this Schedule, "RMR LSEs" are all the LSEs, including Transmission Owners, competitive LSEs and municipal systems, serving Load in the Load Zone or Subzone (as applicable) to which the charges and credits associated with an RMR Generator operating under an RMR Agreement or a Generator operating as an Interim Service Provider are allocated.

Section 6.14.2 establishes how credits and charges to RMR LSEs will be allocated and recovered. Section 6.14.3 establishes how the ISO will calculate and recover the RMR Charge applicable to each RMR Generator operating under an RMR Agreement or as an Interim Service Provider. The RMR Charge for a Billing Period may result in either a charge or a credit to the RMR LSEs. Sections 6.14.4 and 6.14.5 establish how the ISO will charge RMR LSEs any Performance Incentive payment or Availability Incentive payment owed to an RMR Generator with an RMR Agreement that contains an Availability and Performance Rate. Finally, Section 6.14.7 establishes how the ISO will allocate and credit to RMR LSEs any Monthly Repayment Obligation recovered from a former RMR Generator and/or former Interim Service Provider by the ISO pursuant to Sections 15.8.7, 15.8.7.1 and 15.8.7.2 of Rate Schedule 8 to the Services Tariff.

6.14.2 Allocation of RMR Charges

Charges and credits to RMR LSEs under this Schedule will be allocated in accordance with Section 31.5.3 of Attachment Y to the ISO OATT. The ISO will charge or credit each

RMR LSE based on its share of Actual Energy Withdrawals in the Load Zone or Subzone (as applicable) for the relevant Billing Period.

6.14.3 Calculation and Recovery of RMR Charge

6.14.3.1 Applicability

The ISO will calculate the RMR Charge in accordance with Section 6.14.3.3 for each RMR Generator operating under an RMR Agreement that includes an Availability and Performance Rate. The ISO will calculate the RMR Charge in accordance with Section 6.14.3.4 for each RMR Generator operating under a rate that is not an Availability and Performance Rate. The ISO will calculate the RMR Charge in accordance with Section 6.14.3.5 for each Interim Service Provider.

6.14.3.2 Assessing or Crediting the RMR Charge

If the RMR Charge calculated pursuant to Section 6.14.3.3, 6.14.3.4 or 6.14.3.5, as applicable, is positive for a Billing Period, then the ISO will assess the RMR Charge to the RMR LSEs. If the RMR Charge calculated pursuant to Section 6.14.3.3, 6.14.3.4 or 6.14.3.5, as applicable, is negative for a Billing Period, then the ISO will credit the absolute value of the RMR Charge to the RMR LSEs. Credits to the RMR LSEs are drawn from the revenue recovered from Transmission Customers as a result of the RMR Generator's participation in the ISO-Administered Markets during that Billing Period.

6.14.3.3 Calculation of RMR Charge for an RMR Generator Providing Service Under an Availability and Performance Rate

$$RMRCharge_{l,g,P} = \sum_{d \in P} \Bigg(\left(RMRAvoidCost_{g,d} + VarCost_{g,d} - MarketRev_{g,d} \right) * \sum_{z \in Z} \left(ZonalCostAllocation_{g,z} * \left(MWh_{l,z,d} / MWh_{z,d} \right) \right) \Bigg)$$

Where:

g = the relevant RMR Generator that is providing service under an Availability and Performance Rate;

P = the relevant Billing Period;

d = the relevant market day;

l = the relevant RMR LSE;

z = an individual NYCA Load Zone or Subzone (as applicable);

Z = the set of all Load Zones (or Subzones as applicable) that have nonzero allocations for the relevant RMR Generator;

$RMRCharge_{l,g,P}$ = the RMR Charge associated with RMR Generator g for Billing Period P for RMR LSE l;

$RMRAvoidCost_{g,d}$ = the RMR Avoidable Cost amount for RMR Generator g for day d, that has been accepted for filing by the Commission, or as calculated by the ISO in accordance with Sections 31.2.11.8 and 31.2.11.17 of the OATT pending Commission action, shaped on a Capability Period basis, and Additional Costs in accordance with Section 38.16 of the OATT;

$VarCost_{g,d}$ = the Variable Cost amount for RMR Generator g for day d, calculated pursuant to Section 15.8.1 of Rate Schedule 8 to the ISO Services Tariff;

$MarketRev_{g,d}$ = the revenue recovered from Transmission Customers under the ISO Tariffs for day d in connection with the participation of the RMR Generator g in the ISO Administered Markets, including LBMP revenues, Ancillary Services revenues, guarantee or supplemental payments, Day-Ahead to real-time balancing settlements as described in Section 4 of the ISO Services Tariff, and monthly Capacity revenues divided by the number of days in the month;

$ZonalCostAllocation_{g,z}$ = the proportion of the cost of RMR Generator g allocated to Load Zone or Subzone (as applicable) z;

$MWh_{z,d}$ = Actual Energy Withdrawals in Load Zone or Subzone (as applicable) z aggregated across all hours on day d;

$MWh_{l,z,d}$ = Actual Energy Withdrawals for RMR LSE l in Load Zone or Subzone (as applicable) z aggregated across all hours on day d.

6.14.3.4 Calculation of RMR Charge for an RMR Generator Providing Service Under a Rate Other Than an Availability and Performance Rate

$$RMRCharge_{l,g,P} = \sum_{d \in P} \left(\left(RMRCost_{g,d} + VarCost_{g,d} - MarketRev_{g,d}\right) * \sum_{z \in Z} \left(ZonalCostAllocation_{g,z} * \left(MWh_{l,z,d}/MWh_{z,d}\right)\right) \right)$$

Where:

g = the relevant RMR Generator that is providing service under a rate other than an ISO-developed Availability and Performance Rate;

$RMRCost_{g,d}$ = the costs RMR Generator g is authorized to recover for day d pursuant to a rate approved for RMR Generator g by the Commission, or is recovering subject to refund pending Commission action, shaped on a Capability Period basis, and Additional Costs in accordance with Section 38.16 of the OATT.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 6.14.3.3 above.

6.14.3.5 Calculation of RMR Charge for an Interim Service Provider

$$RMRCharge_{l,g,P} = \sum_{d \in P} \left(\left(RMRAvoidCost_{g,d} + VarCost_{g,d} - MarketRev_{g,d}\right) * \sum_{z \in Z} \left(ZonalCostAllocation_{g,z} * \left(MWh_{l,z,d}/MWh_{z,d}\right)\right) \right)$$

Where:

g = the relevant Interim Service Provider Generator;

Z = the set of all Load Zones (or Subzones as applicable) that have nonzero allocations for the relevant Interim Service Provider Generator;

$RMRCharge_{l,g,P}$ = the RMR Charge associated with Interim Service Provider Generator g for Billing Period P for RMR LSE l;

$RMRAvoidCost_{g,d}$ = the Avoidable Cost amount for Interim Service Provider Generator *g* for day *d* calculated by the ISO in accordance with Sections 38.8, 38.16 and 38.17 of the OATT, shaped on a Capability Period basis;

$VarCost_{g,d}$ = the Variable Cost amount for Interim Service Provider Generator *g* for day *d*, calculated pursuant to Section 15.8.6 of Rate Schedule 8 to the ISO Services Tariff;

$MarketRev_{g,d}$ = the revenue recovered from Transmission Customers under the ISO Tariffs for day *d* in connection with the participation of the Interim Service Provider Generator *g* in the ISO Administered Markets, including LBMP revenues, Ancillary Services revenues, guarantee or supplemental payments, Day-Ahead to real-time balancing settlements as described in Section 4 of the ISO Services Tariff, and monthly Capacity revenues divided by the number of days in the month; and

$ZonalCostAllocation_{g,z}$ = the proportion of the cost of Interim Service Provider Generator *g* allocated to Load Zone or Subzone (as applicable) *z*.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 6.14.3.3 above.

6.14.4 Performance Incentive Payment

The ISO will charge the RMR LSEs on a monthly basis for any Performance Incentive payment owed to an RMR Generator pursuant to Section 15.8.2 of the ISO Services Tariff for its performance in that month in accordance with the formula in Section 6.14.4.1.

6.14.4.1 Calculation of RMR Performance Incentive Charge

$$RMRPerformIncentCharge_{l,g,m} = RMRPerformIncentPayment_{g,m} * \sum_{z \in Z} \left(ZonalCostAllocation_{g,z} * \left(MWh_{l,z,m} / MWh_{z,m} \right) \right)$$

Where:

m = the billing month for which the performance was calculated;

$RMRPerformIncentCharge_{l,g,m}$ = the Performance Incentive Charge associated with RMR Generator *g* for billing month *m* for RMR LSE *l*;

$RMRPerformIncenPayment_{g,m}$ = the Performance Incentive amount for RMR Generator *g* for month *m*, calculated pursuant to Section 15.8.2 of Rate Schedule 8 to the ISO Services Tariff;

$MWh_{z,m}$ = Actual Energy Withdrawals in Load Zone or Subzone (as applicable) z aggregated across all hours in month m;

$MWh_{l,z,m}$ = Actual Energy Withdrawals for RMR LSE l in Load Zone or Subzone (as applicable) z aggregated across all hours in month m.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 6.14.3.3 above.

6.14.5 Availability Incentive Payment

The ISO will charge the RMR LSEs on a Capability Period basis for any Availability Incentive payment owed to an RMR Generator pursuant to Section 15.8.3 of the ISO Services Tariff. The ISO will recover the Availability Incentive payment from RMR LSEs in the Billing Period following the first month of the Capability Period for any payment earned for the previous Capability Period in accordance with the formula in Section 6.14.5.1.

6.14.5.1 Calculation of RMR Availability Incentive Charge

$$RMRAvailIncentCharge_{l,g,m} = RMRAvailIncentPayment_{g,m} * \sum_{z \in Z} \left(ZonalCostAllocation_{g,z} * \left(MWh_{l,z,m} / MWh_{z,m} \right) \right)$$

Where:

m = the first billing month after the Incentive from the previous Capability period was calculated;

$RMRAvailIncentCharge_{l,g,m}$ = the Availability Incentive Charge associated with RMR Generator g for billing month m for RMR LSE l;

$RMRAvailIncenPayment_{g,m}$ = the Availability Incentive amount for RMR Generator g for month m, calculated pursuant to Section 15.8.3 of Rate Schedule 8 to the ISO Services Tariff;

$MWh_{z,m}$ = Actual Energy Withdrawals in Load Zone or Subzone (as applicable) z aggregated across all hours in month m;

$MWh_{l,z,m}$ = Actual Energy Withdrawals for RMR LSE l in Load Zone or Subzone (as applicable) z aggregated across all hours in month m.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 6.14.3.3 above.

6.14.6 Distribution of Monthly Repayment Credit to RMR Loads

If, at any time, the ISO recovers from a former RMR Generator or from a former Interim Service Provider any Capital Expenditure or Above Market Revenues in accordance with Sections 15.8.7, 15.8.7.1 or 15.8.7.2 of Rate Schedule 8 to the ISO Services Tariff, then the ISO will credit the recovered costs to the RMR LSEs on the same monthly invoice as the recovery from the RMR Generator or Interim Service Provider, in accordance with the formula in Section 6.14.6.1 below.

6.14.6.1 Calculation of Monthly Repayment Credit

$$MonthlyRepaymentCredit_{l,g,m} = Monthly\ Repayment\ Obligation\ Recovery_{g,m} * \sum_{z \in Z} \left(ZonalCostAllocation_{g,z} * \left(MWh_{l,z,m} / MWh_{z,m} \right) \right)$$

Where:

m = the billing month for which the Monthly Repayment Obligation is recovered;

$MonthlyRepaymentCredit_{l,g,m}$ = the Monthly Repayment Credit associated with former RMR Generator *g* or former Interim Service Provider Generator *g* for billing month *m* for RMR LSE *l*;

$Monthly\ Repayment\ Obligation\ Recovery_{g,m}$ = the Monthly Repayment Obligation recovery from former RMR Generator *g* or former Interim Service Provider Generator *g* for month *m*, calculated pursuant to Section 15.8.7 of Rate Schedule 8 to the ISO Services Tariff;

$MWh_{z,m}$ = Actual Energy Withdrawals in Load Zone or Subzone (as applicable) *z* aggregated across all hours in month *m*;

$MWh_{l,z,m}$ = Actual Energy Withdrawals for RMR LSE *l* in Load Zone or Subzone (as applicable) *z* aggregated across all hours in month *m*.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 6.14.3.3 above, except for the Monthly Repayment Obligation which is defined in Section 15.8.7 of the Services Tariff.

6.15 Schedule 15 – Rate Mechanism for the Recovery of the Marcy South Series Compensation Facilities Charge ("MSSCFC")

6.15.1 Applicability

This Schedule establishes the Marcy South Series Compensation Facilities Charge ("MSSCFC") for the recovery of costs related to NYPA's Marcy South Series Compensation ("MSSC") project.

The MSSCFC shall be separate from the Transmission Service Charge ("TSC") and the NYPA Transmission Adjustment Charge ("NTAC") determined in accordance with Section 14 of Attachment H of the ISO OATT, and any Reliability Facilities Charge ("RFC") determined pursuant to Section 6.10 of the ISO OATT. In addition, with respect to the MSSC project only, NYPA shall receive the outage charges described herein for the MSSC project and shall not be charged O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Auction Revenue Shortfall Charges or U/D Auction Revenue Shortfall Charges or be paid O/R-t-S Congestion Rent Surplus Payments, U/D Congestion Rent Surplus Payments, O/R-t-S Auction Revenue Surplus Payments or U/D Auction Revenue Surplus Payments for the MSSC project under Section 20.2.4 and Section 20.3.6 of the ISO OATT; and NYPA shall be entitled to receive Incremental TCCs, as described in Section 19.2.4 of the ISO OATT, for the MSSC project to the extent requested by NYPA and awarded by the ISO. As it relates solely to the MSSC project, NYPA shall not be a "Transmission Owner" for purposes of Section 20.2.5 or Section 20.3.7 of the ISO OATT and accordingly shall not receive an allocation of Net Congestion Rents under Section 20.2.5 of the ISO OATT or Net Auction Revenues under Section 20.3.7 of the ISO OATT relating to the MSSC project.

6.15.2 Revenue Requirement for MSSCFC

The MSSCFC shall be calculated in accordance with the formula set forth in Section

6.15.3 using the revenue requirement of NYPA necessary to recover the costs of the MSSC project. The revenue requirement to be used in the calculation of the MSSCFC is determined using the Formula Rate Template included in Attachment H, Section 14.2.3.1 of the ISO OATT. The MSSC revenue requirement shall be stated separately on line 11a from NYPA's NTAC revenue requirement on line 11 of the NYPA Formula Rate Template's Transmission Revenue Requirement Summary, and there shall be no duplicative recovery of costs as between the NTAC revenue requirement, the MSSC revenue requirement or any other NYPA project-specific revenue requirement. The costs that may be included in the MSSC revenue requirement include all reasonably incurred costs related to the preparation of proposals for, and the development, financing, construction, operation, and maintenance of, the MSSC project, including, but not limited to, a reasonable return on investment and any incentives for the construction of transmission projects approved under Section 205 or Section 219 of the Federal Power Act and the Commission's regulations implementing those sections, as determined by the Commission.

6.15.3 Calculation and Recovery of MSSCFC and Payment of Recovered Revenue

The ISO will calculate and bill the MSSCFC for the MSSC project in accordance with this Section 6.15.3. The ISO shall collect the MSSCFC from the LSEs. The LSEs, including Transmission Owners, NYPA, competitive LSEs, municipal systems, and any other LSE, serving Load located in Transmission Districts to which the costs of the MSSC project have been allocated (each a "Responsible LSE") shall pay the MSSCFC. The costs of the MSSC project shall be allocated as set forth in the allocation table presented herein in Section 6.15.3.7.

6.15.3.1 The MSSC revenue requirement developed pursuant to Attachment H, Section 14.2.3.1 of the ISO OATT by NYPA will be the basis for the MSSCFC Rate ($/MWh) for the Billing Period that shall be charged by the ISO to each

Responsible LSE based on its Actual Energy Withdrawals as set forth in Section 6.15.3.4. NYPA's revenue requirement for the MSSC project will be calculated according to the formula rate and protocols set forth in Section 14.2.3 of Attachment H to the ISO OATT.

6.15.3.2 NYPA shall in relation to the MSSC project reasonably exercise its right to obtain and maintain in effect all Incremental TCCs, including temporary Incremental TCCs, to which it has rights under Section 19.2.4 of the ISO OATT and shall take the actions required to do so in accordance with the procedures specified therein. Notwithstanding Section 19.2.4.7 and 19.2.4.8 of the ISO OATT, Incremental TCCs created and awarded to NYPA as a result of the MSSC project shall not be eligible for sale in Secondary Markets. Incremental TCCs that may be created and awarded to NYPA as a result of the MSSC project shall be offered by the ISO in all rounds of the six month Sub-Auction of each Centralized TCC Auction conducted by the ISO. The ISO shall disburse the associated auction revenues to NYPA. The total amount of the auction revenues disbursed to NYPA pursuant to this Section 6.15.3.2 shall be used in the calculation of the MSSCFC Rate, as set forth in Section 6.15.3.4. Incremental TCCs associated with the MSSC project shall continue to be offered for the duration of the Incremental TCCs, established pursuant to the terms of Attachment M of the ISO OATT.

As described in Section 6.15.4.2, the revenue offset discussed in this Section 6.15.3.2 shall commence upon the first payment of revenues related to Incremental TCCs associated with the MSSC project, and shall be deferred to the extent necessary through the Formula Rate Template's true-up mechanism until the date the Formula Rate Template first produces a non-zero MSSC revenue requirement and the ISO begins to collect the MSSCFC from the LSEs. The MSSCFC and the revenue offset related to Incremental TCCs associated with the implementation of the MSSC project shall not require and shall not be dependent upon a reopening or review of NYPA's revenue requirement for an RFC pursuant to Section 6.10 of the ISO OATT.

6.15.3.2.1 Outage Charges related to Incremental TCCs. Outage charges developed pursuant to the provisions of OATT Section 19 applicable to Expanders (as that term is defined in OATT Section 19) not subject to OATT Section 20.2.5, shall be payable to the ISO for any hour in the Day-Ahead Market during which the MSSC project is modeled to be wholly or partially out of service.

6.15.3.3 The billing units for the MSSCFC Rate for the Billing Period shall be based on the Actual Energy Withdrawals available for the current Billing Period for those Transmission Districts allocated the costs of the MSSC project in accordance with Section 6.15.3.7.

6.15.3.4 Cost Recovery Methodology

6.15.3.4.1 Cost Recovery Methodology for All Responsible LSEs

The ISO shall calculate the MSSCFC for each Responsible LSE as follows:

Step 1: Calculate the $ assigned to each Transmission District

$$\begin{aligned}\mathrm{MSSCFC}_{t,B} = {} & (\mathrm{AnnualRR}_{B} - \mathrm{Incremental\ TCC\ Revenue}_{B} + \mathrm{Outage\ Cost\ Adjustment}_{B}) \\ & \times (\mathrm{TransmissionDistrictCostAllocation}_{t})\end{aligned}$$

Step 2: Calculate a per-MWh Rate for each Transmission District

$$\mathrm{MSSCFRate}_{t,B} = \mathrm{MSSCFC}_{t,B} / \mathrm{MWh}_{t,B}$$

Step 3: Calculate charge for each Billing Period for each Responsible LSE in each Transmission District

$$\mathrm{Charge}_{B,l,t} = \mathrm{MSSCFRate}_{t,B} \times \mathrm{MWh}_{l,t,B}$$

Step 4: Calculate charge for each Billing Period for each Responsible LSE across all Transmission Districts

$$\mathrm{Charge}_{B,l} = \sum_{t \in T} \left(\mathrm{Charge}_{B,l,t}\right)$$

Where,

l = the relevant Responsible LSE;

T = set of ISO Transmission Districts;

t = an individual Transmission District

B = the relevant Billing Period;

$MWh_{t,B}$ = Actual Energy Withdrawals in Transmission District t aggregated across all hours in Billing Period B;

$MWh_{l,t,B}$= Actual Energy Withdrawals for Responsible LSE l in Transmission District t aggregated across all hours in Billing Period B;

Annual RR_B = the *pro rata* share of the annual revenue requirement for the MSSC project allocated for Billing Period B;

Incremental TCC $Revenue_B$ = the auction revenue derived from the sale of Incremental TCCs related to the MSSC project plus Incremental TCC payments received by NYPA pursuant to Section 20.2.3 of the ISO OATT for the MSSC project allocated for Billing Period B. The revenues from the sale of Incremental TCCs related to the MSSC project in the ISO's six month Sub-Auctions of each Centralized TCC Auction shall be allocated uniformly across all hours of the Billing Period;

Outage Cost Adjustment_B = the Outage Charges determined pursuant to OATT Section 6.15.3.2.1 for any hour in the Day-Ahead Market during which the MSSC project is modeled to be wholly or partially out of service aggregated across all hours in Billing Period B;

Transmission District Cost Allocation_t = the proportion of the cost of the MSSC project allocated to Transmission District t, as set forth below in Section 6.15.3.7.

6.15.3.5 NYPA anticipates that the MSSC project will achieve commercial operation during 2016. Because of the retrospective nature of NYPA's Formula Rate Template in Attachment H, Section 14.2.3.1 of the ISO OATT, the NYPA Formula Rate Template will not produce a revenue requirement for the MSSC project until the Annual Update scheduled for July 1, 2017. NYPA therefore anticipates that ISO will begin billing and collecting NYPA's MSSCFC for energy withdrawals occurring on and subsequent to July 1, 2017; but in any event the ISO shall not commence billing and collecting NYPA's MSSCFC until NYPA's Formula Rate Template produces a MSSC revenue requirement on Line 11a of the Transmission Revenue Requirement Summary.

6.15.3.6 The ISO will collect the appropriate MSSCFC revenues each Billing Period and remit those revenues to NYPA in accordance with the ISO's billing and settlement procedures.

6.15.3.7 Cost Allocation Table for the MSSC Project

Transmission District	Allocation of Project Costs (%)
Consolidated Edison Co. of NY, Inc. Orange and Rockland Utilities, Inc.	63.18
Long Island Power Authority	8.55
Niagara Mohawk Power Corp.	12.16*
New York Gas & Electric Corp. Rochester Gas and Electric Corp.	10.12
Central Hudson Gas & Electric Corp.	5.99
New York Power Authority	Load is treated the same as all other load serving entities (“LSEs”) and NYPA will pay the same rate as the LSEs in each transmission district.

***** NYPA customers that are geographically located in the NYSEG and National Grid transmission districts but are connected directly to NYPA transmission facilities (identified by NYISO for billing purposes as ‘NYPA North’ customers) shall be included in the Niagara Mohawk Transmission District for purposes of the MSSCFC cost allocation and billing.

6.15.4 Recovery of Costs Incurred by NYPA

6.15.4.1 The MSSCFC shall be used as the cost recovery mechanism for the recovery of the costs of the MSSC project.

6.15.4.2 The period for cost recovery will begin if and when the MSSC project is completed and a MSSC revenue requirement is produced by NYPA’s Formula Rate Template as discussed in Section 6.15.3.5, or as otherwise determined by the Commission. The ISO will not begin to assess the MSSCFC solely because NYPA receives incremental TCC revenue or is assessed Outage Charges related to the MSSC project prior to the date NYPA’s Formula Rate Template first produces a non-zero MSSC revenue requirement. Instead any incremental TCC revenue received, or Outage Charge incurred, prior to that time will be reflected in the Formula Rate Template's true-up of calendar year revenue to calendar year costs for the calendar year when such revenue or charge was incurred. In any event, the ISO will not collect the MSSCFC from LSEs under this Schedule 15 unless and until the Commission issues an order approving a settlement in Docket No. ER15-572-000 that includes the cost allocation described in Section 6.15.3.7.

6.16 Schedule 16 - Rate Mechanism for the Recovery of the Generator Deactivation Facilities Charge for a Regulated Transmission Solution in the Generator Deactivation Process ("GDFC").

6.16.1 Applicability.

This Schedule establishes the facilities charge for the recovery of the costs of a regulated transmission Generator Deactivation Solution in connection with a Generator Deactivation Reliability Need arising in the Generator Deactivation Process set forth in Attachment FF of the ISO OATT ("GDFC").[3] A Transmission Owner, an Unregulated Transmitting Utility,[4] or another Developer, may recover through the GDFC the costs that it is eligible to recover pursuant to Attachment FF of the ISO OATT related to: (i) the transmission Generator Deactivation Solution proposed by a Responsible Transmission Owner to address the Generator Deactivation Reliability Need in accordance with Section 38.4.2.1, (ii) the conceptual permanent transmission Generator Deactivation Solution, if applicable, submitted by a Responsible Transmission Owner in accordance with Section 38.4.2.1, or (iii) a regulated transmission Generator Deactivation Solution proposed by a Developer that is selected by the ISO to address the Generator Deactivation Reliability Need in accordance with Section 38.10. Such a project is referred to in this Schedule as an "Eligible Project." Any costs incurred for an Eligible Project by LIPA or NYPA will be collected under a separate LIPA GDFC or NYPA GDFC, as applicable, as described in Section 6.16.5.

This Schedule does not provide for cost recovery related to: (i) projects undertaken by Transmission Owners through their Local Transmission Owner Planning Processes pursuant to Section 31.1.3 and 31.2.1 of Attachment Y of the ISO OATT, (ii) projects eligible for cost recovery

[3] Capitalized terms used in this Schedule that are not defined in this Schedule shall have the same meaning set forth in Section 38.1 of Attachment FF of the ISO OATT.

[4] An "Unregulated Transmitting Utility" is a Transmission Owner, such as LIPA and NYPA, that, pursuant to Section 201(f) of the Federal Power Act, is not subject to the Commission's jurisdiction under Sections 205 and 206(a) of the Federal Power Act.

through Schedule 10 of the ISO OATT in connection with the NYISO's reliability planning process, (iii) a Generator operating under an RMR Agreement, or (iv) a market-based Generator Deactivation Solution identified in accordance with Section 38.6 of the ISO OATT.

The GDFC shall be separate from the Transmission Service Charge ("TSC") and the NYPA Transmission Adjustment Charge ("NTAC") determined in accordance with Attachment H of the ISO OATT.

In addition, with respect to the Eligible Project only, the Developer shall receive the outage charges described herein and shall not be charged O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Auction Revenue Shortfall Charges or U/D Auction Revenue Shortfall Charges or be paid O/R-t-S Congestion Rent Surplus Payments, U/D Congestion Rent Surplus Payments, O/R-t-S Auction Revenue Surplus Payments or U/D Auction Revenue Surplus Payments under Section 20.2.4 and Section 20.3.6 of Attachment N of the ISO OATT. The Developer shall request Incremental TCCs with respect to the Eligible Project in accordance with the requirements of Section 19.2.4 of Attachment M of the ISO OATT and receive any Incremental TCCs to the extent awarded by the ISO pursuant to such request. As it relates solely to the Eligible Project, the Developer shall not be a "Transmission Owner" for purposes of Section 20.2.5 or Section 20.3.7 of Attachment N of the ISO OATT and accordingly shall not receive an allocation of Net Congestion Rents under Section 20.2.5 of Attachment N of the ISO OATT or Net Auction Revenues under Section 20.3.7 of Attachment N of the ISO OATT.

6.16.2 Revenue Requirement for GDFC

The GDFC shall be calculated in accordance with the formula set forth in Section 6.16.3 using the revenue requirement of the Transmission Owner, Unregulated Transmitting Utility, or other Developer, as applicable, necessary to recover the costs of an Eligible Project. The revenue requirement to be used in the calculation and recovery of the GDFC for a Transmission

Owner or other Developer, other than an Unregulated Transmitting Utility, is described in Section 6.16.4. The development of a revenue requirement and recovery of costs for an Eligible Project by an Unregulated Transmitting Utility through the NYPA GDFC or the LIPA GDFC, as applicable, is described in Section 6.16.5.

If an Eligible Project involves construction of a facility identified as a Highway System Deliverability Upgrade in a completed Class Year Interconnection Facilities Study, the Project Cost Allocation for which has been accepted and Security posted by at least one Class Year Developer, the final project cost and resulting revenue requirement will be reduced to the extent permitted by Section 25.7.12.3.3 of Attachment S to the ISO OATT.

6.16.3 Calculation and Recovery of GDFC and Payment of Recovered Revenue

The ISO will calculate and bill the GDFC for each Eligible Project in accordance with this Section 6.16.3. The ISO shall collect the GDFC from LSEs. The LSEs, including Transmission Owners, competitive LSEs, municipal systems, and any other LSE, serving Load in the Load Zones and/or Subzones to which the costs of the Eligible Project have been allocated (each a “Responsible LSE”) shall pay the GDFC. The costs of each Eligible Project shall be allocated as set forth in Section 38.22 of Attachment FF of the ISO OATT.

6.16.3.1 The revenue requirement filed pursuant to this Schedule by the Transmission Owner, Unregulated Transmitting Utility, or another Developer, as applicable, and approved or accepted by the Commission will be the basis for the GDFC Rate ($/MWh) that shall be charged by the ISO to each Responsible LSE based on its Actual Energy Withdrawals as set forth in Section 6.16.3.4.

6.16.3.2 The Developer shall in relation to any Eligible Project reasonably exercise its right to obtain and maintain in effect all Incremental TCCs, including temporary Incremental TCCs, to which it has rights under Section 19.2.4 of Attachment M of the ISO OATT and shall take the actions required to do so in accordance with the procedures specified therein. Notwithstanding Sections 19.2.4.7 and 19.2.4.8 of Attachment M of the ISO OATT, Incremental TCCs created and awarded to the Developer as a result of implementation of an Eligible Project shall not be eligible for sale in Secondary Markets. Incremental TCCs that may be created and awarded to the Developer as a result of the implementation of an Eligible Project, shall be offered by the Developer in all rounds of the six month Sub-Auction of each Centralized TCC Auction conducted by the ISO. The ISO shall disburse the associated auction revenues to the Developer. The total amount of the auction revenues disbursed to the Developer pursuant to this Section 6.16.3.2 shall be used in the calculation of the GDFC Rate, as set forth in Section 6.16.3.4. Incremental TCCs associated with an Eligible Project shall continue to be offered for the duration of the Incremental TCCs, established pursuant to the terms of Attachment M of the ISO OATT. The revenue offset discussed in this Section 6.16.3.2 shall commence upon the first payment of revenues related to Incremental TCCs associated with the implementation of an Eligible Project on or after the date the GDFC is implemented. The GDFC and the revenue offset related to Incremental TCCs associated with the implementation of an Eligible Project shall not require and shall not be dependent upon a reopening or review of the Developer's revenue requirements for an RFC pursuant to Section 6.10 of the ISO OATT or the

Transmission Owners' revenue requirements for the TSCs and NTAC set forth in Attachment H of the NYISO OATT.

6.16.3.2.1 Outage charges related to any Incremental TCCs awarded by the ISO for an Eligible Project shall be assessed to the Developer, and payable by the Developer to the ISO, pursuant to Section 19.2.4 of Attachment M of the ISO OATT for an Expander not subject to Section 20.2.5 of Attachment N of the ISO OATT for any hour in the Day-Ahead Market during which an Expansion, associated with an Eligible Project, is modeled to be wholly or partially out of service**.**

6.16.3.3 The billing units for the GDFC Rate for the Billing Period shall be based on the Actual Energy Withdrawals available for the current Billing Period for those Load Zones and/or Subzones allocated the costs of the project in accordance with Section 38.22 of Attachment FF of the ISO OATT.

6.16.3.4 Cost Recovery Methodology

The ISO shall calculate the GDFC for each Responsible LSE as follows:

Step 1: Calculate the $ assigned to each Load Zone or Subzone (as applicable)

$$\mathrm{GDFC}_{z,B} = \sum_{p \in P} \Big(\big(\mathrm{AnnualRR}_{p,B} - \mathrm{IncrementalTransmissionRightsRevenue}_{p,B} + \mathrm{OutageCostAdjustment}_{p,B} \big) \times \big(\mathrm{ZonalCostAllocation}_{z,P} \big) \Big)$$

Step 2: Calculate a per-MWh Rate for each Load Zone or Subzone (as applicable)

$$\mathrm{GDFCRate}_{z,B} = \mathrm{GDFC}_{z,B} / \mathrm{MWh}_{z,B}$$

Step 3: Calculate charge for each Billing Period for each Responsible LSE in each Load Zone or Subzone (as applicable)

$$\mathrm{Charge}_{B,l,z} = \mathrm{GDFCRate}_{z,B} * \mathrm{MWh}_{l,z,B}$$

Step 4: Calculate charge for each Billing Period for each Responsible LSE across all Load Zones or Subzones (as applicable)

$$\mathrm{Charge}_{B,l} = \sum_{z \in Z} \left(\mathrm{Charge}_{B,l,z}\right)$$

Where,

l = the relevant Responsible LSE;

p = an individual Eligible Project;

P = set of Eligible Projects;

z = an individual Load Zone or Subzone, as applicable;

Z = set of ISO Load Zones or Subzones, as applicable;

B = the relevant Billing Period;

$\mathrm{MWh}_{z,B}$ = Actual Energy Withdrawals in Load Zone or Subzone, as applicable, *z* aggregated across all hours in Billing Period *B*;

$\mathrm{MWh}_{l,z,B}$ = Actual Energy Withdrawals for Responsible LSE *l* in Load Zone or Subzone, as applicable, *z* aggregated across all hours in Billing Period *B*;

$\mathrm{AnnualRR}_{p,B}$ = the pro rata share of the annual revenue requirement for each Eligible Project *p*, as discussed in Section 6.16.2 above, allocated for Billing Period *B*;

$\mathrm{IncrementalTransmissionRightsRevenue}_{p,B}$ = the auction revenue derived from the sale of Incremental TCCs plus Incremental TCC payments received by the Developer pursuant to Section 20.2.3 of Attachment N of the ISO OATT for each Eligible Project *p*, as discussed in Section 6.16.3.2 above, allocated for Billing Period *B*. The revenues from the sale of Incremental TCCs in the ISO's six month Sub-Auctions of each Centralized TCC Auction shall be allocated uniformly across all hours of the Billing Period;

$\mathrm{OutageCostAdjustment}_{p,B}$ = the Outage charges determined pursuant to Section 6.16.3.2.1 above for any hour in the Day-Ahead Market during which the Eligible Project *p* is modeled to be wholly or partially out of service aggregated across all hours in Billing Period *B*;

$\mathrm{ZonalCostAllocation}_{z,p}$ = the proportion of the cost of Eligible Project *p* allocated to Load Zone or Subzone, as applicable, *z*, as set forth in Section 38.22 of Attachment FF of the ISO OATT.

6.16.3.5 The ISO will collect the appropriate GDFC revenues each Billing Period and remit those revenues to the appropriate Transmission Owner, Unregulated

Transmitting Utility, or other Developer in accordance with the ISO's billing and settlement procedures.

6.16.4 Recovery of Costs Incurred by Transmission Owner or Developer

6.16.4.1 The GDFC shall be used as the cost recovery mechanism for the recovery of the costs of an Eligible Project undertaken by a Transmission Owner or Developer, other than an Unregulated Transmitting Utility, which project is authorized by the Commission to recover costs under this rate mechanism; *provided, however,* nothing in this cost recovery mechanism shall be deemed to create any additional rights for a Transmission Owner or Developer to proceed with a regulated transmission project that it does not otherwise have at law. The cost that may be included in the revenue requirement for calculating the GDFC pursuant to Section 6.16.3 include all reasonably incurred costs, as determined by the Commission, related to the preparation of proposals for, and the development, financing, construction, operation, and maintenance of, an Eligible Project. This cost includes, but is not limited to, a reasonable return on investment and any incentives for the construction of transmission projects approved under Section 205 or Section 219 of the Federal Power Act and the Commission's regulations implementing those sections.

6.16.4.2 The period for cost recovery will be determined by the Commission and will begin if and when the Eligible Project is completed or halted, or as otherwise determined by the Commission. The Transmission Owner/Developer and/or the ISO, as applicable, will make a filing with the Commission to provide for its review and approval or acceptance, as appropriate, of the final project cost and resulting revenue requirement to be recovered through the GDFC. The filing may include all reasonably incurred costs specified in Section 6.16.4.1 of this Schedule that are related to the Transmission Owner's or the Developer's undertaking an Eligible Project. The Transmission Owner or Developer shall bear the burden of resolving all concerns about the contents of the filing that might be raised in such proceeding. The ISO will begin to calculate and bill the GDFC after the Commission has accepted or approved the filing.

6.16.5 Recovery of Costs Incurred By Unregulated Transmitting Utility

6.16.5.1 The costs that may be included in the revenue requirement for an Eligible Project undertaken by an Unregulated Transmitting Utility include all reasonably incurred costs related to the preparation of proposals for, and the development, financing, construction, operation, and maintenance of, an Eligible Project as well as a reasonable return on investment. For any recovery of a revenue requirement by an Unregulated Transmitting Utility under the GDFC, the period of cost recovery will be determined by the Commission and will begin if and when the Eligible Project is completed or halted, or as otherwise determined by the Commission. The ISO will begin to calculate and bill the GDFC for an Unregulated Transmitting Utility pursuant to Section 6.16.3 after the Commission has accepted or approved the filing of its revenue requirement.

6.16.5.2 Cost Recovery for LIPA

Any costs incurred for an Eligible Project undertaken by LIPA, as an Unregulated Transmitting Utility, that are eligible for recovery under Section 6.16.5.1 under the LIPA GDFC shall be recovered over the period established by Long Island Power Authority's Board of Trustees as follows:

6.16.5.2.1 For Costs to LIPA Customers: Cost will be recovered pursuant to a rate recovery mechanism approved by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Upon approval of the rate recovery mechanism, LIPA shall provide to the ISO, for purposes of inclusion within the ISO OATT and filing with the Commission on an informational basis only, a description of the rate recovery mechanism, the costs of the Eligible Project, and the rate that LIPA will charge and collect from responsible entities within the Long Island Transmission District in accordance with the ISO cost allocation methodology pursuant to Section 38.22 of Attachment FF of the ISO OATT.

6.16.5.2.2 For Costs to Other Transmission Districts, As Applicable: Where the ISO determines that there are Responsible LSEs serving Load outside of the Long Island Transmission District that should be allocated a portion of the costs of the Eligible Project undertaken by LIPA, LIPA shall coordinate with and inform the ISO of the amount of such costs. Such costs will be an allocable amount of the cost base recovered through the recovery mechanism described in Section 6.16.5.2.1 in accordance with the formula set forth in Section 6.16.3.4. Such costs of the Eligible Project allocable to Responsible LSEs serving Load outside of the Long Island Transmission District shall constitute the "revenue requirement." The ISO shall file the revenue requirement with the Commission, to the extent requested to so by LIPA, for Commission review under the same "comparability" standard as is applied to review of changes in LIPA's TSC under Attachment H of the ISO OATT. LIPA shall intervene in support of such filing at the Commission and shall bear the burden of resolving all concerns about the contents of the filing that might be raised in such proceeding. Using the procedures described in Sections 6.16.3 through 6.16.3.4 of this Schedule, the ISO shall calculate a separate LIPA GDFC based on the revenue requirement and shall bill for LIPA the LIPA GDFC as a separate line item to the Responsible LSEs serving Load in Transmission Districts located outside of the Long Island Transmission District. The ISO shall remit the revenues collected to LIPA in accordance with the ISO's billing and settlement procedures.

6.16.5.2.3 Developers, other than LIPA, that undertake an Eligible Project on Long Island may recover any costs pursuant to Section 6.16.4 of this Schedule.

6.16.5.3 Cost Recovery for NYPA

Any costs incurred for an Eligible Project undertaken by NYPA, as an Unregulated Transmitting Utility, that are eligible for recovery under Section 6.16.5.1 shall be recovered under a NYPA GDFC as described herein. A reasonable return on investment for an Eligible Project undertaken by NYPA may include any incentives for construction of transmission projects available under Section 205 or Section 219 of the Federal Power Act and the Commission's regulations implementing those sections, as determined by the Commission.

6.16.5.3.1 NYPA shall coordinate with and inform the ISO of the amount of the costs it incurred in undertaking an Eligible Project. Such costs shall constitute the revenue requirement. The ISO shall file the revenue requirement with the Commission to the extent requested to do so by NYPA. NYPA shall intervene in support of such filing at the Commission and shall bear the burden of resolving all concerns about the contents of the filing that might be raised in such proceeding, including being solely responsible for making any arguments or reservations regarding its status as a non-Commission-jurisdictional utility and the appropriate standard for Commission review of its revenue requirement. In accordance with Sections 6.16.3 through 6.16.3.4 of this Schedule, the ISO shall calculate a separate NYPA GDFC based on the revenue requirement and bill for NYPA the NYPA GDFC to the Responsible LSEs. The ISO shall remit the revenues collected to NYPA in accordance with the ISO's billing and settlement procedures.

6.16.5.3.2 Developers, other than NYPA, that undertake an Eligible Project in the NYPA North Subzone may recover any costs pursuant to Section 6.16.4 of this Schedule.

6.16.5.4 Savings Clause

The inclusion in the ISO OATT or in a Commission filing of the revenue requirement for recovery of costs incurred by an Unregulated Transmitting Utility, including LIPA or NYPA, related to an Eligible Project undertaken pursuant to Attachment FF to the ISO OATT, as provided for in this Section 6.16.5, or the inclusion of such revenue requirement in the LIPA GDFC or the NYPA GDFC, shall not be deemed to modify the treatment of such rates as non-jurisdictional pursuant to Section 201(f) of the FPA.

6.17 Schedule 17 – Rate Mechanism for the Recovery of the Western New York Facilities Charge for Non-Bulk Transmission Facilities ("WNY-FC")

6.17.1 Applicability

6.17.1.1 Eligible Projects

This Schedule establishes the Western New York Facilities Charge ("WNY-FC") for the recovery of the costs of certain upgrades to non-bulk transmission facilities related to any Public Policy Transmission Project that are eligible for cost recovery in accordance with the Comprehensive System Planning Process requirements set forth in Attachment Y of the ISO OATT.[5] Niagara Mohawk Power Corporation ("NMPC") may recover through the WNY-FC the costs that it is eligible to recover pursuant to Attachment Y of the ISO OATT related to certain upgrades to NMPC non-bulk transmission facilities in connection with a Public Policy Transmission Project that the ISO has selected pursuant to Section 31.4.8.2 of Attachment Y of the ISO OATT as the more efficient or cost-effective solution to Western New York Public Policy Transmission Need. The "Western New York Public Policy Transmission Need" relates to congestion relief in Western New York identified by the NYPSC on July 20, 2015 and October 13, 2016, in NYPSC Case No. 14-E-0454.

The specific upgrades to NMPC non-bulk transmission facilities to address the Western New York Public Policy Transmission Need (the "WNY Ancillary Upgrades.") shall be identified by the ISO in the Public Policy Transmission Planning Report for those needs.

[5] Capitalized terms used in this Schedule that are not defined in this Schedule shall have the meaning set forth in Section 31.1.1 of Attachment Y of the ISO OATT and, if not therein, in Section 1 of the OATT.

6.17.1.2 Projects Not Eligible for Cost Recovery Through the WNY-FC

This Schedule does not apply to projects that are not eligible pursuant to Attachment Y of the ISO OATT for cost allocation and recovery under the ISO OATT, including, but not limited to: (i) projects undertaken by Transmission Owners through the Local Transmission Owner Planning Processes pursuant to Section 31.1.3 and Section 31.2.1 of Attachment Y of the ISO OATT; (ii) market-based solutions to transmission needs identified in the CSPP; (iii) any non-transmission components of an Eligible Project (*e.g.*, generation, energy efficiency, or demand response resources); (iv) transmission Generator Deactivation Solutions selected in the Generator Deactivation Process pursuant to Attachment FF of the ISO OATT and eligible for cost recovery through Schedule 16 (Section 6.16) of the ISO OATT; (v) transmission facilities eligible for cost recovery through another rate schedule of the ISO OATT; and (vi) facilities for which costs are recovered through the Transmission Service Charge (“TSC”) or the NYPA Transmission Adjustment Charge (“NTAC”) determined in accordance with Attachment H of the ISO OATT.

6.17.2 Revenue Requirement for WNY-FC

The WNY-FC shall be calculated in accordance with the formula set forth in Section 6.17.3. The costs that may be included in the WNY-FC revenue requirement include all reasonably incurred costs related to the preparation of proposals for, and the development, financing, construction, operation, and maintenance of, the WNY Ancillary Upgrades, including, but not limited to, a reasonable return on investment and any incentives for the construction of transmission projects approved under Section 205 or Section 219 of the Federal Power Act and the Commission’s regulations implementing those sections, as determined by the Commission.

6.17.3 Calculation and Recovery of WNY-FC and Payment of Recovered Revenue

6.17.3.1 The ISO will calculate and bill the WNY-FC separately for the WNY Ancillary Upgrades in accordance with this Section 6.17.3. The ISO shall collect the WNY-FC from LSEs. The LSEs, including Transmission Owners, competitive LSEs, municipal systems, and any other LSEs, serving Load in the Load Zones and/or Subzones to which the costs of the WNY Ancillary Upgrades have been allocated (each a "Responsible LSE") shall pay the WNY-FC. The costs of the WNY Ancillary Upgrades shall be allocated in accordance with the Commission-approved cost allocation methodology for the Public Policy Transmission Project selected to address Western New York Public Policy Transmission Need in accordance with Section 31.5.5 of Attachment Y of the ISO OATT.

6.17.3.2 The WNY-FC revenue requirement shall be calculated as follows: The annual WNY-FC revenue requirement shall equal the annual Historical Transmission Revenue Requirement ("HTRR") for NMPC's TSC divided by NMPC's gross transmission plant in service multiplied by the gross transmission plant in service for the WNY Ancillary Upgrades. For purposes of this calculation:

(a) NMPC's HTRR is equal to Attachment 1 to Attachment H, Schedule 1, line 17.

(b) NMPC's gross transmission plant is equal to Attachment 1 to Attachment H, Schedule 6, page 2 of 2, line 3.

In addition, to the extent that the revenues received for the WNY Ancillary Upgrades in the prior year were greater (or less) than the annual WNY-

FC revenue requirement for the year, the current year's WNY-FC revenue requirement will be decreased (or increased) by that difference. The annual WNY-FC revenue requirement will be the basis for the applicable WNY-FC Rate ($/MWh) for the Billing Period that shall be charged by the ISO to each Responsible LSE based on its Actual Energy Withdrawals as set forth in Section 6.17.3.5.

6.17.3.3 NMPC shall request Incremental TCCs with respect to the WNY Ancillary Upgrades in accordance with the requirements of Section 19.2.4 of Attachment M of the ISO OATT and receive any Incremental TCCs to the extent awarded by the ISO pursuant to such request. As it relates solely to the WNY Ancillary Upgrades, NMPC shall not be a "Transmission Owner" for purposes of Section 20.2.5 or Section 20.3.7 of Attachment N of the ISO OATT and accordingly shall not receive an allocation of Net Congestion Rents under Section 20.2.5 of Attachment N of the ISO OATT or Net Auction Revenues under Section 20.3.7 of Attachment N of the ISO OATT.

NMPC shall in relation to the WNY Ancillary Upgrades exercise its right to obtain and maintain in effect all Incremental TCCs, including temporary Incremental TCCs, to which it has rights under Section 19.2.4 of Attachment M of the ISO OATT and shall take the actions required to do so in accordance with the procedures specified therein. Notwithstanding Sections 19.2.4.7 and 19.2.4.8 of Attachment M of the ISO OATT, Incremental TCCs created and awarded to NMPC as a result of implementation of the WNY Ancillary Upgrades shall not be eligible for sale in Secondary Markets. Incremental TCCs that may be created and awarded to NMPC as a result of the implementation of the WNY Ancillary Upgrades, shall be offered by NMPC in all rounds of the six month Sub-Auction of each Centralized TCC Auction conducted by the ISO. The ISO shall disburse the associated auction revenues to NMPC. The total amount of the auction revenues disbursed to NMPC pursuant to this Section 6.17.3.3 shall be used in the calculation of the WNY-FC Rate, as set forth in Section 6.17.3.5. Incremental TCCs associated with the WNY Ancillary Upgrades shall continue to be offered for the duration of the Incremental TCCs, established pursuant to the terms of Attachment M of the ISO OATT.

The revenue offset discussed in this Section 6.17.3.3 shall commence upon the first payment of revenues related to Incremental TCCs associated with the implementation of the WNY Ancillary Upgrades on or after the date the WNY-FC is implemented. The WNY-FC and the revenue offset related to Incremental TCCs associated with the implementation of the WNY Ancillary Upgrades shall not require and shall not be dependent upon a reopening or review of: (i) NMPC's revenue requirements for charges set forth in another rate schedule of the ISO OATT, or (ii) NMPC's revenue requirements for its TSC set forth in Attachment H of the ISO OATT.

6.17.3.3.1 With respect to the WNY Ancillary Upgrades only, NMPC shall receive the outage charges specific to Incremental TCCs as described herein and shall not be charged O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Auction Revenue Shortfall Charges or U/D Auction Revenue Shortfall Charges or be paid O/R-t-S Congestion Rent Surplus Payments, U/D Congestion Rent Surplus Payments, O/R-t-S Auction Revenue Surplus Payments or U/D Auction Revenue Surplus Payments under Section

20.2.4 and Section 20.3.6 of Attachment N of the ISO OATT. Outage charges related to any Incremental TCCs awarded by the ISO for the WNY Ancillary Upgrades shall be separately assessed to NMPC as an Expander not subject to Section 20.2.5 of Attachment N of the ISO OATT, and payable by NMPC to the ISO, pursuant to Section 19.2.4 of Attachment M of the ISO OATT for any hour in the Day-Ahead Market during which the WNY Ancillary Upgrades are modeled to be wholly or partially out of service.

6.17.3.4 The billing units for the WNY-FC Rate for the Billing Period shall be based on the Actual Energy Withdrawals available for the current Billing Period for those Load Zones and/or Subzones allocated the costs of the project in the manner described in Section 6.17.3.1.

6.17.3.5 Cost Recovery Methodology

The ISO shall calculate the WNY-FC for each Responsible LSE as follows:

Step 1: Calculate the $ assigned to each Load Zone or Subzone (as applicable)

$$\mathrm{WNYFC}_{p,z,B} = \left(\mathrm{AnnualRR}_{p,B} - \mathrm{IncrementalTransmissionRightsRevenue}_{p,B} + \mathrm{OutageCostAdjustment}_{p,B}\right) \times \left(\mathrm{ZonalCostAllocation}_{z,p}\right)$$

Step 2: Calculate a per-MWh Rate for each Load Zone or Subzone (as applicable)

$$\mathrm{WNYFCRate}_{p,z,B} = \mathrm{WNYFC}_{p,z,B} / \mathrm{MWh}_{z,B}$$

Step 3: Calculate charge for each Billing Period for each Responsible LSE in each Load Zone or Subzone (as applicable)

$$\mathrm{Charge}_{B,l,z,p} = \mathrm{WNYFCRate}_{p,z,B} * \mathrm{MWh}_{l,z,B}$$

Step 4: Calculate charge for each Billing Period for each Responsible LSE across all Load Zones or Subzones (as applicable)

$$\mathrm{Charge}_{B,l,p} = \sum_{z \in Z} \left(\mathrm{Charge}_{B,l,z,p}\right)$$

Where,

l = the relevant Responsible LSE;

p = the WNY Ancillary Upgrades;

z = an individual Load Zone or Subzone, as applicable;

Z = set of ISO Load Zones or Subzones, as applicable;

B = the relevant Billing Period;

$MWh_{z,B}$ = Actual Energy Withdrawals in Load Zone or Subzone, as applicable, z aggregated across all hours in Billing Period B;

$MWh_{l,z,B}$ = Actual Energy Withdrawals for Responsible LSE l in Load Zone or Subzone, as applicable, z aggregated across all hours in Billing Period B;

$AnnualRR_{p,B}$ = the pro rata share of the annual revenue requirement for the WNY Ancillary Upgrades as set forth in 6.17.3.2 above, allocated for Billing Period B;

$IncrementalTransmissionRightsRevenue_{p,B}$ = the auction revenue derived from the sale of Incremental TCCs plus Incremental TCC payments received by NMPC pursuant to Section 20.2.3 of Attachment N of the ISO OATT for the WNY Ancillary Upgrades, as discussed in Section 6.17.3.3 above, allocated for Billing Period B. The revenues from the sale of Incremental TCCs in the ISO's six month Sub-Auctions of each Centralized TCC Auction shall be allocated uniformly across all hours of the Billing Period;

$OutageCostAdjustment_{p,B}$ = the Outage charges determined pursuant to Section 6.17.3.3.1 above for any hour in the Day-Ahead Market during which the WNY Ancillary Upgrades are modeled to be wholly or partially out of service aggregated across all hours in Billing Period B; and

$ZonalCostAllocation_{z,p}$ = the proportion of the cost of the WNY Ancillary Upgrades allocated to Load Zone or Subzone, as applicable, z, in the manner described in Section 6.17.3.1 above.

6.17.3.6 The ISO will collect the appropriate WNY-FC revenues each Billing Period and remit those revenues to NMPC in accordance with the ISO's billing and settlement procedures.

6.17.3.7 Payments received by NMPC for the WNY-FC will be treated as a revenue credit in the revenue requirement for NMPC's TSC. After considering the revenue credit from the WNY-FC, the net cost for the WNY Ancillary Upgrades recovered through the TSC will be deemed to be zero.

6.17.3.8 NMPC shall recalculate the WNY-FC revenue requirement each year as part of the Annual Update process set forth in Section 14.1.9.4 of Attachment H of the ISO OATT. The WNY-FC revenue requirement shall be separately stated in that Annual Update, and the Annual Update shall provide supporting documentation for the calculation of the WNY-FC revenue requirement for the Update Year. Each Responsible LSE paying the WNY-FC shall be an "Interested Party" with respect to any portion of the Annual Update related to the WNY-FC. The WNY-FC revenue requirement for the first year after the WNY Ancillary Upgrades are placed in service will be calculated retroactively to the in-service date. The ISO shall commence charging the WNY-FC beginning with the first billing period for the next effective Update Year, as such term is defined in Section 14.1.9.1.66 of Attachment H of the ISO OATT, after the WNY Ancillary Upgrades are placed into service.

7 Attachment A - Form of Service Agreement for Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between _____________ (the "ISO"), and _______________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the ISO to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

4.0 The ISO agrees to provide and the Transmission Customer agrees to pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

<u>ISO</u>:

____

____

____

<u>Transmission Customer:</u>

____

____

____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

ISO:

By: ________________________________ ____________________ ________________

Name Title Date

Transmission Customer:

By: ________________________________ ____________________ ________________

Name Title Date

8 Attachment B - Form of Service Agreement for Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service is not available in the markets that the NYISO administers.

9 Attachment C - Methodology to Assess Available Transfer Capability

The ISO shall calculate Available Transfer Capability ("ATC") according to the procedures set forth in this Attachment C which adopts the "Rated System Path Methodology" established by the North American Electric Reliability Corporation's Reliability Standard MOD-029-1a, or its successors. Additional information and detail shall be set forth in the ISO's ATC Implementation Document ("ATCID").

9.1 Overview

The ISO shall calculate and post ATC values for its Internal and External Interfaces and for Scheduled Lines. The ISO's Interfaces represent a defined set of transmission facilities that separate Locational Based Marginal Pricing (LBMP) Load Zones within the New York Control Area and that separate the New York Control Area from adjacent Control Areas. External Interfaces may be represented by one or more Proxy Generator Buses for scheduling and dispatching purposes. Each Proxy Generator Bus may be associated with distinct, posted ATC values. Scheduled Lines represent a transmission facility or set of transmission facilities that provide a separate scheduling path interconnecting the ISO to an adjacent Control Area. Each Scheduled Line is associated with a distinct Proxy Generator bus for which the ISO separately posts ATC.

Hourly ATCs for the current day and for the next six days, and daily and monthly ATCs shall be calculated for all External Interfaces and for Scheduled Lines. Specifically, for External Interfaces and for all Scheduled Lines, the ISO shall calculate: (i) hourly ATC values for at least the next forty eight hours; (ii) daily values for at least the next thirty one calendar days; and (iii) monthly values for at least the next twelve months (*i.e.*, months 2-13). For External Interfaces and for all Scheduled Lines, the ISO shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in its ATC equation have changed: (i) for hourly values, once per hour (subject to the exception in MOD-001-1a which allows transmission service providers up to 175 hours per year during which calculations are not required); (ii) for daily values, once per day; and (iii) for monthly values, once per week. Hourly ATCs shall be calculated for all Internal Interfaces for the current day and for the next day. To the extent necessary for compliance with MOD-001-1a, the ISO: (i) accounts for the impacts of its internal congestion on its external interfaces as accurately as possible; and (ii) calculates internal flows in order to fulfill its obligation to calculate external flows. External ATC calculations shall be performed with models that depict system conditions consistent with the expected internal flows.

The ISO's calculation of ATC shall reflect its provision of transmission service under an LBMP system pursuant to the schedules produced by its Day-Ahead Market software (the "Security Constrained Unit Commitment" ("SCUC")) and Real-Time Market software (the "Real Time Commitment" ("RTC")) in the form of "Transmission Flow Utilization" information which is incorporated into the ISO's ATC equation as specified in sections 9.2 and 9.4, below.

The ISO continuously redispatches all resources subject to its control in order to meet Load and to accommodate requests for Firm Transmission Service through the use of SCUC, RTC, and its Real-Time Dispatch software. If the posted ATC value for an Interface is zero that is an indication that the Interface is congested. The ISO may, however, still be able to provide additional Firm Transmission Service over such Interfaces through redispatching and other schedule adjustments directed by the SCUC and RTC algorithms that will be incorporated into the Transmission Flow Utilization component of its ATC equation.

SCUC creates the ISO's Day-Ahead Market schedules and prices by performing a series of commitment and dispatch runs. The SCUC algorithm simultaneously minimizes the ISO's total Bid Production Cost of: (i) supplying power or demand reductions to satisfy accepted purchasers' Bids to buy Energy from the Day-Ahead Market; (ii) providing sufficient Ancillary Services to support Energy purchased from the Day-Ahead Market consistent with the Regulation Service Demand Curve and Operating Reserve Demand Curve; (iii) committing sufficient Capacity to meet the ISO's Load forecast and provide associated Ancillary Services; and (iv) meeting Bilateral Transaction schedules submitted Day-Ahead excluding schedules of Bilateral Transactions with Trading Hubs as their POWs. The power flow information produced by the SCUC algorithm is incorporated into the ISO's ATC calculations as Transmission Flow $\text{Utilization}_{\text{Firm}}$ data pursuant to sections 9.2 and 9.4, below.

RTC is a multi-period security constrained unit commitment and dispatch model that cooptimizes to solve simultaneously for Load, Operating Reserves and Regulation Service on a least as-bid production cost basis over a two hour and fifteen minute optimization period. RTC makes binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of resources that can respond in ten minutes) and thirty minutes (in the case of resources that can respond in thirty minutes) after the scheduled posting time of each RTC run, provides advisory commitment information for the remainder of the two and a half hour optimization period, and will produce binding schedules for External Transactions to begin at the start of each quarter hour. RTC co-optimizes to solve simultaneously for all Load, Operating Reserves and Regulation Service requirements and to minimize the total as bid production costs over its optimization timeframe. RTC considers SCUC's resource commitment for the day, load forecasts that RTC itself will produce each quarter hour, binding transmission constraints, and all Real-Time Bids and Bid parameters. The schedules produced by RTC are incorporated into the

ISO's ATC calculation as Transmission Flow Utilization$_{\text{Firm}}$ data pursuant to sections 9.2 and 9.4 below.

At the conclusion of the SCUC and RTC processes, the ISO's software performs the calculation for determining ATC values for the current day and the next day in accordance with section 9.2. Hourly or quarter-hourly ATC values are then posted to the ISO's OASIS. In addition, the ISO's long-term ATC calculator software runs twice a day and calculates daily and monthly ATC values, and hourly values further ahead than the next day, for the ISO's External Interfaces and all Scheduled Lines, which are in turn posted to the ISO's OASIS.

When calculating ATC the ISO shall use assumptions no more limiting than those used in the planning of operations, for the corresponding time period studied, provided that such planning of operations has been performed for that time period. When different inputs are used in ATC calculations because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall be not be considered to be a difference in assumptions.

9.2 Methodology for Computing Firm ATC

The ISO calculates hourly Firm ATC based on the market schedules determined using its SCUC process for the Day-Ahead Market and its RTC processes for the Real-Time Market for the next day and current day time periods. These ATC values shall be posted for all Interfaces and Scheduled Lines in compliance with applicable North American Energy Standards Board requirements. The ISO also calculates and posts Firm ATC for External Interfaces for the additional hourly, as well as the daily and monthly periods specified in section 9.1, above. The ISO does not calculate Non-Firm ATC because NonFirm PointToPoint Transmission Service is not available in the markets that the NYISO administers.

When calculating Firm ATC (“ATC_F”) for all Interfaces for each of the time periods specified in section 9.1 above, the ISO shall use the algorithm established under Requirement 7 of MOD-029-1a. Specifically:

$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$

Where

ATC_F is the firm Available Transfer Capability for the Interface for that period.

TTC is the Total Transfer Capability of the Interface for that period.

ETC_F is the sum of existing firm commitments for the Interface during that period (including Firm Transmission Flow Utilization).

CBM is the Capacity Benefit Margin for the Interface during that period.

TRM is the Transmission Reliability Margin for the Interface during that period.

$Postbacks_F$ are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$counterflows_F$ are the adjustments to ATC_F as determined by the ISO and specified in its ATCID.

When calculating Non-Firm ATC (“ATC_{NF}”) for all Interfaces for each of the time periods specified in section 9.1 above, the ISO shall use the algorithm established under Requirement 8 of MOD-029-1a. Specifically:

$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$

Where

ATC_{NF} is the non-firm Available Transfer Capability for the Interface for that period.

TTC is the Total Transfer Capability of the Interface for that period.

ETC_F is the sum of existing firm commitments for the Interface during that period (including Firm Transmission Flow Utilization).

ETC_{NF} is the sum of existing non-firm commitments for the Interface during that period.

CBM_S is the Capacity Benefit Margin for the Interface that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the Interface that has not been released for sale (unreleased) as non-firm capacity by the ISO during that period.

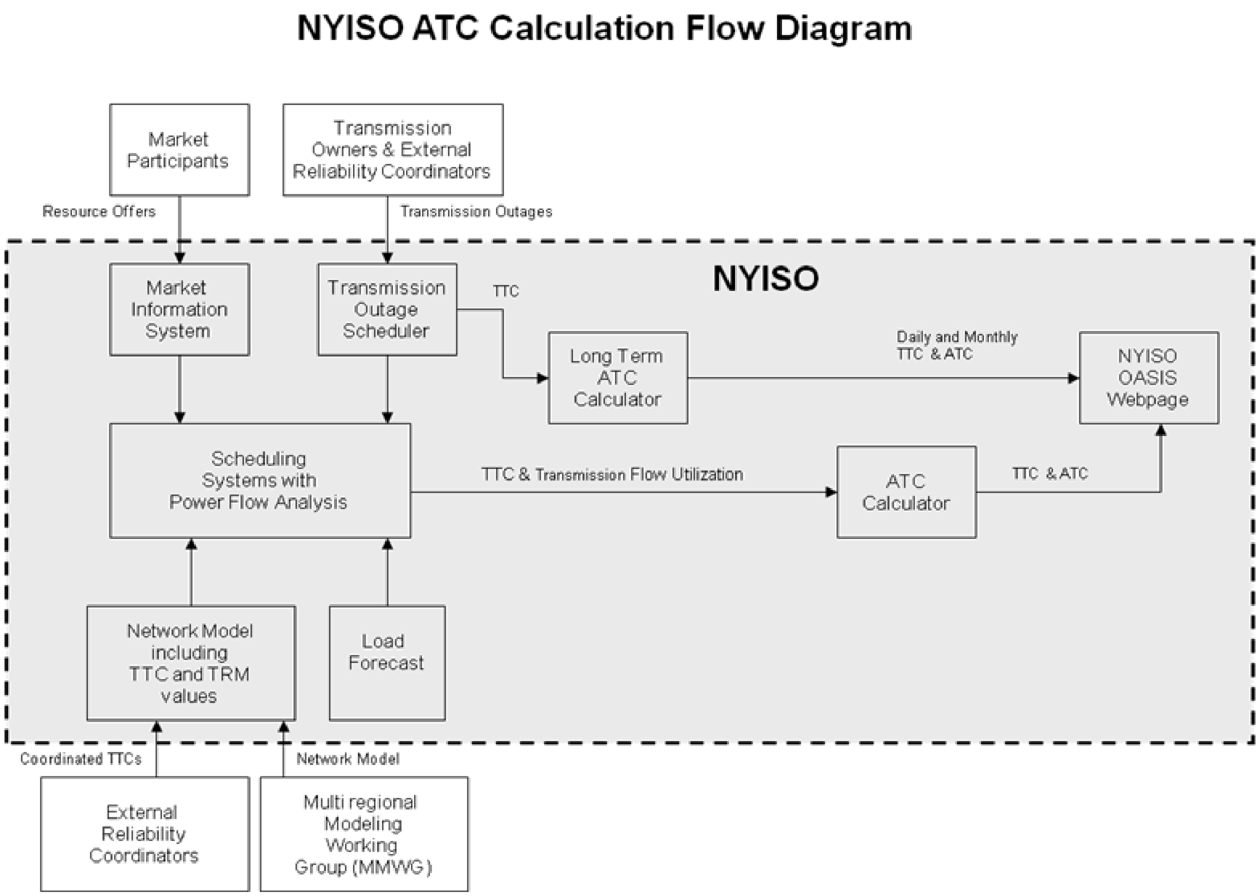
$Postbacks_{NF}$ are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices

$counterflows_{NF}$ are the adjustments to ATC_{NF} as determined by the ISO and specified in its ATCID.

The ISO's ATC calculation algorithms are posted at the "ATC Detailed Algorithms" link at:http://www.nyiso.com/public/webdocs/market_data/power_grid_info/ATCDetailedAlgorithm.pdf

9.3 Process Flow Diagram

The following diagram illustrates the process that the ISO follows when computing and posting ATC.



9.4 Existing Transmission Commitments ("ETC")

The ISO shall calculate ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an Interface, using the formula established under Requirement 5 of MOD-029-1a. Specifically:

ETCF = NLF + NITSF + GFF + PTPF + RORF + OSF

Where:

NLF is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITSF is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GFF is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTPF is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

RORF is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OSF is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

The ISO shall calculate ETC for non-firm Existing Transmission Commitments (ETCNF) for a specified period for an Interface, using the formula established under Requirement 6 of MOD-029-1a. Specifically:

ETCNF = NITSNF + GFNF + PTPNF + OSNF

Where:

NITSNF is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GFNF is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTPNF is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OSNF is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

OS_F and OS_{NF} shall include a Transmission Flow Utilization value which shall be based on the market schedules determined using the SCUC and RTC market software for the current and next day time periods. The Day-Ahead Market and Real-Time Market schedules established by the market software are security constrained network powerflow solutions that are used to determine the Transmission Flow Utilization value for the ISO's Interfaces and Scheduled Lines. Thus:

Transmission Flow Utilization$_{Firm}$ for each Internal and External Interface is determined by the corresponding security constrained network powerflow solutions of SCUC or RTC, as applicable.

Transmission Flow Utilization$_{Non\text{-}Firm}$ for each Internal and External Interface is the sum of Non-Firm Transactions scheduled.

Transmission Flow Utilization$_{Firm}$ for Scheduled Lines is determined by the corresponding security constrained network powerflow solutions of SCUC or RTC, as applicable.

Transmission Flow Utilization$_{Non\text{-}Firm}$ for Scheduled Lines is the sum of Non-Firm Transactions scheduled.

The Transmission Flow Utilization value for OS_F and OS_{NF} for time periods beyond the next day shall be zero because the ISO's Commission-approved market design does not permit transactions to be scheduled for such time periods.

9.5 Total Transfer Capability ("TTC")

The ISO shall develop TTC values for each Interface and Scheduled Line in conformance with all applicable requirements of MOD-001-1a and MOD-029-1a, or their successors. External Interfaces may be represented by one or more Proxy Generator Buses for scheduling and dispatching purposes. Each Proxy Generator Bus associated with an External Interface may be associated with distinct, posted TTC values. Each Scheduled Line is associated with a distinct Proxy Bus for which the ISO separately posts a TTC value.

The TTC value for each Interface and Scheduled Line shall be the maximum amount of electric power that can be reliably transferred over the New York State Transmission System. The ISO shall use studies that it performs, joint studies conducted with neighboring Control

Areas, and real-time system monitoring to determine the appropriate TTC values. The TTC values are periodically reviewed and may be updated as warranted to ensure that accurate values are posted. When calculating TTC the ISO shall use assumptions no more limiting than those used in the planning of operations, for the corresponding time period studied, provided that such planning of operations has been performed for that time period. When different inputs are used in TTC calculations because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall be not be considered to be a difference in assumptions.

Databases used in the determination of the TTC values include Eastern Interconnection Reliability Assessment system representations, and the ISO’s Day-Ahead Market and Real-Time Market system representations.

The normal maximum Interface and Scheduled Line TTC values correspond to TTC assessments that assume: (1) all significant Bulk Power System transmission facilities are in service, (2) Capability Period forecast peak-load conditions, (3) no significant generation outages with generation output levels consistent with typical operation for Capability Period forecast peak-load conditions, and (4) coordination with neighboring Control Area transfer capability assessments.

Interface or Scheduled Line TTC values may be modified in response to identified transmission facility or generation outage conditions. TTC values may also be modified to account for neighboring Control Area transfer capability assessments for identified transmission facility or generation outage conditions, assuming the ISO receives timely notification of such conditions, or to account for operating conditions affecting the New York State Transmission System.

9.6 Transmission Reliability Margin ("TRM")

TRM is the amount of transmission transfer capability necessary to ensure that the interconnected transmission network remains secure under a reasonable range of system conditions. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

The ISO shall maintain a TRM Implementation Document ("TRMID") in compliance with the requirements of MOD-008-1, or its successors..

Databases used in the determination of the TRM values include the MultiRegional Modeling Working Group system representations and the ISO's Day-Ahead Market and Real-Time Market system representations.

TRM equal to the sum of the following components shall be applied to calculations conducted up to eighteen months before the Dispatch Day to address unexpected system conditions including: (1) uncertainty in unscheduled loop or parallel flows ranging in value from zero (0) MW to five hundred (500) MW based on the greater of the average of the last three months of historical parallel flows observed for each External Interface or the average of the deviation in parallel flows observed over the last three months for each External Interface, (2) load forecast uncertainty (normally this value is set to zero (0) MW), (3) uncertainty in external system conditions (normally this value is set to zero (0) MW), and (4) External Interface transmission facility availability ranging in value from zero (0) MW to one thousand (1000) MW reflecting the uncertainty of transfer capability resulting from the most significant single transmission facility outage for each External Interface.

The TRM used for purposes of ATC calculations conducted for External Interfaces for the Day-Ahead Market and the Real-Time Market shall be used to address unexpected system conditions equal to the sum of the following components: (1) uncertainty in unscheduled loop or parallel flows ranging in value from zero (0) to five hundred (500) MW based on the greater of the average of the last three months of historical parallel flows observed for each External Interface or the average of the deviation in parallel flows observed over the last three months for each External Interface, (2) load forecast uncertainty, normally of value zero (0) MW, and (3) uncertainty in external system conditions, normally of value zero (0) MW.

The TRM used for purposes of the ATC calculations conducted for Internal Interfaces for the Day-Ahead Market and the Real-Time Market shall normally be equal to the sum of the following components or a value of one hundred (100) MW, although the ISO may increase it above that level if necessary. TRM is applied to these ATC calculations to address unexpected system conditions including: (1) unscheduled loop or parallel flows normally of value zero (0) MW, (2) load forecast uncertainty normally of value zero (0) MW, (3) uncertainty in external and internal system conditions normally of value one hundred (100) MW, and (4) ISO Balancing Authority requirements normally of value zero (0) MW.

The TRM used for purposes of the ATC calculations conducted for Scheduled Lines for the Day-Ahead Market and the Real-Time Market shall normally be equal to the sum of the following components, which will ordinarily be expected to have a combined value of zero (0) MW, although the ISO may increase it above that level if necessary: (1) unscheduled loop or parallel flows ranging based on the average of the last three months of historical parallel flows observed for each associated External Proxy Generator Bus, normally of value zero (0) MW, (2) load forecast uncertainty, normally of value zero (0) MW, and (3) uncertainty in external system conditions, normally of value zero (0) MW.

TRM is used to decrement TTC from External and Internal Interfaces and from Scheduled Lines when calculating ATC. The ISO may, however, still be able to provide additional Firm Transmission Service over Internal Interfaces for Transmission Customers that are willing to pay congestion charges by redispatching the New York State Power System.

The specific values of TRM used on each Internal and External Interface and Scheduled Line are posted on the ISO's website. The TRM values are periodically reviewed by the ISO and may be updated as warranted. In compliance with Requirement 4 of MOD-008-1, or its successors, the ISO shall establish TRM values at least every thirteen months in accordance with its TRMID.

9.7 Capacity Benefit Margin

The ISO shall not set aside transmission capacity as CBM but shall maintain a CBM Implementation Document ("CBMID") in compliance with the requirements of MOD-004-1, or its successors, which shall include all of the information required by that Reliability Standard. In compliance with Requirements 5 and 6 of MOD-004-1, or its successors, the ISO shall establish CBM values at least every thirteen months in accordance with its CBMID.

9.8 Coordinated ATC Calculations

The ISO's seasonal operating studies are an input into its TTC calculations for External Interfaces that represent Control Area boundaries. The ISO coordinates those seasonal operating studies, and exchanges data necessary to support that coordination, with neighboring Control Areas.

The ISO also coordinates transmission outages and the TTCs associated with these system conditions, and exchanges related data, with neighboring Control Areas. The ISO's and neighboring Control Areas' practice is to provide relevant information to each other in sufficient time for it to be incorporated into their own scheduling and ATC calculation processes. If a neighboring Control Area determines a more limiting TTC corresponding to a transmission outage, the ISO will use the other Control Area's TTC in its scheduling system (SCUC and RTC). These values are correspondingly used in the calculation of ATC consistent with the algorithms set forth in section 9.2 above.

10 Attachment D - Methodology for Completing a System Impact Study

An Eligible Customer may request a System Impact Study.

The purpose of the impact study will be to determine the effect the requested facilities will have on system operations, system Constraints, and whether system expansion will create the requested incremental Transfer Capability and associated TCCs.

The Commission's comparability standard will be applied in evaluating the impact of all requests. Specifically, the ISO will use the same due diligence in completing System Impact Studies for any Eligible Customers that it uses when completing such studies for any Transmission Owner.

System Impact Studies will be evaluated, to the extent possible, as a part of the on-going planning process for expansions of the NYS Power System. Appropriate planning studies will be conducted periodically to assess the capability of the NYS Transmission System to deliver the planned Network Resources to the forecasted Network Loads of the existing LSEs and any prior committed Firm Transmission Service customers. The Loads and resources of Eligible Customers requesting new or additional service during the normal planning cycle will be incorporated into this aggregate planning process along with the Loads and resources of all other Firm Point-to-Point Transmission Customers and LSEs.

The ISO plans and evaluates the NYS Transmission System in strict compliance with the following:

(1) NERC principles and guides;

(2) Principles and standards for planning the bulk electric systems of the NPCC; and

Transmission planning criteria, methods and procedures described in the FERC Form No. 715-Annual Transmission Planning and Evaluation Report for the NPCC Region; and

(3) NYSRC Reliability Rules including Local Reliability Rules.

11 Attachment E - Index Of Point-To-Point Transmission Service Customers

To be provided by the ISO.

12 Attachment F - New York Independent System Operator Code of Conduct

12.1 Introduction

This Code of Conduct shall apply to the ISO's Directors, Officers, and Employees (collectively, "ISO Employees") and provides policies, rules and procedures to be followed in carrying out the ISO's responsibilities. The provisions relating to covered contractors and consultants are set forth in Section 12.13 below.

The ISO Employees shall take all reasonable actions within their authority under the ISO Tariffs and Agreements[6] necessary to:

(1) comply with all laws including, without limitation, the following: federal and state environmental laws; Federal Power Act, FERC Rules and Regulations, FERC Order Nos. 888 et. seq. and 889 et seq.; 18 C.F.R. § 37.1-37.4; federal securities laws; and copyright, trademark and patent laws; Attachment F

(2) provide Transmission Service pursuant to the ISO Open Access Transmission Tariff ("OATT"), acting as the Responsible Party,[7] as defined in Order Nos. 889 et. seq. for all Transmission Owners that are signatories to the ISO Agreement and operate the OASIS in accordance with Section 12.2, below;

(3) refrain from Energy Transactions in accordance with Section 12.3, below;

(4) treat commercially sensitive, proprietary, or regulated information as Confidential Information in accordance with Section 12.4, below;

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[6] The "ISO Tariffs and Agreements" consist of the ISO OATT, the ISO Services Tariff, the ISO Agreement, the NYSRC Agreement, the ISO/NYSRC Agreement, and the ISO/TO Agreement. The term "ISO Tariffs" consists of the ISO OATT and the ISO Services Tariff.

[7] The term "Responsible Party" as defined in Order No. 889 means the Transmission Owner or an agent to whom the Transmission Owner has delegated the responsibility of meeting the requirements of 18 C.F.R. §37 concerning the operation of the OASIS.

(5) protect the integrity of ISO Records[8] in accordance with Section 12.7, below;

(6) protect the ISO's assets including property, facilities, equipment and supplies in accordance with Section 12.12, below; and

(7) avoid contact with Market Participants[9] which could cause or appear to cause a conflict of interest under Section 12.8, below.

[8] ISO Records consist of all documents submitted to, or generated by, the ISO that pertain to ISO business. Examples of ISO Records include, without limitation, requests for Transmission and Ancillary Services, service agreements, system impact studies and facilities studies developed by the Transmission Owners and forwarded to the ISO, audit records, and ISO annual reports.

[9] Market Participant is any person (natural or legal) transacting with the ISO to buy, sell or schedule electric generating Capacity and/or Energy, Ancillary Services or Transmission Services. The term includes, but is not limited to, Power Exchanges, power brokers, power marketers, Buyers, Sellers, Transmission Owners, Non-Utility Generators, Independent Power Producers, load aggregators, Load Serving Entities, and municipalities or groups of these entities.

12.2 Fair and Non-Discriminatory Administration of the Tariff

It is the policy of the ISO to offer open-access Transmission Service under the ISO Tariff in a non-discriminatory manner to all Market Participants. In compliance with this policy, all ISO Employees must administer the ISO OATT and ISO Services Tariff (the "ISO Tariffs") and the ISO related Agreements with impartiality toward all Market Participants.

Where the ISO OATT allows the exercise of discretion in applying the ISO OATT, to the extent that discretion is exercised, the ISO will maintain a written log of each waiver or act of discretion, the circumstances involved, the person authorizing the waiver and the source of authority for the waiver. The ISO will provide the log for review and copying at the request and expense of any interested persons during regular business hours of operation in a manner that treats similarly situated persons on a comparable and non-discriminatory basis.

The ISO shall also require an officer of the ISO or designee to periodically review these discretionary decisions to ensure compliance with the Code of Conduct. The ISO shall post information on the OASIS for a period of ninety (90) days, detailing the circumstances and manner under which that discretion was exercised; and make this information available for review, but not on the OASIS, for three (3) years from the date it is first posted.

In providing Transmission Service pursuant to the ISO OATT, the ISO shall strictly comply with the Reliability Rules developed by the NYSRC.

12.3 Non-Participation in Energy Transactions

To assure that the ISO and the ISO Employees maintain independence from any Market Participant, except as otherwise provided or required by the terms of the ISO Agreement, the ISO and ISO Employees are prohibited from engaging in any Energy Transactions other than in the performance of duties under the ISO Tariffs. This provision shall not, however, prevent the ISO and any ISO Employee from purchasing electricity, power and Energy as retail customers for their own account and consumption.

12.4 Treatment of Confidential and Transmission System Information

This section deals with Confidential Information, including Transmission System Information. Confidential Information consists of: (1) data designated as such in NYPP Operating Policy OP-18 (or its successor); (2) any commercially sensitive information including, without limitation, trade secrets, equipment specific information (*e.g.*, Generator specific data such as heat rates, etc.), and business strategies, affirmatively designated as Confidential Information by its supplier or owner; and (3) Transmission System Information ("TSI") that has not yet been posted on the OASIS or provided in some public forum such as a FERC filing. TSI is information: (1) that is commercially valuable and (2) access to which is necessary to buy, sell or schedule Energy, Capacity, Ancillary Services or Transmission Service. Examples of TSI include, but are not limited to, the following:

- Available Transfer Capability;
- Total Transfer Capability;
- Information regarding physical Curtailments and Interruptions;
- Information regarding Ancillary Services;
- Pricing for Transmission Service; and
- Discounts offered.

In the course of responding to requests for Energy, Capacity, Transmission Services or Ancillary Services, the ISO shall not disclose Confidential Information to any Market Participant. The ISO shall disclose data that is not Confidential Information, and information required to be disclosed by FERC, by posting the information on the OASIS. If an ISO Employee improperly discloses TSI to any Market Participant, the ISO shall immediately post the information on the OASIS and notify the Commission.

ISO Employees shall also report all improper disclosures of Confidential Information to the ISO compliance officer (as described in Section 12.11) or its designee immediately. In the case of an Emergency, the ISO may disclose such TSI, and then notify the Commission, posting the information on the OASIS as soon as practicable but no later than twenty-four (24) hours after the information is disclosed.

The procedures described in this section do not apply to the following:

(1) communication of TSI between the ISO and the Transmission Owner's control centers, and other power pools or ISOs;

(2) communication of non-public, operational information concerning natural gas-fueled generation from resources located within the New York Control Area between the ISO and the operating personnel of an interstate natural gas pipeline company for the purpose of promoting reliable service or operational planning;

(3) communication of non-public, operational information concerning natural gas-fueled generation from resources located within the New York Control Area between the ISO and the operating personnel of natural gas local distribution companies ("LDCs") and/or intrastate natural gas pipeline companies for the purpose of promoting reliable service or operational planning, if such party has acknowledged, in writing, that it is prohibited from disclosing—or using anyone as a conduit for disclosure of—non-public, operational information received from the ISO to: (a) an employee other than operating personnel of that LDC and/or intrastate natural gas pipeline company, (b) a third party, or (c) any affiliate except for (i) the operating personnel of an affiliated interstate natural gas pipeline company, or (ii) the operating personnel of an intrastate pipeline which has a non-

disclosure agreement with the ISO. The operating personnel of an affiliated interstate natural gas pipeline company accepting non-public operational information pursuant to this section shall agree to comply with 18 CFR 284.12(b)(4)(ii). Unless otherwise authorized by the Commission, for purposes of this section LDC or intrastate pipeline "operating personnel" shall exclude employees engaged in marketing functions as defined by 18 CFR 358.3(c) or who make sales of natural gas;

(4) communication of information from a Market Participant to the ISO;

(5) information that is no longer Confidential Information because it was made public by posting it on the OASIS; or it was legally disclosed by a third party in good faith and without violating a trade secret, secrecy agreement or employment contract with a non-disclosure clause; or it was made public by a government agency, court or other process of law;

(6) requests by a Market Participant for a report regarding the status of that Market Participant's particular contracts or transactions. The ISO shall provide all Market Participants requesting a report the same type and level of detail of information;

(7) information that is not listed in NYPP OP-18 and has not been designated by the supplier or owner as Confidential Information;

(8) disclosures by the ISO that are authorized under ISO Services Tariff Attachment H Section 23.4.5.7 and its subsections (except as restricted in section 23.4.5.7.3.2);

(9) identification of a Generator first entering service, becoming Retired, or entering into or returning from a Mothball Outage or ICAP Ineligible Forced Outage, including dates thereof; and

(10) New York State Transmission System reliability impacts that would occur if a Generator were unavailable due to events such as becoming Retired or entering a Mothball Outage or ICAP Ineligible Forced Outage.

If Confidential Information is required to be divulged in compliance with an order or a subpoena of a court or regulatory body other than FERC or the Commodity Futures Trading Commission ("CFTC"), the ISO will seek to obtain a protective order or other appropriate protective relief from the court or regulatory body, provided, however, that the ISO staff shall not be required to do any additional analysis to produce such information. With the exception of requests for Confidential Information submitted to the ISO from FERC or the CFTC, the ISO shall provide advance written or electronic notice to the parties providing the Confidential Information as soon as practicable upon receipt of such an order or a subpoena from a court or regulatory body, and the ISO shall not be held liable for any losses, consequential or otherwise, resulting from the ISO divulging such Confidential Information pursuant to a subpoena or an order of a court or regulatory body.

The ISO shall establish procedures for handling Confidential Information that minimize the possibility of intentional or accidental improper disclosure.

12.4.1 Information Provided to NYSERDA Consistent with Article 8, Title 9 of New York Public Authorities Law, Section 1854(19)

Article 8, Title 9 of New York Public Authorities Law, Section 1854(19) directs NYSERDA to, on its own or through a qualified entity, develop and administer a generation attribute tracking system. Consistent with Section 1854(19), the ISO will provide to NYSERDA or its designee the following generation, delivery, and consumption data that is otherwise required to be maintained in confidence pursuant to this tariff: (i) generator output data; (ii) load consumption data; and (iii) import and export transaction data. The data provided will be summed to the monthly level, except where hourly data is required to support the generation attribute tracking system. The ISO shall provide this information pursuant to a confidentiality agreement with NYSERDA and/or its designee. The ISO shall, consistent with state rules or regulations that may provide for protected treatment of such information, request that Confidential Information be withheld from public disclosure by NYSERDA unless presented in masked or aggregated form. The ISO shall not be held liable for any losses, consequential or otherwise, resulting from the ISO divulging such Confidential Information pursuant to the ongoing electronic delivery.

After Confidential Information has been provided to NYSERDA or its designee, the ISO shall immediately notify any affected Market Participant(s) when it becomes aware that a request for disclosure of such Confidential Information has been received by NYSERDA or its designee, or a decision to disclose such Confidential Information has been made by NYSERDA or its designee, at which time the ISO and the affected Market Participant(s) may respond before such information would be made public, pursuant to state rules or regulations that may provide for protected treatment of such information.

12.4.2 Information Provided to FERC Pursuant to FERC Order No. 760, or to the CFTC

The ISO is required to provide data and information to the FERC or its staff, pursuant to

FERC Order No. 760,[10] that is otherwise required to be maintained in confidence pursuant to this section. FERC Order No. 760 requires the ISO to engage in the ongoing electronic delivery of data related to physical and virtual offers and bids, market awards, resource outputs, marginal cost estimates, shift factors, TCCs, internal bilateral contracts, interchange pricing, capacity markets and uplift charges and credits. The ISO shall provide the data described in FERC Order No. 760 to the FERC or its staff on a continuous basis.

If the FERC or CFTC or their staff, during the course of an investigation or otherwise, requests information, in addition to the ongoing electronic delivery pursuant to FERC Order No. 760, from the ISO that is otherwise required to be maintained in confidence pursuant to this section, the ISO shall provide the requested information to the FERC or CFTC or their staff within the time provided for in the request for information. In providing the ongoing electronic delivery or additional requested information to the FERC or its staff or information requested by the CFTC, the ISO shall, consistent with any FERC or CFTC rules or regulations that may provide for privileged treatment of that information, request that the information be treated as confidential and non-public by the FERC or CFTC and their staff and that the information be withheld from public disclosure. The ISO shall not be held liable for any losses, consequential or otherwise, resulting from the ISO divulging such Confidential Information pursuant to the ongoing electronic delivery or an additional request under this paragraph.

After Confidential Information has been provided to the FERC or CFTC or their staff, the ISO shall immediately notify any affected Market Participant(s) when it becomes aware that a request for disclosure of such Confidential Information has been received by the FERC or CFTC

[10] *Enhancement of Electricity Market Surveillance and Analysis Through Ongoing Electronic Delivery of Data From Regional Transmission Organizations and Independent System Operators*, Order No. 760, 139 FERC ¶ 61,053 (2012) (“Order No. 760” or “the Order”).

or their staff, or a decision to disclose such Confidential Information has been made by the FERC or CFTC, at which time the ISO and the affected Market Participant(s) may respond before such information would be made public, pursuant to the FERC's and CFTC's rules and regulations that may provide for privileged treatment of information provided to the FERC or CFTC or their staff.

12.5 Insider Trading

This section defines insider trading, explain the duties of ISO Employees and describes behavior that is prohibited under securities laws.

12.5.1 Insider Information:

Federal laws prohibit the purchase or sale of any publicly traded security by a person in possession of important information about the security or its issuer that is not publicly known. These laws have special significance to the ISO because ISO Employees routinely learn of Confidential Information about Market Participants and others. This circumstance creates two duties for all ISO Employees: (1) a duty not to trade while in possession of "material, nonpublic information," also known as "inside information" or "insider information," as defined below, and (2) a duty not to communicate such information to anyone outside of the ISO, also known as "tipping." It has been and remains the policy of the ISO that there be scrupulous compliance with each of these duties.

Material: Much of the information obtained about Market Participants and any of their Affiliates may be material information under the law. Information is material if a reasonable investor would consider it important in determining whether to buy or sell the securities of the company involved. The information may be either positive or negative. If the information would affect the price of the stock, it is material. If the information makes you or anyone else think about wanting to buy or sell the stock, that is probably the best indication that it is material. Some examples of information that could be considered material are key personnel changes, earnings information, fines or assessments that the ISO imposes on the company, and Confidential Information (as described in Section 12.4) including information relating to future generation capacity. If in doubt, one should assume that any information which could have any significance to an investor is material and not purchase or sell or allow anyone else to purchase or sell the securities in question until such information has been made public.

Nonpublic: Information that has not been disclosed to the public generally is nonpublic. To show that information is public, one should be able to point to some evidence that it is widely disseminated. Information would generally be deemed widely disseminated if it has been disclosed, for example, in the Dow Jones broad tape; news wire services such as AP or Reuters; radio or television; newspapers or magazines; the OASIS; or widely circulated public disclosure documents filed with the federal Securities and Exchange Commission ("SEC"), such as prospectuses or proxies.

Although it is natural to "talk shop," no Confidential Information should be given to outsiders; for this purpose "outsiders" include one's immediate family (as defined in Section 12.8), relatives, friends and anyone else other than those working on the matter at the ISO. In general, ISO matters should not be discussed with any outside individuals. Particular care is necessary in discussing ISO matters in elevators, restaurants, taxicabs, trains, commercial aircraft and other public places where names and other scraps of information might be overheard. Care should also be taken not to expose nonpublic papers in such places or leave them lying around in conference rooms or other places even within the ISO.

12.5.2 Penalties for Trading on Insider Information

It is against ISO policy and a violation of law to make use of insider information for personal advantage in securities trading or to disclose such information to an outsider. ISO Employees who have any knowledge or insider trading activities or improper disclosure committed by other ISO Employees must immediately notify the ISO compliance officer (as described in Section 12.11) or his designee. ISO Employees who have engaged in insider trading or have provided insider information to outsiders will be terminated immediately. In addition, both the ISO and the ISO Employee may be subject to severe civil and criminal penalties as a result of insider trading by the ISO Employee or by an outsider who has received insider information from the ISO Employee.

12.6 Training

The ISO shall develop procedures to train ISO Employees soon after their hiring or appointment on the Code of Conduct, and to assess the effectiveness of the Code of Conduct in preventing insider trading and conflicts of interest. All ISO Employees will receive annual training thereafter for as long they remain associated with the ISO. All personnel receiving this training shall sign a Compliance Certificate stating that they attended the training, understand the Code of Conduct, and will not violate it.

12.7 ISO Records

The ISO shall develop and maintain procedures for the handling, safeguarding, use, storage and retention of ISO Records. The ISO shall require all ISO Records to be accurate.

12.8 Conflicts of Interest

Certain contacts between ISO Employees, or their immediate family members (*i.e.*, spouse or minor children), and Market Participants may constitute or appear to constitute a conflict of interest. Potential conflicts of interest and the ISO's ability to restrict actions and duties to avoid potential conflicts are discussed below.

12.8.1 Financial Interests and Associations:

12.8.1.1 Prohibited Securities

"Prohibited Securities" shall mean the Securities[11] of a Market Participant that has been active in the ISO Administered Markets in the preceeding twelve months or the Securities of its Affiliates, in either case, if:

(1) the primary business purpose of the Market Participant or its Affiliate is to buy, sell or schedule Energy, Capacity, Ancillary Services or Transmission Services as indicated by an industry code within the "Electric Power Generation, Transmission, and Distribution" industry group under the North American Industry Classification System ("NAICS") or otherwise determined by the ISO;

(2) the total activity in the ISO Administered Markets (purchases and sales) for all Market Participants affiliated with the publicly traded company during its most recently completed fiscal year is equal to or greater than 0.5% of its gross revenues for the same time period; or

(3) the total activity in the ISO Administered Markets (purchases and sales) for all Market Participants affiliated with the publicly traded company during the prior

[11] The term "Securities" refers to stocks, stock options, bonds and any other instruments of debt or equity.

calendar year is equal to or greater than 3% of the total ISO Administered Market activity (purchases and sales) for the same time period.

The ISO shall compile a list of the Prohibited Securities traded publicly and distribute this list to ISO Employees.

In order for the ISO to remain truly independent, free of any control, or appearance of control, of decision-making by any individual Market Participant, ISO Employees must strictly observe the following rules regarding financial interests in Prohibited Securities:

No ISO Employee or his/her immediate family member shall own, control, or hold with power to vote, Prohibited Securities; *provided*, *however*,

(1) an ISO Employee or his/her immediate family member may transfer to a single blind trust Prohibited Securities that qualify under Section 12.8.2 to this Attachment F;

(2) any matching contributions made in the Securities of a Market Participant in connection with any savings, pension, or 401(k) plans of a former employee of a Market Participant shall be permitted until the completion of the transfer, spin off and merger of assets and liabilities of such plans to new plans maintained by the ISO;

(3) this provision shall not apply to any purchase of Prohibited Securities by a spouse of an ISO Employee who was, as of the effective date of the ISO OATT, employed by a Market Participant or any Affiliate of such Market Participant and is required to purchase Securities of such Market Participant or Affiliate as a part of his or her employment. Any such purchases by a spouse must be disclosed to the ISO Board which shall have the authority to consider appropriate limitations

on the duties of the ISO Employee, including changing his or her duties, to avoid an appearance of a conflict of interest; and

(4) Ownership of mutual funds by ISO Employees that contain Prohibited Securities is permitted provided: (i) the fund is publicly traded; (ii) the fund's prospectus does not indicate the objective or practice of concentrating its investment in Market Participants or their Affiliates; and (iii) the ISO Employee does not exercise or have the ability to exercise control over the financial interests held by the fund.

An ISO director shall make an appropriate disclosure to the ISO Board if the director is aware that he or she, or an immediate family member, has a financial interest in a Market Participant or its Affiliate that is the subject of a matter before the ISO Board. The Chair of the ISO Board Governance Committee and ISO legal counsel shall consult with the director to determine whether the director should be recused from Board deliberations and decision making regarding the matter.

12.8.1.2 Prohibited Associations

No ISO Employee shall be Associated with any Market Participant. For the purposes of this paragraph, an ISO Employee shall be deemed "Associated" with a Market Participant or its Affiliate if: (1) the ISO Employee is an officer, director, partner, or employee of a Market Participant or any of its Affiliates; (2) the ISO Employee is a former executive officer of a Market Participant, which Market Participant together with its Affiliates has three (3) percent or more of the voting shares on the Management Committee, or of any Affiliate of the Market Participant, and the ISO Employee is receiving continuing benefits under an existing employee benefit plan (other than a defined benefit pension plan or other plan pursuant to which the benefits are independent of the financial condition of the Market Participant and pension payments are distributed to the former employee by a trustee, not as compensation but in accordance with the rules of the pension plan), arrangement or policy of the Market Participant or any of its Affiliates; or (3) the ISO Employee has a material ongoing business or professional relationship with a Market Participant or any of its Affiliates; *provided, however,* that no ISO Employee shall be deemed to have a material ongoing business relationship with a Market Participant or any of its Affiliates solely as a result of being served as a retail customer by a Market Participant or its Affiliates.

12.8.1.3 Consultants

The ISO Board will establish reasonable guidelines with respect to the financial interests of covered consultants or contracts, in accordance with Section 12.13.

12.8.2 ISO Policy on Divestiture or Transfer to a Blind Trust of Financial Interests:

Except as provided in Section 12.8.1, if an ISO Employee or his/her immediate family member owns, controls or has the power to vote Prohibited Securities, the ISO Employee or his/her immediate family member must, within the timeframe set forth below, either (i) divest the Prohibited Securities or (ii) transfer the Prohibited Securities to a single blind trust if they qualify for this option unless material hardship would result. The ISO shall develop a procedure establishing the conditions under which the divestiture or transfer would result in material hardship.

For purposes of this Section 12.8.2, a “blind trust” is a legally binding arrangement pursuant to which a third-party fiduciary, as the trustee, has full management discretion over the assets contained in the trust, and the ISO Employee or his/her immediate family, as the trust beneficiary, has no visibility regarding the specific assets contained in the trust.

Prohibited Securities shall qualify for a blind trust if: (1) the publicly traded company's NAICS code is not within the "Electric Power Generation, Transmission, and Distribution" industry group, and (2) the total activity in the ISO Administered Markets (purchases and sales) for all Market Participants affiliated with the publicly traded companyduring its most recently completed fiscal year is less than 0.5% of its gross revenues for the same time period. The ISO shall review each year whether the Prohibited Securities that previously qualified for inclusion in a blind trust continue to be qualified under this two-part test.

The timeframe to divest or transfer Prohibited Securities is as follows: (1) new ISO Employees must divest or transfer to a blind trust Prohibited Securities within six months of commencement of employment; (2) if ownership, control or the power to vote such Prohibited Securities results from an entity becoming a Market Participant, divestiture or transfer to a blind trust must occur within six months of receipt of the ISO's list of prohibited Securities referencing such Prohibited Securities; (3) if ownership, control or the power to vote such Prohibited Securities is as a result of a gift, inheritance, distribution of marital property or other involuntary acquisition, divestiture or transfer to a blind trust must occur within six months of the acquisition; and (4) if the ISO determines that Prohibited Securities that were previously qualified for inclusion in a blind trust are no longer qualified, divestiture must occur within six months of the ISO's notice to ISO Employees of this change.

12.8.3 Political Activities:

Restrictions on the political activities of ISO Employees are limited only to the extent that ISO Employees may not engage in lobbying activities on behalf of a Market Participant. Beyond this political activity, ISO Employees are not restricted from participating in any legal political activity so long as they do not purport, directly or indirectly, to represent the ISO without authorization.

ISO Employees are not precluded from holding public office so long as upon accepting public office the ISO compliance officer or designee is notified in writing. The ISO Employee's work in the public office must not detract from the ISO Employee' s performance in connection with the ISO, and the ISO Employee shall not represent the ISO in his/her capacity as a public official and shall not use ISO resources for work related to the public office.

Any ISO Employee holding a public office shall abstain from voting or participating in any debate or matters relating to the ISO as part of his/her duties in public office.

12.8.4 Secondary Employment:[12]

ISO Employees shall not take Secondary Employment with a Market Participant or its Affiliate nor transact business with a Market Participant or its Affiliate other than as a retail customer. ISO Employees may take Secondary Employment with a non-Market Participant if the employment: (1) will not embarrass or discredit the ISO; (2) will not interfere with the duties or involve the use of ISO resources, materials or assets; (3) will not create a conflict of interest for the ISO or the ISO Employee; (4) will not result in any Market Participant receiving an advantage, real or apparent, over other Market Participants with respect to the ISO; and (5) is fully disclosed to the ISO prior to commencement of employment with a Secondary Employer and the ISO compliance officer or designee determines whether the criteria of (1) through (4) are met and then authorizes the Secondary Employment in writing.

Where an ISO Employee takes Secondary Employment with a non-Market Participant,

[12] Secondary Employment refers to participation in (1) a second job (part-time, full-time or project related), or (2) an organization including, without limitation, a corporation, association, partnership or sole proprietorship.

that ISO Employee may not transact business with the ISO on behalf of the Secondary Employer.

An ISO Employee shall not serve as a representative of a member of the Executive Committee of the NYSRC.

12.8.5 Other Conflicts of Interest:

ISO Employees must not directly or indirectly request or accept any service (other than as a retail customer of a Market Participant receiving electric, gas or steam service for heating, etc.), money, gift, loan or discount from any Market Participant or any of its Affiliates. Gifts should be returned or offers declined with an appropriate explanation. If a gift is not returnable (*e.g.*, perishable), the gift should be given to the compliance officer for donation to a charity or destroyed. ISO Employees shall not accept meals or entertainment from actual or potential Market Participants, except when it would be socially humiliating to decline the meal or entertainment; if an ISO Employee accepts such a meal or entertainment, the ISO Employee shall promptly report such acceptance to the compliance officer.

Acceptance of an offer of anything of more than nominal value, including but not limited to vacations, property, loans, contributions or unpaid services by ISO Employees from a representative of a Market Participant or any of its Affiliates shall be considered a conflict of interest.

Engaging in outside non-business activity that materially decreases the impartiality, judgment, or effectiveness of ISO Employees shall also be considered a conflict of interest.

12.9 Additional Controls

The ISO shall establish a periodic audit process to verify compliance with the Code of Conduct and determine whether conflicts of interest exist. Except where prohibited by law or judicial order, the ISO may request that ISO Employees complete an annual conflict of interest survey requiring disclosure of the ISO Employee's or immediate family member's interests in Market Participants or their Affiliates.

The ISO shall require, as a condition precedent to association, that ISO Employees who will have access to Confidential Information agree to reasonable restrictions on future employment following termination of the association.

12.10 Termination of Association

Upon termination of association with the ISO, an ISO Employee with access to Confidential Information shall not disclose the information to any person outside of the ISO, nor use Confidential Information in any manner for personal benefit or for the benefit of a third party.

12.11 Violations of the Code of Conduct

Any ISO Employee who violates the Code of Conduct or fails to report a known violation may be subject to disciplinary action including suspension or termination of employment, unless such violation involves insider trading whereby such violation will result in the termination of employment. In addition, any current or former ISO Employee that violates the Code of Conduct may be required to provide restitution to the ISO for financial injury suffered by the ISO as a result of the violation.

The ISO shall assign the responsibility of reviewing compliance with the Code of Conduct to the ISO compliance officer (*e.g.*, a senior staff member such as the ISO General Counsel) who will be responsible for interpreting the Code of Conduct; responding to questions regarding the Code of Conduct; advising the ISO Employees regarding potential conflicts of interest; overseeing the auditing process; and to follow-up on all suspected violations. The ISO compliance officer may designate one or more individuals to assist in carrying out these responsibilities. The ISO also shall establish a "hot-line" to provide a means to anonymously and confidentially report suspected violations over the telephone.

12.12 ISO Property and Other Assets

ISO property and other assets shall be used only for ISO-related business.

12.13 Determination by the ISO Board as to Consultants and Contractors

The ISO Board shall apply reasonable and objective criteria as conflicts-of-interest screening guidelines for consultants and contractors. In applying the guidelines to individual cases, the ISO Board will consider the nature of the services provided by the consultant or contractor, whether the consultant or contractor is engaged by the ISO on a substantially full-time basis, whether the consultant or contractor is required to comply with its own professional conflict of interest standard (*e.g.*, attorneys, accountants, etc.), and whether the consultant or contractor will have access to market information. The guidelines will be made known to the appropriate ISO Employees authorized to enter into contracts for outside services, and application of the Board's criteria by the ISO Employees will be monitored by the ISO compliance officer. The guidelines will preclude consultants or contractors from serving as a Member or a representative of a Member of the NYSRC Executive Committee. In the event that any entity disputes a determination regarding a consultant or contractor, the matter may be referred to ADR, as covered in Section 12.13 of the ISO OATT.

12.14 Waiver

Subject to Section 12.2, the ISO Board may grant a waiver of compliance with a specific provision of the Code of Conduct to a Director, or the ISO compliance officer may grant a waiver of compliance to a non-Director ISO Employee, in appropriate cases to avoid unjust or unreasonable results. Each waiver shall be properly disclosed along with an appropriate explanation.

12.15 Annual Compliance Certificate

I have received the Code of Conduct which I have read, been trained in, and fully understand. I will comply with the Code of Conduct during and after association with the ISO, to the extent required by the Code of Conduct.

I am ( ) a Director ( ) an Officer ( ) an ISO Employee.

a. I have no financial interest in Prohibited Securities other than those I still have time to divest or transfer to a blind trust in accordance with the ISO's policy in Section 12.8.2 to this Attachment F (or if I do, I have been granted a hardship exception).

b. I have no other financial or business relationship with a Market Participant that would create a conflict of interest as defined in the Code of Conduct (or if I do, I have been granted a waiver by the ISO Board or compliance officer).

c. Since the date that I last signed a Compliance Certificate, I have complied with the rules and policies contained in the Code of Conduct, except the following matters which I disclose to the management of the ISO (if none, so state):

Signature: ____________________________ Date: ________________________________

Name (print): _________________________ Title/Position: ________________________

13 Attachment G - Network Operating Agreement

For Network Customers that also take service under the ISO Services Tariff, the ISO Services Tariff shall serve as the Network Operating Agreement. For all other Network Customers, the ISO shall negotiate a Network Operating Agreement and file such Agreement with the Commission. These Agreements shall specify the following:

(1) Provisions for the operation and maintenance of equipment necessary for integrating the Network Customer within the NYS Transmission System including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment.

(2) Requirements for transfer of data between the ISO, Transmission Owners, and the Network Customer including, but not limited to, bid curves and operational characteristics of Network Resources, generation schedules for units outside of the NYS Transmission System, interchange schedules, unit outputs for redispatch required under Section 4.8, voltage schedules, loss factors and other real time data.

(3) Software programs for data links and Constraint dispatching.

(4) Data requirements on forecasted Loads and resources necessary for long-term planning.

(5) Any other technical requirements required for implementation of Part 4 of the Tariff.

14 Attachment H - Annual Transmission Revenue Requirement for Point-To-Point Transmission Service and Network Integration Transmission Service

14.1 Transmission Service Charge ("TSC")

14.1.1 Applicability of the Transmission Service Charge to Wholesale Customers

Each month, each wholesale Transmission Customer shall pay to the appropriate Transmission Owner the applicable Wholesale Transmission Service Charge ("Wholesale TSC") calculated in accordance with Section 14.1.2.1 of this Attachment. The TSC shall apply to Transmission Service:

14.1.1.1 from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area ("Wheels Through"); provided, however, that the TSC shall not apply to Wheels Through scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied;

14.1.1.2 from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection Point ("Exports"); provided, however, that the TSC shall not apply to Exports scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied; or

14.1.1.3 to serve Load within the NYCA; except, the Wholesale TSC shall not apply to:

14.1.1.3.1 a Transmission Owner's use of its own system to provide bundled retail service to its Native Load Customers pursuant to a retail service tariff on file with the PSC or, in the case of LIPA, has been approved by the Long Island Power Authority's Board of Trustees;

14.1.1.3.2 Transmission Service pursuant to an Existing Transmission Agreement whereby the otherwise applicable TSC does not apply pursuant to Attachment K; or

14.1.1.3.3 retail Transmission Service pursuant to any tariff or rate schedule of a Transmission Owner that explicitly provides for other transmission charges in lieu of the Wholesale TSC, subject to any applicable provisions of the Federal Power Act.

Each Transmission Owner subject to FERC and/or PSC jurisdiction may file with FERC a separate TSC applicable to retail access in accordance with its retail access program filed with the PSC. To the extent that LIPA's rates for service are established by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Section 1020-f(u) and 1020-s and are not subject to FERC jurisdiction, this requirement will not apply to LIPA.

14.1.2 Wholesale TSC Calculation

Sections 14.1.2-14.1.6 do not apply to the development of the NYPA TSC, which is described in Section 14.1.7.

14.1.2.1 Wholesale TSC Formula

Each Transmission Owner, except NYPA, shall calculate its TSC applicable to Transmission Service to serve Load within or exiting the NYCA at its Transmission District as follows:

$$\text{WHOLESALE TSC} = \{(RR \div 12) + (CCC \div 12) - SR - ECR - CRR - WR - \text{Reserved}\}/(BU \div 12).$$

Where:

RR = The Annual Transmission Revenue Requirement, as stated in Table 1 of this Attachment. Gross Receipts Tax ("GRT") treatment by each individual company is described in Section 14.1.7. Revenues from grandfathered agreements listed on Attachment H-1 are treated as a revenue credit in the RR;

CCC = The annual Scheduling, System Control and Dispatch Costs of the individual Transmission Owner (*i.e.*, the transmission component of control center costs) as stated on Table 1 of this Attachment;

SR = The Transmission Owner's revenues associated with the sale of certain TCCs, as described in Section 14.1.2.1.1 of this Attachment;

ECR = The Transmission Owner's share of Net Congestion Rents in a month, calculated pursuant to Attachment N of the OATT;

CRR = The Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from ETA's, the expenses for which are included in the Transmission Owner's Revenue Requirement;

WR = The Transmission Owner's revenues from external sales (Wheels Through and Export Transactions) not associated with Existing Transmission Agreements included in Attachment L, Tables 18.1, 18.2 and 18.3 and wheeling revenue, associated with OATT reservations extending beyond the start-up of the ISO. (i.e., grandfathered OATT agreements), as described in Section 14.1.2.1.2 of this Attachment;

Reserved = The Transmission Owner’s Congestion payments associated with, and value from the sale of ETCNL TCCs and RCRR TCCs, as described in Section 14.1.2.1.3 of this Attachment; and

BU = The Transmission Owner's Billing Units (annual MWh) for the Transmission District (see Table 1 of this Attachment). The Transmission Owner's BU has been adjusted upward to include subtransmission and distribution losses.

14.1.2.1.1 Elements of SR Component

$SR = SR_1 + SR_2 + SR_3 + SR_4$.

SR_1 will equal the revenues from the Direct Sale by the Transmission Owner of Original Residual TCCs, TCCs derived from Existing Transmission Capacity for Native Load, and Grandfathered TCCs associated with ETAs, the expenses for which are included in the Transmission Owner’s Revenue Requirements where the Transmission Owner is the Primary Holder of said TCCs. SR1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that the Transmission Owner will receive under each applicable TCC sold in a Direct Sale divided by the duration of that TCC (in months).

SR_2 will equal the Transmission Owner's revenues from the Centralized TCC Auctions and Reconfiguration Auctions allocated pursuant to Attachments N. SR_2 includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auctions and Reconfiguration Auctions; (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for those ETAs are included in the Transmission Owner’s Revenue Requirements; and (c) TCCs derived from Existing Transmission Capacity for Native Load that are sold in the Centralized TCC Auction.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Owners sell through the Centralized TCC Auctions and the allocation of revenue for other TCCs sold through the Centralized TCC Auctions and Reconfiguration Auctions (per the Facility Flow-Based Methodology described in Attachment N).

SR_3 shall equal the Transmission Owner's share of revenues from the award and renewal of Historic Fixed Price TCCs, as determined pursuant to Section 20.4 of Attachment N. The share of revenues allocated to a Transmission Owner pursuant to Section 20.4 of Attachment N shall be adjusted after each Centralized TCC Auction and divided equally across the months for which the Historic Fixed Price TCCs that were awarded or renewed prior to the relevant Centralized TCC Auction are valid. Notwithstanding anything to the contrary herein, with respect to the Transmission Owner's share of any revenues for Historic Fixed Price TCCs that took effect on or before November 1, 2016, such revenues (or any portion thereof) shall be accounted for in SR_3 by dividing such revenues (or any portion thereof) equally across the six months of the first Capability Period following the effective date of this provision provided that the NYISO has informed the Transmission Owner of its respective share of such revenues (or any portion thereof) at least two weeks prior to the start of such Capability Period, otherwise such revenues (or any remaining portion thereof) shall be accounted for in SR_3 by dividing such revenues (or any remaining portion thereof) equally across the six months of the Capability Period that follows the first Capability Period following the effective date of this provision.

SR_4 shall equal the Transmission Owner's share of revenues from the initial award and renewal of Non-Historic Fixed Price TCCs, as determined pursuant to Section 20.5 of Attachment N. The share of revenues allocated to a Transmission Owner pursuant to Section

20.5 of Attachment N shall be adjusted after each Centralized TCC Auction and divided equally across the months for which the Non-Historic Fixed Price TCCs that were initially awarded or renewed as part of the relevant Centralized TCC Auction are valid. Notwithstanding anything to the contrary herein, with respect to the Transmission Owner's share of any revenues for Non-Historic Fixed Price TCCs that took effect on or before May 1, 2017, such revenues (or any portion thereof) shall be accounted for in SR_4 by dividing such revenues (or any portion thereof) equally across the six months of the first Capability Period that commences following the effective date of this provision provided that the NYISO has informed the Transmission Owner of its respective share of such revenues (or any portion thereof) at least two weeks prior to the start of such Capability Period, otherwise such revenues (or any remaining portion thereof) shall be accounted for in SR_4 by dividing such revenues (or any remaining portion thereof) equally across the six months of the Capability Period that follows the first Capability Period that commences following the effective date of this provision.

14.1.2.1.2 Elements of the WR Component

The WR component will equal the sum of: (1) TSC revenues received from new external transactions (Wheels Through and Export Transactions); (2) transmission revenues received under grandfathered OATT agreements and actual revenues under Schedule 1 to the grandfathered OATT agreements, but not under Schedules 2 through 6 to the grandfathered OATT agreements; and (3) any revenues related to pre-OATT grandfathered arrangements if the transmission owner increased its OATT revenue requirement to derive its RR component to reflect the fact that revenues related to such transactions are at risk due to options available to the customers resulting from the current restructuring, and the customer retains its grandfathered arrangement.

In each subcomponent of the WR component above, the revenues will include the Gross Receipts Tax ("GRT") when the Transmission Owner has included the GRT in the RR.

14.1.2.1.2.1 Treatment of Schedule 1 Associated with Grandfathered OATT Service

All customers under grandfathered OATT service agreements must continue to pay the Schedule 1 charge applicable under the individual OATT, absent a settlement to the contrary. The revenues received from Schedule 1 charges paid by grandfathered OATT customers will be treated as revenue credit in the WR component as part of the wheeling revenue associated with OATT reservations extending beyond the start-up of the ISO.

14.1.2.1.3 Elements of the Reserved Component

Reserved = $Reserved_1 + Reserved_2 + Reserved_3 + Reserved_4$

$Reserved_1$ will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner's ETCNL TCCs.

$Reserved_2$ will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner's RCRR TCCs.

$Reserved_3$ will equal the value that a Transmission Owner receives for the sale of its ETCNL TCCs in a month, with the value for each ETCNL TCC sold divided equally over the month(s) for which that sold ETCNL TCC is valid.

$Reserved_4$ will equal the value that a Transmission Owner receives for the sale of its RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the month(s) for which that sold RCRR TCC is valid.

The RR, SR and CRR will not include expenses for the Transmission Owner's purchase of TCCs or revenues from the sale of said TCCs or from the collection of Congestion Rents for said TCCs. The ECR, CRR, WR, and Reserved shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (e.g., January actual data will be used in February to calculate the TSC effective in March). The TSC shall not apply to the scheduled quantities physically Curtailed by the ISO.

Each Member System is responsible for calculating: (1) the RR component of its TSC charge; (2) the CCC component of its TSC charge; (3) the SR_1 portion of the SR component of its TSC charge; and (4) the BU component of its TSC charge.

The NYISO is responsible for calculating or providing the information necessary to calculate: (1) the SR_2, SR_3 and SR_4 portions of the SR component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation; (2) the ECR component of each Member System's TSC charge based on information derived from ISO operation; (3) the CRR component of each Member System's TSC charge based on information derived from ISO operation; (4) the Reserved component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation; and (5) the WR component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation. Any calculations that the ISO is responsible for are subject to review and comment by all affected parties.

The RR term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when a Transmission Owner determines that a change to its RR is required under Section 205.

The CCC term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to the CCC is required.

SR: The revenue from the Direct Sale of TCCs will be determined monthly and will enter the TSC formula through the SR term with a two-month lag (e.g., January actual data will be used in February to calculate the SR term used in the TSC for March). The revenue that a Transmission Owner receives from a TCC sold in a Centralized Auction or Reconfiguration Auction will be divided equally among the month(s) for which the sold TCC is valid. The revenue from these TCCs will enter the TSC formula month-by-month through the SR term with a two-month lag (e.g., January actual data will be used in February to calculate the SR term used in the TSC for March). For Balance of Period Auctions, the ISO shall also provide each Transmission Owner information regarding their respective share of Net Auction Revenues for each month covered by each Balance-of-Period Auction. The ISO is responsible for providing the information necessary to calculate the SR_2, SR_3 and SR_4 portions of the SR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the information provided by the ISO.

The ECR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (e.g., January actual data will be used in February to calculate the ECR term used in the TSC for March). The ISO is responsible for calculating the ECR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation.

The CRR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (e.g., January actual data will be used in February to calculate the CRR term used in the TSC for March). Each Transmission Owner will identify for the ISO each ETA ("Identified ETA"), under which the Transmission Owner is a customer, the expenses for which are included in the Transmission Owner's RR. The ISO shall calculate that Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from the Transmission Owner's Identified ETAs. If the inclusion of the costs under an Identified ETA in the Transmission Owner's RR is subject to refund, then the CRR shall be subject to adjustment. If the costs under one or more of the Identified ETAs are removed from the RR and the Transmission Owner is required to recalculate its TSC with the adjusted RR, then in recalculating the TSC, the Transmission Owner shall reverse the portion of the CRR that was attributed to each such ETA. The Transmission Owner shall rebill the customers based on the recalculated TSC. To the extent the Transmission Owner owes a refund to the customer, it shall comply with any applicable refund obligations, including payment of interest to the extent due pursuant to 18 C.F.R. § 35.19a(a)(2)(iii), or its successor. If the reversal of the CRR results in a higher TSC than was charged, the customer shall pay in the time prescribed for payment of TSCs the Transmission Owner the difference between the TSC payments it made and the rebilled amounts, with interest thereon from the dates payments were made to the date that the rebilled amounts are due. Said interest will be calculated in the same manner as interest on over-payments as specified in 18 C.F.R. § 35.19a(a)(2)(iii), or its successor.

The Reserved will be calculated monthly and will enter the TSC formula with a two-month lag (e.g., January actual data will be used in February to calculate the ETCNL TCC term used in the TSC for March). The ISO is responsible for providing the information necessary to calculate the Reserved Component of each Transmission Owner's TSC.

WR: The revenue that a Transmission Owner collects for new external sales will be calculated monthly and will enter the WR term in the TSC formula with a two-month lag (*i.e.*, January actual data will be used in February to calculate the WR term used in the TSC for March). The ISO is responsible for calculating new external sales subcomponent of the WR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation. The actual revenue that a Transmission Owner collects for grandfathered OATT service that extends beyond ISO start-up, and revenues related to pre-OATT grandfathered arrangements as provided for under numbers (2) and (3) of Original Sheet No. 214A, will also be calculated monthly and will enter the WR term in the TSC formula based upon the prior month's information. For the first month the credit will be equal to the actual revenues received under those grandfathered agreements to be included in the WR component.

The BU term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to its BU is required.

14.1.3 Filing and Posting of Wholesale TSCs

The Transmission Owners shall coordinate with the ISO to update certain components of the Wholesale TSC formula on a monthly basis or Capability Period basis. Each Transmission Owner may update its Wholesale TSC calculation to change its RR, CCC, or BU component value(s). Such updates, however, shall be subject to necessary FERC filings under the FPA. Each Transmission Owner will calculate its monthly Wholesale TSC and provide the ISO with the Wholesale TSC by no later than the fourteenth of each month, for posting on the OASIS to become effective on the first of the next calendar month. The monthly Wholesale TSCs for each of the Transmission Districts shall be posted on the OASIS by the ISO no later than the fifteenth of each month or as soon thereafter as is reasonably possible but in no event later than the 20th of the month to become effective on the first of the next calendar month.

14.1.4 TSC Calculation Information

The Annual Transmission Revenue Requirements ("RR"); Scheduling, System Control and Dispatch Costs ("CCC"), Billing Units ("BU") and Rates of the Transmission Owners, except NYPA, for the purpose of calculating the respective Transmission District-based Wholesale TSC are shown in Table 1 below.

TABLE 1 - WHOLESALE TSC CALCULATION INFORMATION

Transmission Owner	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate $/MWh[1]
Central Hudson Gas & Electric Corp.	$16,375,919	$1,309,980	4,723,659	$3.7441
Consolidated Edison Co. of NY, Inc.	$385,900,000	$21,000,000	49,984,628	$8.1405
LIPA	$105,602,083	$3,453,343	20,618,939	$5.2891
New York Electric & Gas Corporation[2]	$94,143,899	$1,633,000	14,817,111	$6.4639
Niagara Mohawk Power Corporation	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9
Orange and Rockland Utilities, Inc.	$21,034,831	$942,579	3,595,947	$6.1117
Rochester Gas and Electric Corporation	$25,795,509	$583,577	6,967,556	$3.7860

[1]The rate column represents the unit rate prior to crediting; the actual rate will be determined pursuant to the applicable TSC formula rate.

[2]NYSEG's RR, BU and unit Rate prior to adjustment pursuant to Attachment H, are subject to retroactive modification pursuant to the provisions of the Settlement Agreement approved by

the Commission in its March 26, 2004 order issued in Docket No. EL04-56-000. For any Transmission Customer that "opts out" of the Settlement Agreement as described in paragraph 1.E thereof, the applicable NYSEG "RR" shall be $100,541,739; the "BU" shall be 13,741,901 MWh; and, the "Rate" prior to adjustment pursuant to Attachment H, shall be $7.4235 effective as of March 1, 2004.

14.1.5 Treatment of Gross Receipts Tax

14.1.5.1 Central Hudson Gas & Electric Corporation

Central Hudson's TSC shall be increased by dividing the following surcharge factors into the total of all applicable rates and charges to reflect the New York State GRT (0.94922 in the MTA regions and 0.95750 in the non-MTA regions), which is not specifically provided for in the transmission rate, to the extent such tax is imposed on Central Hudson as a result of the transmission service provided to such Customer. Central Hudson shall make an appropriate filing pursuant to Section 205 of the Federal Power Act to implement any change in the specified tax rate prior to altering the tax rate under this provision.

14.1.5.2 Consolidated Edison Company of New York, Inc.

The GRT is included in Con Edison's TSC rate. Con Edison will not charge separately for GRT.

14.1.5.3 LIPA

The GRT is included in LIPA's TSC rate. LIPA will not charge separately for GRT.

14.1.5.4 New York State Electric & Gas Corporation

The Transmission Customer shall pay an amount sufficient to reimburse NYSEG for any amounts payable by NYSEG as sales, excise, value-added, gross receipts or other applicable taxes with respect to the total amount payable to NYSEG pursuant to the Tariff. The total of all rates and charges will be divided by the appropriate tax factor listed below, depending upon the geographic location of the Transmission Customer's Point(s) of Delivery

Within the Metropolitan Commuter Transportation District:	0.984583
Not within the Metropolitan Commuter Transportation District:	0.986823

These tax factors incorporate the taxes imposed on the Transmission Provider's electric revenues pursuant to New York law and represents the Franchise Tax on Gross Earnings, the Gross Income Tax, and where applicable the Metropolitan Commuter Transportation District Surcharge.

This Provision shall be effective upon commencement of services under the ISO OATT.

14.1.5.5 Niagara Mohawk Power Corporation

For the settled Niagara Mohawk TSC rate, the GRT is included in the RR and there will be no separate GRT tax assessed; For the filed Niagara Mohawk TSC rate, GRT initially is included in the RR and there will be no separate GRT assessed; however, this issue with regard to GRT is subject to final Commission action in Docket No. OA96-194-000, including all stipulations executed in connection therewith.

14.1.5.6 Orange and Rockland Utilities, Inc.

The Transmission Customer's rate will be increased to reflect the gross receipts tax ("GRT") which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on Orange and Rockland as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and 186-a of the New York Tax Law. The current effective GRT rate for the Section 186-a tax is 3.25% from October 1, 1998 through October 31, 1999 and 2.5% on and after January 1, 2000. The maximum locality rate allowable under state law for each locality is specified below.

However, if the actual locality rate is less than the maximum locality rate permitted under state law, O&R shall charge the actual tax rate levied by the locality. The currently effective GRT rate for the Section 186 tax is .75%.

Airmont	1.0%
Bloomingburg	1.0%
Chestnut Ridge	1.0%
Goshen	1.0%
Grandview on Hudson	1.0%
Greenwood Lake	1.0%
Harriman	1.0%
Haverstraw	1.0%
Highland Falls	1.0%
Hillburn	1.0%
Kaser	1.0%
Kiryas Joel	1.0%
Middletown	1.0%
Monroe	1.0%
Montebello	1.0%
New Hempstead	1.0%
New Square	1.0%
Nyack	1.0%
Otisville	1.0%
Piermont	1.0%
Pomona	1.0%
Port Jervis	1.0%
Sloatsburg	1.0%
South Nyack	1.0%
Spring Valley	1.0%
Suffern	1.0%
Unionville	1.0%
Upper Nyack	1.0%
Warwick	1.0%
Washingtonville	1.0%
Wesley Hills	1.0%
West Haverstraw	1.0%
Wurtsboro	1.0%

14.1.5.7 Rochester Gas & Electric Corporation

The Transmission Customer's rate will be increased to reflect the gross receipts tax which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on RG&E as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and 186-a of the New York Tax Law. The currently effective GRT rate for the Section 186-a tax is 3.5% and each locality rate is specified below. The currently effective GRT rate for the Section 186 tax is .75%.

City of Rochester	3.0%
Leroy	1.0%
Manchester	1.0%
Perry	1.0%
Shortsville	1.0%
Warsaw	1.0%
Hilton	1.0%
Pittsford	1.0%
Caledonia	1.0%
Wolcott	1.0%
Avon	1.0%
Leicester	1.0%
Nunda	1.0%
Genesco	1.0%
Mt. Morris	1.0%
Sodus Point	1.0%
Livonia	1.0%
Meridian	1.0%
City of Canandaigua	1.0%
Fairport	1.0%
Brockport	1.0%
Scottsville	1.0%
East Rochester	1.0%

14.1.6 TSC For Retail Access Customers ("RTSC")

Customers who apply for unbundled Transmission Service in accordance with the provisions of a Transmission Owner's retail access program filed with the PSC or, in the case of LIPA, approved by the Long Island Power Authority's Board of Trustees, will be responsible for paying a retail transmission service charge as detailed in Section 5 of this Tariff.

14.1.7 NYPA Transmission Service Charge

The NYPA TSC for service to its directly connected Loads (Reynolds Metals, GM-Massena, Town of Massena and the City of Plattsburgh) shall, at the Eligible Customer's option, be (a) $1.30 per kilowatt-month or (b) no more than $3.75 per MWh; not to exceed $60.00 per MW Day applied to peak MWh scheduled any hour each day; not to exceed $300.00 per MW-Week applied to the peak MWh scheduled any hour each week. The TSC applicable to service over the Vermont intertie and the Ontario-Hydro intertie shall be the same as (b); provided, however, that the NYPA TSC shall not apply to service over the Vermont intertie provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied. The TSC applicable to service over the Hydro-Quebec intertie shall be no more than $4.62 per MWh; not to exceed $73.85 per MW-Day applied to peak MWh scheduled each day; not to exceed $369.23 per MW-Week applied to the peak MWh scheduled any hour each week. NYPA shall coordinate with the ISO to update its TSC. Such updates shall be subject to FERC filings.

14.1.8 Discounting

Each Transmission Owner may advise the ISO of discounts to its TSC applicable during a specified period to all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO shall post the discounts on the OASIS for the specified period.

Three principal requirements apply to discounts for Transmission Service as follows: (1) any offer of a discount made by a Transmission Owner must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by a Transmission Owner's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount that the Transmission Owner agrees to and advises the ISO of, the same discounted Transmission Service rate will be offered to all Transmission Customers for the same period for all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO will post the discounts on the OASIS for the specified period.

TABLE 2
Applicable Wholesale TSC for Exports from New York State, by Transmission Circuit

Ckt.Id	From/To	kV	From Co./To Ext.	Wholesale TSC Paid
5018	Ramapo / Branchburg	500	O&R/PJM	Con Ed/O&R
398	Pleasant Valley/ Long Mtn	345	CHG&E / NE	Con Ed
B3402	Farragut / Hudson	345	Con Ed / PJM	Con Ed
C3403	Farragut / Hudson	345	Con Ed / PJM	Con Ed
A2253	Goethals / Linden	230	Con Ed / PJM	Con Ed
FE	Smithfield / Falls Village	69	CHG&E/NE	CHG&E
1385	Northport / Norwalk 1	138	LIPA / NE	LIPA
393	Alps / Berkshire	345	NMPC / NE	NMPC
69	So. Ripley / Erie East	230	NMPC / PJM	NMPC
E205W	Rotterdam / Bear Swamp	230	NMPC / NE	NMPC
BP76	Packard / Beck	230	NMPC / OH	NMPC
171	Falconer / Warren	115	NMPC / PJM	NMPC
6	Hoosick / Bennington	115	NMPC /NE	NMPC
7	Whitehall / Blissville	115	NMPC / NE	NMPC
1	Dennison / Rosemont	115	NMPC / HQ	NMPC
2	Dennison / Rosemont	115	NMPC / HQ	NMPC
37-HS	Stolle Road / Homer City	345	NYSEG / PJM	NYSEG
30-HW	Watercure / Homer City	345	NYSEG / PJM	NYSEG
70-EH	Hillside / East Towanda	230	NYSEG / PJM	NYSEG
952	Goudey / Laurel Lake	115	NYSEG / PJM	NYSEG
956	No. Waverly / East Sayre	115	NYSEG / PJM	NYSEG
J	So. Mahwah / Waldwick	345	O&R / PJM	Con Ed/O&R
K	So. Mahwah / Walkwick	345	O&R / PJM	Con Ed/O&R
7040	Massena / Chateaugay	765	NYPA / HQ NYPA	NYPA
PA302	Niagara / Beck A	345	NYPA / OH	NYPA
PA301	Niagara / Beck B	345	NYPA / OH	NYPA
L34P	Moses / St. Lawrence	230	NYPA / OH	NYPA
L33P	Moses / St. Lawrence	230	NYPA / OH	NYPA
PA27	Niagara / Beck	230	NYPA / OH	NYPA
PV-20	Plattsburgh / Grand Isle	115	NYPA / NE	NYPA

[1] All scheduling over the Northport - Norwalk Intertie is conducted by LIPA pursuant to Section 5.7 of this Tariff.

TABLE 3
Applicable Wholesale TSC for Municipal Utilities, Electric Cooperatives and Loads

Except for those municipal utilities and electric cooperatives that continue to take transmission service under an Existing Transmission Agreement, the following Loads shall be obligated to pay the noted Transmission District - based TSC as applicable in accordance with Section 2.7 of this Tariff.

Load	TSC Paid	Load	TSC Paid	Load	TSC Paid
		Greene	NYSEG	Sherrill	NMPC
		Green Island	NMPC	Silver Springs	NYSEG
		Greenport	LIPA	Skaneateles	NMPC
		Groton	NYSEG	Solvay	NMPC
		Hamilton	NYSEG	Spencerport	RG&E
		Holley	NMPC	Springville	NMPC
		Ilion	NMPC	Steuben	NYSEG
Akron	NMPC	Lake Placid	NMPC	Theresa	NMPC
Andover	NMPC	Little Valley	NMPC	Tupper Lake	NMPC
Angelica	RG&E	Marathon	NYSEG	Watkins Glen	NYSEG
Arcade	NMPC	Mayville	NMPC	Wellsville	NMPC
Bath	NYSEG	Mohawk	NMPC	Westfield	NMPC
Bergen	NMPC	Oneida -Madison	NMPC/ NYSEG	Massena	NYPA
Boonville	NMPC	Otsego	NYSEG	Freeport	LIPA
Brolton	NMPC	Penn Yan	NYSEG	Jamestown	NMPC
Castile	NYSEG	Philadelphia	NMPC	Rockville Ctr.	LIPA
Churchville	NMPC	Plattsburgh	NYPA	Alcoa	(1)
Delaware	NYSEG	Richmondville	NMPC	Reynolds	NYPA
Endicott	NYSEG	Rouses Point	NYSEG	Gen. Motors (Massena, NY)	NYPA
Fairport	NMPC	Salamanca	NMPC	Cornwall	NMPC
Frankfort	NMPC	Sherburne	NYSEG		

Notes: (1) - Load is treated as an entity external to the NYCA.

14.1.9 Niagara Mohawk Power Corporation Wholesale TSC Formula Components RR, CCC and BU and Sources of Data Inputs

Niagara Mohawk Power Corporation ("NMPC") will calculate and update each of its RR, CCC, and BU components annually using the formulas for each component contained in

Attachment 1 and in accordance with the update procedures set forth in Section 14.1.9.4. With the exception of forecasted information, the cost data used in the Formula Rate will be cost data from NMPC's annual FERC Form 1, NMPC's Annual Report to the New York State Public Service Commission, or NMPC's official books of record.

14.1.9.1 Definitions

Capitalized terms used in this calculation will have the following definitions:

Allocation Factors

14.1.9.1.1 Electric Wages and Salaries Allocation Factor shall be fixed at 0.835.

14.1.9.1.2 Gross Transmission Plant Allocation Factor shall equal the total investment in Transmission Plant in Service, Transmission Related Electric General Plant, Transmission Related Common Plant and Transmission Related Intangible Plant divided by Gross Electric Plant.

14.1.9.1.3 Transmission Wages and Salaries Allocation Factor shall be fixed at 0.13.

14.1.9.1.4 Gross Electric Plant Allocation Factor shall equal Gross Electric Plant divided by the sum of Total Gas Plant, Total Electric Plant, and total Common Plant.

Ratebase and Expense Items

14.1.9.1.5 Administrative and General Expense shall equal expenses as recorded in FERC Account Nos. 920-935. FERC Account No. 926 shall be adjusted by reversing the adjustment to the deferred pension costs booked per the NYPSC Statement of Policy for Accounting and Ratemaking Treatment for Pension and Post-Retirement Benefits Other than Pensions. In addition, Administrative and

General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions ("PBOP") expenses included in FERC Account No. 926, and shall add back the FERC accepted Post Employment Benefit Other than Pensions of $88,644,000 annually or $7,387,000 per month or any other amount subsequently approved by FERC under Section 205 or 206 of the Federal Power Act.

14.1.9.1.6 Amortization of Investment Tax Credits shall equal credits as recorded in FERC Account No. 420, per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.7 Amortization of Debt Discount Expense shall equal expenses as recorded in FERC Account No. 428.

14.1.9.1.8 Amortization of Loss on Reacquired Debt shall equal expenses as recorded in FERC Account No. 428.1.

14.1.9.1.9 Amortization of Premium on Debt –Credit shall equal the expenses as recorded in FERC Account 429.

14.1.9.1.10 Amortization of Gain on Reacquired Debt--Credit shall equal the expenses as recorded in FERC Account No. 429.1.

14.1.9.1.11 Common Plant shall equal the balance of plant recorded in FERC Account Nos. 389-399. Common Plant shall be defined as the plant common to NMPC's gas and electric functions per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.12 Common Plant Depreciation Expense shall equal the common plant depreciation expenses as recorded in FERC Account No. 403, 404 and 405 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.13 Common Plant Depreciation Reserve shall equal the common plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.14 Depreciation Expense for Transmission Plant in Service shall equal depreciation expenses as recorded in FERC Account No. 403, 404 and 405 calculated using the depreciation rates set forth in the following table:

Depreciation Rates

FERC Account/NMPC Internal Account No.		Annual Rate
350	Land –Rights of Way and Easements	1.32
352	Structures and Improvements	2.08
353	Station Equipment	2.44
353.55	Station Equipment – EMS	3.40
354	Towers and Fixtures	1.71
355	Poles and Fixtures	2.00
356	Overhead Conductors and Devices	1.60
357	Underground Conduit	1.33
358	Underground Conductors and Devices	1.48
359	Roads and Trails	1.33
370	Meters	
	Meters	5.05
	Installation	5.05

14.1.9.1.15 Distribution Plant shall equal the plant balance as recorded in FERC Account Nos. 360 – 374.

14.1.9.1.16 Equity AFUDC Component of Depreciation Expense shall equal the activity recorded in FERC Account No. 419.1.

14.1.9.1.17 Electric Environmental Remediation Expense shall be the environmental remediation expense as recorded in FERC Account 930.2.

14.1.9.1.18 Electric General Plant shall equal the plant balance recorded in FERC Account Nos. 389-399. Electric General Plant shall be defined as the general plant associated with NMPC's electric function.

14.1.9.1.19 Electric General Plant Depreciation Expense shall equal general plant depreciation expenses as recorded in FERC Account No. 403, 404 and 405 associated with Electric General Plant.

14.1.9.1.20 Electric General Plant Depreciation Reserve shall equal the general plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Electric General Plant.

14.1.9.1.21 Electric Property Insurance shall equal property insurance recorded in FERC Account No. 924.

14.1.9.1.22 Electric Research and Development Expense shall equal research and development expenses as recorded in FERC Account No. 930.2.

14.1.9.1.23 Gain on Reacquired Debt shall equal the balance as recorded in FERC Account No. 257.

14.1.9.1.24 Gross Electric Plant shall equal Total Electric Plant plus an allocation of Common Plant determined by multiplying Common Plant by the Electric Wages and Salaries Allocation Factor.

14.1.9.1.25 Gross Plant (Gas & Electric) shall equal Total Gas Plant plus Total Electric Plant plus Total Common Plant.

14.1.9.1.26 Gross Transmission Investment shall equal the total of Transmission Plant in Service, Transmission Related Electric General Plant, Transmission Related Common Plant and Transmission Related Intangible Plant.

14.1.9.1.27 Intangible Electric Plant shall equal the balance of plant recorded in FERC Account Nos. 301-303. Intangible Electric Plant shall be defined as the intangible plant associated with NMPC's electric functions.

14.1.9.1.28 Intangible Electric Plant Depreciation Expense shall equal the intangible electric plant depreciation expenses as recorded in FERC Account No. 403, 404 and 405 associated with Intangible Electric Plant.

14.1.9.1.29 Intangible Electric Plant Depreciation Reserve shall equal the intangible plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Intangible Electric Plant.

14.1.9.1.30 Loss on Reacquired Debt shall equal the loss on reacquired debt as recorded in FERC Account No. 189.

14.1.9.1.31 Materials and Supplies shall equal materials and supplies balance as recorded in FERC Account No. 154 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.32 Payroll Taxes shall equal the electric payroll tax expenses related to FICA and federal and state unemployment as recorded in FERC Account 408.1..

14.1.9.1.33 Plant Held for Future Use shall equal the balance as recorded in FERC Account No. 105 for transmission uses within 5 years.

14.1.9.1.34 Prepayments shall equal prepayment balance as recorded in FERC Account No. 165 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas) less prepaid state and Federal income taxes.

14.1.9.1.35 Real Estate Tax Expenses shall equal electric real estate tax expense as recorded in FERC Account 408.1..

14.1.9.1.36 Regulatory Assets and Liabilities shall equal state and federal regulatory asset balances in FERC Account Nos. 182.3 and 254, assets and liabilities solely related to FAS109, and excess AFUDC.

14.1.9.1.37 Total Accumulated Deferred Income Taxes shall equal the sum of deferred tax balances recorded in FERC Account Nos. 281 - 283 plus accumulated deferred investment tax credits as reflected in FERC Account No. 255, minus the deferred tax balance in FERC Account No. 190. Total Accumulated Deferred Income Taxes shall exclude the specifically identified generation-related stranded cost deferred taxes.

14.1.9.1.38 Total Electric Plant shall equal the sum of Transmission Plant, Distribution Plant, Electric General Plant and Intangible Electric Plant.

14.1.9.1.39 Total Gas Plant shall equal the plant balance recorded in 18 C.F.R. Part 201, FERC Account Nos. 301-399. Total Gas Plant shall exclude Common Plant.

14.1.9.1.40 Transmission Depreciation Reserve shall equal electric transmission plant related depreciation reserve balance as recorded in FERC Account No. 108, plus Transmission Related General Plant Accumulated Depreciation, Transmission Related Amortization of Other Utility Plant, and Common Plant Accumulated Depreciation associated with Gross Electric Plant.

14.1.9.1.41 Transmission Operation and Maintenance Expense shall equal the sum of electric expenses as recorded in FERC Account Nos. 560 and 562-574 which shall include Transmission Support Payments, but shall exclude expenses incurred pursuant to agreements entered into with generators or other similar resources for the purpose of supporting transmission reliability that do not qualify as Transmission Support Payments .

14.1.9.1.42 Transmission Plant shall equal the gross plant balance as recorded in FERC Account Nos. 350-359.

14.1.9.1.43 Transmission Related Bad Debt Expense shall equal Bad Debt Expense as reported in FERC Account 904 related to NMPC’s wholesale transmission billing.

14.1.9.1.44 Unamortized Discount on Long-Term Debt shall equal the balance in FERC Account No. 226.

14.1.9.1.45 Wholesale Metering Investment shall equal the gross plant investment associated with any Revenue or Remote Terminal Unit (“RTU”) meters and associated equipment connected to an internal or external tie at voltages equal to or greater than 23 kV. The gross plant investment shall be determined by multiplying the number of such existing wholesale meters recorded in FERC Account No. 370.3 and in blanket metering accounts by the average cost of the meters plus the average costs of installation. To the extent future gross plant investment for Wholesale Metering can be specifically identified, actual gross meter costs will be used.

Forecast and True-up Related Terms

14.1.9.1.46 Forecast Period shall mean the calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available, as of the beginning of the Update Year.

14.1.9.1.47 Forecasted Transmission Plant Additions ("FTPA") shall mean the sum of:

14.1.9.1.47.1 NMPC's actual Transmission Plant additions during the first quarter (January 1 through March 31) of the Forecast Period; and

14.1.9.1.47.2 NMPC's forecasted transmission investment for the Forecast Period less the amount (i), divided by 2.

14.1.9.1.48 Interest on refunds, surcharges, or adjustments, as applicable, shall mean interest calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii) (or as such provision may be renumbered in the future).

14.1.9.1.49 Actual Transmission Revenue Requirement shall mean the current Historical Transmission Revenue Requirement (as defined in Attachment 1).

14.1.9.1.50 Actual Scheduling, System Control and Dispatch cost shall mean the most recently established CCC (as defined in Attachment 1).

14.1.9.1.51 Actual Billing Units shall mean the most recently established BU (as defined in Attachment 1).

14.1.9.1.52 Prior Year Transmission Revenue Requirement shall equal RR less Annual True-Up ("ATU"), as defined in Attachment 1, for the most recently ended calendar year as of the beginning of the Update Year.

14.1.9.1.53 Prior Year Scheduling, System Control and Dispatch shall equal the CCC, as defined in Attachment 1, for the prior calendar year.

14.1.9.1.54 Prior Year Billing Units shall equal the BU, as defined in Attachment 1, for the prior calendar year.

14.1.9.1.55 Prior Year Unit Rate shall equal the sum of RR, as defined in Attachment 1, for the most recently ended Prior Year Revenue Requirement and the Prior Year Scheduling, System Control and Dispatch divided by the Prior Year Billing Units.

14.1.9.1.56 Annual Update shall mean the calculation of the RR, CCC, and BU components with Data Inputs for an Update Year in accordance with Section 14.1.9.4.

14.1.9.1.57 Data Input shall mean any data required for the calculation of RR, CCC and BU, in accordance with the Formula Rate.

14.1.9.1.58 Formal Challenge shall mean a challenge presented in accordance with Section 14.1.9.4.3.2.

14.1.9.1.59 Informational Filing shall mean the filing that NMPC makes in accordance with Section 14.1.9.4 to establish the Annual Update for an Update Year.

14.1.9.1.60 Interested Party shall mean a person that is (i) a party to FERC Docket No. ER08-552, (ii) the New York State Public Service Commission; (iii) a transmission customer under this Tariff that pays charges based on the Formula Rate during the calendar year prior to the submission of the Informational Filing; or (iv) a state regulatory authority having jurisdiction over the retail electric rates of such a transmission customer, provided that such regulatory authority or such customer notifies NMPC of that fact no later than 30 days prior to the Publication Date. An Interested Person includes employees of or consultants to such person.

14.1.9.1.61 Material Accounting Change shall mean an accounting policy or practice, including, but not limited to, a policy or practice affecting the allocation of costs or revenues, employed by NMPC during an Update Year that differs from the corresponding policy or practice in effect during any of the three previous calendar years which change affects any Data Input for the Update Year by $1.0 million or more, as compared to the previous calendar year.

14.1.9.1.62 Preliminary Challenge shall mean a challenge presented by an Interested Party in accordance with Section 14.1.9.4.2.1.

14.1.9.1.63 Publication Date shall be the date of an Informational Filing for an Update Year.

14.1.9.1.64 Review Period shall be the period ending one-hundred and fifty (150) days after the Publication Date, unless extended in accordance with Section 14.1.9.4.2.1.

14.1.9.1.65 Formula Rate shall be the formulas set forth in Attachment 1.

14.1.9.1.66 Update Year shall be the period from July 1 of a given calendar year through June 30 of the subsequent calendar year for a particular Annual Update.

14.1.9.1.67 Transmission Support Payments shall be expenses accepted by FERC for inclusion in the Historical Transmission Revenue Requirement pursuant to agreements entered into with generators or other similar resources for the purpose of supporting transmission reliability that have been submitted to FERC for review. Pursuant to the settlement agreement accepted by FERC in Docket No.

ER14-543, Transmission Support Payments shall include the costs incurred by Niagara Mohawk pursuant to the reliability support services agreements entered into between Niagara Mohawk and Dunkirk Power, LLC on July 12, 2012 and March 4, 2013, including the costs of extending the March 4, 2013 agreement through the end of 2015, less a sum total of $35 million.

All references to FERC accounts in the above definitions are references to 18 C.F.R. Part 101, unless specifically noted otherwise. In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

14.1.9.2 Calculation of RR

The RR component shall equal the (a) Historical Transmission Revenue Requirement, plus (b) the Forecasted Transmission Revenue Requirement which shall exclude the impact of any Transmission Support Payments, plus (c) the Annual True-Up, determined in accordance with the Formula Rate.

14.1.9.3 Fixed Formula Inputs

Formula Rate inputs for (i) the authorized return on common equity (“ROE”), (ii) any cap on the common equity component of the capital structure, (iii) amount and amortization period of extraordinary property losses, (iv) depreciation and/or amortization rates, (v) PBOP expenses, and (vi) the electric wages and salaries allocation factor and transmission wages and salaries allocation factor shall be stated values until changed by the FERC pursuant to Section 205 or Section 206 of the Federal Power Act. An application under Section 205 or 206 or a proceeding initiated by FERC sua sponte under Section 206 to modify any of these stated values under the

Formula Rate other than the ROE, the cap on the common equity component of the capital structure or the allocation factors in (vi) shall not be deemed to open for review other components of the Formula Rate.

14.1.9.4 Annual Update Process

14.1.9.4.1 Annual Updates

14.1.9.4.1.1 On or before June 14th of each year, NMPC shall recalculate its RR, CCC, and BU components, applying the Data Inputs called for in the Formula Rate to produce the Annual Update for the upcoming Update Year, and:

14.1.9.4.1.1.1 shall post such Annual Update and a "workable" excel file containing that year's Annual Update on the NYISO's Internet website;

14.1.9.4.1.1.2 shall file such Annual Update with the FERC as the Informational Filing. The submission of such Informational Filing with FERC shall not require any action by the agency; and

14.1.9.4.1.1.3 shall serve the Annual Update electronically on all Interested Parties.

14.1.9.4.1.2 If the date for making the Informational Filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall coincide with the NYISO posting requirement for July rates.

14.1.9.4.1.3 The Annual Update for the Update Year:

14.1.9.4.1.3.1 shall use the Data Inputs specified in NMPC's Formula Rate, and therefore, to the extent specified in NMPC's Formula Rate, be based upon NMPC's FERC Form No. 1 data for the most recent calendar year; to the extent specified in NMPC's Formula Rate, be based upon the books and records of

NMPC consistent with FERC accounting policies, and, to the extent specified in NMPC's Formula Rate, be based on projections for the upcoming calendar year;

14.1.9.4.1.3.2 shall provide supporting documentation for Data Inputs in the form of the data provided in Attachment C to the Offer of Settlement dated April 6, 2009, in Docket No. ER08-552; and, with respect to Billing Units, shall include monthly documents in PDF format with redacted names and revised reference numbers for each entity to protect confidentiality, showing the Billing Units for each month of the most recently completed calendar billing year (the six-month updated BUs), including NMPC's Transmission Owner Load ("TOL"), consisting of metered loads for the December through November timeframe showing the calendar billing year BUs reported to the NYISO by NMPC. The total MWh of generation (including load modifiers) and net interchange for each NMPC transmission zone will be displayed. National Grid will also provide a document as a "workable" Excel file summarizing the TOL for disputed station service, High Load Factor Fitzpatrick and any other entity excluded from the Billing Units calculation in Attachment 1, Schedule 6.12, of the Formula Rate. The summary will be labeled to show the reason for exclusion, consistent with the definition of Billing Units and will reconcile to the totals shown on Attachment 1, Schedule 6.12.

14.1.9.4.1.3.3 shall provide notice of and describe all Material Accounting Changes, which description shall include an explanation of the purpose for and the circumstances giving rise to the Material Accounting Change, including references to any relevant orders, policies or notices of the Securities and

Exchange Commission, the FERC or a retail regulator, which explanation may incorporate by reference any applicable disclosure statements filed with any such agency;

14.1.9.4.1.3.4 shall provide notice of the date and location of the meeting to be held in accordance with Section 14.1.9.4.2.2;

14.1.9.4.1.3.5 shall be subject to challenge and review only in accordance with the procedures set forth in this Section 14.1.9.4, provided that such procedures shall not preclude investigation of the Annual Update by FERC, including through hearing procedures;

14.1.9.4.1.3.6 shall not seek to modify NMPC’s Formula Rate and shall not be subject to challenge by an Interested Party seeking to modify NMPC’s Formula Rate (i.e., all such modifications to the Formula Rate will require, as applicable, a Federal Power Act Section 205 or Section 206 proceeding), provided that an Interested Party may propose for consideration a change to the Formula Rate, as provided in Section 14.1.9.4.3.5;

14.1.9.4.1.3.7 shall include a list of the email addresses of Interested Parties upon which the Annual Update was served; and

14.1.9.4.1.3.8 shall provide a description of, and workpapers for, any correction of an error discovered by NMPC that affects the calculation of any charges under the Formula Rate during a prior year within the period applicable under Section 14.1.9.4.4.

14.1.9.4.1.4 The fixed Formula Rate inputs set forth in Section 14.1.9.3 shall not be subject to adjustment in an Annual Update.

14.1.9.4.2 Annual Review Procedures

Each Annual Update shall be subject to the following review procedures:

14.1.9.4.2.1 Any Interested Party shall have up to one hundred fifty (150) days after the Publication Date (unless such period is extended with the written consent of NMPC) to review the calculations and to notify NMPC in writing of any specific challenges to the accuracy of any Data Input in the Annual Update or the conformance of any such Data Input with the requirements of the Formula Rate ("Preliminary Challenge"); provided, however, that each Interested Party shall make a good faith effort to submit Preliminary Challenges at the earliest practicable date so that they may be resolved as soon as possible, and provide NMPC with a non-binding list of potential Preliminary Challenges it may present, based on its review of the Annual Update and on responses to information requests provided to that point, within ninety (90) days of the Publication Date. Any Preliminary Challenge shall be posted on the NYISO's internet website and served by electronic service on all Interested Parties by the next business day following the date it is provided to NMPC.

14.1.9.4.2.2 Within thirty (30) days of the Publication Date, NMPC shall hold a meeting open to all Interested Parties, at which meeting: (a) NMPC shall present and explain the Annual Update; (b) NMPC shall respond to questions from Interested Parties, to the extent such questions can be answered immediately; and (c) Interested Parties shall identify any areas of potential Preliminary Challenges, to the extent they have identified them at the time of the meeting.

14.1.9.4.2.3 Interested Parties shall have up to one hundred thirty (130) days after each annual Publication Date (unless such period is extended with the written consent of NMPC) to serve reasonable information requests on NMPC; provided, however, that the Interested Parties shall make a good faith effort to submit consolidated sets of information requests that limit the number and overlap of questions to the extent practicable. Such information requests may be directed to matters relevant to the accuracy of the Data Inputs included in the Annual Update and the conformance of those Data Inputs with the requirements of the corresponding provisions of the Formula Rate, including: (a) the reasons for any change in a Data Input from the corresponding Data Input in an earlier Annual Update; (b) the reasons for any change in a Data Input based on actual costs from the corresponding Data Input based on a cost projection in an earlier Annual Update; (c) any reports or other materials provided to fulfill the requirements of a state or federal regulatory agency that explain the basis for projected or actual costs reflected in a Data Input; and (d) the impact of any Material Accounting Change identified in the Annual Update on the charges produced by the Formula Rate.

14.1.9.4.2.4 NMPC shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) business days of receipt of such requests. NMPC may give reasonable priority to responding to requests that satisfy the practicable coordination and consolidation provision of Section 14.1.9.4.2.3, above. NMPC's responses to information requests shall not be entitled to protection as privileged settlement communications; provided, however, that: (a) any communications between NMPC and any Interested Party in connection with efforts to negotiate a resolution of a Preliminary Challenge or

Formal Challenge shall be entitled to such protection; (b) if NMPC's response to an information request contains proprietary or trade secret information or critical energy infrastructure information, NMPC and the Interested Party or Parties receiving such information shall enter into a confidentiality agreement materially similar to the model protective order used by the FERC to protect the confidentiality of such information; and (c) nothing herein shall require NMPC to provide information that is protected by the attorney-client privilege, the attorney work product doctrine, or any other legally recognized privilege.

14.1.9.4.3 Resolution of Challenges

14.1.9.4.3.1 NMPC and the Interested Parties shall negotiate in good faith throughout the Review Period to attempt to resolve any Preliminary Challenges.

14.1.9.4.3.2 If NMPC and any Interested Party or Parties have not resolved any Preliminary Challenge to the Annual Update within the Review Period, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of NMPC to continue efforts to resolve a Preliminary Challenge) to present the subject matter of the Preliminary Challenge to the FERC as a Formal Challenge, which shall be served on NMPC and all other Interested Parties by electronic service on the date of such filing and posted on the NYISO's internet website, however, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 14.1.9.4.2 if the FERC already has initiated a proceeding to investigate the Annual Update. By no later than five (5) business days after the end of the Review Period, NMPC shall apprise Interested Parties of the resolution of all Preliminary Challenges that have been resolved and of the impact of the resolution of all such Preliminary Challenges on the Annual Update. Within an additional fifteen (15) business days, NMPC shall submit a supplement to its Informational Filing to the FERC, with electronic service upon the Interested Parties, reflecting the impact of all successfully resolved Preliminary Challenges.

14.1.9.4.3.3 Any response by NMPC to a Formal Challenge must be submitted to the FERC within twenty-one (21) days of the date of the filing of the Formal Challenge, and shall be posted on the NYISO's Internet website and served on all Interested Parties by electronic service on the date of such filing.

14.1.9.4.3.4 In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, NMPC shall bear the burden of proving that the Data Inputs in that year's Annual Update are correct and conform to the terms of the Formula Rate and refunds or adjustments may be made, in either case with interest, to charges collected under the Formula Rate if the FERC concludes that the Data Inputs are incorrect or do not conform to the terms of the Formula Rate. In all other respects, any such proceeding shall be governed by the rules and requirements applicable to proceedings under Section 206 of the Federal Power Act.

14.1.9.4.3.5 An Interested Party may propose that resolution of a Preliminary Challenge or Formal Challenge concerning a Material Accounting Change necessitates changes to the Formula Rate to ensure that the resulting charges, including the effect of the Material Accounting Change, are just and reasonable. If NMPC agrees to such a proposed change to the Formula Rate to resolve a

Preliminary Challenge, NMPC shall file the change to the Formula Rate with the FERC for approval pursuant to Section 205 of the Federal Power Act. If NMPC does not agree to such a proposed change, the Interested Party may file the proposed change with the FERC for approval pursuant to Section 206 of the Federal Power Act concurrent with its submission of a Formal Challenge; provided that if FERC approves the proposed change, the change to the Formula Rate shall take effect as of the beginning of the Update Year during which the Section 206 filing is made, and refunds or surcharges shall be made, in either case with interest, to charges under the Formula Rate after the beginning of such Update Year to reflect the proposed change.

14.1.9.4.3.6 Nothing herein shall be deemed to limit in any way the right of NMPC to file unilaterally, pursuant to Section 205 of the Federal Power Act and the regulations thereunder, changes to NMPC's Formula Rate (including changes in connection with any incentive mechanism) or any of its Data Inputs (including, but not limited to, any fixed Data Inputs) or the right of any other party to file for such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. All parties reserve all rights to challenge, or take any position in response to, any such filing by any other party.

14.1.9.4.4 Changes to Data Inputs

14.1.9.4.4.1 Any changes to the Data Inputs for an Annual Update, including but not limited to revisions resulting from any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall take effect as of the beginning of the Update Year and the impact of such changes shall be incorporated into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19(a)) in the Annual Update for the next effective Update Year. This mechanism shall apply in lieu of mid-Update Year adjustments and any refunds or surcharges, except that, if an error in a Data Input is discovered and agreed upon within the Review Period, the impact of such change shall be incorporated prospectively into the charges produced by the Formula Rate during the remainder of the year preceding the next effective Update Year, in which case the impact reflected in subsequent charges shall be reduced accordingly.

14.1.9.4.4.2 The impact of an error affecting a Data Input on charges collected during the Formula Rate during the five (5) years prior to the Update Year in which the error was first discovered shall be corrected by incorporating the impact of the error on the charges produced by the Formula Rate during the five-year period into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19(a)) in the Annual Update for the next effective Update Year. Charges collected before the five-year period shall not be subject to correction.

14.2 Attachment 1 to Attachment H (Niagara Mohawk Power Corporation) and NYPA Transmission Adjustment Charge

14.2.1 Attachment 1 to Attachment H: Schedules (Niagara Mohawk Power Corporation)

Table of Contents

Niagara Mohawk Power Corporation

Attachment 1

Schedule 1

Calculation of RR Pursuant to Attachment H, Section 14.1.9.2

	Year

Calculation of RR

14.1.9.2 The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the formula below.

Historical Transmission Revenue Requirement (Historical TRR)

Line No.					
1		**Historical Transmission Revenue Requirement (Historical TRR)**			
2					
3	14.1.9.2 (a)	Historical TRR shall equal the sum of NMPC's (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C)			
4		Transmission Related Real Estate Tax Expense, (D) Transmission Related Amortization of Investment Tax Credits,			
5		(E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission			
6		Related Payroll Tax Expense, (H) Billing Adjustments, and (I) Transmission Related Bad Debt Expense less			
7		(J) Revenue Credits, and (K) Transmission Rents, all determined for the most recently ended calendar year as of the beginning of the update year.			
8			Reference		
9			*Section:*	**0**	
10		Return and Associated Income Taxes	(A)	#DIV/0!	Schedule 8, Line 64
11		Transmission-Related Depreciation Expense	(B)	#DIV/0!	Schedule 9, Line 6, column 5
12		Transmission-Related Real Estate Taxes	(C)	#DIV/0!	Schedule 9, Line 12, column 5
13		Transmission - Related Investment Tax Credit	(D)	#DIV/0!	Schedule 9, Line 16, column 5 times minus 1
14		Transmission Operation & Maintenance Expense	(E)	$0	Schedule 9, Line 23, column 5
15		Transmission Related Administrative & General Expense	(F)	#DIV/0!	Schedule 9, Line 38, column 5
16		Transmission Related Payroll Tax Expense	(G)	$0	Schedule 9, Line 44, column 5
17		Sub-Total (sum of Lines 10 - Line 16)		#DIV/0!	
18					
19		Billing Adjustments	(H)	$0	Schedule 10, Line 1
20		Bad Debt Expenses	(I)	$0	Schedule 10, Line 4
21		Revenue Credits	(J)	$0	Schedule 10, Line 7
22		Transmission Rents	(K)	$0	Schedule 10, Line 14
23					
24		Total Historical Transmission Revenue Requirement (Sum of Line 17 - Line 22)		#DIV/0!	
25					

Niagara Mohawk Power Corporation **Attachment 1**
Forecasted Transmission Revenue Requirement **Schedule 2**
Attachment H, Section 14.1.9.2

Shading denotes an input

Line No.		Description	Period	Reference	Year	Source
1	14.1.9.2	**FORECASTED TRANSMISSION REVENUE REQUIREMENTS**				
	(b)					
2		Forecasted TRR shall equal (1) the Forecasted Transmission Plant Additions (FTPA) multiplied by the Adjusted Annual (AFTRRF), plus (2) Forecasted ADIT Adjustment (FADITA), plus (3) the Mid-Year Trend				
3		Adjustment (MYTA), less (4) Transmission Support Payments (TSP), plus (5) the Tax Rate Adjustment (TRA), less (6) Other Billing Adjustments (OBA) as shown in the following formula:				
4						
5		Forecasted TRR = (FTPA * AFTRRF) + FADITA + MYTA - TSP + TRA - OBA				
6						
7			Period	Reference		Source
8						
9						
10	(1)	FORECASTED TRANSMISSION PLANT ADDITIONS (FTPA)			$0	Workpaper 8, Section I, Line 16
11		Adjusted Annual Transmission Revenue Requirement Factor (AFTRRF)			#DIV/0!	Line 78
12		Sub-Total (Lines 10*11)			#DIV/0!	
13						
14	(2)	FORECASTED ADIT ADJUSTMENT (FADITA)				
15		The Forecasted ADIT Adjustment (FADITA) shall equal the Forecasted ADIT (FADIT)				
16		multiplied by the Cost of Capital Rate, where:				
17						
18		Forecasted ADIT(FADIT) shall equal the projected change in Accumulated Deferred Income Taxes from the most recently				
19		concluded calendar year related to accelerated depreciation and associated with Transmission Plant for the				
20		Forecasted Period calculated in accordance with Treasury regulation Section 1.167(1)-1(h)(6).				
21						
22		Forecasted ADIT (FADIT)			#DIV/0!	Schedule 13, Line 24
23		Cost of Capital Rate			#DIV/0!	Schedule 8, Line 62
24		Forecasted ADIT Adjustment (FADITA)			#DIV/0!	Line 22 * Line 23
25						
26	(3)	MID YEAR TREND ADJUSTMENT (MYTA)				
27		The Mid-Year Trend Adjustment shall be the difference, whether positive or negative, between				
28		(i) the Historical TRR Component (E) excluding Transmission Support Payments, based on actual data for the first three months of the				

		Forecast Period,		
29		and (ii) the Historical TRR Component (E) excluding Transmission Support Payments, based on data for the first three months of the year prior to the Forecast Period.		
30				
31		Plus Mid-Year Trend Adjustment (MYTA)	$0	Workpaper 9, line 32, variance column
32				
33	(4)	TRANSMISSION SUPPORT PAYMENTS (TSP)		
34		Less Impact of Transmission Support Payments on Historical Transmission Revenue Requirement	$0	Worpaper 9A
35		Less: Other Billing Adjustments - Dunkirk Settlement ER14-543-000	**$0**	Schedule 10
36				
37	(5)	TAX RATE ADJUSTMENT (TRA)		
38		The Tax Rate Adjustment shall be the amount, if any, required to adjust Historical TRR Component (A) for any change in the Federal Income Tax Rate		
39		and/or the State Income Tax Rate that takes effect during the first five months of the Forecast Period.		
40				
41		Tax Rate Adjustment (TRA)	**$0**	
42				
43	(6)	OTHER BILLING ADJUSTMENTS (OBA)		
44		Other Billing Adjustments shall equal any amounts related to the HTRR calculation that are		
45		required to be adjusted in the current year's FTRR to remove the impact on the Update Year		
46				
47		Other Billing Adjustments (OBA)	**$0**	Schedule 10, Line 1
48				
49		Forecasted Transmission Revenue Requirement (Line 12 + Line 24 + Line 31 – Line 34 – Line 35 + Line 41-Line 47)	**#DIV/0!**	
50				
51	14.1.9.2(c)	**ANNUAL FORECAST TRANSMISSION REVENUE REQUIREMENT FACTOR**		
52				
53		Adjusted Annual Forecast Transmission Revenue Requirement Factor (AFTRRF) shall equal the difference between the Annual Forecast		
54		Transmission Revenue Requirement Factor (FTRRF) and the quotient of (1) Cost of Capital Rate multiplied by the Transmission Related		
55		Accumulated Deferred Taxes less Accumulated Deferred Inv. Tax Cr (255) for the most recently concluded calendar year,		
56		and (ii) the year-end Transmission Plant in Service determined in accordance with Section 14.1.9.2 (a), component (A)1(a).		
57				
58		The Annual Forecast Transmission Revenue Requirement Factor (Annual FTRRF) shall equal the sum of Historical TRR components (A) through (C),		
59		divided by the year-end balance of Transmission Plant in Service determined in accordance with Section 14.1.9.2 (a), component (A)1(a).		
60				
61		Deriviation of Annual Forecast Transmission Revenue Requirement		

	Factor (FTRRF)			
62	Investment Return and Income Taxes	(A)	#DIV/0!	Schedule 1, Line 10
63	Depreciation Expense	(B)	#DIV/0!	Schedule 1, Line 11
64	Property Tax Expense	(C)	#DIV/0!	Schedule 1, Line 12
65	Total Expenses (Lines 62 thru 64)		#DIV/0!	
66	Transmission Plant	(a)	#DIV/0!	Schedule 6, Page 1, Line 12
67	Annual Forecast Transmission Revenue Requirement Factor (Lines 65/ Line 66)		#DIV/0!	
68				
69	Adjustment to FTRRF to reflect removal of ADIT that is subject to normalization			
70	Transmission Related ADIT Balance at year-end		#DIV/0!	Schedule 7, Line 6, Column L
71	Less: Accumulated Deferred Inv. Tax Cr (255)		#DIV/0!	Schedule 7, Line 5, Column L
72	Net Transmission ADIT Balance at year-end		#DIV/0!	Line 70 - Line 71
73	Cost of Capital Rate		#DIV/0!	Schedule 8, Line 62
74	Total Return and Income Taxes Associated with ADIT Balance at year-end		#DIV/0!	Line 72 * Line 73
75				
76	Annual Forecast Transmission Revenue Requirement Factor (FTRRF)		#DIV/0!	Line 67
77	Less: Incremental Annual Forecast Transmission Revenue Requirement Factor Adjustment for ADIT		#DIV/0!	Line 74 / Line 66
78	Adjusted Annual Forecast Transmission Revenue Requirement Factor (AFTRRF)		#DIV/0!	Line 76 - Line 77

Niagara Mohawk Power Corporation | **Attachment 1**
Annual True-up (ATU) | **Schedule 3**
Attachment H Section 14.1.9.2 (c)

Line No.				Year	Source:
1					
2	14.1.9.2(d)		The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year		
3			Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs		
4			and Prior Year Scheduling, System Control and Dispatch costs, plus (3) the difference between the Prior Year Billing Units and the Actual Year		
5			Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.		
6					
7		(1)	Revenue Requirement (RR) of rate effective July 1 of prior year	$0	Schedule 4, Line 1, Col (d)
8			Less: Annual True-up (ATU) from rate effective July 1 of prior year	$0	Schedule 4, Line 1, Col (c)
9			Prior Year Transmission Revenue Requirement	$0	Line 7 - Line 8
10					
11			Actual Transmission Revenue Requirement	#DIV/0!	Schedule 4, Line 2, Col (a)
12			Difference	#DIV/0!	Line 11 - Line 9
13					
14		(2)	Prior Year Scheduling, System Control and Dispatch costs (CCC)	$0	Schedule 4, Line 1, Col (e)
15			Actual Scheduling, System Control and Dispatch costs (CCC)	$0	Schedule 4, Line 2, Col (e)
16			Difference	$0	Line 15 - Line 14
17					
18		(3)	Prior Year Billing Units (MWH)	$0	Schedule 4, Line 1, Col (f)
19			Actual Billing Units	-	Schedule 4, Line 2, Col (f)
20			Difference	-	Line 18 - Line 19
21			Prior Year Indicative Rate	#DIV/0!	Schedule 4, Line 1, Col (g)
22			Billing Unit True-Up	#DIV/0!	Line 20 * Line 21
23					
24			Total Annual True-Up before Interest	#DIV/0!	(Line 12 + Line 16 + Line 22)
25					
26		(4)	Interest	#DIV/0!	Line 57, Column 9
27					
28			Annual True-up RR Component	#DIV/0!	(Line 24 + Line 26)
29					

30 Interest Calculation per 18 CFR § 35.19a

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
32	Quarters	Annual	Accrued Prin	Monthly	Days			Accrued Prin	Accrued
33		Interest	& Int. @ Beg	(Over)/Under	in	Period		& Int. @ End	Int. @ End
34		Rate (a)	Of Period	Recovery	Period (b)	Days	Multiplier	Of Period	Of Period
35									
36	3rd QTR		0		92	92	1.0000	$0	$0
37	July	0.00%		#DIV/0!	31	92	1.0000	#DIV/0!	#DIV/0!
38	August	0.00%		#DIV/0!	31	61	1.0000	#DIV/0!	#DIV/0!

39	September	0.00%		#DIV/0!	30	30	1.0000	#DIV/0!	#DIV/0!
40									
41	4th QTR		#DIV/0!		92	92	1.0000	#DIV/0!	#DIV/0!
42	October	0.00%		#DIV/0!	31	92	1.0000	#DIV/0!	#DIV/0!
43	November	0.00%		#DIV/0!	30	61	1.0000	#DIV/0!	#DIV/0!
44	December	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
45									
46	1st QTR		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!
47	January	0.00%		#DIV/0!	31	91	1.0000	#DIV/0!	#DIV/0!
48	February	0.00%		#DIV/0!	28	60	1.0000	#DIV/0!	#DIV/0!
49	March	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
50									
51	2nd QTR		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!
52	April	0.00%		#DIV/0!	30	91	1.0000	#DIV/0!	#DIV/0!
53	May	0.00%		#DIV/0!	31	61	1.0000	#DIV/0!	#DIV/0!
54	June	0.00%		#DIV/0!	30	30	1.0000	#DIV/0!	#DIV/0!
55									
56									
57	Total (over)/under Recovery			#DIV/0!	(line 24)	#DIV/0!			#DIV/0!

(a) Interest rates shall be the interest rates as reported on the FERC Website http://www.ferc.gov/legal/acct-matts/interest-rates.asp

(b) For leap years use 29 days in the month of February

Attachment 1
Schedule 4

Niagara Mohawk Power Corporation

Wholesale TSC Calculation Information

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Historical Transmission Revenue Requirement (Historical TRR)	Forecasted Transmission Revenue Requirement	Annual True Up	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate $/MWh (*)
1	Prior Year Rates Effective ________	-	-	-	-	-	-	#DIV/0!
2	Current Year Rates Effective July 1, _______	#DIV/0!	#DIV/0!		#DIV/0!	-	-	#DIV/0!
3	Increase/(Decrease)							#DIV/0!
4	Percentage Increase/(Decrease)							#DIV/0!

1.) Information directly from Niagara Mohawk Prior Year Informational Filing
2.)
(a) Schedule 1, Line 24
(b) Schedule 2, Line 49
(c) Schedule 3, Line 28
(d) Attachment H, Section 14.1.9.2 The RR Component shall equal Col (a) Historical Transmission Revenue Requirement plus Col (b) the Forecasted Transmission Revenue Requirement which shall exclude Transmission Support Payments, plus Col (c) the Annual True-Up plus Col (c) the Annual True-Up
(e) Schedule 11, Line 21 - Annual Scheduling, System Control and Dispatch Costs. (i.e. the Transmission Component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts from the prior calendar year excluding any NY Independent System Operator (NYISO) system control and load dispatch expenses already recovered under Schedule 1 of the NYISO Tariff.
(f) Schedule 12, line 17 - Billing Units shall be the total Niagara Mohawk load as reported to the NYISO for the calendar year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR, and Reserved components of Attachment H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.
(g) (Col (d) + Col (e)) / Col (f)

(*) The rate column represents the unit rate prior to adjustments; the actual rate will be determined pursuant to the applicable TSC formula rate.

Niagara Mohawk Power Corporation
Allocation Factors - As calculated pursuant to Section 14.1.9.1

Attachment 1
Schedule 5

Year

Shading denotes an input

Line No.		Description	Amount	Source	Definition
1	14.1.9.1 1.	**Electric Wages and Salaries Factor**	**83.5000%**		Fixed per settlement Docket ER08-552
2					
3	14.1.9.1 3.	**Transmission Wages and Salaries Allocation Factor**	**13.0000%**		Fixed per settlement Docket ER08-552
4					
5					
6					
7					
8	14.1.9.1 2.	**Gross Transmission Plant Allocation Factor**			
9		Transmission Plant in Service	#DIV/0!	Schedule 6, Page 2, Line 3, Col 5	Gross Transmission Plant Allocation Factor shall equal the total investment in
10		Plus: Transmission Related General	$0	Schedule 6, Page 2, Line 5, Col 5	Transmission Plant in Service, Transmission Related Electric General Plant,
11		Plus: Transmission Related Common	$0	Schedule 6, Page 2, Line 10, Col 5	Transmission Related Common Plant and Transmission Related Intangible Plant
12		Plus: Transmission Related Intangible Plant	$0	Schedule 6, Page 2, Line 15, Col 5	divided by Gross Electric Plant.
13		Gross Transmission Investment	#DIV/0!	Sum of Lines 9 - 13	
14					
15		Total Electric Plant		FF1 207.104g	
16		Plus: Electric Common	$0	Schedule 6, Page 2, Line 10, Col 3	
17		Gross Electric Plant in Service	$0	Line 15 + Line 16	
18					
19		**Percent Allocation**	**#DIV/0!**	Line 13 / Line 17	
20					
21	14.1.9.1 4.	**Gross Electric Plant Allocation Factor**			
22					
23		Total Electric Plant in Service	$0	Line 15	Gross Electric Plant Allocation Factor shall equal
24		Plus: Electric Common Plant	$0	Schedule 6, Page 2, Line 10, Col 3	Gross Electric Plant divided by the sum of Total Gas Plant,
25		Gross Electric Plant in Service	$0	Line 23 + Line 24	Total Electric Plant, and Total Common Plant
26					
27		Total Gas Plant in Service		FF1 201.8d	

28	Total Electric Plant in Service	$0	Line 15
29	Total Common Plant in Service	$0	Schedule 6, Page 2, Line 10, Col 1
30	Gross Plant in Service (Gas & Electric)	-	Sum of Lines 27-Lines 29
31			
32	**Percent Allocation**	**#DIV/0!**	Line 25 / Line 30

Attachment 1
Schedule 6
Page 1 of 2

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H, section 14.1.9.2

Line No.

1 14.1.9.2 (a) Transmission Investment Base

2

3 A.1. Transmission Investment Base shall be defined as (a) Transmission Plant in Service, plus (b) Transmission Related Electric General Plant, plus
4 (c) Transmission Related Common Plant, plus (d) Transmission Related Intangible Plant, plus (e) Transmission Related Plant Held for Future Use, less
5 (f) Transmission Related Depreciation Reserve, less (g) Transmission Related Accumulated Deferred Taxes, plus (h) Transmission Related
6 Regulatory Assets net of Regulatory Liabilities, plus (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies,
7 plus (k) Transmission Related Cash Working Capital.

8

9

Line No.	Description	Reference	**Year**	Reference
11		*Section:*		
12	Transmission Plant in Service	(a)	#DIV/0!	Schedule 6, page 2, line 3, column 5
13	General Plant	(b)	$0	Schedule 6, page 2, line 5, column 5
14	Common Plant	(c)	$0	Schedule 6, page 2, line 10, column 5
15	Intangible Plant	(d)	$0	Schedule 6, page 2, line 15, column 5
16	Plant Held For Future Use	(e)	$0	Schedule 6, page 2, line 19, column 5
17	Total Plant (Sum of Line 12 - Line 16)		#DIV/0!	
18				
19	Accumulated Depreciation	(f)	#DIV/0!	Schedule 6, page 2, line 29, column 5
20	Accumulated Deferred Income Taxes	(g)	#DIV/0!	Schedule 7, line 6, column 5
21	Other Regulatory Assets	(h)	#DIV/0!	Schedule 7, line 11, column 5
22	Net Investment (Sum of Line 17 -Line 21)		#DIV/0!	
23				
24	Prepayments	(i)	#DIV/0!	Schedule 7, line 15, column 5
25	Materials & Supplies	(j)	#DIV/0!	Schedule 7, line 21, column 5
26	Cash Working Capital	(k)	$0	Schedule 7, line 28, column 5
27				
28	Total Investment Base (Sum of Line 22 - Line 26)		#DIV/0!	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H Section 14.1. 9.2 (a) A. 1.

Attachment 1
Schedule 6
Page 2 of 2

Year

Shading denotes an input

Line No.		(1) Total	(2) Allocation Factor		(3) = (1)*(2) Electric Allocated	(4) Allocation Factor		(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Plant								FF1 207.58g	14.1.9.2(a)A.1.(a)	Transmission Plant in Service shall equal the
2	Wholesale Meter Plant							#DIV/0!	Workpaper 1		balance of total investment in Transmission Plant
3	Total Transmission Plant in Service (Line 1+ Line 2)							#DIV/0!			plus Wholesale Metering Investment.
4											
5	General Plant		100.00%		$0	13.00%	(c)	$0	FF1 207.99g	14.1.9.2(a)A.1.(b)	Transmission Related Electric General Plant shall
6											equal the balance of investment in Electric General
7											Plant mulitplied by the Transmission Wages and
8											Salaries Allocation Factor.
9											
10	Common Plant		83.50%	(a)	$0	13.00%	(c)	$0	FF1 201. 8h	14.1.9.2(a)A.1.(c)	Transmission Related Common Plant shall equal Common
11											Plant multiplied by the Electric Wages and Salaries
12											Allocation Factor and further multiplied by the
13											Transmission Wages and Salaries Allocation Factor.
14											
15	Intangible Plant		100.00%		-	13.00%	(c)	$0	FF1 205.5g	14.1.9.2(a)A.1.(d)	Transmission Related Intangible Plant shall equal Intangible
16											Electric Plant multiplied by the

17											Transmission Wages and Salaries Allocation Factor.
18											
19	Transmission Plant Held for Future Use	$0						$0	Workpaper 10	14.1.9.2(a)A.1.(e)	Transmission Related Plant Held for Future Use shall equal
20											the balance in Plant Held for Future Use associated with
21											property planned to be used for transmission service within
22											five years.
23	Transmission Accumulated Depreciation										
24	Transmission Accum. Depreciation							$0	FF1 219.25b	14.1.9.2(a)A.1.(f)	Transmission Related Depreciation Reserve shall equal the
25	General Plant Accum.Depreciation		100.00%		$0	13.00%	(c)	$0	FF1 219.28b		balance of: (i) Transmission Depreciation Reserve, plus (ii)
26	Common Plant Accum Depreciation		83.50%	(a)	$0	13.00%	(c)	$0	FF1 356.1 end of year balance		the product of Electric General Plant Depreciation Reserve
27	Amortization of Other Utility Plant		100.00%		$0	13.00%	(c)	$0	FF1 200.21c		multiplied by the Transmission Wages and Salaries
28	Wholesale Meters	#DIV/0!						#DIV/0!	Workpaper 1		Allocation Factor, plus (iii) the product of Common Plant
29	Total Depreciation (Sum of Line 24 - Line 28)							#DIV/0!			Depreciation Reserve multiplied by the Electric Wages and
30											Salaries Allocation Factor and further multiplied by the
31											Transmission Wages and Salaries Allocation Factor plus (iv)
32											the product of Intangible Electric Plant Depreciation Reserve
33											multiplied by the Transmission Wages and Salaries
34											Allocation Factor plus (v) depreciation reserve associated with
35											the Wholesale Metering Investment.
36											

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32 - not used on this Schedule

(c) Schedule 5, line 3
(d) Schedule 5, line 19 - not used on this Schedule

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 2 of 2)

Attachment 1
Schedule 7

Attachment H Section 14.1.9.2 (a) A. 1.
Shading denotes an input

Year

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor		(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Accumulated Deferred Taxes									
2	Accumulated Deferred Taxes (281-282)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 275.2k	14.1.9.2(a)A.1.(g)	Transmission Related Accumulated Deferred Income Taxes
3	Accumulated Deferred Taxes (283)	$0	100.00%	$0	#DIV/0!	(d)	#DIV/0!	Workpaper 2, Line 5		shall equal the electric balance of Total Accumulated Deferred
4	Accumulated Deferred Taxes (190)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 234.8c		Income Taxes (FERC Accounts 190, 55,281, 282, and 283 net of
5	Accumulated Deferred Inv. Tax Cr (255)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 267.8h		stranded costs), multiplied by the Gross Transmission Plant
6	Total (Sum of Line 2 - Line 5)			$0			#DIV/0!			Allocation Factor.
7										
8	Other Regulatory Assets									
9	FAS 109 (Asset Account 182.3)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 232 lines 2,20,25,31	14.1.9.2(a)A.1.(h)	Transmission Related Regulatory Assets shall be Regulatory
10	FAS 109 (Liability Account 254)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 278lines 1& 29(f)		Assets net of Regulatory Liabilities multiplied by the Gross
11	Total (Line 9 + Line 10)	$0		$0			#DIV/0!			Transmission Plant Allocation Factor.
12										
13	Transmission Prepayments							FF1 111.57c	14.1.9.2(a)A.1.(i)	Transmission Related Prepayments shall be the product of
14	Less: Prepaid State and Federal Income Tax							FF1 263 lines 2 &7 (h)		Prepayments excluding Federal and State taxes multiplied by
15	Total Prepayments (Line 13 + Line 14)	$0	#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!			the Gross Electric Plant Allocation Factor and further
16										multiplied by the Gross Transmission Plant Allocation Factor.
17										
18	Transmission Material and Supplies								14.1.9.2(a)A.1.(j)	Transmission Related Materials and Supplies shall equal: (i)
19	Trans. Specific O&M Materials and						$0	FF1 227.8c		the balance of Materials and Supplies assigned to

	Supplies								
20	Construction Materials and Supplies	#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!	FF1 227.5c		Transmission plus (ii) the product of Material and Supplies
21	Total (Line 19 + Line 20)					#DIV/0!			assigned to Construction multiplied by the Gross Electric
22									Plant Allocation Factor and further multiplied by Gross
23									Transmission Plant Allocation Factor.
24									
25	Cash Working Capital							14.1.9.2(a)A.1.(k)	Transmission Related Cash Working Capital shall be an
26	Operation & Maintenance Expense					$0	Schedule 9, Line 23		allowance equal to the product of: (i) 12.5% (45 days/ 360 days = 12.5%)
27						0.1250	x 45 / 360		multiplied by (ii) Transmission Operation and Maintenance Expense.
28	Total (Line 26 * Line 27)					$0			
29									
30									

Allocation Factor Reference
(a) Schedule 5, line 1 - not used on this Schedule
(b) Schedule 5, line 32
(c) Schedule 5, line 3 - not used on this Schedule
(d) Schedule 5, line 19

Niagara Mohawk Power Corporation | **Attachment 1**
Annual Revenue Requirements of Transmission Facilities | **Schedule 8**
Cost of Capital Rate

Shading denotes an input | **Year**

Line No.

1 **The Cost of Capital Rate shall equal the proposed Weighted Costs of Capital plus Federal Income Taxes and State Income Taxes.**

2 The Weighted Costs of Capital will be calculated for the Transmission Investment Base using NMPC's actual capital structure and will equal the sum of (i), (ii), and (iii) below:

3

4 (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's long-term debt outstanding during the year and the sum of (a) the ratio of actual long-term debt to total capital at year-end; and

5 (b) the extent, if any, by which the ratio of NMPC's actual common equity to total capital at year-end exceeds fifty percent (50%). Long term debt shall be defined as the average of the beginning of the year and end of year balances of the following: long term debt less the unamortized

6 Discounts on Long-Term Debt less the unamortized Loss on Reacquired Debt plus unamortized Gain on Reacquired Debt. Cost to maturity of NMPC's long-term debt shall be defined as the cost of long term debt included in the debt discount expense and

7 any loss or gain on reacquired debt.

8 (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's preferred stock then outstanding and the ratio of actual preferred stock to total capital at year-end;

9

10 (iii) the return on equity component shall be the product of the allowed return on equity of 10.3% and the ratio of NMPC's actual common equity to total capital at year-end, provided that such ratio

11 shall not exceed fifty percent (50%).

12

Line No.			CAPITALIZATION	Source:	CAPITALIZATION RATIOS	COST OF CAPITAL	Source:	WEIGHTED COST OF CAPITAL	EQUITY PORTION
13									
14									
15									
16									
17	(i)	Long-Term Debt	$0	Workpaper 6, Line 16b	#DIV/0!	#DIV/0!	Workpaper 6, Line 17c	#DIV/0!	
18	(ii)	Preferred Stock		FF1 112.3c	#DIV/0!	#DIV/0!	Workpaper 6, Line 24d	#DIV/0!	#DIV/0!
19	(iii)	Common Equity		FF1 112.16c - FF1 112.3,12,15c	#DIV/0!	10.30%		#DIV/0!	#DIV/0!
20									
21		Total Investment Return	$0		#DIV/0!			#DIV/0!	#DIV/0!
22									
23									
24									
25									

26 Federal Income Federal Income
14.1.9.2.2.(b) Tax shall equal = (A + [B / C] X Tax Rate)
27 Federal Income
(1 - Tax Rate)
28
29 where A is the sum of the preferred stock component and the return on equity component, each as determined in Sections (a)(ii) and for the ROE set forth in (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for
30 Transmission Plant in Service as defined at Section 14.1.9.1.16 (FF1 117.38c), and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.
31
32 =
(#DIV/0! +($0) / #DIV/0! X)
33 (1 - 0)
34
35 = #DIV/0!
36
37
38 State Income State
Tax shall = Federal Income Income Tax
14.1.9.2.2.(c) equal (A + [B / C] + Tax Rate) X Rate
39 State Income
(1 - Tax Rate)
40
41 where A is the sum of the preferred stock component and the return on equity component as determined in (a)(ii) and (a)(iii) above , B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in
42 Service as defined at Section 14.1.9.1.16 above, and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.
43
44
45
= #DIV/0 + $ #DIV/
46 (! (0) / 0! + #DIV/0!) X
47 (1 - 0)
48
49 = #DIV/0!
50
51
52
(a)+(b)+(c) Cost of
53 Capital Rate = #DIV/0!
54
55
14.1.9.2(a) A. Return and Associated Income Taxes shall equal the product of the
56 **Transmission Investment Base and the Cost of Capital Rate**

57			
58			
59			
60	Transmission Investment Base	#DIV/0!	Schedule 6, page 1 of 2, Line 28
61			
62	Cost of Capital Rate	#DIV/0!	Line 53
63			
64	= Investment Return and Income Taxes	#DIV/0!	Line 60 X Line 62

Niagara Mohawk Power Corporation | **Attachment 1**
Annual Revenue Requirements of Transmission Facilities | **Schedule 9**
Transmission Expenses

Attachment H Section 14.1.9.2

Year

Shading denotes an input

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1/ PSC Report Reference for col (1)		Definition
	Depreciation Expense								
1	Transmission Depreciation					$0	FF1 336.7f	14.1.9.2.B.	Transmission Related Depreciation Expense shall equal the sum of:
2	General Depreciation		100.0000%	$0	13.0000% (c)	$0	FF1 336.10f		(i) Depreciation Expense for Transmission Plant in Service, plus (ii)
3	Common Depreciation		83.5000% (a)	$0	13.0000% (c)	$0	FF1 356.1		the product of Electric General Plant Depreciation Expense multiplied
4	Intangible Depreciation		100.0000%	$0	13.0000% (c)	$0	FF1 336.1f		by the Transmission Wages and Salaries Allocation Factor plus (iii)
5	Wholesale Meters					#DIV/0!	Workpaper 1		Common Plant Depreciation Expense multiplied by the Electric
6	Total (Line 1+2+3+4+5)					#DIV/0!			Wages and Salaries Allocation Factor, further multiplied by the
7									Transmission Wages and Salaries Allocation Factor plus (iv)
8									Intangible Electric Plant Depreciation Expense multiplied by the
9									Transmission Wages and Salaries Factor plus (v) depreciation
10									expense associated with the Wholesale Metering Investment.
11									
12	Real Estate Taxes		100.0000%	$0	#DIV/0! (d)	#DIV/0!	FF1 263.25i	14.1.9.2.C.	Transmission Related Real Estate Tax Expense shall equal the
13									electric Real Estate Tax Expenses multiplied by the Gross
14									Transmission Plant Allocation Factor.
15									
16	Amortization of Investment Tax Credits		#DIV/0! (b)	#DIV/0!	#DIV/0! (d)	#DIV/0!	FF1 117.58c	14.1.9.2.D.	Transmission Related Amortization of Investment Tax Credits shall
17									equal the product of Amortization of Investment Tax Credits multiplied
18									by the Gross Electric Plant Allocation Factor and further multiplied by
19									the Gross Transmission Plant Allocation Factor.
20	Transmission Operation and Maintenance								
21	Operation and Maintenance					$0	FF1 321.112b	14.1.9.2.E.	Transmission Operation and Maintenance Expense shall equal
22	less Load Dispatching - #561					$0	FF1 321.84-92b		the sum of electric expenses as recorded in
23	O&M (Line 21 - Line 22)	$0				$0			FERC Account Nos. 560, 562-574.
24									
25	Transmission Administrative and General							14.1.9.2.F.	Transmission Related Administrative and General Expenses shall
26	Total Administrative and General						FF1 323.197b		equal the product of electric Administrative and General Expenses,
27	less Property Insurance (#924)						FF1 323.185b		excluding the sum of Electric Property Insurance, Electric

28	less Pensions and Benefits (#926)						FF1 323.187b
29	less: Research and Development Expenses (#930)	$0					Workpaper 12
30	Less: 50% of NY PSC Regulatory Expense						50% of Workpaper 15
31	Less: 18a Charges (Temporary Assessment						Workpaper 15
32	less: Environmental Remediation Expense	$0					Workpaper 11
33	Subtotal (Line 26-27-28-29-30-31-32)	$0	100.0000%	$0	13.0000% (c)	$0	
34	PLUS Property Insurance alloc. using Plant Allocation	$0	100.0000%	$0	#DIV/0! (d)	#DIV/0!	Line 27
35	PLUS Pensions and Benefits	$88,644,000	100.0000%	$88,644,000	13.0000% (c)	$11,523,720	Workpaper 3
36	PLUS Transmission-related research and development	$0				$0	Workpaper 12
37	PLUS Transmission-related Environmental Expense	$0				$0	Workpaper 11
38	Total A&G (Line 33+34+35+36+37)	$88,644,000		$88,644,000		#DIV/0!	
39							
40	Payroll Tax Expense						
41	Federal Unemployment						FF1 263.4i
42	FICA						FF1 263.3i
43	State Unemployment						FF1 263.9i
44	Total (Line 41+42+43)	$0	100.0000%	$0	13.0000% (b)	$0	

Research and Development Expense and Electric Environmental Remediation Expense, and 50% of the NYPSC Regulatory Expense multiplied by the Transmission Wages and Salaries Allocation Factor, plus the sum of Electric Property Insurance multiplied by the Gross Transmission Plant Allocation Factor, plus transmission-specific Electric Research and Development Expense, and transmission-specific Electric Environmental Remediation Expense. In addition, Administrative and General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926, and shall add back in the amounts shown on Workpaper 3, page 1, or other amount subsequently approved by FERC under Section 205 or 206.

14.1.9.2.G. Transmission Related Payroll Tax Expense shall equal the product of electric Payroll Taxes multiplied by the Transmission Wages and Salaries Allocation Factor.

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32
(c) Schedule 5, line 3
(d) Schedule 5, line 19

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Billing Adjustments, Revenue Credits, Rental Income

Attachment 1
Schedule 10

Year

Attachment H Section
14.1.9.2 (a)

Shading denotes an input

Line No.	Description	(1) Total	Source		Definition
1	Billing Adjustments			14.1.9.2.H.	Billing Adjustments shall be any adjustments made in accordance with Section 14.1.9.4.4 below.
2					( ) indicates a refund or a reduction to the revenue requirement on Schedule 1.
3					
4	Bad Debt Expense	$0	Workpaper 4	14.1.9.2.I.	Transmission Related Bad Debt Expense shall equal
5					Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.
6					
7	Revenue Credits	$0	Workpaper 5	14.1.9.2.J.	Revenue Credits shall equal all Transmission revenue recorded in FERC account 456
8					excluding (a) any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved
9					components in Attachment H of the NYISO TSC rate; (b) any revenues associated
10					with expenses that have been excluded from NMPC’s revenue requirement; and (c) any
11					revenues associated with transmission service provided under this TSC rate, for which the
12					load is reflected in the calculation of BU.
13					
14	Transmission Rents	$0	Workpaper 7	14.1.9.2.K.	Transmission Rents shall equal all Transmission-related rental income recorded in FERC
15					account 454.615
16					
17				14.1.9.4(d)	
18				1	Any changes to the Data Inputs for an Annual Update, including but not limited to
19					revisions resulting from any FERC proceeding to consider the Annual Update, or
20					as a result of the procedures set forth herein, shall take effect as of the beginning
21					of the Update Year and the impact of such changes shall be incorporated into the
22					charges produced by the Formula Rate (with interest determined in accordance
23					with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
24					Year. This mechanism shall apply in lieu of mid-Update Year adjustments and
25					any refunds or surcharges, except that, if an error in a Data Input is discovered
26					and agreed upon within the Review Period, the impact of such change shall be
27					incorporated prospectively into the charges produced by the Formula Rate during
28					the remainder of the year preceding the next effective Update Year, in which case
29					the impact reflected in subsequent charges shall be reduced accordingly.
30				2	The impact of an error affecting a Data Input on charges collected during the

Formula Rate during the five (5) years prior to the Update Year in which the error was first discovered shall be corrected by incorporating the impact of the error on the charges produced by the Formula Rate during the five-year period into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update Year. Charges collected before the five-year period shall not be subject to correction.

(b)	List of Items excluded from the Revenue Requirement	Reason

Attachment 1
Schedule 11
Page 1 of 1

Niagara Mohawk Power Corporation
System, Control, and Load Dispatch Expenses (CCC)
Attachment H, Section
14.1.9.5

The CCC shall equal the annual Scheduling, System Control and Dispatch Costs (i.e., the transmission component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts using information from the prior calendar year, excluding NYISO system control and load dispatch expense already recovered under Schedule 1 of the NYISO Tariff.

Line No.				Year	Source
1	**Scheduling and Dispatch Expenses**			**Year**	**Source**
2					
3	Accounts	561	Load Dispatching		FF1 321.84b
4	Accounts	561.1	Reliability		FF1 321.85b
5	Accounts	561.2	Monitor and Operate Transmission System		FF1 321.86b
6	Accounts	561.3	Transmission Service and Schedule		FF1 321.87b
7	Accounts	561.4	Scheduling System Control and Dispatch		FF1 321.88b
8	Accounts	561.5	Reliability, Planning and Standards Development		FF1 321.89b
9	Accounts	561.6	Transmission Service Studies		FF1 321.90b
10	Accounts	561.7	Generation Interconnection Studies		FF1 321.91b
11	Accounts	561.8	Reliability, Planning and Standards Dev. Services		FF1 321.92b
12					
13		Total Load Dispatch Expenses (sum of Lines 3 - 11)			Sum of Lines 3 - 11
14					
15	Less Account 561 directly recovered under Schedule 1 of the NYISO Tariff				
16					
17	Accounts	561.4	Scheduling System Control and Dispatch		Line 7
18	Accounts	561.8	Reliability, Planning and Standards Dev. Services		Line 11
19		Total NYISO Schedule 1			Line 17 + Line 18
20					
21	Total CCC Component				Line 13 - Line 19

Attachment 1
Schedule 12
Page 1 of 1

Niagara Mohawk Power Corporation
Billing Units - MWH
Attachment H, Section 14.1.9.6

BU shall be the total Niagara Mohawk load as reported to the NYISO for the calendar billing year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC Rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR and Reserved components of Workpaper H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.

Line No.			SOURCE
1	Subzone 1		NIMO TOL (transmission owner load)
2	Subzone 2		NIMO TOL (transmission owner load)
3	Subzone 3		NIMO TOL (transmission owner load)
4	Subzone 4		NIMO TOL (transmission owner load)
5	Subzone 29		NIMO TOL (transmission owner load)
6	Subzone 31		NIMO TOL (transmission owner load)
7	Total NIMO Load report to NYISO	**0.000**	Sum of Lines 1-6
8	LESS: All non-retail transactions		
9	Watertown		FF1 page 329.10.j
10	Disputed Station Service		NIMO TOL (transmission owner load)
11	Other non-retail transactions		All other non-retail transactions (Sum of 300,000 series PTID's from TOL)
12	Total Deductions	**0.000**	Sum of Lines 9 - 11
13	PLUS: TSC Load		
14	NYMPA Muni's, Misc. Villages, Jamestown (X1)		FF1 page 329.17.j
15	NYPA Niagara Muni's (X2)		FF1 page 329.1.j
16	Total additions	**0.000**	Sum of Lines 14 -15
17	Total Billing Units	**0.000**	Line 7 - Line 12 + Line 16

Niagara Mohawk Power Corporation | **Attachment 1**

Forecasted Accumulated Deferred Income Taxes (FADIT) | **Schedule 13**

Page 1 of 1

Shading denotes an input

Line No.	Description	Amount	
1	Transmission Related ADIT Balance at year-end		Schedule 7, Line 6, Column L
2	Less: Accumulated Deferred Inv. Tax Cr (255)		Schedule 7, Line 5, Column L
3	Net Transmission ADIT Balance at year-end (a)		Line 1 - Line 2
4			
5	Forecasted Transmission Related ADIT balance		Internal Records
6			
7	Change in ADIT		Line 5 - Line 3
8			
9	Monthly Change in ADIT		Line 7 / 12 Months
10			

11	**(A) Month**	**(B) Remaining Days**	**(C) = (B)/ Line 17 (B) IRS Proration %**	**(D) = Line 9 *(C) Prorated ADIT**	
12	Month 1		100.00%	-	
13	Month 2		100.00%	-	
14	Month 3		100.00%	-	
15	Month 4		100.00%	-	
16	Month 5		100.00%	-	
17	Month 6		100.00%	-	
18	Month 7		#DIV/0! %	-	
19	Month 8		#DIV/0! %	-	
20	Month 9		#DIV/0! %	-	
21	Month 10		#DIV/0! %	-	
22	Month 11		#DIV/0! %	-	
23	Month 12		#DIV/0! %	-	
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ -	to Schedule 2, Line 22
				-	

(a) The balance in Line 1, Total Transmission ADIT

Balance at year-end, shall equal such ADIT that is subject to the normalization rules prescribed by the IRS and the net of the amounts recorded in FERC Account Nos. 281-283 and 190.

14.2.2 NYPA Transmission Adjustment Charge ("NTAC")

14.2.2.1 Applicability of the NYPA Transmission Adjustment Charge

Each Billing Period, the ISO shall charge, and each Transmission Customer shall pay, the applicable NYPA Transmission Adjustment Charge ("NTAC") calculated in accordance with Section 14.2.2.2.1 of this Attachment. The NTAC shall apply to Transmission Service:

14.2.2.1.1 from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area ("Wheels Through"); provided, however, that the NTAC shall not apply to Wheels Through scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied; or

14.2.2.1.2 from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection ("Exports"); provided, however, that the NTAC shall not apply to Exports scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied; or

14.2.2.1.3 to serve Load within the NYCA.

In summary, the NTAC will be applied to all Energy Transactions, including internal New York State Loads and Wheels Through and Exports out of the NYCA at a uniform, non-discountable rate.

14.2.2.2 NTAC Calculation

14.2.2.2.1 NTAC Formula

NYPA shall calculate the NTAC applicable to Transmission Service to serve New York State Load, Wheels Through and Exports as follows:

$$NTAC = \{(ATRR_{NTAC} \div 12) - (EA) - (IR \div 12) - SR - CRN - WR - ECR - NR - NT\}/(BU \div 12)$$

Where:

$ATRR_{NTAC}$ = NYPA's Annual Transmission Revenue Requirement for costs not recoverable through project-specific transmission revenue requirements, which includes the Scheduling, System Control and Dispatch Costs of NYPA's control center, all as determined in accordance with the Formula Rate Template provided in Section 14.2.3.1 of this Attachment, and as reflected on SCH - Summary, line 11 of the Formula Rate Template;

EA = Monthly Net Revenues from Modified Wheeling Agreements, Facility Agreements and Third Party TWAs, and Deliveries to directly connected Transmission Customers;

SR = $SR_1 + SR_2 + SR_3 + SR_4$

SR_1 will equal the revenues from the Direct Sale by NYPA of Original Residual TCCs, and Grandfathered TCCs associated with ETAs, the expenses for which are included in NYPA's $ATRR_{NTAC}$ where NYPA is the Primary Holder of said TCCs. SR1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that NYPA will receive under each applicable TCC sold in a Direct Sale divided by the duration of that TCC (in months).

SR_2 will equal NYPA's revenues from the Centralized TCC Auctions and Reconfiguration Auctions allocated pursuant to Attachment N; this includes revenues from: (a)

TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auctions and Reconfiguration Auctions; and (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for these ETAs are included in NYPA's $ATRR_{NTAC}$. The revenue that NYPA receives from a TCC sold in a Centralized Auction or Reconfiguration Auction will be divided equally among the month(s) for which the sold TCC is valid. For Balance of Period Auctions, the ISO shall provide NYPA information regarding its respective share of Net Auction Revenues for each month covered by each Balance-of-Period Auction.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Owners sell through the Centralized TCC Auctions and the allocation of revenue for other TCCs sold through the Centralized TCC Auctions and Reconfiguration Auctions (per the Facility Flow-Based Methodology described in Attachment N);

SR_3 shall equal NYPA's share of revenues from the award and renewal of Historic Fixed Price TCCs, as determined pursuant to Section 20.4 of Attachment N. The share of revenues allocated to NYPA pursuant to Section 20.4 of Attachment N shall be adjusted after each Centralized TCC Auction and divided equally across the months for which the Historic Fixed Price TCCs that were awarded or renewed prior to the relevant Centralized TCC Auction are valid. Notwithstanding anything to the contrary herein, with respect to NYPA's share of any revenues for Historic Fixed Price TCCs that took effect on or before November 1, 2016, such revenues (or any portion thereof) shall be accounted for in SR_3 by dividing such revenues (or any portion thereof) equally across the six months of the first Capability Period following the effective date of this provision provided that the NYISO has informed NYPA of its respective share of such revenues (or any portion thereof) at least two weeks prior to the start of such

Capability Period, otherwise such revenues (or any remaining portion thereof) shall be accounted for in SR_3 by dividing such revenues (or any remaining portion thereof) equally across the six months of the Capability Period that follows the first Capability Period following the effective date of this provision.

SR_4 shall equal NYPA's share of revenues from the initial award and renewal of Non-Historic Fixed Price TCCs, as determined pursuant to Section 20.5 of Attachment N. The share of revenues allocated to NYPA pursuant to Section 20.5 of Attachment N shall be adjusted after each Centralized TCC Auction and divided equally across the months for which the Non-Historic Fixed Price TCCs that were initially awarded or renewed as part of the relevant Centralized TCC Auction are valid. Notwithstanding anything to the contrary herein, with respect to NYPA's share of any revenues for Non-Historic Fixed Price TCCs that took effect on or before May 1, 2017, such revenues (or any portion thereof) shall be accounted for in SR_4 by dividing such revenues (or any portion thereof) equally across the six months of the first Capability Period that commences following the effective date of this provision provided that the NYISO has informed NYPA of its share of such revenues (or any portion thereof) at least two weeks prior to the start of such Capability Period, otherwise such revenues (or any remaining portion thereof) shall be accounted for in SR_4 by dividing such revenues (or any remaining portion thereof) equally across the six months of the Capability Period that follows the first Capability Period that commences following the effective date of this provision.

ECR = NYPA's share of Net Congestion Rents in a month, calculated pursuant to Attachment N. The computation of ECR is exclusive of any Congestion payments or Rents included in the CRN term;

CRN = Monthly Day-Ahead Congestion Rents in excess of those required to offset Congestion paid by NYPA's SENY governmental customers associated with the NYPA OATT Niagara/St. Lawrence Service reservations, net of the Initial Cost.

IR = A. The amount that NYPA will credit to its $ATRR_{NTAC}$ assessed to the SENY Load on account of the foregoing NYPA Niagara/St. Lawrence OATT reservations for SENY governmental customers. Such annual revenues will be computed as the product ("Initial Cost") of NYPA's current OATT system rate of $2.23 per kilowatt per month and the 600 MW of TCCs (or the amount of TCCs reduced by Paragraph C below). In the event NYPA sells these TCCs (or any part thereof), all revenues from these sales will offset the NTAC and the Initial Cost will be concomitantly reduced to reflect the net amount of Niagara/St. Lawrence OATT Reservations, if any, retained by NYPA for the SENY Load. The parties hereby agree that the revenue offset to NTAC will be the greater of the actual sale price obtained by NYPA for the TCCs sold or that computed at the applicable system rate in accordance with Paragraph B below;

B. The system rate of $2.23 per kilowatt per month will be benchmarked to the $ATRR_{NTAC}$ for NYPA transmission initially accepted by FERC ("Base Period $ATRR_{NTAC}$") for the purposes of computing the Initial Cost. Whenever an amendment to the $ATRR_{NTAC}$ is accepted by FERC or the $ATRR_{NTAC}$ is updated pursuant to the procedures set forth in Section 14.2.3.2 of this Attachment ("Amended $ATRR_{NTAC}$"), the system rate for the purpose of computing the Initial Cost will be increased (or decreased) by the ratio of the Amended $ATRR_{NTAC}$ to the Base Period $ATRR_{NTAC}$ and the effect of Paragraph A on NTAC will be amended accordingly.

C. If prior to the Centralized TCC Auction all Grandfathered Transmission Service including NYPA's 600 MW Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers are found not to be feasible, then such OATT reservations will be reduced until feasibility is assured. A reduction, subject to a 200 MW cap on the total reduction as described in Attachment M, will be applied to the NYPA Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers.

WR = NYPA’s revenues from external sales (Wheels Through and Exports) not associated with Existing Transmission Agreements in Attachment L, Tables 1 and 2 and Wheeling revenues from OATT reservations extending beyond the start-up of the ISO;

NR = NYPA Reserved1 + NYPA Reserved2

NYPA Reserved1 will equal NYPA’s Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for NYPA’s RCRR TCCs.

NYPA Reserved2 will equal the value that NYPA receives for the sale of RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the month(s) for which that sold RCRR TCC is valid.

NT = The amount of actual NYPA transmission revenues minus NYPA's monthly revenue requirement.

BU = Annual Billing Units are New York State Loads and Loads associated with Wheels Through and Exports in megawatt-hours ("MWh").

The $ATRR_{NTAC}$ and SR will not include expenses for NYPA's purchase of TCCs or revenues from the sale of such purchased TCCs or from the collection of Congestion Rents for such TCCs.

The ECR, EA, SR, CRN, WR, NR, and NT shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (i.e., January actual data will be used in February to calculate the NTAC effective in March).

The NTAC shall be calculated as a $/MWh charge and shall be applied to Actual Energy Withdrawals, except for Wheels Through and Exports in which case the NTAC shall be applied to scheduled Energy quantities. The NTAC shall not apply to scheduled quantities that are Curtailed by the ISO.

14.2.2.2.3

NYPA's recovery of capital expenditure pursuant to NTAC is subject to limitations set forth in Section 14.2.3.2.7 of this Attachment H. NYPA may also invest in transmission facilities outside the NTAC recovery mechanism. In that case, NYPA cannot recover any expenses or return associated with such additions under NTAC and any TCC or other revenues associated with such additions will not be considered NYPA transmission revenue for purposes of developing the NTAC nor be used as a credit in the allocation of NTAC to transmission system users.

14.2.2.3 Filing and Posting of NTAC

NYPA shall coordinate with the ISO to update certain components of the NTAC formula on a monthly or Capability Period basis. NYPA may update the NTAC calculation to change the $ATRR_{NTAC}$, initially approved by FERC, and such updates shall be submitted to FERC each year as part of NYPA's informational filing pursuant to Section 14.2.3.2.6 of this Attachment. An integral part of the agreement between the other Transmission Owners and NYPA is NYPA's consent to the submission of its $ATRR_{NTAC}$ for FERC review and approval on the same basis and subject to the same standards as the Revenue Requirements of the Investor-Owned Transmission Owners. Each January, beginning with January 2001, the ISO shall inform NYPA of the prior year's actual New York internal Load requirements and the actual Wheels Through and Exports and shall post this information on the OASIS. NYPA shall change the BU component of the NTAC formula to reflect the prior calendar year's information, with such change to take effect beginning with the March NTAC of the current year. NYPA will calculate the monthly NTAC and provide this information to the ISO by no later than the fourteenth day of each month, for posting on the OASIS to become effective on the first day of the next calendar month. Beginning with LBMP implementation, the monthly NTAC shall be posted on the OASIS by the ISO no later than the fifteenth day of each month or as soon thereafter as is reasonably possible but in no event later than the 20th of the month to become effective on the first day of the next calendar month.

14.2.2.4 NTAC Calculation Information

NYPA's $ATRR_{NTAC}$ for facilities owned as of January 31, 1997, and Annual Billing Units (BU) of the NTAC are:

$ATRR_{NTAC}$ = $165,449,297

BU = 133,386,541MWh

NYPA's $ATRR_{NTAC}$ is subject to FERC review because it is collected through the ISO's jurisdictional rates, and will be filed, together with any project-specific revenue requirements, with the Commission each year for informational purposes pursuant to Section 14.2.3.2.6 of this Attachment.

14.2.2.5 Billing

The New York State Loads, Wheels Through, and Exports will be billed based on the product of: (i) the NTAC; and (ii) the Customer's billing units for the Billing Period. The billing units will be based on the metered energy for all Transactions to supply Load in the NYCA during the Billing Period, and hourly Energy schedules for the Billing Period for all Wheels Through and Exports.

14.2.3 NYPA Formula Rate

14.2.3.1 Formula Rate Template

Exhibit No. PA-102, INDEX

INDEX
NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT

Exhibit No. PA-102, SCH - Summary

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

TRANSMISSION REVENUE REQUIREMENT SUMMARY

Line No.	**A. OPERATING EXPENSES**	**TOTAL $** (1)	**SOURCE/COMMENTS** (2)
1	Operation & Maintenance Expense	-	Schedule A1, Col 5, Ln 17
2	Administration & General Expenses	-	Schedule A2, Col 5, Ln 22
3	Depreciation & Amortization Expense	-	Schedule B1, Col 6, Ln 26
4	**TOTAL OPERATING EXPENSE**	**-**	Sum lines 1, 2, & 3
5	**B. RATE BASE**	**-**	Schedule C1, Col 5, Ln 10
6	Return on Rate Base	**-**	Schedule C1, Col 7, Ln 10
6a	Total Project Specific Return Adustment	**-**	Schedule D2, Col 3, Ln A
7	**TOTAL REVENUE REQUIREMENT**	**-**	Line 4 + Line 6 + Line 6a
8	Incentive Return	-	Schedule F1, page 2, line 2, col. 13
9	True-up Adjustment	-	Schedule F3, page 1, line 3, col. 10
10	**NET ADJUSTED REVENUE REQUIREMENT**	**-**	Line 7 + line 8 + line 9
	Breakout by Project		
11	NTAC Facilities	-	Schedule F1, page 2, line 1a, col. 16
11a	Project 1 - Marcy South Series Compensation	-	Schedule F1, page 2, line 1b, col. 16
11b	Project 2	-	Schedule F1, page 2, line 1c, col. 16
11c	-	-	
...	-	-	-
12	Total Break out	**-**	Sum lines 11

Note 1 The revenue requirements shown on lines 11 and 11a et seq. and annual revenue requirements. If the first year is a partial year, 1/12 of the amounts should be recovered for every month of the Rate Year.

Exhibit No. PA-102, SCH-A1

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

SCHEDULE A1
OPERATION & MAINTENANCE EXPENSE SUMMARY ($)

Line No.	FERC Account (1)	FERC Account Description (2)	Source (3)	Total (4)	Grand Total (5)	NYPA Form 1 Equivalent (6)
	Transmission:					
		OPERATION:				
1	560	Supervision & Engineering	WP-AA, Col (5)	-		Page 321 line 83
2	561	Load Dispatching	WP-AA, Col (5)	-		Page 321 lines 85-92
3	562	Station Expenses	WP-AA, Col (5)	-		Page 321 line 93
4	566	Misc. Trans. Expenses	WP-AA, Col (5)	-		Page 321 line 97
5		**Total Operation**	(sum lines 1-4)	**-**		
		MAINTENANCE:				
6	568	Supervision & Engineering	WP-AA, Col (5)	-		Page 321 line 101
7	569	Structures	WP-AA, Col (5)	-		Page 321 line 102-106
8	570	Station Equipment	WP-AA, Col (5)	-		Page 321 line 107
9	571	Overhead Lines	WP-AA, Col (5)	-		Page 321 line 108
10	572	Underground Lines	WP-AA, Col (5)	-		Page 321 line 109
11	573	Misc. Transm. Plant	WP-AA, Col (5)	-		Page 321 line 110
12		**Total Maintenance**	(sum lines 6-11)	**-**		
13		**TOTAL O&M TRANSMISSION**	(sum lines 5 & 12)		**-**	
		Adjustments (Note 2)				
14		Step-up Transformers	WP-AC, Col (1) line 5		-	
15		FACTS (Note 1)	WP-AD,Col (1) line 5		-	
16		Microwave Tower Rental Income	WP-AE, Col (3) line 2		-	
17		**TOTAL ADJUSTED O&M TRANSMISSION**	(sum lines 13-16)		**-**	

Note 1 Flexible Alternating Current Transmission System device
Note 2 Revenues that are credited in the NTAC are not revenue credited here.

Exhibit No. PA-102, SCH-A2

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

SCHEDULE A2
ADMINISTRATIVE AND GENERAL EXPENSES

Line No.	FERC Account	FERC Account Description	Source	Unallocated A&G ($)	Transmission Labor Ratio	Allocated to Transmission ($)	Source/Comments	NYPA Form 1 Equivalent
	(1)	(2)		(3)	(4)	(5)	(6)	(7)
	Administrative & General Expenses							
1	920	A&G Salaries	WP-AA, Col (5)	-				Page 323 line 181
2	921	Office Supplies & Expenses	WP-AA, Col (5)	-				Page 323 line 182
3	922	Admin. Exp. Transferred-Cr	WP-AA, Col (5)	-				Page 323 line 183
4	923	Outside Services Employed	WP-AA, Col (5)	-				Page 323 line 184
5	924	Property Insurance	WP-AA, Col (5)	-		-	See WP-AG; Col (3) ,Ln 4	Page 323 line 185
6	925	Injuries & Damages Insurance	WP-AA, Col (5)	-		-	See WP-AH; Col (3) ,Ln 4	Page 323 line 186
7	926	Employee Pensions & Benefits	WP-AA, Col (5)	-				Page 323 line 187
8	928	Reg. Commission Expenses	WP-AA, Col (5)	-		-	See WP-AA; Col (3), Ln 2x	Page 323 line 189
9	930	Obsolete/Excess Inv	WP-AA, Col (5)	-				Page 323 line 190.5
10	930.1	General Advertising Expense	WP-AA, Col (5)	-				Page 323 line 191
11	930.2	Misc. General Expenses	WP-AA, Col (5)	-				Page 323 line 192
12	930.5	Research & Development	2/	-		-	2/	Page 323 line 192.5
13	931	Rents	WP-AA, Col (5)	-				Page 323 line 193
14	935	Maint of General Plant A/C 932	WP-AA, Col (5)	-				Page 323 line 196
15		**TOTAL**	(sum lines 1-14)	**-**				
16		Less A/C 924	Less line 5	-				Page 323 line 185
17		Less A/C 925	Less line 6	-				Page 323 line 186
18		Less EPRI Dues	1/	-				
19		Less A/C 928	Less line 8	-				Page 323 line 189
20		Less A/C 930.5	Less line 12	-			3/	
21		PBOP Adjustment	WP-AF	-				
22		**TOTAL A&G Expense**	(sum lines 16 to 21)	**-**	**-**	**-**	- Allocated based on transmission labor allocator (Schedule E1)	
23		**NET A&G TRANSMISSION EXPENSE**	(sum lines 1 to 22)			**-**		

1/ NYPA does not pay EPRI dues
2/ Column 5 is populated as 0 (zero) for data pertaining to calendar years ____ and 2015. It is populated as a sum of Transmission R&D Expense [Workpaper WP-AA Col (3) ln(2ab)] plus the portion of Admin & General allocated to transmission [Workpaper WP-AA Col (4) ln (2ab) multiplied by Workpaper E1-Labor Ratio Col (3) ln (2)] for data pertaining to calendar years 2016 and later.
3/ Populated as 0 (zero) for data pertaining to calendar years ____ and 2015. Populated as WP-AA Col (3) for data pertaining to calendar years 2016 and later.

Exhibit No. PA-102, SCH-B1

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

SCHEDULE B1
ANNUAL DEPRECIATION AND AMORTIZATION EXPENSES ($)

Line No.	FERC Account	FERC Account Description	Source (1)	Transmission (2)	General Plant (3)	Transmission Labor Ratio (%) (4)	General Plant Allocated to Transm. Col (3)*(4) (5)	Total Annual Depreciation Col (2)+(5) (6)
1	352	Structures & Improvements	WP-BA, Col (4)	-				
2	353	Station Equipment	WP-BA, Col (4)	-				
3	354	Towers & Fixtures	WP-BA, Col (4)	-				
4	355	Poles & Fixtures	WP-BA, Col (4)	-				
5	356	Overhead Conductors & Devices	WP-BA, Col (4)	-				
6	357	Underground Conduit	WP-BA, Col (4)	-				
7	358	Underground Conductors & Devices	WP-BA, Col (4)	-				
8	359	Roads & Trails	WP-BA, Col (4)	-				
9		**Unadjusted Depreciation**		**-**				
10	390	Structures & Improvements	WP-BA, Col (4)		-			
11	391	Office Furniture & Equipment	WP-BA, Col (4)		-			
12	392	Transportation Equipment	WP-BA, Col (4)		-			
13	393	Stores Equipment	WP-BA, Col (4)		-			
14	394	Tools, Shop & Garage Equipment	WP-BA, Col (4)		-			
15	395	Laboratory Equipment	WP-BA, Col (4)		-			
16	396	Power Operated Equipment	WP-BA, Col (4)		-			
17	397	Communication Equipment	WP-BA, Col (4)		-			
18	398	Miscellaneous Equipment	WP-BA, Col (4)		-			
19	399	Other Tangible Property	WP-BA, Col (4)		-			
20		**Unadjusted General Plant Depreciation**			**-**			
		Adjustments						
21		Capitalized Lease Amortization	Schedule B2, Col 4, line 14	-				
22		FACTS	Schedule B2, Col 4, line 13	-				
23		Windfarm	Schedule B2, Col 4, line 11	-				
24		Step-up Transformers	Schedule B2, Col 4, line 12	-				
25		Relicensing Reclassification	WP-BG, Col 4		-			
26		**TOTAL**	(Sum lines 1-25)	**-**	**-**	**-** **1/**	**-**	**-**

1/ See Schedule-E1, Col (3), Ln 2

Exhibit No. PA-102, SCH- B2

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT YEAR ENDING DECEMBER 31, ____

SCHEDULE B2
ADJUSTED PLANT IN SERVICE

____ ____ - ____ Average

Line in No.		Source	NYPA Form 1 Equivalent Plant in Service (p. 204-207 column (g))	Depreciation (p.219)	Plant in Service ($) (1)	Accumulated Depreciation ($) (2)	Plant in Service - Net ($) (3)	Depreciation Expense ($) (4)	Plant in Service ($) (5)	Accumulated Depreciation ($) (6)	Plant in Service - Net ($) (7)	Depreciation Expense ($) (8)	Plant Service ($) (9)
(10)					Accumulated Depreciation ($)	Plant in Service ($) (11)							
	PRODUCTION												
1	Production - Land -	WP-BC -	ln. 8 + ln. 27 + ln. 37		-	-	-	-	-	-	-	-	-
2	Production - Hydro -	WP-BC -	ln. 35 - ln. 27	ln. 22 - Cost of Removal 5/	-	-	-	-	-	-	-	-	-
3	Production - Gas Turbine / Combined Cycle -	WP-BC -	ln. 16 + ln. 45 + ln. 100.5 - ln. 8 - ln. 37	ln. 20 + ln. 23	-	-	-	-	-	-	-	-	-
4					- -	- -	-	-	-	-	-	-	-
	TRANSMISSION												
5	Transmission - Land -	WP-BC -	ln. 48		-	-	-	-	-	-	-	-	-
6	Transmission -	WP-BC -	ln. 58 + ln. 100.6 - ln. 48	ln. 24 - Cost of Removal 5/	-	-	-	-	-	-	-	-	-
7					- -	- -	-	-	-	-	-	-	-
8	Transmission - Cost of Removal 1/ -	WP-BC -			-	-	-	-	-	-	-	-	-
9	Excluded Transmission 2/ - -	WP-BB			-	-	-	-	-	-	-	-	-
	Adjustments to Rate Base												
10	Transmission - Asset Impairment -	WP-BC -			-	-	-	-	-	-	-	-	-
11	Windfarm -	WP-BC -			-	-	-	-	-	-	-	-	-
12	Generator Step-ups -	WP-BF -			-	-	-	-	-	-	-	-	-
13	FACTS -	WP-BE -			-	-	-	-	-	-	-	-	-
14	Marcy South Capitalized Lease 3/							-				-	
15	Total Adjustments -				- -	-	-	-	-	-	-	-	-
16													
17	**Net Adjusted Transmission** -				- -	-	-	-	-	-	-	-	-
									-				
	GENERAL												
18	General - Land -	WP-BC -	ln. 86		-	-	-	-	-	-	-	-	-
19	General -	WP-BC -	ln. 99 - ln. 86	ln. 27 - Cost of Removal 5/	-	-	-	-	-	-	-	-	-
20			ln. 99 -		- -	-	-	-	-	-	-	-	-
	Adjustments to Rate Base												

21	General - Asset Impairment -		- -	-	-	-	-	-	-	-	-
22	General - Cost of Removal -	WP-BC -	-	-	-	-	-	-	-	-	-
23	Relicensing -	WP-BG -	-	-	-	-	-	-	-	-	-
24	Excluded General 4/ - -	WP-BC	-	-	-	-	-	-	-	-	-
24	Total Adjustments -		- -	-	-	-	-	-	-	-	-
25	**Net Adjusted General Plant** **-**		**-** **-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Notes

1/ Cost of Removal: Bringing back to accumulated depreciation cost of removal which was reclassified to regulatory liabilities in annual report.

2/ Excluded Transmission: Assets not recoverable under ATRR, FERC Accounts 350 and 352-359 for 500 MW, AEII, Poletti, SCPPs, Small Hydro, and Flynn. 3/ Marcy South Capitalized Lease amount is added separately to the Rate Base.

4/ Excluded General: Assets not recoverable under ATRR, FERC Accounts 389-399 for 500 MW, AEII, Poletti, SCPPs, Small Hydro, and Flynn.

SCPPs include Brentwood, Gowanus, Harlem River, Hell Gate, Kent, Pouch and Vernon. Small Hydro includes Ashokan, Crescent, Jarvis and Vischer Ferry.

5/ The difference between the Accumulated Depreciation contained in the NYPA Form 1 Equivalent and the amount contained here is equal to the Cost of Removal.

Exhibit No. PA-102, SCH-B3

" 1 $ 2 " # 3 *
4 !5*6 54 * 78 5*98!
! "# $ %& ' ( )* + # ' , # ' "- .+/+ 0

Line No.	FERC Account	FERC Account Description	Headquarters	St. Lawrence/FDR	Niagara	Blenheim-Gilboa	J. A. FitzPatrick	Massena-Marcy	Marcy-South	Long Island Sound Cable 2/	New Project
			Rate (Annual) Percent 1/								
	TRANSMISSION PLANT										
1	350	Land Rights									
2	352	Structures and Improvements		1.34%	1.22%	1.05%		1.30%		3.33%	1.60%
3	353	Station Equipment		1.51%	1.62%	1.75%		1.48%	1.55%	3.33%	1.87%
4	354	Towers and Fixtures		3.20%	2.04%	1.72%	1.06%	1.89%	2.04%		2.06%
5	355	Poles and Fixtures		2.22%	1.98%	1.30%		1.45%	1.77%		2.06%
6	356	Overhead Conductor and Devices		2.50%	1.95%	1.36%	0.97%	2.14%	1.74%		1.88%
7	357	Underground Conduit		0.18%					1.23%	3.33%	1.40%
8	358	Underground Conductor and Devices		0.17%					1.29%	3.33%	1.75%
9	359	Roads and Trails		0.55%	0.28%	0.64%	0.13%	0.73%	0.90%		1.00%
	GENERAL PLANT										
10	390	Structures & Improvements	1.14%	1.45%	0.97%	1.50%		1.34%		3.45%	1.67%
11	391	Office Furniture & Equipment	5.56%	5.56%	5.56%	5.56%		5.56%		9.08%	5.56%
12	391.2	Computer Equipment 5 yr	20.00%	20.00%	20.00%	20.00%		20.00%			20.00%
13	391.3	Computer Equipment 10 yr	10.00%	10.00%	10.00%	10.00%		10.00%			10.00%
14	392	Transportation Equipment	2.56%	4.49%	2.96%	5.03%		4.48%		13.04%	10.00%
15	393	Stores Equipment		2.65%	3/	3.21%		3.33%		3.15%	3.33%
16	394	Tools, Shop & Garage Equipment	2.88%	6.45%	4.14%	3.67%		1.20%		4.94%	5.00%
17	395	Laboratory Equipment	4.82%	5.48%	1.57%	2.30%		1.52%		4.43%	5.00%
18	396	Power Operated Equipment		5.47%	6.51%	7.23%		4.81%	3/	9.33%	8.33%
19	397	Communication Equipment	6.67%	6.67%	6.67%	6.67%		6.67%	6.67%	6.63%	6.67%
20	398	Miscellaneous Equipment 4/	0.002%	11.04%	0.86%	3.67%		0.02%		5.94%	5.00%
21		5 Year Property	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
22		10 Year Property	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
23		20 Year Property	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
24	399	Other Tangible Property		6.67%	6.67%	6.67%					6.67%
	INTANGIBLE PLANT										
25	303	Miscellaneous Intangible Plant									
26		5 Year Property	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
27		7 Year Property	14.29%	14.29%	14.29%	14.29%	14.29%	14.29%	14.29%	14.29%	14.29%
28		10 Year Property	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
29		Transmission facility Contributions in Aid of Construction 5/									

Notes:

1/ Where no depreciation rate is listed for a transmission or general plant account for a particular project (other than the Long Island Sound Cable), NYPA lacks depreciable plant as of 12/31/2015 (or all plant has been fully depreciated). If new plant corresponding to these accounts is subsequently added for the relevant projects, the “New Project” depreciation rate for the relevant account will apply.

2/ This schedule does not contain updated depreciation rates for the Long Island Sound Cable, an asset not included in the NYPA Depreciation Study filed at FERC in 2017. NYPA recovers the cost of the cable from the Long Island Power Authority through debt service, and consistent with past practice NYPA uses a 30-year depreciable life for the cable based on the 30-year term of of the bonds purchased to construct the facility in 1991.

3/ Fully accrued. If plant added to Marcy-South Account 396, 8.33% rate applies; if plant added to Niagara Account 393, 3.33% rate applies. 4/ For Headquarters Account 398, plant nearly fully accrued. If plant is added to this account, 5.00% rate applies.

5/ In the event a Contribution in Aid of Construction (CIAC) is made for a transmission facility, the transmission depreciation rates above will be weighted based on the relative amount of underlying plant booked to the accounts shown in lines 1-9 above and the weighted average depreciation rate will be used to amortize the CIAC. The life of a facility subject to a CIAC will be equivalent to the depreciation rate calculated above, i.e., 100% ÷ deprecation rate = life in years. The estimated life of the facility or rights associated with the facility will not change over the life of a CIAC without prior FERC approval.

These depreciation rates will not change absent the appropriate filing at FERC.

Exhibit No. PA-102, SCH-C1

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

SCHEDULE C1
TRANSMISSION - RATE BASE CALCULATION

	RATE BASE	TRANSMISSION PLANT ($) (1)		TOTAL GENERAL PLANT ($) (2)		TRANSM. LABOR RATIO [Schedule E1] (3)	GENERAL PLANT ALLOCATED TO TRANSMISSION ($) (2) * (3) (4)	TOTAL TRANSMISSION ($) (1) + (4) (5)	RATE OF RETURN [Schedule D1] (6)	RETURN ON RATE BASE (5) * (6) (7)
1	A) Net Electric Plant in Service	-	1/	-	2/	-	-	-		
2	B) Rate Base Adjustments									
3	* Cash Working Capital (1/8 O&M)	-	3/					-		
4	* Marcy South Capitalized Lease	-	4/					-		
5	* Materials & Supplies	-	5/			-		-		
6	* Prepayments	-	6/			-		-		
7	* CWIP	-	7/							
8	* Regulatory Asset	-	7/							
9	* Abandoned Plant	-	7/							
10	TOTAL (sum lines 1-9)	-		-		-	-	-	-	-

1/ Schedule B2; Net Electric Plant in Service; Ln 17

2/ Schedule B2; Net Electric Plant in Service; Ln 25

3/ 1/8 of (Schedule A1; Col 5, Ln 17 + Schedule A2; Col 5, Ln 22) [45 days] 4/

WP-BD; Average of Year-end Unamortized Balances, Col 5

5/ Average of year-end inventory Materials & Supplies (WP-CA). NYPA Form 1 Equivalent, page 227, Ln 12, average of columns b and c. 6/

WP-CB; Col 3, Ln 3

7/ CWIP, Regulatory Asset and Abandoned Plant are zero until an amount is authorized by FERC as shown below. CWIP amount is shown in the NYPA Form 1 Equivalent, page 216, line 1

Docket Number	Authorized Amount

Exhibit No. PA-102, SCH-D1

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

SCHEDULE D1
CAPITAL STRUCTURE AND COST OF CAPITAL

Line No.	TITLE	CAPITALIZATION RATIO from WP-DA 1/ (1)	COST RATE from WP-DA 2/ (2)	WEIGHTED AVERAGE (3)	SOURCE/COMMENTS (4)
1	LONG-TERM DEBT	0.00%	-	-	Col (1) * Col (2)
2	COMMON EQUITY	0.00%	9.45%	-	Col (1) * Col (2)
3	TOTAL CAPITALIZATION	0.00%		-	Col (3); Ln (1) + Ln (2)

Notes
1/ The Common Equity share listed in Col (1) is capped at 50%. The cap may only be changed pursuant to an FPA Section 205 or 206 filing to FERC. The Long-Term Debt share is calculated as 1 minus the Common Equity share.
2/ The ROE listed in Col (2) Ln (2) is the base ROE plus 50 basis-point incentive for RTO participation. ROE may only be changed pursuant to an FPA Section 205 or 206 filing to FERC.

Exhibit No. PA-102, SCH-D2

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

SCHEDULE D2
PROJECT SPECIFIC CAPITAL STRUCTURE AND COST OF CAPITAL 3/

Line No.	TITLE	CAPITALIZATION RATIO from WP-DA (1)		COST RATE from WP-DA (2)		WEIGHTED AVERAGE (3)	SOURCE/COMMENTS (4)
Project 1 - Marcy South Series Compensation - Capital Structure							
1	LONG-TERM DEBT	-	1/	-		-	Col (1) * Col (2)
2	COMMON EQUITY	-	1/	9.45%	2/	-	Col (1) * Col (2)
3	TOTAL CAPITALIZATION	-				-	Col (3); Ln (1) + Ln (2)
4	PROJECT NET PLANT					-	
5	PROJECT BASE RETURN					-	Col (3) Ln (4) * WP-DA Col (7) Ln (4)
6	PROJECT ALLOWED RETURN					-	Col (3); Ln (3) * Ln (4)
A	PROJECT SPECIFIC RETURN ADJUSTMENT					-	Col (3); Ln (6) - Ln (5)

Project X

Notes

1/ The MSSC Common Equity share listed in Col (1) is capped at 53%. The cap may only be changed pursuant to an FPA Section 205 or 206 filing to FERC. The MSSC Long-Term Debt share is calculated as 1 minus the Common Equity share.

2/ The MSSC ROE listed in Col (2) Ln (2) is the base ROE plus 50 basis-point incentive Congestion Relief Adder. ROE may only be changed pursuant to an FPA Section 205 or 206 filing to FERC.

3/ Additional project-specific capital structures added to this Schedule D2 must be approved by FERC. The cost of long-term debt and common equity for any such project shall reflect the cost rates in Col (2), Lns (1) and (2) unless a different cost rate is approved by FERC.

Exhibit No. PA-102, SCH-E1

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

SCHEDULE E1
LABOR RATIO

Line No.	DESCRIPTION	LABOR AMOUNT ($) From WP-EA (1)	RATIO (2)	ALLOCATED TO TRANSMISSION (3)	SOURCE/ COMMENTS (4)	NYPA Form 1 Equivalent (5)
1	PRODUCTION	-	-			Page 354 lines 17, 20, 24
2	TRANSMISSION	-	-	-	Col (1); Ln (2) / Ln (3)	Page 354 line 21
3	**TOTAL LABOR**	**-**	-			

Exhibit No. PA-102, SCH-F1

Schedule F1

Project Revenue Requirement Worksheet

NEW YORK POWER AUTHORITY

YEAR ENDING DECEMBER 31, ____

Line No.	Item	Page, Line, Col.	Transmission ($)	Allocator
		(1)	(2)	(3)

1	Gross Transmission Plant - Total	Schedule B2, line 17, col 9 (Note A)	-	
1a	Transmission Accumulated Depreciation	Schedule B2, line 17, col 10	-	
1b	Transmission CWIP, Regulatory Asset and Abandoned Plant	Schedule C1, lines 7, 8, & 9 (Note B)	-	
2	Net Transmission Plant - Total	Line 1 minus Line 1a plus Line 1b	-	
	O&M TRANSMISSION EXPENSE			
3	Total O&M Allocated to Transmission	Schedule A1, line 17, col 5 and Schedule A2, line 22, Col 5	-	
	GENERAL DEPRECIATION EXPENSE			
5	Total General Depreciation Expense	Schedule B1 line 26, col 5	-	
6	**Annual Allocation Factor for Expenses**	([line 3 + line 5] divided by line 1, col 2)	**-**	**-**
	RETURN			
7	Return on Rate Base	Schedule C1 line 10, col 7	-	
8	**Annual Allocation Factor for Return on Rate Base**	(line 7 divided by line 2 col 2)	**-**	**-**

Exhibit PA-102, SCH-F1 Page 2 of 2

Schedule F1
Project Revenue Requirement Worksheet
NEW YORK POWER AUTHORITY

(14) ROJECT PECIFIC Annual Line No. ($) 7)	(1) Project Name and # Discount		(2) (14a) Type CAPITAL	(3) (15) Project Gross Plant Revenue ($) Requirement ($) (Note C)	(4) (16) Project Accumulated True-Up Depreciation ($) Adjustment ($)	(5) (17) Annual Allocation Requirement Factor for Expenses ($) Page 1 line 6 (Note I)	(6) Annual Allocation for Expenses ($) Col. 3 * Col. 5 Schedule D2	(7) Project Net Plant ($) (Note D) + 14 +14a)	(8) Annual Allocation Factor for Return (Page 1, line 8) (Note F)	(9) Annual Return Charge ($) (Col. 7 * Col. 8) 16	(10) Project Depreciation/Amortization Expense ($) (Note E)	(11) CAPITAL Annual Revenue Requirement ($) (Sum Col. 6, 9 & 10)	(12) Incentive Net Revenue Return in basis Points Per FERC order (Note (Sum Col. 11 + 13 H)	(13) STRUCTURE Total AND COST OF Incentive Return (Schedule F2, Line 10 * (Col. 12/100)* Sum Col. 15 + Col.
1a	NTAC Facilities -		-	-	-	-	-	-	-	-	-	-	-	-
1b			-	-	-	-	-	-	-	-		-	-	-
1c			-	-	-	-	-	-	-	-	-	-	-	-
1d		-	-	-	-	-	-	-	-	-	-	-	-	-
1e		-	-	-	-	-	-	-	-	-	-	-	-	-
1f		-	-	-	-	-	-	-	-	-	-	-	-	-
1g		-	-	-	-	-	-	-	-	-	-	-	-	-
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1i		-	-	-	-	-	-	-	-	-	-	-	-	-
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		-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-
2	Total -			-	-		-	-			-	-		-

Note Letter

A Gross Transmission Plant that is included on Schedule B2, Ln 17, Col 5.
B Inclusive of any CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant balances included in rate base when authorized by FERC order.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in page 1, line 1 . This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Gross plant does not include CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation in page 2, column 4. Net Plant includes any FERC approved CWIP, Unamortized Abandoned Plant and Regulatory Asset.
E Project Depreciation Expense is the amount in Schedule B1, Ln 26, Col. 2 that is associated with the specified project. Project Depreciation Expense includes the amortization of Abandoned Plant and any FERC approved Regulatory Asset. However, if FERC grants accelerated depreciation for a project the depreciation rate authorized by FERC will be used instead of the rates shown on Schedule B3 for all other projects.
F Reserved
G The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 8.
H Requires approval by FERC of incentive return applicable to the specified project(s). A negative number of basis points may be entered to reduce the ROE applicable to a project if a FERC order specifies a lower return for that project.
I The discount is the reduction in revenue, if any, that NYPA agreed to, for instance, to be selected to build facilities as the result of a competitive process and equals the amount by which the annual revenue requirement is reduced from the ceiling rate

Exhibit No. PA-102, SCH-F2

Schedule F2
Incentives
NEW YORK POWER AUTHORITY
YEAR ENDING DECEMBER 31, ____

Line No.	Item	Reference		%		Cost	Weighted Cost	$
1	Rate Base	Schedule C1, line 10, Col. 5						-
2	100 Basis Point Incentive Return						$	
3	Long Term Debt	(Schedule D1, line 1)			-	-	-	
4	Common Stock	(Schedule D1, line 2)	Cost = Schedule E, line 2, Cost plus .01		-	0.1045	-	
5	Total (sum lines 3-4)						-	
6	100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 5)							-
7	Return	(Schedule C1, line 10, Col. 7)						-
8	Incremental Return for 100 basis point increase in ROE		(Line 6 less line 7)					-
9	Net Transmission Plant		(Schedule C1, line 1, col. (1)					-
10	Incremental Return for 100 basis point increase in ROE divided by Rate Base		(Line 8 / line 9)					-

Notes:

A Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with a 100 basis point increase in ROE. Any actual incentive is calculated on Schedule F1 and must be approved by FERC. For example, if FERC were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point increase in ROE would be multiplied by 137 on Schedule F1, Col. 13.

Exhibit No. PA-102, SCH-F3

Schedule F3
Project True-Up
Incentives
YEAR ENDING DECEMBER 31, ____
($)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Project Name	NTAC ATRR or Project Number	Actual Revenues Received (Note 1)	Actual Net Revenue Requirement (Note 2)	True-Up Adjustment Principal Under/(Over)	Prior Period Adjustment	Applicable Interest Rate on Under/(Over)	True-Up Adjustment Interest Under/(Over)	Total True-Up Adjustment
			Amount Actually Received for Transmission Service	Schedule F2 Using Actual Cost Data	Col. (5) - Col. (4)	(Note A) Line 25, Col. (e)	Line 24	(Col. (6) + Col. (7)) x Col. (8) x 24 months	Col. (6) + Col. (7) + Col. (9)
1a	NTAC Facilities	-	-	-	-	-	-	-	-
1b		-	-	-	-	-	-	-	-
1c		-	-	-	-	-	-	-	-
1d	-	-	-	-	-	-	-	-	-
1e	-	-	-	-	-	-	-	-	-
…									
…									
2	Subtotal				-			-	-
3	Under/(Over) Recovery								-

Notes:
1) For all projects and NTAC ATRR, the Actual Revenues Received are the actual revenues NYPA receives from the NYISO in that calendar year. If NYISO does not break out the revenues per project, the Actual Revenues Received will be allocated pro rata to each project based on their Actual Net Revenue Requirement in col (5).
2) Schedule F1, Page 2 of 2, col (16).

Exhibit No. PA-102, SCH-F3

Schedule F3
Project True-Up
Incentives

FERC Refund Interest Rate

		Year	Interest Rates under Section 35.19(a)
4	Interest Rate (Note A):		
5	January	-	-
6	February	-	-
7	March	-	-
8	April	-	-
9	May	-	-
10	June	-	-
11	July	-	-
12	August	-	-
13	September	-	-
14	October	-	-
15	November	-	-
16	December	-	-
17	January	-	-
18	February	-	-
19	March	-	-
20	April	-	-
21	May	-	-
22	June	-	-
23	July	-	-
			-
24	Avg. Monthly FERC Rate		-

Prior Period Adjustments

	(a) Project or Schedule 1	(b) Adjustment A Description of the Adjustment		(c) Amount In Dollars	(d) Interest (Note A)	(e) Total Adjustment Col. (c) + Col. (d)
25	-		-	-	-	-
25a	-		-	-	-	-
25b	-		-	-	-	-
25c						-
…						-
						-
26	Total					-

Notes: A Prior Period Adjustments are when an error is discovered relating to a prior true-up or refunds/surcharges ordered by FERC. The interest on the Prior Period Adjustment excludes interest for the current true up period, because the interest is included in Ln 25 Col (d).

Exhibit No. PA-102, WP-AA

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AA
Operation and Maintenance Summary

Line No.	(1) Amount ($)	(2) PRODUCTION	(3) TRANSMISSION	(4) ADMIN & GENERAL	(5) OVERALL RESULT	(6) Major Category
1a	555 - OPSE-Purchased Power	-	-	-	-	-
1b	501 - Steam Product-Fuel	-	-	-	-	-
1c	565 - Trans-Xmsn Elect Oth		-	-	-	-
...	-	-	-	-	-	-
2a	506 - SP-Misc Steam Power	-	-	-	-	
2b	535 - HP-Oper Supvr&Engrg	-	-	-	-	
2c	537 - HP-Hydraulic Expense	-	-	-	-	
2d	538 - HP-Electric Expenses	-	-	-	-	
2e	539 - HP-Misc Hyd Pwr Gen	-	-	-	-	
2f	546 - OP-Oper Supvr&Engrg	-	-	-	-	
2g	548 - OP-Generation Expens	-	-	-	-	
2h	549 - OP-Misc Oth Pwr Gen	-	-	-	-	
2i	560 - Trans-Oper Supvr&Eng	-	-	-	-	
2j	561 - Trans-Load Dispatcng	-	-	-	-	
2k	562 - Trans-Station Expens	-	-	-	-	
2l	566 - Trans-Misc Xmsn Exp	-	-	-	-	
2n	905 - Misc. Customer Accts. Exps	-	-	-	-	
2m	Contribution to New York State			-	-	
2o	916 - Misc. Sales Expense	-	-	-	-	
2p	920 - Misc. Admin & Gen'l Salaries	-	-	-	-	
2q	921 - Misc. Office Supp & Exps	-	-	-	-	
2r	922 - Administrative Expenses Transferred	-	-	-	-	
2s	923 - Outside Services Employed	-	-	-	-	
2t	924 - A&G-Property Insurance	-	-	-	-	
2u	925 - A&G-Injuries & Damages Insurance	-	-	-	-	
2v	926 - A&G-Employee Pension & Benefits	-	-	-	-	
2w	926 - A&G-Employee Pension & Benefits(PBOP)	-	-	-	-	
2x	928 - A&G-Regulatory Commission Expense	-	-	-	-	
2y	930 - Obsolete/Excess Inv	-	-	-	-	
2z	930.1-A&G-General Advertising Expense	-	-	-	-	
2aa	930.2-A&G-Miscellaneous & General Expense	-	-	-	-	
2ab	930.5-R & D Expense	-	-	-	-	
2ac	931 - Rents	-	-	-	-	
2ad	935 - A&G-Maintenance of General Plant	-	-	-	-	Operations
...	-	-	-	-	-	-
3a	545 - HP-Maint Misc Hyd Pl	-	-	-	-	
3b	512 - SP-Maint Boiler Plt	-	-	-	-	
3c	514 - SP-Maint Misc Stm Pl	-	-	-	-	
3d	541 - HP-Maint Supvn&Engrg	-	-	-	-	
3e	542 - HP-Maint of Struct	-	-	-	-	
3f	543 - HP-Maint Res Dam&Wtr	-	-	-	-	
3g	544 - HP-Maint Elect Plant	-	-	-	-	
3h	551 - OP-Maint Supvn & Eng	-	-	-	-	
3i	552 - OP-Maint of Struct	-	-	-	-	
3j	553 - OP-Maint Gen & Elect	-	-	-	-	
3k	554 - OP-Maint Oth Pwr Prd	-	-	-	-	
3l	568 - Trans-Maint Sup & En	-	-	-	-	
3n	569 - Trans-Maint Struct	-	-	-	-	
3m	570 - Trans-Maint St Equip	-	-	-	-	
3o	571 - Trans-Maint Ovhd Lns	-	-	-	-	
3p	572 - Trans-Maint Ungrd Ln	-	-	-	-	
3q	573 - Trans-Maint Misc Xmn	-	-	-	-	Maintenance
...	-	-	-	-	-	-
4a	403 - Depreciation Expense	-	-	-	-	
...	-	-	-	-	-	-
5	TOTALS	-	-	-	-	-

Exhibit No. PA-102, WP-AB

NEW YORK POWER AUTHORITY

TRANSMISSION REVENUE REQUIREMENT YEAR ENDING DECEMBER 31, ____

WORK PAPER AB
Operation and Maintenance Detail

FERC by accounts and profit center

(14)	(1)	(2) (15)	(3) (16)	(4) (17)	(5) (18)	(6) (19)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
			Amount ($)										
0100/155			0100/105	0100/110 0100/156	0100/115 0100/157	0100/120 0100/158	0100/122 0100/159	0100/125 0100/160	0100/130	0100/135	0100/140	0100/145	0100/150
Line No. Ferry	FERC G/L Accounts Ashokan		Blenheim-Gilboa Kensico	St. Lawrence Hell Gate	Niagara Harlem River	Poletti Vernon Blvd.	Astoria Energy II 23rd & 3rd (Gowanus)	Flynn N 1st &Grand (Kent)	Jarvis	Crescent Pouch Terminal	Vischer		
1a	403 -	Depreciation Expense											
1b	501 -	Steam Product-Fuel											
1c	506 -	SP-Misc Steam Power											
1d	512 -	SP-Maint Boiler Plt											
1e	514 -	SP-Maint Misc Stm Pl											
1f	535 -	HP-Oper Supvr&Engrg											
1g	537 -	HP-Hydraulic Expense											
1h	538 -	HP-Electric Expenses											

1i		539 - HP-Misc Hyd Pwr Gen														
1j		541 - HP-Maint Supvn&Engrg														
1k		542 - HP-Maint of Struct														
1l		543 - HP-Maint Res Dam&W tr														
1n		544 - HP-Maint Elect Plant														
1m		545 - HP-Maint Misc Hyd Pl														
1o		546 - OP-Oper Supvr&Engrg														
1p		548 - OP-Generation Expens														
1q		549 - OP-Misc Oth Pwr Gen														
1r		551 - OP-Maint Supvn & Eng														
1s		552 - OP-Maint of Struct														
1t		553 - OP-Maint Gen & Elect														
1u		554 - OP-Maint Oth Pwr Prd														
1v		555 - OPSE-Purchased Power														
1w		560 - Trans-Oper Supvr&Eng														
1x		561 - Trans-Load Dispatcng														
1y		562 - Trans-Station Expens														
1z		565 - Trans-Xmsn Elect Oth														
1aa		566 - Trans-Misc Xmsn Exp														
1ab		568 - Trans-Maint Sup & En														
1ac		569 - Trans-Maint Struct														
1ad		570 - Trans-Maint St Equip														
1ae		571 - Trans-Maint Ovhd Lns														
1af		572 - Trans-Maint Ungrd Ln														
1ag		573 - Trans-Maint Misc Xmn														
1ah		905 - Misc. Customer Accts. Exps														
1ai		916 - Misc. Sales Expense														
1ak		920 - Misc. Admin & Gen'l Salaries														
1al		921 - Misc. Office Supp & Exps														
1am		922 - Administrative Expenses Transferred														
1an		923 - Outside Services Employed														
1ao		924 - A&G-Property Insurance														
1ap		925 - A&G-Injuries & Damages Insurance														
1aq		926 - A&G-Employee Pension & Benefits(PBOP)														
1ar		926 - A&G-Employee Pension & Benefits														
1as		928 - A&G-Regulatory Commission Expense														
1at		930 - Obsolete/Excess Inv														
1au		931 - Rents														
1av		930.5-R & D Expense														
1aw		930.1-A&G-General Advertising Expense														
1ax		930.2-A&G-Miscellaneous & General Expense														
1ay		935 - A&G-Maintenance of General Plant														
1az																
...		-														
2		**Contribution to New York State**														
3	Overall Result		-	-	-	-	-	-	-	-	-	-	-	-		
	-		-	-	-	-	-									

Exhibit No. PA-102, WP-AB

FERC by accounts and profit center

(1)	(2)	(12)
FERC G/L Accounts		0100/161 Brentwood
403 - Depreciation Expense		
501 - Steam Product-Fuel		
506 - SP-Misc Steam Power		
512 - S		

P-Maint Boiler Plt 514 - SP-Maint Misc Stm Pl 535 - HP-Oper Supvr &Engrg 537 - HP-Hydraulic Expense 538 - HP-Ele ctric Expenses 539 - HP-Misc Hyd Pwr Gen 541 - HP-Maint Supvn&Engrg 542 - HP-Maint of Struct 543 - HP-Maint Res

Dam&W tr 544 - HP-Maint Elect Plant 545 - HP-Maint Misc Hyd Pl 546 - OP-Oper Supvr&Engrg 548 - OP-Generation E xpens 549 - OP-Misc Oth Pwr Gen 551 - OP-Maint Supvn & Eng 552 - OP-Maint of Struct 553 - OP-Maint Gen & Elect

554 - OP-Maint Oth Pwr Prd

555 - OPSE-Purchased Power

560 - Trans-Oper Supvr&Eng

561 - Trans-Load Dispatcng

562

- Trans-Station Expens 565
- Trans-Xmsn Elect Oth 566
- Trans-Misc Xmsn Exp 568
- Trans-Maint Sup & En 569
- T

rans-Maint Struct 570 - Trans-Maint St Equip 571 - Trans-Maint Ovhd Lns 572 - Trans-Maint Ungrd Ln 573 - Trans-

Maint Misc Xmn 905 - Misc. Customer Accts. Exps 916 - Misc. Sales Expense 920 - Misc. Admin & Gen'l Salaries 92

1 - Misc. Office Supp & Exps 922 - Administrative Expenses Transferred 923 - Outside Services Employed 924 - A

&G-Property Insurance

925 - A&G-Injuries & Damages Insurance

926 - A&G-Employee Pension & Benefits(PBOP)

926 - A&G-Employee Pension & Benefits

928 -

A&G-Regulatory Commission Expense 930 - Obsolete/Excess Inv

931 - Rents

930.5-R & D Expense

930.1-A&G-General Advertising Expense

930.2-A&G-Miscellaneous & General Expense 935

-

A&G - Maintenance of General Plant

-

Contribution to New York State

Overall Result	-

Exhibit No. PA-102, WP-AB **Page 1 of 2**

FERC by accounts and profit center

(1)	(2)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)
(32)	(33)	(34)	(35)	(36)	(37)								
		0100/165	0100/205	0100/210	0100/215	0100/220	0100/225	0100/230	0100/235	0100/240	0100/245	0100/255	0100/305
0100/310			0100/320	0100/321	0100/410	0100/600	…						
FERC G/L Accounts		500MW Combined Cycle	BG Trans	JAF Trans	IP3/Pol Trans	Marcy/Clark Trans	Marcy South Trans	Niagara Trans	Sound Cable	ST Law Trans	765 KV Trans	HTP	
Trans		DSM	Headquarters	Power for Jobs	Recharge NY	JAF	SENY	-					
	403 - Depreciation Expense												
	501 - Steam Product-Fuel												
	506 - SP-Misc Steam Power												
	512 - SP-Maint Boiler Plt												
	514 - SP-Maint Misc Stm Pl												
	535 - HP-Oper Supvr&Engrg												
	537 - HP-Hydraulic Expense												
	538 - HP-Electric Expenses												
	539 - HP-Misc Hyd Pwr Gen												
	541 - HP-Maint Supvn&Engrg												
	542 - HP-Maint of Struct												
	543 - HP-Maint Res Dam&W tr												
	544 - HP-Maint Elect Plant												
	545 - HP-Maint Misc Hyd Pl												
	546 - OP-Oper Supvr&Engrg												
	548 - OP-Generation Expens												
	549 - OP-Misc Oth Pwr Gen												
	551 - OP-Maint Supvn & Eng												
	552 - OP-Maint of Struct												
	553 - OP-Maint Gen & Elect												
	554 - OP-Maint Oth Pwr Prd												
	555 - OPSE-Purchased Power												
	560 - Trans-Oper Supvr&Eng												
	561 - Trans-Load Dispatcng												
	562 - Trans-Station Expens												
	565 - Trans-Xmsn Elect Oth												
	566 - Trans-Misc Xmsn Exp												
	568 - Trans-Maint Sup & En												
	569 - Trans-Maint Struct												
	570 - Trans-Maint St Equip												
	571 - Trans-Maint Ovhd Lns												
	572 - Trans-Maint Ungrd Ln												
	573 - Trans-Maint Misc Xmn												
	905 - Misc. Customer Accts. Exps												
	916 - Misc. Sales Expense												
	920 - Misc. Admin & Gen'l Salaries												
	921 - Misc. Office Supp & Exps												
	922 - Administrative Expenses Transferred 923 - Outside Services Employed												
	924 - A&G-Property Insurance												
	925 - A&G-Injuries & Damages Insurance												
	926 - A&G-Employee Pension & Benefits(PBOP) 926 - A&G-Employee Pension & Benefits												
	928 - A&G-Regulatory Commission Expense 930 - Obsolete/Excess Inv												
	931 - Rents												
	930.5-R & D Expense												
	930.1-A&G-General Advertising Expense												
	930.2-A&G-Miscellaneous			&				General					Expense
	935 - A&G-Maintenance of General Plant												
	-												
	Contribution to New York State -												
Overall Result		-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-						

Exhibit No. PA-102, WP-AB **Page 2 of 2**

FERC by accounts and profit center

(1)	(2)	(38)
		Overall Result
FERC G/L Accounts		
	403 - Depreciation Expense	-
	501 - Steam Product-Fuel	-
	506 - SP-Misc Steam Power	-
	512 - SP-Maint Boiler Plt	-
	514 - SP-Maint Misc Stm Pl	-
	535 - HP-Oper Supvr&Engrg	-
	537 - HP-Hydraulic Expense	-
	538 - HP-Electric Expenses	-
	539 - HP-Misc Hyd Pwr Gen	-
	541 - HP-Maint Supvn&Engrg	-
	542 - HP-Maint of Struct	-
	543 - HP-Maint Res Dam&W tr	-
	544 - HP-Maint Elect Plant	-
	545 - HP-Maint Misc Hyd Pl	-
	546 - OP-Oper Supvr&Engrg	-
	548 - OP-Generation Expens	-
	549 - OP-Misc Oth Pwr Gen	-
	551 - OP-Maint Supvn & Eng	-
	552 - OP-Maint of Struct	-
	553 - OP-Maint Gen & Elect	-
	554 - OP-Maint Oth Pwr Prd	-
	555 - OPSE-Purchased Power	-
	560 - Trans-Oper Supvr&Eng	-
	561 - Trans-Load Dispatcng	-
	562 - Trans-Station Expens	-
	565 - Trans-Xmsn Elect Oth	-
	566 - Trans-Misc Xmsn Exp	-
	568 - Trans-Maint Sup & En	-
	569 - Trans-Maint Struct	-
	570 - Trans-Maint St Equip	-
	571 - Trans-Maint Ovhd Lns	-
	572 - Trans-Maint Ungrd Ln	-
	573 - Trans-Maint Misc Xmn	-
	905 - Misc. Customer Accts. Exps	-
	916 - Misc. Sales Expense	-
	920 - Misc. Admin & Gen'l Salaries	-
	921 - Misc. Office Supp & Exps	-
	922 - Administrative Expenses Transferred	-
	923 - Outside Services Employed	-
	924 - A&G-Property Insurance	-
	925 - A&G-Injuries & Damages Insurance	-
	926 - A&G-Employee Pension & Benefits(PBOP)	-
	926 - A&G-Employee Pension & Benefits	-
	928 - A&G-Regulatory Commission Expense	-
	930 - Obsolete/Excess Inv	-
	931 - Rents	-
	930.5-R & D Expense	-
	930.1-A&G-General Advertising Expense	-
	930.2-A&G-Miscellaneous & General Expense	-
	935 - A&G-Maintenance of General Plant	-
		-
	-	
	Contribution to New York State	**-**
Overall Result		-

Exhibit No. PA-102, WP-AC

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AC
STEP-UP TRANSFORMERS O&M ALLOCATOR

Line No.		Amount ($) (1)	Ratio (2)	Notes
1	Avg. Transmission Plant in Service	-		Sch B2; Col 9, Sum Ln 5, 6 and 10
2	Generator Step-Up Transformer Plant-in-Service	-		Sch B2, Line 12, Col 9
3	**Ratio**		**-**	Col 1, Ln 2 / Col 1, Ln 1
4	Transmission Maintenance	-		Sch A1; Col 4, Ln 12
5	**Removed Step-up Transmission O&M**	**-**		Col 1, Ln 4 x Col 2, Ln 3

Exhibit No. PA-102, WP-AD

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AD
FACTS O&M ALLOCATOR

Line No.		Amount ($) (1)	Ratio (2)	Notes
1	Avg. Transmission Plant in Service	-		Sch B2; Col 5, Sum Ln 5, 6 and 10
2	FACTS Plant-in-Service	-		Sch B2, Line 13, Col 9
3	**Ratio**		**-**	Col 1, Ln 2 / Col 1, Ln 1
4	Transmission Maintenance	-		Sch A1: Col 4, Ln 12
5	**Reclassified FACTS Transmission Plant**	**-**		Subtract Col 1, Ln 4 * Col 2, Ln 3

Exhibit No. PA-102, WP-AE

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AE
MICROWAVE TOWER RENTAL INCOME

	(1)	(2)	(3)
Line No.	**Posting Date**	**Account**	**Income Amount ($)**
1a			
1b			
1c			
1d			
1e			
1f			
1g			
1h			
1i			
1j			
1k			
1l			
1n			
…			
2			-

Exhibit No. PA-102, WP-AF

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AF
POSTRETIREMENT BENEFITS OTHER THAN PENSIONS (PBOP)

Line No.	(1) Item		(2) Amount ($)
1	Total NYPA PBOP		
2	PBOP Capitalized		
3	PBOP contained in Cost of Service	Line 1 less line 2	-
4	Base PBOP Amount		**35,797,785**
5	**PBOP Adjustment**	Line 4 less line 3	-

This work paper includes total NYPA PBOP which is allocated to transmission by labor ratio as shown on Schedule A2.

Exhibit No. PA-102, WP-AG

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AG
PROPERTY INSURANCE ALLOCATION

Line No.	Site	Amount ($)	Ratio	Allocated Insurance Expense - Transmission ($)	Notes
		(1)	(2)	(3)	(4)
1a					
1b					
1c					
1d					
…					
2	**Subtotal (Gross Transmission Plant Ratio)**	**-**	-	**-**	Allocated based on transmission gross plant ratio from Work Paper AI
3a					
3b					
…					
4	**Subtotal (Full Transmission)**	**-**	100.00%	**-**	
5	**Grand Total**			**-**	

Exhibit No. PA-102, WP-AH

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AH
INJURIES & DAMAGES INSURANCE EXPENSE ALLOCATION

Line No.	Site	Amount ($)	Ratio (%)	Allocated Injury/Damage Insurance Expense - Transmission ($)	Notes
		(1)	(2)	(3)	(4)
1a					
1b					
1c					
1d					
…					
2	**Subtotal**	-	-	-	Allocated based on transmission labor ratio from Schedule E1
3a					
…					
		-	100.00	-	
4	**Grand Total**			-	

Exhibit No. PA-102, WP-AI

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AI
PROPERTY INSURANCE ALLOCATOR

		12/31/ ($)	12/31/ ($)	Average	Gross Plant in Service Ratio	Source
		(1)	(2)	(3)	(4)	(5)
1	PRODUCTION	-	-	-	-	WP-BC
2	TRANSMISSION (353 Station Equip.)	-	-	-	-	WP-BC
3	TOTAL	-	-	-	-	

Exhibit No. PA-102, WP-BA

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER BA
DEPRECIATION AND AMORTIZATION EXPENSES (BY FERC ACCOUNT)

Included General & Transmission Plant - Depreciation ____

		(1)	(2)	(3)	(4)
		Site	FERC Acct #	Item	Depreciation ($)
Line No.	Source/Comments	Included General Plant			
1a			390		-
1b			390		-
1c			390		-
1d			390		-
1e			390		-
1f			390		-
…			390		-
…			390		-
2			390	**Subtotal General - Structures & Improvements**	**-**
3a			391		-
3b			391		-
3c			391		-
3d			391		-
3e			391		-
…			391		-
…			391		-
4			391	**Subtotal General - Office Furniture & Equipment**	**-**
5a			392		-
5b			392		-
5c			392		-
5d			392		-
5e			392		-
…			392		-
…			392		-
6			392	**Subtotal General - Transportation Equipment**	**-**
7a			393		-
7b			393		-
7c			393		-
7d			393		-
…			393		-
…			393		-
8			393	**Subtotal General - Stores Equipment**	**-**
9a			394		-
9b			394		-
9c			394		-
9d			394		-
9e			394		-
…			394		-
…			394		-
10			394	**Subtotal General - Tools, Shop & Garage Equipment**	**-**
11a			395		-
11b			395		-
11c			395		-
11d			395		-
11e			395		-
…			395		-
…			395		-
12			395	**Subtotal General - Laboratory Equipment**	**-**
13a			396		-
13b			396		-
13c			396		-
13d			396		-
13e			396		-
…			396		-
…			396		-
14			396	**Subtotal General - Power Operated Equipment**	**-**
15a			397		-
15b			397		-
15c			397		-
15d			397		-
15e			397		-
15f			397		-
15g			397		-
			397		-
			397		-
16			397	**Subtotal General - Communication Equipment**	**-**
17a			398		-
17b			398		-
17c			398		-
17d			398		-
17e			398		-
…			398		-
…			398		-
18			398	**Subtotal General - Miscellaneous Equipment**	**-**
19a			399		-
19b			399		-
19c			399		-
…			399		-
…			399		-
20			399	**Subtotal General - Other Tangible Property**	**-**

Exhibit No. PA-102, WP-BA

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER BA
DEPRECIATION AND AMORTIZATION EXPENSES (BY FERC ACCOUNT)

Included General & Transmission Plant - Depreciation ____

	(1)	(2)	(3)	(4)
	Site	FERC Acct #	Item	Depreciation ($)
21	**Total Included General Plant**			-
	Included Transmission Plant			
22a		352		-
22b		352		-
22c		352		-
22d		352		-
22e		352		-
22f		352		-
22g		352		-
…		352		-
…		352		-
23		352	**Subtotal Transmission - Structures & Improvements**	-
24a		353		-
24b		353		-
24c		353		-
24d		353		-
24e		353		-
24f		353		-
24g		353		-
24h		353		-
…		353		-
…		353		-
25		353	**Subtotal Transmission - Station Equipment**	-
26a		354		-
26b		354		-
26c		354		-
26d		354		-
26e		354		-
26f		354		-
…		354		-
…		354		-
27		354	**Subtotal Transmission - Towers & Fixtures**	-
28a		355		-
28b		355		-
28c		355		-
28d		355		-
28e		355		-
…		355		-
…		355		-
29		355	**Subtotal Transmission - Poles & Fixtures**	-
30a		356		-
30b		356		-
30c		356		-
30d		356		-
30e		356		-
30f		356		-
…		356		-
…		356		-
31		356	**Subtotal Transmission - Overhead Conductors & Devices**	-
32a		357		-
32b		357		-
32c		357		-
…		357		-
…		357		-
33		357	**Subtotal Transmission - Underground Conduit**	-
34a		358		-
34b		358		-
34c		358		-
…		358		-
…		358		-
35		358	**Subtotal Transmission - Underground Conductors & Devices**	-
36a		359		-
36b		359		-
36c		359		-
36d		359		-
36e		359		-
36f		359		-
…		359		-
…		359		-
37		359	**Subtotal Transmission - Roads & Trails**	-
38	**Total Included Transmission Plant**			-

Exhibit No. PA-102, WP-BB

NEW YORK POWER AUTHORITY

TRANSMISSION REVENUE REQUIREMENT

YEAR ENDING DECEMBER 31, ____

WORK PAPER BB

____-____ EXCLUDED PLANT IN SERVICE

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
		(8)	(9)	(10)	(11)			
					Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant in Service (Net $)	Depreciation Expense ($)
						Electric Plant in Service ($)	Accumulated Depreciation ($)	Depreciation Expense ($)	Electric Plant in Service (Net $)
Line No.	**Source/Comments**	**EXCLUDED TRANSMISSION**						
1								

1a			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
2	**SUBTOTAL 500mW C - C at Astoria**		-		-		-		-	
	-		-		-		-			
3										
3a			-		-		-		-	
			-		-		-		-	
3b			-		-		-		-	
			-		-		-		-	
3c			-		-		-		-	
			-		-		-		-	
3d			-		-		-		-	
			-		-		-		-	
3e			-		-		-		-	
			-		-		-		-	
3f			-		-		-		-	
			-		-		-		-	
3g			-		-		-		-	
			-		-		-		-	
3h			-		-		-		-	
			-		-		-		-	
3i			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
4	**SUBTOTAL Astoria 2 (AE-II) Substation**		-		-		-		-	
	-		-		-		-			
5										
5a			-		-		-		-	
			-		-		-		-	
5b			-		-		-		-	
			-		-		-		-	
5c			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
6	**SUBTOTAL Small Hydro**		-		-		-		-	
	-		-		-		-			
7										
7a			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
8	**SUBTOTAL FLYNN (Holtsville)**		-		-		-		-	
	-		-		-		-			
8a			-		-		-		-	
			-		-		-		-	
8b			-		-		-		-	
			-		-		-		-	
8c			-		-		-		-	
			-		-		-		-	
8d			-		-		-		-	
			-		-		-		-	
8e			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
9	**SUBTOTAL Poletti**		-		-		-		-	
	-		-		-		-			
10										
10a			-		-		-		-	
			-		-		-		-	
10b			-		-		-		-	
			-		-		-		-	
10c			-		-		-		-	
			-		-		-		-	
10d			-		-		-		-	
			-		-		-		-	
10e			-		-		-		-	
			-		-		-		-	
10f			-		-		-		-	
			-		-		-		-	
10g			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
11	**SUBTOTAL SCPP**		-		-		-		-	
	-		-		-		-			
12										
...		-			-		-		-	
		-			-		-		-	
			-		-		-		-	
					-		-		-	
					-					
13	**TOTAL EXCLUDED TRANSMISSION**		-		-		-		-	
	-		-		-		-			

Exhibit No. PA-102, WP-BB

NEW YORK POWER AUTHORITY

T R A N S M I S S I O N R E V E N U E R E Q U I R E M E N T

Y E A R E N D I N G D E C E M B E R 3 1 , _ _ _ _

WORK PAPER BB

____-____ EXCLUDED PLANT IN SERVICE

(1) (2) (3) (4) (5) (6) (7)

(8) (9) (10) (11)

____ ____

Electric Plant in Service ($)

Accumulated Depreciation ($)

Depreciation Expense ($)

Electric Plant in Service (Net $)

Electric Plant in Service ($)

Electric Accumulated Depreciation ($)

Electric Depreciation Expense ($)

Plant in Service (Net $)

14	**EXCLUDED GENERAL**									
14a			-		-		-		-	
			-		-		-		-	
14b			-		-		-		-	
			-		-		-		-	
14c			-		-		-		-	
			-		-		-		-	
14d			-		-		-		-	
			-		-		-		-	
14e			-		-		-		-	
			-		-		-		-	
14f			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
15	**SUBTOTAL 500Mw CC**		**-**		**-**		**-**		**-**	
	-		**-**		**-**		**-**			
16										
16a			-		-		-		-	
			-		-		-		-	
16b			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
17	**SUBTOTAL Small Hydro**		**-**		**-**		**-**		**-**	
	-		**-**		**-**		**-**			
18										
18a			-		-		-		-	
			-		-		-		-	
18b			-		-		-		-	
			-		-		-		-	
18c			-		-		-		-	
			-		-		-		-	
18d			-		-		-		-	
			-		-		-		-	
18e			-		-		-		-	
			-		-		-		-	
18f			-		-		-		-	
			-		-		-		-	
18g			-		-		-		-	
			-		-		-		-	
18h			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
19	**SUBTOTAL Flynn**		**-**		**-**		**-**		**-**	
	-		**-**		**-**		**-**			
20										
20a			-		-		-		-	
			-		-		-		-	
20b			-		-		-		-	
			-		-		-		-	
20c			-		-		-		-	
			-		-		-		-	
20d			-		-		-		-	
			-		-		-		-	
20e			-		-		-		-	
			-		-		-		-	
20f			-		-		-		-	
			-		-		-		-	
20g			-		-		-		-	
			-		-		-		-	
20h			-		-		-		-	
			-		-		-		-	
20i			-		-		-		-	
			-		-		-		-	
20j			-		-		-		-	
			-		-		-		-	
20k			-		-		-		-	
			-		-		-		-	
...		-		-		-		-		-
		-		-		-				
21	**SUBTOTAL Poletti**		**-**		**-**		**-**		**-**	
	-		**-**		**-**		**-**			

Exhibit No. PA-102, WP-BB

NEW YORK POWER AUTHORITY

T R A N S M I S S I O N R E V E N U E R E Q U I R E M E N T Y E A R E N D I N G D E C E M B E R 3 1 , _ _ _ _

WORK PAPER BB

____-____ EXCLUDED PLANT IN SERVICE

(1) (8)	(2) (9)	(3) (10)	(4) (11)	(5)	(6)	(7)
			Electric Plant in Service ($)	Accumulated Plant in Depreciation Depreciation ($) Service ($) Expense ($)	Electric Electric Electric Plant in Accumulated Service (Net $) Depreciation ($)	Depreciation Plant in Expense ($) Service (Net $)

22a			-	-	-	-
			-	-	-	-
22b			-	-	-	-
			-	-	-	-
22c			-	-	-	-
			-	-	-	-
22d			-	-	-	-
			-	-	-	-
22e			-	-	-	-
			-	-	-	-
22f			-	-	-	-
			-	-	-	-
22g			-	-	-	-
			-	-	-	-
22h			-	-	-	-
			-	-	-	-
22i			-	-	-	-
			-	-	-	-
22j			-	-	-	-
			-	-	-	-
22k			-	-	-	-
			-	-	-	-
22l			-	-	-	-
			-	-	-	-
22n			-	-	-	-
			-	-	-	-
...		-	-	-	-	-
		-	-	-		
23	**SUBTOTAL SCPP**		-	-	-	-
	-		-	-	-	
24						
...		-	-	-	-	
		-	-	-	-	
			-	-	-	-
				-	-	-
				-		
25	**TOTAL EXCLUDED GENERAL**		-	-	-	-
	-		-	-	-	

Exhibit No. PA-102, WP-BC

NEW YORK POWER AUTHORITY
TRANSMISSION
REVENUE
REQUIREMENT
YEAR ENDING
DECEMBER 31, ____

WORK PAPER BC
PLANT IN SERVICE DETAIL

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
P/T/G	Plant Name	A/C	Description	Electric Plant in Service ($)	Accumulated Depreciation Depreciation ($)	Electric Plant in Service (Net $)	Depreciation Expense ($)	Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant Service (Net

(12)
in
$)
Expense ($)

Capital assets, not being depreciated:

1 **Land**
1a
1b
1c
1d
1e
1f
1g
1h
1i
1j
1k
1l
1n
1m
1o
1p

1q

1r

1s

1t

1u
1v
1w
1x
1y
1z
1aa
1ab
1ac
1ad
1ae
1af
1ag
1ah
1ai
…

…

2	**Land Total**	-	-	-	-	-	-	-
	-							
3	**Construction in progress**							

Exhibit No. PA-102, WP-BC

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER BC
PLANT IN SERVICE DETAIL

(12) in $)	(1) P/T/G	(2) Plant Name	(3) A/C	(4) Description	(5) Electric Plant in Service ($)	(6) Accumulated Depreciation Depreciation ($)	(7) Electric Plant in Service (Net $)	(8) Depreciation Expense ($)	(9) Electric Plant in Service ($)	(10) Accumulated Depreciation ($)	(11) Electric Plant Service (Net
		Expense ($)									
3a		*Adjustments*		**CWIP**							
4				**Construction in progress Total** -	-	-	-	-	-	-	-
5			**Total capital assets not being depreciated -**		**-**	**-**	**-**	**-**	**-**	**-**	**-**
			Capital assets, being depreciated:								
6				**Production - Hydro**							
6a											
6b											
6c											
6d											
6e											
6f											
6g											
6h											
6i											
6j											
6k											
6l											
6n											

6m

6o

6p

6q

6r

6s

6t

6u
6v
6w
6x
6y
6z
6aa
6ab
6ac
6ad
6ae
6af
6ag
…
…

Exhibit No. PA-102, WP-BC

NEW YORK POWER AUTHORITY
TRANSMISSION
REVENUE
REQUIREMENT
YEAR ENDING
DECEMBER 31, ____

WORK PAPER BC
PLANT IN SERVICE DETAIL

(12)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
in $)	P/T/G	Plant Name Expense ($)	A/C	Description	Electric Plant in Service ($)	Accumulated Depreciation Depreciation ($)	Electric Plant in Service (Net $)	Depreciation Expense ($)	Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant Service (Net
7				Production - Hydro Total -	-	-	-	-	-	-	-
8				Production - Gas turbine/combined cycle							
8a											
8b											
8c											
8d											
8e											
8f											
8 g											
8 h											
8 i											
8 j											
8 k											
8 l											
8 n											
8 m											
8 o											
8											

p

8
q

8
r

8
s

8
t

8u
8v
. 8w
. 8x
8y
8z
. 8aa
8ab
8ac
8ad
8ae
8af
8ag
8ah
8ai
8ak
8al
8
a
m

8
a
n

8
a
o

8
a
p

Exhibit No. PA-102, WP-BC

**NEW YORK POWER AUTHORITY
TRANSMISSION
REVENUE
REQUIREMENT
YEAR ENDING
DECEMBER 31, ____**

**WORK PAPER BC
PLANT IN SERVICE DETAIL**

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	P/T/G	**Plant Name**	**A/C**	**Description**	**Electric Plant in Service ($)**	**Accumulated Depreciation Depreciation ($)**	**Electric Plant in Service (Net $)**	**Depreciation Expense ($)**	**Electric Plant in Service ($)**	**Accumulated Depreciation ($)**	**Electric Plant Service (Net**	**in $)** **Expense ($)**
8aq												
8ar												
8as												
8at												
8au												
8av												
8aw												
8ax												
8ay												
8az												
8ba												
8bb												
8bc												
8bd												
…												
…												
9				**Production - Gas turbine/combined cycle Total**	-	-	-	-	-	-	-	-
10				**Transmission**								
10a												
10b												

10c

10d

10e

10f

10g

10h

10i

10j

10k

10l
10n
10m
10o
10p
10q
10r
10s
10t
10u
10v
10w
10y

Exhibit No. PA-102, WP-BC

**NEW YORK POWER AUTHORITY
TRANSMISSION
REVENUE
REQUIREMENT
YEAR ENDING
DECEMBER 31, ____**

**WORK PAPER BC
PLANT IN SERVICE DETAIL**

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	P/T/G	**Plant Name**	**A/C**	**Description**	**Electric Plant in Service ($)**	**Accumulated Depreciation Depreciation ($)**	**Electric Plant in Service (Net $)**	**Depreciation Expense ($)**	**Electric Plant in Service ($)**	**Accumulated Depreciation ($)**	**Electric Plant Service (Net $)**	**in Expense ($)**
10z												
10aa												
10ab												
10ac												
10ad												
10ae												
10af												
10ag												
10a												

h

10ai
10ak
10al
10am
10an
10ao
10ap
10aq
10ar
10as
10at
10au
10av
10aw
10ax
10ay
10az
10ba
10bb
10bc
10bd
10be
10bh
10bi
10bk
10bl
10bm
10bn
10bo
10bp
10bq
1
0
b
r

1
0
b
s

1
0
b
t

1
0
b
u

1
0
b
v

Exhibit No. PA-102, WP-BC

NEW YORK POWER AUTHORITY TRANSMISSION REVENUE REQUIREMENT YEAR ENDING DECEMBER 31, ____

WORK PAPER BC PLANT IN SERVICE DETAIL

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	P/T/G	Plant Name	A/C	Description	Electric Plant in Service ($)	Accumulated Depreciation Depreciation ($)	Electric Plant in Service (Net $)	Depreciation Expense ($)	Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant in Service (Net $)	Depreciation Expense ($)
10bw												
…												
…												
11				**Transmission Total**	-	-	-	-	-	-	-	-
12				**General**								
12a												
12b												
12c												
12d												
12e												
12f												
12												

g

1
2
h

1
2
i

1
2
j

1
2
k

12l
12n
12m
12o
12p
12q
12r
12s
12t
12u
12v
12w
12x
12y
12z
12aa
12ab
12ac
12ad
12ae
12af
12ag
12ah
12ai
12ak
12al

Exhibit No. PA-102, WP-BC

NEW YORK POWER AUTHORITY TRANSMISSION REVENUE REQUIREMENT YEAR ENDING DECEMBER 31, ____

WORK PAPER BC PLANT IN SERVICE DETAIL

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	P/T/G	Plant Name	A/C	Description	Electric Plant in Service ($)	Accumulated Depreciation Depreciation ($)	Electric Plant in Service (Net $)	Depreciation Expense ($)	Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant Service (Net	in $) Expense ($)
12am												
12an												
12ao												
12ap												
12aq												
12ar												
12as												
12at												
12au												
12av												
12aw												
12ax												
12ay												
12az												
12ba												
12bb												
12bc												
12bd												

12be
12bh
12bi
12bk
12bl
12bm
12bn
12bo
12bp
12bq
12br
12bs
12bt
12bu
12bv
12bw
12bx
12by
12bz
12ca
12cb
12cc
12cd
12ce
12cf
12cg
12ch

Exhibit No. PA-102, WP-BC

NEW YORK POWER AUTHORITY TRANSMISSION REVENUE REQUIREMENT YEAR ENDING DECEMBER 31, ____

WORK PAPER BC
PLANT IN SERVICE DETAIL

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	P/T/G	Plant Name	A/C	Description	Electric Plant in Service ($)	Accumulated Depreciation Depreciation ($)	Electric Plant in Service (Net $)	Depreciation Expense ($)	Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant Service (Net in $)	Expense ($)
12ci												
12ck												
12cl												
12cm												
12cn												
12co												
12cp												
……												
13				**General Total**	-	-	-	-	-	-	-	-

14	Total capital assets, being depreciated -	-	-	-	-	-	-	-
15	Net value of all capital assets -	-	-	-	-	-	-	-

Exhibit No. PA-102, WP-BD

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER BD
MARCY-SOUTH CAPITALIZED LEASE AMORTIZATION AND UNAMORTIZED BALANCE

Line No.	Year	Beginning Unamortized Lease Asset/ Obligation ($)	Ending Unamortized Lease/Asset ($)	Capitalized Lease Amortization ($)	Current Year Average Unamortized Balance
	(1)	(2)	(3)	(4)	(5)
1	1988	-	-	-	
2	1989	-	-	-	
3	1990	-	-	-	
4	1991	-	-	-	
5	1992	-	-	-	
6	1993	-	-	-	
7	1994	-	-	-	
8	1995	-	-	-	
9	1996	-	-	-	
10	1997	-	-	-	
11	1998	-	-	-	
12	1999	-	-	-	
13	2000	-	-	-	
14	2001	-	-	-	
15	2002	-	-	-	
16	2003	-	-	-	
17	2004	-	-	-	
18	2005	-	-	-	
19	2006	-	-	-	
20	2007	-	-	-	
21	2008	-	-	-	
22	2009	-	-	-	
23	2010	-	-	-	
24	2011	-	-	-	
25	2012	-	-	-	
26	2013	-	-	-	
27	2014	-	-	-	-
28	2015	-	-	-	
29	2016	-	-	-	
30	2017	-	-	-	
31	2018	-	-	-	
32	2019	-	-	-	
33	2020	-	-	-	
34	2021	-	-	-	
35	2022	-	-	-	
36	2023	-	-	-	
37	2024	-	-	-	
38	2025	-	-	-	
39	2026	-	-	-	
40	2027	-	-	-	
41	2028	-	-	-	
42	2029	-	-	-	
43	2030	-	-	-	
44	2031	-	-	-	
45	2032	-	-	-	
46	2033	-	-	-	
47	2034	-	-	-	
48	2035	-	-	-	
49	2036	-	-	-	

50	2037	-	-	-
51	**Total**			**-**

Exhibit No. PA-102, WP-BE

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER BE
FACTS PROJECT PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND DEPRECIATION EXPENSE

LN	Cap.Date	Asset Description	(1) Electric Plant in Service ($)	(2) Accumulated Depreciation ($)	(3) Electric Plant in Service (Net $)	(4) Depreciation Expense ($)	(5) Electric Plant in Service ($)	(6) Accumulated Depreciation ($)	(7) Electric Plant in Service (Net $)	(8) Depreciation Expense ($)
2		Total Plant	-	-	-	-	-	-	-	-
3		Year-Over-Year Accumulated Depreciation		-						

Note: The FACTS project data is based on NYPA's financial records with adherence to FERC's Uniform System of Accounts and U.S. generally accepted accounting principles.

Exhibit No. PA-102, WP-BF

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE
REQUIREMENT
YEAR ENDING DECEMBER 31,

WORK PAPER BF
GENERATOR STEP-UP TRANSFORMERS BREAKOUT

Line	Description	Asset No.	Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant (Net $)	Depreciation Expense ($)	Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant (Net $)	Depreciation Expense ($)
1			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1 a										
1 b										
1 c										
…										
			-	-	-	-	-	-	-	-
2										
2a										
2b										
2c										
2d										
2e										
2f										
2g										
2h										
…										
			-	-	-	-	-	-	-	-
3										
a										
…										
			-	-	-	- -	-	-	-	-
4										
a										
…										
			-	-	-	-	-	-	-	-
5										
5 a										
5 b										
5 c										
…										
			-	-	-	-	-	-	-	-
6a										
…										
			-	-	-	-	-	-	-	-
7	**Grand Total**		-	-	-	-	-	-	-	-
8	**Adjusted Grand Total (Excludes 500MW C - C at Astoria)**		-	-		-	-	-		-

Exhibit No. PA-102, WP-BG

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER BG
RELICENSING/RECLASSIFICATION EXPENSES

		Plant in Service ($) (1)	Accumulated Depreciation ($) (2)	Plant in Service (Net $) (3)	Depreciation Expense ($) (4)	Plant in Service ($) (5)	Accumulated Depreciation ($) (6)	Plant in Service (Net $) (7)	Depreciation Expense ($) (8)
	NIAGARA								
1a									
1b									
1c									
…									
1		-	-	-	-	-	-	-	-
	ST. LAWRENCE								
2a									
2b									
2c									
2d									
2e									
2f									
2g									
…									
2		-	-	-	-	-	-	-	-
	-								
3a									
…									
…									
…									
3		-	-	-	-	-	-	-	-
4	**Total Expenses**	-	-	-	-	-	-	-	-

Exhibit No. PA-102, WP-BH

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER BH
ASSET IMPAIRMENT

	(1)	(2)	(3)	(4)	(5)
	Posting Date	**Cost Center**	**Account**	**Impairment Amount ($)**	**Facility**
1a					
1b					
1c					
1d					
1e					
1f					
1g					
…					
2				-	

3	Total Impairment - Production	-
4	Total Impairment - Transmission	-
5	Total Impairment - General Plant	-

Exhibit No. PA-102, WP-BI

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER BI
COST OF REMOVAL

Cost of Removal to Regulatory Assets - Depreciation:

	(1)	(2)	(3)
		____ **Amount ($)**	____ **Amount ($)**
1	Production		
2	Transmission		
3	General		
4	**Total**	**-**	**-**

Note: The Cost of Removal data is based on NYPA's accounting records under the provisions of FASB Accounting Standards Codification Topic 980.

Exhibit No. PA-102, WP-CA

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER CA
MATERIALS AND SUPPLIES

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	NYPA Acct #	**Facility**	**Total M&S Inventory ($) 12/31/____**	**Total M&S Inventory ($) 12/31/____**	**Avg. M&S Inventory ____-14**	**Transmission Allocator**	**Allocated M&S ($)**
1a	1100	NIA					
1b	1200	STL					
1c	3100	POL					
1d	3200	Flynn					
1e	1300	B/G					
1f	3300	500MW					
1g	2100	CEC					
…	-	-					
2		Facility Subtotal	-	-			
3a	Reserve for Degraded Materials						
3b	Reserve for Excess and Obsolete Inventory						
…	-	-					
4		Reserves Subtotal	-	-			
5		**Total**	**-**	**-**	**-**	**-**	**-**

Exhibit No. PA-102, WP-CB

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER CB
ESTIMATED PREPAYMENTS AND INSURANCE

	(1)	(2)	(3)
	Date	**Property Insurance ($)**	**Other Prepayments ($)**
1	12/31/____	-	
2	12/31/____	-	
3	**Beginning/End of Year Average**	**-**	**-**

Exhibit No. PA-102, WP-DA

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER DA
WEIGHTED COST OF CAPITAL

	(1) Component	(2) Amount ($)		(3) Actual Share	(4) Equity Cap	(5) Applied Share		(6) Cost Rate		(7) Weighted Cost
1	Long-Term Debt	-	6/	-	50.00%	-		-	2/	-
2	Preferred Stock	-		-	-	-		-	3/	-
3	Common Equity	-	1/	-	50.00%	-	4/	9.45%	5/	-
4	Total	-		-	100%	-				-

Notes

	1/:			
5	Total Proprietary Capital	-		Workpaper WP-DB Ln (5), average of Col (2) and (3)
6	less Preferred			
7	less Acct. 216.1			
8	Common Equity	-		
	2/:			
9	Total Long Term Debt Interest	-		Workpaper WP-DB Col (2) Ln (2)
10	Net Proceeds Long Term Debt	-		Workpaper WP-DB Ln (4), average of Col (2) and (3)
11	LTD Cost Rate	-	7/	
	3/:			
12	Preferred Dividends	-		
13	Preferred Stock	-		
14	Preferred Cost Rate	-		

15 4/: The capital structure listed in Col (3) is calculated based on the total capitalization amount listed in column (2). The Equity Cap in Col (4) Ln (3) is fixed and cannot be modified or deleted absent an FPA Section 205 or 206 filing to FERC. The Applied Equity Share in Col (5) Ln (3) will be the actual common equity share, not to exceed the Equity Cap in Col (4) Ln (3). The debt share is calculated as 1 minus the equity share.

16 5/: The ROE listed in Col (6), Ln (3) is the base ROE plus 50 basis-point incentive for RTO participation. ROE may only be changed pursuant to an FPA Section 205 or 206 filing to FERC.

17 6/: The Long-Term Debt Amount ($) in Col (2) Ln (1) is the Gross Proceeds Outstanding Long Term Debt, the average of WP-DB Ln (3e), Col (2) and (3).

18 7/: The Long-Term Debt Cost Rate is calculated as the Total Long Term Debt Interest [Workpaper WP-DB Col (2) Ln (2)] divided by the Net Proceeds Long Term Debt [Workpaper WP-DB row (4), average of Col (2) and (3)].

Exhibit No. PA-102, WP-DB

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER DB
CAPITAL STRUCTURE
LONG-TERM DEBT AND RELATED INTEREST

	(1)	(2)	(3)	(4)
		____ Amount ($)	**____ Amount ($)**	**NYPA Form 1 Equivalent**
1	**Long Term Debt Cost**			
1a	Interest on Long-Term Debt			p. 117 ln. 62 c,d
1b	Amort. of Debt Disc. and Expense			p. 117 ln. 63 c,d
1c	Amortization of Loss on Reacquired Debt			p. 117 ln. 64 c,d
1d	(Less) Amort. of Premium on Debt			p. 117 ln. 65 c,d
1e	(Less) Amortization of Gain on Reacquired Debt			p. 117 ln. 66 c,d
2	**Total Long Term Debt Interest**	-	-	
3	**Long Term Debt**			
3a	Bonds			p. 112 ln. 18 c,d
3b	(Less) Reacquired Bonds			p. 112 ln. 19 c,d
3d	Other Long Term Debt			p. 112 ln. 21 c,d
3e	Gross Proceeds Outstanding LT Debt	-	-	
3f	(Less) Unamortized Discount on Long-Term Debt			p. 112 ln. 23 c,d
3g	(Less) Unamortized Debt Expenses			p. 111 ln. 69 c,d
3h	(Less) Unamortized Loss on Reacquired Debt			p. 111 ln. 81 c,d
3i	Unamortized Premium on Long-Term Debt			p. 112 ln. 22 c,d
3k	Unamortized Gain on Reacquired Debt			p. 113 ln. 61 c,d
4	**Net Proceeds Long Term Debt**	-	-	
5	**Net Position**	-	-	

Exhibit No. PA-102, WP-EA

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER EA
CALCULATION OF LABOR RATIO

	(1)	(2)	(3)	(4)
	Cost Center(s)	**Site**	**Labor Actual Postings $**	**Ratio**
1a	**105**	**Blenheim-Gilboa**		-
1b	**110**	**St. Lawrence**		-
1c	**115**	**Niagara**		-
1d	**120**	**Poletti**		-
1e	**125**	**Flynn**		-
1f				
1g	**122**	**AE II**		-
1h				
1i	**130-150**	**Total Small Hydro**		-
1j				
1k	**155-161**	**Total Small Clean Power Plants**		-
1l				
1n	**165**	**500MW Combined Cycle**		-
1m				
1o	**205-245**	**Total Included Transmission**		-
1p				
1q	**321**	**Recharge New York**		-
1r				
1s	**600**	**SENY**		-

... -	-		-
	Total - Production + Transmission	**-**	**-**
	Total - Production Only	**-**	-

Exhibit No. PA-102, WP-AR-IS

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AR- IS
STATEMENT OF REVENUES, EXPENSES AND CHANGES IN NET POSITION
($ Millions)

	Description (1)	Actual ____ (2)	Actual ____ (3)
1	**Operating Revenues**		
1a	Power Sales		
1b	Transmission Charges		
1c	Wheeling Charges		
…	-		
2	**Total Operating Revenues**	**-**	**-**
3	**Operating Expenses**		
3a	Purchased Power		
3b	Fuel Oil and Gas		
3c	Wheeling		
3d	Operations		
3e	Maintenance		
3f	Depreciation		
…	-		
4	**Total Operating Expenses**	**-**	**-**
5	**Operating Income**	**-**	**-**
6	**Nonoperating Revenues**		
6a	Investment Income		
6b	Other		
…	-		
7	**Investments and Other Income**	**-**	**-**
8	**Nonoperating Expenses**		
8a	Contribution to New York State		
8b	Interest on Long-Term Debt		
8c	Interest - Other		
8d	Interest Capitalized		
8e	Amortization of Debt Premium		
…	-		
9	**Investments and Other Income**	**-**	**-**
10	**Net Income Before Contributed Capital**	**-**	**-**
11	Contributed Capital - Wind Farm Transmission Assets		
…	-		
		-	-
13	Change in net position	-	-

ue

14	Net position at January 1		
15	Net position at December 31	-	-

Exhibit No. PA-102, WP-AR-BS

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AR-BS
STATEMENT OF NET POSITION
($ Millions)

	DESCRIPTION	DECEMBER ____	DECEMBER ____
	(1)	(2)	(3)
1	**Assets and Deferred Outflows**		
1a	Current Assets:		
1b	Cash and cash equivalents		
1c	Investment in securities		
1d	Receivables - customers		
1e	Materials and supplies, at average Cost:		
1f	Plant and general		
1g	Fuel		
1h	Miscellaneous receivables and other		
…	-		
2	Total current assets	-	-
3	Noncurrent Assets:		
3a	Restricted funds:		
3b	Cash and cash equivalents		
3c	Investment in securities		
…	-		
4	Total restricted assets	-	-
5	Capital funds:		
5a	Cash and cash equivalents		
5b	Investment in securities		
…	-		
6	Total capital funds	-	-
7	Capital Assets		
7a	Capital assets not being depreciated		
7b	Capital assets, net of accumulated depreciation		
…	-		
8	Total capital assets	-	-
9	Other noncurrent assets:		
9a	Receivable - New York State		
9b	Notes receivable - nuclear plant sale		
9c	Other long-term assets		
…	-		
10	Total other noncurrent assets	-	-
11	Total noncurrent assets	-	-
12	Total assets	-	-
13	Deferred outflows:		

13a	Accumulated decrease in fair value of hedging derivatives		
…	-		
14	Total Deferred outflows	-	-
15	**Total assets and deferred outflows**	**-**	**-**

Exhibit No. PA-102, WP-AR-BS

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AR-BS
STATEMENT OF NET POSITION
($ Millions)

1/ Source: Annual Financial Statements

Exhibit No. PA-102, WP-AR-BS

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AR-BS
STATEMENT OF NET POSITION
($ Millions)

	DESCRIPTION	DECEMBER ____	DECEMBER ____
16	**Liabilities, Deferred Inflows and Net Position**		
16a	Current Liabilities:		
16b	Accounts payable and accrued liabilities		
16c	Short-term debt		
16d	Long-term debt due within one year		
16e	Capital lease obligation due within one year		
16f	Risk management activities - derivatives		
…	-		
17	Total current liabilities	-	-
18	Noncurrent liabilities:		
18a	Long-term debt:		
18b	Senior:		
18c	Revenue bonds		
18d	Adjustable rate tender notes		
18e	Subordinated:		
18f	Subordinated Notes, Series 2012		
18g	Commercial paper		
…	-		
19	Total long-term debt	-	-
20	Other noncurrent liabilities:		
20a	Capital lease obligation		
20b	Liability to decommission divested nuclear facilities		
20c	Disposal of spent nuclear fuel		
20d	Relicensing		
20e	Risk management activities - derivatives		
20f	Other long-term liabilities		
…	-		
21	Total other noncurrent liabilities	-	-
22	Total noncurrent liabilities	-	-
23	Total liabilities	-	-
24	Deferred inflows:		
24a	Cost of removal obligation		
…	-		
		-	-
25	Net position:		
25a	Net investment in capital assets		
25b	Restricted		
25c	Unrestricted		
…	-		
26	Total net position	-	-

27	**Total liabilities, deferred inflows and net position**	-	-

1/ Source: Annual Financial Statements

Exhibit No. PA-102, WP-AR-Cap Assets

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER AR-Cap Assets
CAPITAL ASSETS - Note 5 ($ Millions)

New York Power Authority
Capital Assets - Note 5
____ Annual Report

		12/31/____ Ending balance	Additions	Deletions
	(1)	(2)	(3)	(4)
1	Capital assets, not being depreciated:			
1a	Land			
1b	Construction in progress			
…	-			
2	Total capital assets not being depreciated	-	-	-
3	Capital assets, being depreciated:			
3a	Production - Hydro			
3b	Production - Gas			
3c	turbine/combined cycle			
3d	Transmission			
3e	General			
…	-			
4	Total capital assets being depreciated	-	-	-
5	Less accumulated depreciation for:			
5a	Production - Hydro			
5b	Production - Gas			
5c	turbine/combined cycle			
5d	Transmission			
5e	General			
…	-			
6	Total accumulated depreciation	-	-	-
7	Net value of capital assets being depreciated	-	-	-
8	Net value of all capital assets	-	-	-

12/31/____ Ending balance (5)
-
-
-
-
-
-
-
-
-
-
-
-
-
-
-
-
-
-

Exhibit No. PA-102, WP-Reconciliations

NEW YORK POWER AUTHORITY
TRANSMISSION REVENUE REQUIREMENT
YEAR ENDING DECEMBER 31, ____

WORK PAPER Reconciliations
RECONCILIATIONS BETWEEN ANNUAL REPORT & ATRR

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**OPERATION & MAINTANANCE EXPENSES**							
		Operations	Maintenance	Total O&M				
1a	Operations & Maintenance Expenses - as per Annual Report	-	-	-				
1b	Excluded Expenses							
1c	Production	-	-	-				
1d	A&G in FERC Acct 549 - OP-Misc Oth Pwr Gen	-	-	-				
1e	FERC acct 905 (less contribution to New York State)	-	-	-				
1f	FERC acct 916 - Misc Sales Expense	-	-	-				
1g	A&G allocated to Production and General	-	-	-				
1h	Adjustments			-				
1i	Less A/C 924 - Property Insurance	-	-	-				
1j	Less A/C 925 - Injuries & Damages Insurance	-	-	-				
1k	Less EPRI Dues	-	-	-				
1l	Less A/C 928 - Regulatory Commission Expense	-	-	-				
1n	PBOP Adjustment	-	-	-				
1m	924 -Property Insurance as allocated	-	-	-				
1o	925 - Injuries & Damages Insurance as allocated	-	-	-				
1p	Step-up Transformers	-	-	-				
1q	FACTS	-	-	-				
1r	Microwave Tower Rental Income	-	-	-				
1s	Reclassifications (post Annual Report)	-	-	-				
	Operations & Maintenance Expenses - as per ATRR	-	-	-				
	check	-	-	-				

2 ELECTRIC PLANT IN SERVICE & DEPRECIATION

			Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant in Service - Net ($)	Depreciation Expense ($)	Electric Plant in Service ($)	Accumulated Depreciation ($)	Electric Plant in Service - Net ($)
2a	As per Annual Report								
2b	Capital Assets not being depreciated		-	-	-	-	-	-	0
2c	Capital Assets being depreciated		-	-	-	-	-	-	0
2d	Total Capital Assets		-	-	-	-	-	-	0
2e	Less CWIP		-	-	-	-	-	-	0
2f	Total Assets in Service		-	-	-	-	-	-	0
2g	Adjustments for ATRR								
2h	Cost of Removal (note 1)								
2i	Transmission		-	-	-	-	-	-	0
2j	General		-	-	-	-	-	-	0
2k	Total		-	-	-	-	-	-	0
2l	Excluded (note 2)								
2n	Transmission		-	-	-	-	-	-	0
2m	General		-	-	-	-	-	-	0
2o	Total		-	-	-	-	-	-	0
2p	Adjustments to Rate Base (note 3)								
2q	Transmission		-	-	-	-	-	-	0
2r	General		-	-	-	-	-	-	0
2s	Total		-	-	-	-	-	-	0
2t									
2u	Total Assets in Service - As per ATRR		-	-	-	-	-	-	0
2v	Comprising:								
2w	Production		-	-	-	-	-	-	0
2x	Transmission		-	-	-	-	-	-	0
2y	General		-	-	-	-	-	-	0
2z	Total		-	-	-	-	-	-	0
2aa	*check*	differences due to rounding	-	-	-	-	-	-	*0*

Notes

2ab 1 Cost of Removal: Bringing back to accumulated depreciation cost of removal which was reclassified to regulatory liabilities in annual report

2ac 2 Excluded: Assets not recoverable under ATRR

2ad 3 Adjustments to Rate Base: Relicensing, Windfarm, Step-up transformers, FACTS & Asset Impairment

	3	**MATERIALS & SUPPLIES**				
3a		As per Annual Report				
3b		Plant and General	-	-		
3c		As per ATRR	-	-		
3d		*check*	-	-		
	4	**CAPITAL STRUCTURE**				
			Long -Term Debt	Common Equity	Long -Term Debt	Common Equity
4a		As per Annual Report				
4b		Long-Term				
4c		Short-Term	-		-	
4d		Total	-	-	-	-
4e		As per ATRR	-	-	-	-
4f		*check*	-	-	-	-
	5	**INTEREST ON LONG-TERM DEBT**				
5a		As per Annual Report				
5b		Interest LTD (including Swaps, Deferred Refinancing)	-	-		
5c		Debt Discount/Premium	-	-		
5d		Total	-	-		
5e		As per ATRR				
5f		Interest LTD (including Swaps, Deferred Refinancing)	-	-		
5g		Debt Discount/Premium	-	-		
5h		Total	-	-		
5i		*check*	-	-		
	6	**REVENUE REQUIREMENT**				
6a		As per Annual Report	-			
6b		SENY load (note 4)				
6c		FACTS revenue (note 5)				
6d		Timing differences				
…						
…						
7a		Total (sum lines 64-66)	**-**			
7b		**FERC approved ATRR** (line 63 - line 67)	-			
7c		*check*	-			

Notes

7d	4	Amount that NYPA will credit to its ATRR assessed to the SENY customer load. These revenues are included in the Annual Report within Production Revenues.
7e	5	Compensation for FACTS through the NYISO's issuance of Transmission Congestion Contract ("TCC") payments

	8	**OTHER POSTEMPLOYMENT BENEFIT PLANS**	
8a		As per Annual Report	
8b		Annual OPEB Cost	-
8c		As per ATRR	
8d		Total NYPA PBOP	-
8e		*check*	-

(9)

Depreciation Expense ($)
0
0
0
0
0
0
0
0
0
0
0
0
0
0
0
0
0
0
0
0

14.2.3.2 NYPA Formula Rate Implementation Protocols

14.2.3.2.1 General

(a) NYPA employs the Formula Rate (contained in Section 14.2.3.1 ("Formula Rate Template" or "Formula") of this Attachment) to calculate its Annual Transmission Revenue Requirement ("ATRR") in accordance with the Protocols set forth herein. NYPA employs an Annual Update Process, which refreshes the calculation of the ATRR by populating the Formula in Section 14.2.3.1 of this Attachment with prior-year information from the Financial Report contained in the NYPA annual report and other historical data from NYPA's books and records, which are maintained using the FERC Uniform System of Accounts. The Annual Update Process does not effect any changes to the Formula Rate itself. NYPA will hold an Open Meeting each year to provide an additional opportunity for Interested Parties to obtain information about the Annual Update, and will make the Open Meeting remotely accessible to Interested Parties.

(b) Protocols Definitions:

"Accounting Change" means any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate, including (A) any change in NYPA's accounting policies, practices and procedures (including changes resulting from revisions to the U.S. generally accepted accounting principles) from those in effect during the Calendar Year upon which the most recent Actual ATRR was based that affects the Formula Rate or calculations under the Formula; (B) any change in NYPA's cost allocation policies from those policies or methodologies in effect for the Initial Rate Year or Calendar Year upon which the immediately preceding True-Up Adjustment was based that affects the Formula Rate or calculations under the Formula; (C) the initial implementation of an accounting standard or policy; (D) the initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction; (E) the implementation of new estimation methods or policies that change prior estimates; and (F) the correction of errors and prior-period adjustments.

"Actual Annual Transmission Revenue Requirement" ("Actual ATRR") means the actual net annual transmission revenue requirement calculated in accordance with the Formula Rate, using as inputs only those costs and credits properly recorded in NYPA's most recent Financial Report (to the extent the Formula Rate specifies Financial Report data as the input source) or data reconcilable to the Financial Report by the application of clearly identified and supported information that is properly recorded in NYPA's books and records, which books and records are maintained in accordance with (A) the FERC Uniform System of Accounts; (B) NYPA's internal accounting policies and practices; (C) U.S. generally accepted accounting principles; and (D) NYPA's cost allocation policies. Where the reconciliation to the Financial Report is provided through a workpaper, the inputs to the workpaper shall be either taken directly from the Financial Report or reconcilable to the Financial Report by the application of clearly identified and supported information.

"Annual Review Procedures" means the procedures for review of each Annual Update, as described in these Protocols.

"Annual Update" means the calculation and publication of the Actual ATRR for the prior Calendar Year, and the Projected ATRR (including the True-Up Adjustment and any Prior Period Adjustment, if applicable) to be applicable for the upcoming Rate Year.

"Annual Update Process" means the annual process by which NYPA calculates the Annual Update and makes it available to Interested Parties.

"Calendar Year" means January 1st through December 31st of a given year.

"Discovery Period" means the period for serving Information Requests pursuant to Section 14.2.3.2.3 of this Attachment, commencing as of the calendar day immediately following the Publication Date and ending one hundred twenty (120) calendar days after the Publication Date. The Discovery Period may be extended only as provided in Sections 14.2.3.2.3(a)(i) and 14.2.3.2.3(a)(v) of this Attachment.

"Financial Report" means the independently audited financial statements contained in the NYPA annual report which is issued in April of each year for the prior Calendar Year.

"Formal Challenge" means a dispute regarding an aspect of the Annual Update that is raised with FERC by an Interested Party pursuant to these Protocols, and served on NYPA by electronic service on the date of such filing.

"Formula" means the cost-of-service template and associated schedules shown in Section 14.2.3.1 of this Attachment.

"Formula Rate" means the Formula together with the Protocols.

"Information Request" means a request served upon NYPA by an Interested Party within the Discovery Period for information or documents relating to an Annual Update as provided for in these Protocols.

"Initial Rate Year" means the initial period, from the date the rates are first made effective by the Commission through June 30, 2016.

"Interested Party" includes, but is not limited to, customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

"NYPA Exploder List" means an e-mail list maintained by NYPA that includes all Interested Parties who have notified NYPA of their intent to be included. Interested Parties can subscribe to the NYPA Exploder List on the NYPA website.

NYPA Form 1 Equivalent" means a form developed by the parties to the settlement in Docket No. ER16-835-000 that presents NYPA's financial information in substantially the same format as selected pages of the FERC Form No. 1.

"Open Meeting" means an open meeting and conference call (in webinar format) that shall permit NYPA to explain and clarify, and shall provide Interested Parties an opportunity to seek information and clarification concerning the Annual Update. The Open Meeting shall be held no earlier than twenty (20) calendar days and no later than fourty (40) calendar days after the Publication Date. NYPA shall provide notice of the Open Meeting no less than fifteen (15) calendar days prior to such meeting via the NYPA Exploder List and by posting on the ISO website.

"Other Developers" is defined as that term is defined in Section 31.1.1 of Attachment Y of the ISO OATT.

"Preliminary Challenge" means a written notification by an Interested Party to NYPA, during the Review Period, of any specific challenge to the Annual Update.

"Prior Period Adjustment" means any change to the True-Up Adjustment agreed upon or determined through the review and challenge procedures outlined in these Protocols that is carried forward with interest to the subsequent True-Up Adjustment.

"Projected Annual Transmission Revenue Requirement" ("Projected ATRR") means the Actual ATRR for the prior Calendar Year as adjusted to reflect the True-Up Adjustment and any Prior Period Adjustments.

"Protocols" means the Formula Rate implementation protocols set forth in Section 14.2.3.2 of this Attachment.

"Publication Date" means the date of the posting on the ISO website (in a workable Excel format with cell formulas and links intact) of the Annual Update. The Publication Date shall be no later than July 1st, provided, however, that if July 1st should fall on a weekend or a holiday recognized by FERC, then the posting or filing shall be due no later than the next business day, and the Publication Date shall correspond to the actual posting or filing date.

"Rate Year" means July 1st of a given Calendar Year through June 30th of the succeeding Calendar Year.

"Review Period" means the period during which an Interested Party may review the Annual Update calculations and make a Preliminary Challenge. The Review Period commences as of the calendar day immediately following the Publication Date and ends on the later of (1) January 15 following the Publication Date; (2) sixty (60) calendar days after the close of the Discovery Period; or (3) thirty (30) calendar days after NYPA has responded to all timely submitted information requests.

"True-Up Adjustment" means the amount of under- or over-collection of NYPA's Actual ATRR during the preceding Calendar Year, measured by the difference between the Actual ATRR and the transmission revenues received by NYPA during the preceding Calendar Year, plus interest, as calculated on Schedule F3 of the Formula using the interest rates specified in 18 C.F.R. § 35.19a.

14.2.3.2.2 Annual Update Process

(a) The Projected ATRR derived pursuant to the Formula Rate each year shall be applicable to services during the upcoming Rate Year.

(b) On or before the Publication Date of each year, as part of the Annual Update Process, NYPA shall:

(i) Calculate the Actual ATRR for the preceding Calendar Year;

(ii) Calculate the Projected ATRR, reflecting the True-Up Adjustment and any Prior Period Adjustments, for the upcoming Rate Year;

(iii) Post on the ISO website (and on the NYPA website via a link to the ISO website):

(A) the Annual Update, including a data-populated Formula Rate Template and underlying workpapers in native "workable" Excel file format with all formulas and links intact;

(B) sufficiently detailed supporting documentation, including underlying data and calculations and a populated version of the NYPA Form 1 Equivalent, that explains the source and derivation of any data affecting the Formula that is not drawn directly from NYPA's Financial Report, such that

Interested Parties can replicate the calculation of the Formula results using the Financial Report and can verify that each input is consistent with the requirements of the Formula Rate;

(C) the date, time, location, and call-in information for the Open Meeting;

(c) Within one (1) business day of the Publication Date, NYPA shall notify Interested Parties via the NYPA Exploder List of the posting of the Annual Update and the date, time, location, and call-in information for the Open Meeting.

(d) The Annual Update for the Rate Year:

(i) Shall identify and provide a narrative explanation of Accounting Changes and their impacts on inputs to the Formula Rate or resulting charges billed under the Formula Rate;

(ii) Shall identify and provide a narrative explanation of any items included in the Formula at an amount other than on a historic cost basis (e.g., fair value adjustments), and their impacts on inputs to the Formula Rate or resulting charges billed under the Formula Rate;

(iii) Shall be based on NYPA's Financial Report;

(iv) Shall provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Formula Rate that are not otherwise available in the Financial Report;[13]

[13] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from NYPA's Financial Report or reconcilable to the Financial Report by the application of clearly identified and supported information.

(v) Shall provide underlying data for Formula Rate inputs that provide greater granularity than is required for the Financial Report;

(vi) Shall be subject to challenge and review in accordance with the procedures set forth in these Protocols;

(vii) Shall not seek to modify the Formula Rate and shall not be subject to challenge by anyone seeking to modify the Formula Rate (i.e., all such modifications/amendments to the Formula Rate shall require, as applicable, a Section 205 or Section 206 filing with FERC);

(viii) Shall identify any changes in the Formula references to NYPA's Financial Report;

(ix) Shall identify all material adjustments made to NYPA's Financial Report data in determining Formula inputs, including relevant footnotes to the Financial Report and any adjustments not shown in the Financial Report; and

(x) Shall reflect any corrections or modifications to NYPA's Financial Report if said corrections or modifications are made prior to the Publication Date and would affect the True-Up Adjustment for a prior Rate Year. The True-Up Adjustment for each Rate Year(s) affected by the corrections or modifications shall be updated to reflect the corrected or modified Financial Report and the Annual Update and shall incorporate the changes in such True-Up Adjustment for the next effective Rate Year(s), with interest. Corrections or modifications to a Financial Report filed after the Publication Date of an Annual Update and not included in a revised Annual Update shall be incorporated in the next True-Up Adjustment or Annual Update, as applicable. NYPA shall report in a timely manner to the ISO and to Interested Parties, via the NYPA Exploder List, any corrections or modifications to its Financial Report, that affect the past or present implementation of the Formula Rate, whether such corrections or modifications have the effect of increasing or decreasing the resulting transmission rates.

(e) Joint Informational Meeting

NYPA shall endeavor to coordinate with other Transmission Owners and Other Developers using formula rates to recover the costs of transmission projects under the ISO OATT that utilize the same regional cost sharing mechanism and to hold annual joint informational meetings to enable all Interested Parties to understand how those Transmission Owners and Other Developers are implementing their formula rates for recovering the costs of such projects. No less than fifteen (15) calendar days prior to such meeting, NYPA shall provide notice of the joint informational meeting, including the date, time, location, and call-in information, via the NYPA Exploder List and by posting this information on the ISO website (and on the NYPA website via a link to the ISO website). NYPA shall make the joint informational meeting remotely accessible to Interested Parties.

14.2.3.2.3 Annual Review Procedures

Each Annual Update shall be subject to the following Annual Review Procedures:

(a) Discovery Period

(i) Interested Parties shall have up to one hundred twenty (120) calendar days after the Publication Date (unless such period is extended with the written consent of NYPA or by FERC order) to serve Information Requests on NYPA. If the deadline for Interested Parties should fall on a weekend or a holiday recognized by FERC, then Information Requests shall be due no later than the next business day. Such Information Requests shall be limited to what is or may reasonably be necessary to determine:

(A) The extent or effect of an Accounting Change;

(B) Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

(C) The proper application of the Formula Rate and the procedures in these Protocols;

(D) The accuracy of data and consistency with the Formula Rate of the calculations included in the Annual Update (including the Actual ATRR, Projected ATRR, True-Up Adjustment, and any Prior Period Adjustment) under review;

(E) The prudence of the costs and expenditures included in the Annual Update under review, including information on procurement methods and cost control methodologies;

(F) The effect of any change to the underlying Uniform System of Accounts or the Financial Report; and

(G) Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate or aid in the understanding or derivation of such charge.

The Information Requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable under the FPA.

(ii) NYPA shall make a good faith effort to respond to Information Requests pertaining to the Annual Update within ten (10) business days of receipt of such requests. NYPA shall respond to all Information Requests submitted during the Discovery Period by no later than November 30 following the Publication Date, or thirty (30) calendar days after the close of the Discovery Period, whichever is later. If the deadline should fall on a weekend or a holiday recognized by FERC, then NYPA's responses to Information Requests shall be due no later than the next business day.

(iii) NYPA shall post all Information Requests, and NYPA's responses to Information Requests, on the ISO website and will distribute a link to the website to Interested Parties via the NYPA Exploder List; except, however, if responses to Information Requests include material deemed by NYPA to be confidential, such information will not be publicly posted, but confidential information will be made available to requesting parties provided that a confidentiality agreement is executed by NYPA and the requesting party.

(iv) NYPA shall be precluded from claiming settlement privilege with respect to responses to Information Requests pursuant to these Protocols in any subsequent FERC proceeding addressing NYPA's Annual Update.

(v) To the extent NYPA and any Interested Party are unable to resolve disputes related to Information Requests submitted in accordance with these Protocols, NYPA or the Interested Party may petition FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes, and compel the production of discovery, as appropriate, in accordance with these Protocols, and, if deemed appropriate, to extend the Discovery Period and Review Period to permit completion of the discovery process.

(vi) All information produced pursuant to these Protocols may be included in any Preliminary or Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the FPA, or in any proceeding before the U.S. Court of Appeals to review a FERC decision involving the Formula Rate. NYPA may, however, designate any response to an Information Request as confidential if the information conveyed is not publicly available and if NYPA in good faith believes the information should be treated as confidential. Interested Parties' representatives shall treat such response as confidential in connection with any of the proceedings discussed in this Section 14.2.3.2 of this Attachment; provided, however, that when so used, such response shall initially be filed under seal (unless the claim of confidentiality is waived by NYPA), subject to a later determination by the presiding authority that the material is, in whole or part, not entitled to confidential treatment.

(b) Challenges and Resolution of Challenges

(i) Any Interested Party shall have the duration of the Review Period to review the inputs, supporting explanations, allocations, and calculations, and to submit a Preliminary Challenge. The Review Period ends on the later of (1) January 15 following the Publication Date; (2) sixty (60) calendar days after the close of the Discovery Period; or (3) thirty (30) calendar days after NYPA has responded to all timely submitted information requests. If the deadline for

Interested Parties to submit Preliminary Challenges should fall on a weekend or a holiday recognized by FERC, then Preliminary Challenges shall be due no later than the next business day. An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge.

(ii) NYPA shall promptly post all Preliminary Challenges, and written responses by NYPA to Preliminary Challenges, on the ISO website and will distribute a link to the website to Interested Parties via the NYPA Exploder List; except, however, if Preliminary Challenges or responses to Preliminary Challenges include material deemed by NYPA to be confidential, such information will not be publicly posted, but confidential information will be made available to requesting parties provided that a confidentiality agreement is executed by NYPA and the requesting party.

(iii) NYPA shall make a good faith effort to respond to a Preliminary Challenge within twenty (20) business days, and NYPA and any Interested Party raising a Preliminary Challenge shall attempt in good faith to resolve the Preliminary Challenge in a timely manner. Where applicable, NYPA shall appoint senior representatives to work with Interested Parties to resolve Preliminary Challenges. If NYPA disagrees with such challenge, NYPA will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. NYPA shall respond to all Preliminary Challenges submitted during the Review Period by no later than February 15 following the Publication Date or thirty (30) calendar days after the close of the Review Period, whichever is later. If the deadline should fall on a weekend or a holiday recognized by FERC, then NYPA's response to Preliminary Challenges shall be due no later than the next business day.

(iv) An Interested Party shall make a good faith effort to raise all issues in a Preliminary Challenge; however, the failure to raise an issue in a Preliminary Challenge shall not act as a bar to raising the issue in a Formal Challenge provided the Interested Party raised one or more other issues in a Preliminary Challenge.

(v) An Interested Party that submitted a Preliminary Challenge shall have until April 15 following the Publication Date or thirty (30) calendar days after NYPA makes its informational filing, whichever is later, to make a Formal Challenge with FERC, which shall be served on NYPA by electronic service on the date of such filing. If the deadline for Interested Parties should fall on a weekend or a holiday recognized by FERC, then Formal Challenges shall be due no later than the next business day. An Interested Party shall file a Formal Challenge in the new docket assigned to NYPA's informational filing. Nothing in this paragraph shall alter the rights of any party to file a complaint under Section 206 of the FPA regarding NYPA's Formula Rate.

(vi) Formal Challenges shall satisfy all of the following requirements[14]:

14 Requiring interested parties to satisfy filing requirements for formal challenges "does not improperly shift the burden of persuasion to interested parties." *See Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,025 at P 51 (2015) (internal quotations omitted).

(A) Clearly identify the action or inaction which is alleged to violate the Formula Rate or Protocols;

(B) Explain how the action or inaction violates the Formula Rate or Protocols;

(C) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

(1) The extent or effect of an Accounting Change;

(2) Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

(3) The proper application of the Formula Rate and procedures in these Protocols;

(4) The accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update (including the Actual ATRR, Projected ATRR, True-Up Adjustment, and any Prior Period Adjustment) under review;

(5) The prudence of actual costs and expenditures;

(6) The effect of any change to the underlying Uniform System of Accounts or the Financial Report; or

(7) Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula.

(D) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(E) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(F) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(G) State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(vii) Any response by NYPA to a Formal Challenge must be submitted to FERC within thirty (30) calendar days following the date of the filing of the Formal Challenge and shall be served by NYPA on the filing party(ies) by electronic service on the date of such filing and shall also be sent to the NYPA Exploder List on the date of such filing. If the deadline should fall on a weekend or a holiday recognized by FERC, then NYPA's response to the Formal Challenge shall be due no later than the next business day.

(viii) Preliminary and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual Update fails to include data properly recorded in accordance with these Protocols; (3) the proper application of the Formula Rate and procedures in these Protocols; (4) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update (including the

Actual ATRR, Projected ATRR, True-Up Adjustment, and any Prior Period Adjustment) under review; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or the Financial Report; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula.

(ix) In any proceeding on a Formal Challenge, or proceeding initiated sua sponte by FERC challenging an Annual Update or an Accounting Change, NYPA shall bear the burden of proof, consistent with Section 205 of the FPA, with respect to the correctness of its Annual Update and/or the Accounting Change, and with respect to proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.[15]

(x) Failure to make a Preliminary Challenge or Formal Challenge as to any Annual Update shall not act as a bar to a Preliminary Challenge or Formal Challenge related to the same issue in any subsequent Annual Update to the extent such issue affects the subsequent Annual Update.

(c) Challenges to Accounting Changes

(i) Preliminary Challenges or Formal Challenges related to Accounting Changes are not intended to serve as a means of pursuing changes to the Formula Rate.

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15 *See Midwest Indep. Transmission Sys. Operator, Inc*., 143 FERC ¶ 61,149 at P 121 (2013) (“[P]arties seeking to challenge the prudence of a transmission owner’s expenditures must first create a serious doubt as to the prudence of those expenditures before the burden of proof shifts to the transmission owner.”).

(ii) Failure to make a Preliminary Challenge with respect to an Accounting Change to an Annual Update shall not act as a bar with respect to making a Formal Challenge regarding the Accounting Change to that Annual Update, provided the Interested Party submitted a Preliminary Challenge with respect to one or more other issues. Nor shall failure to make a Preliminary Challenge or Formal Challenge with respect to an Accounting Change as to any Annual Update act as a bar to a Preliminary Challenge or Formal Challenge related to that Accounting Change in any subsequent Annual Update to the extent such Accounting Change affects the subsequent Annual Update.

(iii) Preliminary Challenges or Formal Challenges related to Accounting Changes shall be subject to the procedures and limitations in Section 14.2.3.2.3(b) of this Attachment. It is recognized that resolution of Formal Challenges concerning Accounting Changes may necessitate adjustments to the Formula input data for the applicable Annual Update or changes to the Formula to achieve a just and reasonable end result consistent with the intent of the Formula.

14.2.3.2.4 Changes Pursuant to Annual Update Process

Any changes to the data inputs, including but not limited to revisions to NYPA's Financial Report, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the Annual Review Procedures set forth herein, shall be incorporated into the Formula and into the charges produced by the Formula (with interest determined in accordance with 18 C.F.R. § 35.19a) in the Annual Update for the next effective Rate Year as a Prior Period Adjustment. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments and any associated refunds or surcharges. However, actual refunds or surcharges (with interest determined in accordance with 18 C.F.R. § 35.19a) shall be made, as appropriate, in the event that the Formula Rate is replaced by a stated rate for NYPA.

14.2.3.2.5 Changes to the Formula Rate

(a) Any modification to the Formula or to these Protocols requires a filing under FPA Section 205 or Section 206. The following Formula inputs shall be stated values to be used in the Formula until changed pursuant to an FPA Section 205 or Section 206 proceeding: (i) rate of return on common equity; (ii) Post-Retirement Benefits other than Pensions ("PBOPs") expense; (iii) the depreciation and/or amortization rates as set forth in Schedule B3 to the Formula; and (iv) the caps on the equity percentage component of NYPA's capital structure for the Marcy-South Series Compensation Project (53% equity) and the assets recovered through the NTAC (50% equity).

(b) Except as specifically provided herein, nothing in these Protocols shall be deemed to limit in any way (i) the right of NYPA to file unilaterally, pursuant to Section 205 of the FPA and the regulations thereunder, to change the Formula Rate or any of its stated inputs or to replace the Formula Rate with a stated rate, or (ii) the right of any other party to challenge inputs to, or the implementation of, or to request changes to, the Formula Rate pursuant to Section 206, or any other applicable provision, of the FPA and the regulations thereunder.

(c) NYPA may, at its discretion and at a time of its choosing, make a limited filing pursuant to Section 205 to change stated values in the Formula Rate for amortization/depreciation rates and PBOPs expense. The sole issue in any such limited Section 205 filing shall be whether such proposed changes or recovery are just and reasonable, and shall not include other aspects of the Formula Rate.

14.2.3.2.6 Informational Filing

By March 15 following the Publication Date or by sixty (60) calendar days following the close of the Review Period, whichever is later, NYPA shall submit to FERC an informational filing of its Annual Update for the Rate Year. If the deadline should fall on a weekend or a holiday recognized by FERC, then the informational filing shall be due no later than the next business day. Within one (1) business day of submitting the informational filing, NYPA shall notify Interested Parties via the NYPA Exploder List that it has made its informational filing, and shall post the docket number assigned to the informational filing on the ISO website. This informational filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying schedules and workpapers; (2) that NYPA has properly applied the Formula and these Protocols; (3) the accuracy of data and the consistency with the Formula Rate of the Actual ATRR, Projected ATRR (including any True-Up Adjustment and Prior Period Adjustments), and rates under review; (4) the extent and effects of Accounting Changes that affect Formula inputs; and (5) the reasonableness of projected costs. The informational filing must also describe any corrections or adjustments made during the Review Period or as a result of the Preliminary Challenge process, and must describe all aspects of the Annual Update or its inputs that are the subject of an ongoing dispute under the Preliminary Challenge procedures. Any challenges to the implementation of the Formula must be made through the annual review and challenge procedures described in these Protocols or in a separate complaint proceeding, and not in response to the informational filing.

14.2.3.2.7 Bounds on NTAC Recovery of Capital Expenditures

The following terms, for the purposes of this Section 14.2.3.2.7, shall be defined as follows:

"Annual Incremental Capital Expenditures" means incremental capital expenditures incurred during a calendar year irrespective of whether the plant that is the product of these capital expenditures has been placed in service during the calendar year, except that (i) capital expenditures for Repairs or Replacements, (ii) capital expenditures for projects meeting the requirements of Section 14.2.3.2.7(a)(ii)(b), and (iii) capital expenditures for projects meeting the requirements of Section 14.2.3.2.7(a)(iv), shall not be included as "Annual Incremental Capital Expenditures" and shall not be counted against the $40 million annual cap described in Section 14.2.3.2.7(a)(iii).

"Substantive Cost Allocation Order" means an order from which rehearing may be sought on the issue of cost recovery for the purposes of Section 14.2.3.2.7(b)(x) (i.e., an order accepting a cost allocation without setting the matter for hearing, an order approving a settlement agreement stipulating a cost allocation for the contested project, or an order on exceptions to an initial decision following an evidentiary hearing; but not a tolling order or some other procedural order that refers the issue of cost allocation for a hearing or settlement judge procedures).

"Gross ATRR for the Major Y-49 Reconstruction or Replacement" means the ATRR attributable to the Major Y-49 Reconstruction or Replacement, including but not limited to return on rate base, depreciation expense, operation and maintenance expense, and allocated administrative and general costs.

"Major Y-49 Reconstruction or Replacement" means a major reconstruction or replacement of the Y-49 Facility with a projected capital cost of greater than $150 million in 2016 dollars (as adjusted annually by the Consumer Price Index).

"Moses to Adirondack Line" means the Moses-Adirondack 1 and 2 transmission lines that originate at the Moses Switchyard at the St. Lawrence-FDR project in Massena, New York and continue south to the NYPA Adirondack switching station in Croghan, New York for a distance of approximately 85 miles. The lines consist of eight miles of double circuit steel lattice structures and seventy-seven miles of single circuit wooden H-frame structures.

"NYPA Backbone System" means the facilities that are listed and defined in Exhibit C to the settlement approved by the Commission in Docket No. ER16-835-000. This list of facilities that comprise the NYPA Backbone System is not anticipated to be static, and will be updated periodically to include, for example, projects NYPA is required to construct as contemplated by Section 14.2.3.2.7(a)(iv) below.

"NYPA-LIPA Y-49 Contract" means the existing 1987 contract for the sale of transmission service on the Y-49 Facility by NYPA to LIPA.

"Remaining Y-49 ATRR" has the meaning set forth in Section 14.2.3.2.7(a)(ii)(a)(i) of this Attachment.

"Repair or Replacement" means any capitalized repair or replacement of an existing NYPA transmission facility that comprises a part of the NYPA Backbone System provided that the repair or replacement, to the extent it involves installation of new equipment, utilizes items with substantially the same capacity rating as the existing equipment (or that any increase in facility rating is limited to the smallest change possible with commercially available replacements, or is no more costly than the price of a like-for-like replacement plus 10%).

"Voting Member Systems" means: (1) Central Hudson Gas and Electric Corporation; (2) Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. (as a single Voting Member System); (3) Niagara Mohawk Power Corporation d/b/a National Grid; (4) New York State Electric and Gas Corporation and Rochester Gas and Electric Corporation (as a single Voting Member System); and (5) Long Island Power Authority.

"Y-49 Facility" means the Y-49 transmission facility interconnecting Westchester County, New York and Long Island that is included as part of the NYPA Backbone System as reflected in Exhibit C to the settlement approved by the Commission in Docket No. ER16-835-000.

"Y-49 TCC Revenue" means revenue related to Transmission Congestion Contracts ("TCCs") associated with the Y-49 Facility.

(a) Cap on New NTAC Capital Expenditures

(i) As provided in Section 14.2.2.2 of this Attachment, the NTAC allows NYPA to recover the portion of NYPA's ATRR that is not recovered via existing customer transmission service agreements or from other revenue streams identified in the NTAC Formula described in Section 14.2.2.2.1 of this Attachment. The following provisions in this Section 14.2.3.2.7 shall apply only to the NYPA Backbone System. No other NYPA capital expenditures, other than those contemplated by this Section 14.2.3.2.7, may be recovered via the NTAC absent express approval by FERC, subject to Section 14.2.3.2.7(b)(x) below.

(ii) Capitalized expenditures incurred by NYPA that may be recovered through the NTAC without Voting Member System review and approval, as described in Section 14.2.3.2.7(b) below, are:

(a) Any Repair or Replacement provided that the estimated project cost of any such Repair or Replacement is less than $90 million in 2016 dollars (as adjusted annually using the Consumer Price Index), except that the Y-49 Facility and the Moses to Adirondack Line will be treated as follows:

(i) With respect to the Y-49 Facility, after the date that the NYPA-LIPA Y-49 Contract is terminated, the cost of normal repairs and maintenance of the Y-49 Facility will be included in the NTAC, subject to the otherwise applicable provisions of this Section 14.2.3.2.7(a), along with revenue credits related to Y-49 TCC Revenue. However a major reconstruction or replacement shall be treated as follows: whether or not the NYPA-LIPA Y-49 Contract has been terminated, the first year a Major Y-49 Reconstruction or Replacement appears in NYPA's five-year capital expenditure plan (described in Section 14.2.3.2.7(b) below), NYPA will initiate an FPA section 205 proceeding to determine whether the Major Y-49 Reconstruction or Replacement, as proposed or as NYPA may modify it on its own or in response to issues raised by other parties, is a prudent investment and, if so, the appropriate allocation of project costs that are not otherwise recoverable through the NTAC. After the date that the NYPA-LIPA Y-49 Contract is terminated, and if the Major Y-49 Reconstruction or Replacement is found prudent by FERC in that section 205 proceeding, the parties agree that (a) unless reduced by the formula below, $20 million in 2016 dollars (as adjusted annually by the Consumer Price Index) of ATRR attributable to the Major Y-49 Reconstruction or Replacement cost shall be automatically recovered in the NTAC but only after the later of the NYPA-

LIPA Y-49 Contract's expiration or the in-service date of the Major Y-49 Reconstruction or Replacement; and (b) the allocation of the Remaining Y-49 ATRR shall be in accord with the result of the section 205 proceeding. For purposes of this provision, the Remaining Y-49 ATRR shall be calculated annually after the later of the NYPA-LIPA Y-49 Contract's expiration or the in-service date of the Major Y-49 Reconstruction or Replacement as:

Remaining Y-49 ATRR = (Gross ATRR for the Major Y-49 Reconstruction or Replacement) – (Y-49 TCC Revenue) – ($20 million + Consumer Price Index adjustment)

To the extent the Remaining Y-49 ATRR is negative it shall be applied to the NTAC ATRR. For the avoidance of doubt, there shall be no double-crediting of the same Y-49 TCC Revenue between (i) the above "Remaining Y-49 ATRR" formula, and (ii) the first sentence of this Section 14.2.3.2.7(a)(ii)(a)(i), which requires NYPA to include revenue credits related to Y-49 TCC Revenue in the NTAC after the date that the NYPA-LIPA Y-49 Contract is terminated. If the Remaining Y-49 ATRR is positive, it will be recovered pursuant to the project-specific cost allocation determined in the section 205 proceeding described above and included in this Tariff.

(ii) With respect to the Moses to Adirondack Line, reconstruction or complete replacement of that line will be subject to a Voting Member System vote as described in Section 14.2.3.2.7(b). Repairs and maintenance-type replacement of the Moses to Adirondack Line will be subject to the otherwise applicable limitations of this Section 14.2.3.2.7(a).

(b) Emergency projects undertaken in response to damage caused by storms, vandalism, or terrorism, or in response to any force majeure events. Where appropriate, NYPA will apply for Federal Emergency Management Agency ("FEMA") reimbursement for such projects, and any FEMA or insurance reimbursements shall be applied to the NTAC as a credit against the cost of such projects.

(iii) For capital expenditures related to the NYPA Backbone System that do not meet the requirements of Section 14.2.3.2.7(a)(ii) above or Section 14.2.3.2.7(a)(iv) below, NYPA's Annual Incremental Capital Expenditures that may be recovered through the NTAC, absent Voting Member System review and approval, are capped at $40 million in 2016 dollars (as adjusted annually using the Consumer Price Index).

(iv) Any capital expenditures related to the NYPA Backbone System incurred (i) as a result of directives issued by NERC, FERC, the New York State Reliability Council, or in compliance with the ISO OATT or manuals to build, maintain, or operate required interconnections of a generation or transmission facility, except for the costs that have been otherwise recovered from third parties such as generator or transmission developers or insurance companies or, (ii) as a result of directives issued by some other regulatory agency in the event that, due to changes in the New York Public Authorities Law or other legislative action, such regulatory agency obtains legal authority to order NYPA to undertake capital projects, shall be excluded from Voting Member System review and approval and excluded from the $40 million annual cap described in Section 14.2.3.2.7(a)(iii) above. For the avoidance of doubt, future capital expenditures in such facilities will be subject to this Section 14.2.3.2.7(a).

(b) Voting Member System Review of Expenditures that Exceed Applicable Caps Described in Section 14.2.3.2.7(a)

(i) NYPA will conduct an annual meeting, on no less than three weeks' advance notice to the Voting Member Systems and other Interested Parties that have subscribed to the NYPA Exploder List, at which it will present to the Voting Member Systems and other Interested Parties a five-year capital expenditure plan. This meeting will occur prior to the commencement of the Annual Update Process described in these Protocols. NYPA may conduct additional meetings on no less than three weeks' advance notice to the Voting Member Systems and other Interested Parties that have subscribed to the NYPA Exploder List.

(ii) NYPA's presentation of the capital expenditure plan will identify for each project under construction or anticipated to begin construction within the five-year planning horizon:

(a) Description of the project;

(b) Total project cost;

(c) Anticipated start and end date of construction;

(d) Whether the project is a Repair or Replacement of a NYPA Backbone System facility; and

(e) Whether the project is subject to any of the exclusions identified in Section 14.2.3.2.7(a) above.

(iii) The Voting Member Systems and other Interested Parties may issue data requests concerning NYPA's capital expenditure plan for forty (40) calendar days following the annual capital expenditure plan meeting, and NYPA will make commercially reasonable efforts to respond within fourteen (14) calendar days of receipt of a data request.

(iv) (a) If the capital expenditure plan as presented by NYPA, or in the opinion of the Voting Member Systems, includes (i) a Repair or Replacement that exceeds $90 million (as adjusted annually using the Consumer Price Index); (ii) a suite of projects subject to Section 14.2.3.2.7(a)(iii) above for which NYPA plans to spend more than $40 million (as adjusted annually using the Consumer Price Index) in a single calendar year; or (iii) a project that NYPA proposes to recover through the NTAC which the Voting Member Systems believe is not related to the NYPA Backbone System, the Voting Member Systems must notify NYPA of their intent to vote on whether to allow NYPA to recover in the NTAC any project or suite of projects meeting the criteria above within sixty (60) calendar days of the publication of the capital expenditure plan that first identifies the project or annual suite of projects, with a vote to occur within thirty (30) calendar days after such notification. The Voting Member Systems must notify NYPA of the outcome of the vote by the end of the next business day after such vote is made.

(b) Subject to Section 14.2.3.2.7(b)(ix) below, and with regard to a project or suite of projects for which the Voting Member Systems have provided timely notice to NYPA under Section 14.2.3.2.7(b)(iv)(a), a 3/5 majority vote in favor is required for NYPA to recover the costs of such project or suite of projects contained in the capital expenditure plan through the NTAC. The five Voting Member Systems shall have one vote each.

(v) If the Voting Member Systems elect not to vote on a Repair or Replacement that exceeds $90 million (as adjusted annually using the Consumer Price Index), or an annual suite of projects under Section 14.2.3.2.7(a)(iii) that exceeds $40 million (as adjusted annually using the Consumer Price Index), or 3/5 of the Voting Member Systems vote to approve the Repair or Replacement or annual suite of projects, then no further voting shall be permitted with respect to such Repair or Replacement or annual suite of projects and NYPA shall recover the cost of such Repair or Replacement or suite of projects through the NTAC subject to the Annual Update Process set forth in these Protocols. This provision shall not apply to Repairs or Replacements or annual suites of projects that are modified in a subsequent five-year capital expenditure plan where such modification would either (i) change the categorization of a project or suite of projects under Section 14.2.3.2.7(a); or (ii) would result in a 10% increase in the original project costs the Voting Member Systems previously had a right to vote on, and either approved or elected not to vote on.

(vi) If 3/5 of the Voting Member Systems vote against allowing NTAC recovery of a NYPA project or suite of projects meeting the criteria set forth in 14.2.3.2.7(b)(iv)(a), the Voting Member Systems that voted against NTAC recovery must provide a written statement explaining their rationale for their negative votes within sixty (60) calendar days of notifying NYPA of the outcome of the vote. Such rationale may include, but is not limited to, whether those Voting Member Systems voting against the project believed the project or suite of projects in question: (i) was segmented; (ii) is inconsistent with good utility practice; (iii) should be expanded beyond Repair or Replacement and submitted as a project fitting the definition of one of the categories of projects identified in the ISO's Comprehensive System Planning Process; (iv) has costs that have been improperly estimated or are too high; and/or (v) has been inaccurately categorized by NYPA as a Repair or Replacement (for projects subject to the $90 million cap). The Voting Member Systems will not assert that a project is not a Repair or Replacement where the New York Public Service Commission has determined that a project is a Repair or Replacement in response to a petition for a declaratory ruling from NYPA with prior notice to the Voting Member Systems. The explanation of any "no" vote with respect to a suite of projects exceeding the limit prescribed in Section 14.2.3.2.7(a)(iii) could include a description of one or more specific objectionable projects.

(vii) NYPA shall have the opportunity to submit a revised package of capital expenditures in response to a "no" vote by the Voting Member Systems. If a revised package is submitted, the Voting Member System voting process described above shall be repeated starting with Section 14.2.3.2.7(b)(iii) above.

(viii) In the event of a "no" vote, the Voting Member Systems and NYPA agree to convene a meeting that includes senior management within sixty (60) calendar days of the Voting Member Systems providing NYPA with a written explanation of the vote.

(ix) NYPA may make a filing at FERC to include capital expenditures rejected by 3/5 of the Voting Member Systems in the NTAC ATRR. In any such proceeding, NYPA would bear the burden of demonstrating (i) that its proposed rate treatment and cost allocation is just and reasonable, (ii) that the reasons offered by the Voting Member Systems for voting against the project or suite of projects are arbitrary, unduly discriminatory, or otherwise not supported by substantial evidence, and (iii) that the proposed costs are eligible to be recovered using the NTAC. The settlement in Docket No. ER16-835-000 shall not preclude or inhibit the ability of a party to that settlement to submit comments or protests on any such filing by NYPA.

(x) If NYPA makes a filing as contemplated in Section 14.2.3.2.7(b)(ix) above, NYPA shall not be entitled to recover the costs of any such project or suite of projects through the NTAC until FERC issues a Substantive Cost Allocation Order and subject to any adjustments directed by FERC in such Substantive Cost Allocation Order; provided, however, if a Substantive Cost Allocation Order has not been issued as of a contested project’s in-service date, NYPA shall record the expenses and return related to any such project or projects in a regulatory asset, with carrying costs accruing at NYPA’s weighted average cost of capital as determined by the Formula Rate Template. Such costs may be amortized and recovered over the useful life of the project once FERC issues a Substantive Cost Allocation Order approving NTAC recovery for the project or directing NYPA to recover the costs of the project according to some other allocation, subject to any adjustments directed by FERC.

14.2.3.2.8 Costs Excluded from Formula Rate

Costs allocated to NYPA as a part of PJM Interconnection, L.L.C.'s Regional Transmission Expansion Plan, and costs and expenses related to the New York State Canal Corporation, shall be excluded from recovery under the Formula Rate.

14.3 Attachment H-1 - List of Member Systems' Pre-OATT Grandfathered Agreements Shown on Attachment L and Revenues which are Treated as Revenue Credits in Developing the R Component of each Company TSC Rate

14.3.1 LIPA

LIPA made an adjustment in the form of a revenue credit to reduce its revenue requirement by 4,282,350 reflecting the projected revenues it expects to receive in 1999 from grandfathered non-OATT transmission services provided to the New York Power Authority on behalf of its three Long Island municipal utilities and its Economic Development Power Customers, and LIPA's two Municipal Distribution Agencies Customers on Long Island.

Contract No. in Attachment L	Customer
65	Munis on Long Island
74	MDA on LI
75	EDP on LI
76	Brookhaven
77	Grumman

14.3.2 Orange and Rockland

Rate Schedule	Contract No. In Attachment L	Service to	Revenues
50	108	NYPA on behalf of Out-of-State Munis NJ	$121,475

14.3.3 RG&E

RG&E has no revenue from pre-OATT grandfathered agreements treated as revenue credits in the development of RG&E's RR component.

14.3.4 NYSEG

Customer	Treatment	FERC Rate Schedule	Contract No. in Attachment L	Annual Revenue
Delaware Coop	Coop	67, 70, 80	88, 154	390,435
Marathon	In-State Muni	67,70,80	87, 153	153,492
Oneida-Madison Coop	Coop	67, 70, 80	88, 154	89,274
Otsego Coop	Coop	67, 70, 80	88, 154	396,234
Penn Yan	In-State Muni	67, 70, 80	87, 153	566,549
Steuben Coop	Coop	67, 70, 80	87, 153	514,367
Watkins Glen	In-State Muni	67, 70, 80	87, 153	343,221
Gilboa	MWA	54	48	$432,000
Mohansic-Wheeling	Facilities Agreeme	87	5	$659,443

Revenues from the above grandfathered agreements are treated as credits to the Revenue Requirement in the development of NYSEG's TSC.

14.3.5 Central Hudson

Rate Schedule	Contract No. In Attachment L	Tariff Sheet No
22	20g	524
49	20h	524
26	21	524
51	31b	525
32	41	525
65	55a	526
73 (Should be 68)	73	527
73 (Should be 69)	108b	532
73 (Should be 69)	150b	533

Revenues for the above grandfathered agreements (total $568,499) are based on the 1995 test year.

14.3.6 Con Edison

Pre-OATT Grandfathered Agreements in Attachment L that are included in Con Edison's RR component and are not considered at risk by the Company at this time

Contract No. in Attachment L	FERC Rate Schedule No.	Delivery For	Revenues[1] ($x1000)
76	60	NYPA - Brookhaven	609
12	117	LIPA - Fitzpatrick	1,665
16	117	LIPA - Nine Mile	2,643
17	94	LIPA - Gilboa	1,465
		St./Brewster	

[1] Revenues based on 1995 Test Year Data

14.3.7 Niagara Mohawk Power Corporation

Attachment L Table 1A Contract No.

Rate Schedule No.	Customer
82, 84,86, 151, 152, 155-158/204	NYPA IS Munis
98/136	NFTA
66/134	Festival of Lights
109, 110, 112, 113/138	NYPA OOS Munis -
57/180	NYPA C-V-J
Attachment L Table 2 No. 19/58	RG&E Clyde
49/176	RG&E Agreement
1/141	CH 9M2
2/128	CH Gilboa
Attachment L Table 2 No. 4/55	CH N. Catskill
12/142	LILCO B Fitz
16/142	LILCO - 9M2
19, 20/165	NYSEG
Contract No. yet to be designated/174	Watertown
105/172	Lockport
104/171	Selkirk
102/178	Sithe
103/175	Indeck

Niagara Mohawk made an adjustment in the form of a revenue credit to reduce its revenue requirement by $69,016.475

15 Attachment I - Index of Network Integration Transmission Service Customers

16 Attachment J

16.1 See Attachment B to the Services Tariff for provisions related to the LBMP Calculation

16.2 Accounting for Transmission Losses

16.2.1 Charges

Subject to Attachment K of this Tariff, the ISO shall charge all Transmission Customers for transmission system losses based on the marginal cost of losses on either a bus or zonal basis, described below.

16.2.1.1 Loss Matrix

The ISO's RTD software will use a power flow model and penalty factors to estimate losses incurred in performing generation dispatch and billing functions for losses.

16.2.1.2 Residual Loss Payment

The ISO will determine the difference between the payments by Transmission Customers for losses and the payments to Suppliers for losses associated with all Transactions (LBMP Market or Transmission Service under Sections 3, 4, and 5 of this Tariff) for both the Day-Ahead and Real-Time Markets. The accounting for losses at the margin may result in the collection of more revenue than is required to compensate the Generators for the Energy they produced to supply the actual losses in the system. This over collection is termed residual loss payments. The ISO shall calculate residual loss payments revenue on an hourly basis and will credit them against the ISO's Residual Adjustment (See Rate Schedule 1 of the ISO OATT).

16.2.2 Computation of Residual Loss Payments

16.2.2.1 Marginal Losses Component LBMP

The ISO shall utilize the Marginal Losses Component of the LBMP on an Internal bus, an External bus, or a zone basis for computing the marginal contribution of each Transaction to the system losses. The computation of these quantities is described in this Attachment.

16.2.2.2 Marginal Losses Component Day-Ahead

The ISO shall utilize the Marginal Losses Component computed by computing the marginal contributions of each Transaction in the Day-Ahead Market.

16.2.2.3 Marginal Losses Component Real-Time

The ISO shall utilize the Marginal Losses Component calculated by the (i) RTD programs in most cases; or (ii) during intervals when the conditions specified in Part 17.1 of Attachment B of the Services Tariff exist at Proxy Generator Buses, the RTC program, for computing the Marginal Losses Component associated with each Transaction scheduled in the Real-Time Market (or deviations from Transactions scheduled in the Day-Ahead Market). The computations will be performed on an RTD-interval basis and aggregated to an hourly total.

16.2.2.4 Charges

Charges to reflect the impact of Energy consumed by each Load, or transmitted by each Transmission Customer on Marginal Losses Component shall be determined as follows. Each of these charges may be negative.

16.2.2.5 Day-Ahead Charges

As part of the LBMP charged to all LSEs scheduled Day-Ahead to purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of: (a) the withdrawal scheduled Day-Ahead in each Load Zone by that LSE in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP in that Load Zone, in $/MWh.

As part of the TUC charged to all Transmission Customers whose transmission service has been scheduled Day-Ahead, the ISO shall charge each such Transmission Customer the product of (a) the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission

Customer in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of Delivery (*i.e.*, Load Zone in which Energy is scheduled to be withdrawn or the bus where Energy is scheduled to be withdrawn under if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Day-Ahead LBMP at the Point of Receipt, in $/MWh.

16.2.2.6 Real-Time Charges

As part of the LBMP charged to all Customers or Transmission Customers that purchase Energy from the Real-Time LBMP Market, the ISO shall charge each such Customer or Transmission Customer the product of (a) the Actual Energy Withdrawals by that Customer or Transmission Customer in each Load Zone or at each Proxy Generator Bus in each hour, minus the Energy withdrawal scheduled Day-Ahead in that Load Zone or at that Proxy Generator Bus by that Customer or Transmission Customer for that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $/MWh.

As part of the TUC charged to all Transmission Customers whose transmission service was scheduled after the determination of the Day-Ahead schedule, or who schedule additional transmission service after the determination of the Day-Ahead schedule, the ISO shall charge each such Transmission Customer the product of (a) Actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (*i.e.*, the Load Zone in which Energy is scheduled to be withdrawn or the external bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Real-Time LBMP at the Point of Receipt, in $/MWh.

16.3 Transmission Service, Schedules and Curtailment

16.3.1 Requests for Bilateral Transaction Schedules

Firm Point-to-Point Transmission Service shall be available for internal Bilateral Transactions, CTS Interface Bids for Bilateral Transactions, Import and Export Bilateral Transactions, and Wheel-Through Transactions. Except as specified in Services Tariff section 4.4.1.2.2, External Transaction Bids may not vary over the course of an hour. Each such Bid must offer to import, export or wheel the same amount of Energy at the same price at each point in time within that hour. At Variably Scheduled Proxy Generator Buses that are not CTS Enabled Proxy Generator Buses, the ISO may vary External Transaction Schedules if the party submitting the Bid for such a Transaction indicates that the ISO may vary schedules associated with those Bids within the hour. The ISO will subject all CTS Interface Bids to variable scheduling in accordance with Services Tariff section 4.4.4. Transmission Customers may modify Bilateral Transactions that were scheduled Day-Ahead or propose new Bilateral Transactions, including External Bilateral Transactions, for economic evaluation within the Real-Time Market, provided however, that Bilateral Transactions with Trading Hubs as their POWs that were previously scheduled Day-Ahead may not be modified.

Transmission Customers scheduling Transmission Service to support a Bilateral Transaction with Energy supplied by an External Generator or Internal Generator shall submit the following information to the ISO:

(1) Point of Injection location. For Transactions with Internal sources, the Point of Injection is the Generator’s bus; for Transactions with Trading Hubs as their sources, the Point of Injection is the Trading Hub Generator bus; for Transactions

with External sources, the Point of Injection is the Proxy Generator Bus designated for Imports.

(2) Point of Withdrawal location. For Transactions to serve Internal Load, the Point of Withdrawal is the Load bus; for Transactions to serve External load, the Point of Withdrawal is the Proxy Generator Bus designated for Exports; for Transactions with Trading Hubs as their sinks, the Point of Withdrawal is the Trading Hub Load bus;

(3) Desired hourly MW schedules;

(4) NERC Tag data;

(5) A Sink Price Cap Bid for Export Transactions up to the MW level of the desired schedule, a Decremental Bid for Import and Wheel Through Transactions up to the MW level of the desired schedule; or a CTS Interface Bid for Transactions other than Wheels Through at CTS Enabled Proxy Generator Buses;

(6) A direction for the desired flow for CTS Interface Bids submitted at the CTS Enabled Proxy Generator Buses; and

(7) Other data required by the ISO.

16.3.2 ISO's General Responsibilities

The ISO shall evaluate requests for Bilateral Transactions, and associated Transmission Service, submitted in the Day-Ahead scheduling process using Security Constrained Unit Commitment ("SCUC"), and will subsequently establish a Day-Ahead schedule. During the Dispatch Day, the ISO shall use the Real-Time Market to establish schedules for each hour of dispatch in that day.

The ISO shall use the information provided by Real-Time Market when making Curtailment decisions pursuant to the Curtailment rules described in Section 16.3.4 of this Attachment J.

16.3.3 Scheduling of Bilateral Transactions in the Day-Ahead Market and Real-Time Market

16.3.3.1 ISO Responsibilities

The ISO shall model Bids for Import Bilateral Transactions and Bids for Export Bilateral Transactions as Bids to buy or sell a block of MW at a single price at their respective buses.

The ISO shall compute all NYCA Interface Transfer Capabilities and interface Ramp and NYCA Ramp capabilities prior to scheduling Transmission Service Day-Ahead and in real-time. The ISO shall evaluate (i) Decremental Bids from entities engaged in Bilateral Import Transactions and Wheels Through, (ii) Bids from entities engaged in Imports to the LBMP Market,; (iii) CTS Interface Bids from entities engaged in Imports and Exports at CTS Enabled Proxy Generator Buses; (iv) Energy Bids from internal Generators; (v) Sink Price Cap Bids from entities engaged in Bilateral Export Transactions; and (vi) Bids from entities engaged in Exports from the LBMP Market simultaneously when committing internal Generators and scheduling Import, Export and Wheel Through Transactions and Imports and Exports to and from the LBMP Market in the Day Ahead and Real-Time Markets, provided however, the ISO shall also evaluate Price Capped Load Bids simultaneously with (i) through (vi) in the Day Ahead Market.

16.3.3.2 Scheduling Internal Bilateral Transactions

The ISO shall schedule Firm Transmission Service between the Point of Injection at the Generator bus to the Point of Withdrawal at the Load bus equal to the request for Transmission Service in both the Day-Ahead and Real-Time Markets. The ISO shall use Energy Bids to determine commitment and dispatch schedules for internal Generators including those providing Energy for an Internal Bilateral Transaction.

16.3.3.3 Scheduling Export Bilateral Transactions and Firm Point-to-Point Transmission Service to Support Them

The ISO shall use Bids supplied by Transmission Customers proposing Export Bilateral Transactions in the Day Ahead and Real-Time Markets to determine the amount of Energy scheduled to be exported under those Transactions in the Day-Ahead and Real-Time Markets respectively. The ISO shall not schedule Energy to be exported in amounts that exceed the Transfer Capability of the Interface.

The ISO shall schedule in the Day-Ahead and Real-Time Markets Firm Transmission Service for Export Bilateral Transactions between the Point of Receipt at the internal Generator bus and the Point of Delivery at the Proxy Generator Bus in an amount equal to the amount of Energy scheduled to be exported under those Transactions Day-Ahead and in real-time respectively.

The ISO shall use Energy Bids supplied by internal Generators designated as supporting Export Bilateral Transactions scheduled with Firm Transmission Service in the Day Ahead and Real-Time Markets to determine the Generator’s commitment and dispatch schedule.

16.3.3.4 Scheduling Import Bilateral Transactions and Firm Point-to-Point Transmission Service to Support Them

The ISO shall use Bids from Transmission Customers proposing Import Bilateral Transactions in the Day Ahead and Real-Time Markets to determine the amount of Energy scheduled to be imported under those Transactions in the Day-Ahead and Real-Time Markets respectively. The ISO shall not schedule Energy to be imported in amounts that exceed the Transfer Capability of the Interface. The ISO shall schedule Firm Transmission Service in the

Day-Ahead and Real-Time Markets for Import Bilateral Transactions between the Point of Receipt at the Proxy Generator Bus and the Point of Delivery at the Load bus equal to the amount of Transmission Service requested to support those Transactions Day-Ahead and in real-time respectively.

16.3.3.5 Scheduling Wheel Through Bilateral Transactions and Firm Point-to-Point Transmission Service to Support Them

The ISO shall use Decremental Bids supplied by Transmission Customers proposing Wheel-Through Transactions in the Day Ahead and Real-Time Markets to determine the amount of Energy scheduled to be wheeled under those Transactions Day-Ahead and in real-time respectively. The ISO shall schedule Firm Transmission Service in the Day-Ahead and Real-Time Markets between the Point of Receipt at a Proxy Generator Bus designated for Imports and the Point of Delivery at a Proxy Generator Bus designated for Exports equal to the amount of Energy scheduled to be imported and Wheeled Through under those Transactions Day-Ahead and in real-time respectively.

16.3.3.6 Scheduling Non Firm Transmission Service

Non-Firm Point-To-Point Transmission Service is not available in the markets that the NYISO administers.

16.3.3.7 Scheduling External Transactions at the Proxy Generator Buses Associated with Scheduled Lines

Scheduling External Transactions at the Proxy Generator Buses that are associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, and the HTP Scheduled Line shall also be governed by Section 29, Attachment N to the ISO Services Tariff.

16.3.3.8 Prohibited Transmission Paths

The ISO shall not permit Market Participants to schedule External Transactions over the following prohibited scheduling paths:

1. External Transactions that are scheduled to exit the NYCA at the Proxy Generator Bus that represents its Interface with the Control Area operated by the Independent Electricity System Operator of Ontario ("IESO"), and to sink in the Control Area operated by PJM Interconnection, LLC ("PJM");
2. External Transactions that are scheduled to exit the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to sink in the Control Area operated by IESO;
3. External Transactions that are scheduled to enter the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to source from the Control Area operated by IESO;
4. External Transactions that are scheduled to enter the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by IESO, and to source from the Control Area operated by PJM;
5. Wheels Through the NYCA that are scheduled to enter the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to sink in the Control Area operated by the Midwest Independent Transmission System Operator, Inc. ("MISO");
6. Wheels Through the NYCA that are scheduled to exit the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to source from the Control Area operated by the MISO;

7. Wheels Through the NYCA that are scheduled to enter the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by IESO, and to sink in the Control Area operated by the MISO; and

8. Wheels Through the NYCA that are scheduled to exit the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by IESO, and to source from the Control Area operated by the MISO.

The ISO may add additional prohibited scheduling paths to the above list when the ISO, acting in consultation with its Market Monitoring Unit, determines that one or more scheduling paths are being used to schedule External Transactions in a manner that is not consistent with the manner in which power is actually expected to flow. The ISO shall inform its Market Participants of the additional prohibited scheduling path or paths by providing notice at least one week in advance of the implementation of any such prohibition. At the time the NYISO provides notice to its Market Participants the ISO shall submit a compliance filing in FERC Docket No. ER13-780 requesting authority to update the above list to reflect the additional prohibited scheduling path or paths. Any such compliance filing will include: (1) an explanation of the scheduling behavior the ISO has identified and why that behavior presents a concern to the ISO and its Market Monitoring Unit; and (2) an explanation of why the ISO believes that the problem it has identified can be remedied or mitigated by adding one or more new prohibited scheduling paths. The compliance filing will also include, or be accompanied by, a discussion of the Market Monitoring Unit's position regarding the ISO's proposal to add a new prohibited scheduling path or new prohibited scheduling paths. Unless FERC acts on the ISO's compliance filing, the ISO shall implement the new scheduling path prohibition(s) on the date proposed in its compliance filing.

The responsibilities of the Market Monitoring Unit that are addressed in this Section are also addressed in Section 30.4.6.8.1 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

16.3.4 Bilateral Transaction Adjustments, Curtailments and Settlements

The DNI between the NYCA and adjoining Control Areas will be adjusted as necessary to reflect the effects of any Curtailments of Import or Export Transactions.

To the extent possible, Curtailments of External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, and the HTP Scheduled Line shall be based on the transmission priority of the associated Advance Reservation for use of the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, and the HTP Scheduled Line (as appropriate).

If a Transmission Customer's Firm Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Internal Bilateral Transaction, or an Import Bilateral Transaction, the ISO shall not reduce the Transmission Service. If a Transmission Customer's Firm Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Export Bilateral Transaction or a Wheel Through, the ISO shall reduce Transmission Service to the extent the amount of Energy scheduled to be exported or wheeled is reduced.

16.3.4.1 Import Bilateral Transactions

If the amount of Energy scheduled to be imported in an Import Bilateral Transaction in the Day-Ahead Market is less than the amount of Transmission Service requested and scheduled Day-Ahead in association with that Import Bilateral Transaction, the Transmission Customer shall pay the Energy Imbalance Service Charge pursuant to Rate Schedule 4 of this OATT. The

Transmission Customer shall continue to pay the Day-Ahead TUC for the amount of Transmission Service scheduled.

If the Import Bilateral Transaction was scheduled following the Day-Ahead Market, or the schedule for the Import Bilateral Transaction was revised following the Day-Ahead Market, and the amount of Energy scheduled to be imported in real-time (modified for within-hour changes in DNI, if any) is less than the amount of Transmission Service requested in real-time in association with that Transaction, then the Transmission Customer shall pay an Energy Imbalance Service Charge pursuant to Rate Schedule 4 of this OATT. If the Import Bilateral Transaction was scheduled following the Day-Ahead Market, or the schedule for the Import Bilateral Transaction was revised following the Day-Ahead Market, the Transmission Customer shall pay or be paid the Real-Time TUC for the amount of Transmission Service requested in real-time in association with that Transaction minus the amount of Transmission Service requested Day-Ahead in association with that Transaction.

16.3.4.2 Export Bilateral Transactions, Internal Bilateral Transactions and Wheel Through Transactions

If the internal Generator designated to supply the Export Bilateral Transaction or internal Bilateral Transaction has been scheduled Day-Ahead to produce Energy in an amount that is less than the amount of Transmission Service scheduled Day-Ahead in association with that internal or Export Bilateral Transaction, the internal Generator shall pay an Energy Imbalance Service Charge pursuant to Rate Schedule 4 of this OATT.

If the internal Generator designated to supply the Export Bilateral Transaction or internal Bilateral Transaction has been dispatched in real-time to produce Energy in an amount that is less than the amount of Transmission Service scheduled in real-time in association with that internal or Export Bilateral Transaction, the internal Generator shall pay an Energy Imbalance Service Charge pursuant to Rate Schedule 4 of this OATT.

If the Export Bilateral Transaction or internal Bilateral Transaction was scheduled following the Day-Ahead Market, or the schedule for the Export Bilateral Transaction or internal Transaction was revised following the Day-Ahead Market, the Transmission Customer shall pay or be paid the Real-Time TUC for the amount of Transmission Service scheduled in real time in association with that Transaction minus the amount of Transmission Service scheduled Day-Ahead in association with that Transaction.

If a Wheel-Through Transaction was scheduled following the Day-Ahead Market, or the schedule for the Wheel-Through transaction was revised following the Day-Ahead Market, the Transmission Customer shall pay or be paid the Real-Time TUC for the amount of Transmission Service scheduled in real time in association with that Transaction minus the amount of Transmission Service scheduled Day-Ahead in association with that Transaction.

16.3.4.2.1 Generators

Notwithstanding the foregoing, the amount of Transmission Service scheduled in real-time for internal Bilateral Transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each RTD interval:

16.3.4.2.1.1 Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule;

16.3.4.2.1.2 Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 523 MW of such units; and

16.3.4.2.3 Intermittent Power Resources that depend on landfill gas or solar for their fuel, existing Intermittent Power Resources that depend on wind as their fuel, other than those for which the NYISO has imposed a Wind Output Limit, and Limited Control Run of River Hydro Resources in operation on or before November 18, 1999 within the NYCA, plus up to an additional 3300 MW of such Generators.

This procedure shall not apply for those hours the Generator supplying that Transaction has bid in a manner that indicates it is available to provide Regulation Service or Operating Reserves.

16.3.4.3 Non-Firm Transmission

Non-Firm Point-To-Point Transmission Service is not available in the markets that the NYISO administers.

16.3.4.4 Procedure for Relieving Security Violations

If a security violation occurs or is anticipated to occur, the ISO shall attempt to relieve the violation using the following procedures:

16.3.4.4.1 Dispatch Internal Generators, based on Incremental Energy Bids , including committing additional resources, if necessary;

16.3.4.4.2 Adjust the DNI associated with External Transactions: Curtail External Firm Transactions until the Constraint is relieved by (1) Curtailing based on , CTS Interface Bids, Decremental Bids and Sink Price Cap Bids; and (2) except for External Transactions with minimum run times, prorating Curtailment of equal cost transactions;

16.3.4.4.3 Request Internal Generators to voluntarily operate in manual mode below minimum or above maximum dispatchable levels. When operating in manual mode, Generators will not be required to adhere to minimum ramp rates, nor will they be required to be respond to RTD Base Point Signals;

16.3.4.4.4 In over generation conditions, decommit Internal Generators based on Minimum Generation Bid rate in descending order; and

16.3.4.4.5 Invoke other emergency procedures including involuntary load Curtailment, if necessary.

17 Attachment K – Reservation of Certain Transmission Capacity and LBMP Transition Period

17.1 General Description of Existing Transmission Capacity Reservations

This Attachment describes (i) the treatment of Existing Transmission Agreements ("ETA"), including Transmission Wheeling Agreements ("TWA"), Third Party Transmission Wheeling Agreements ("Third Party TWA"), and Transmission Facility Agreements ("TFA"), (ii) the treatment of Grandfathered Rights and Grandfathered TCCs arising out of such Existing Transmission Agreements, and (iii) the creation of Existing Transmission Capacity for Native Load.

Nothing in this Attachment K shall impact the rights of parties to make Section 205 filings pursuant to the FPA to amend, terminate, or otherwise modify ETAs or, for agreements not subject to FERC jurisdiction, the rights of parties to amend, terminate, or otherwise modify ETAs.

17.2 TWA, Third Party TWA, and TFA Treatment; ETCNL Creation

17.2.1 TWAs between Transmission Owners Associated with Generators or Power Supply Contracts (Modified Wheeling Agreements)

17.2.1.1 Each TWA between Transmission Owners associated with a Generator or a power supply contract was converted into a Modified Wheeling Agreement ("MWA") on or around the start-up of the ISO. Such TWAs converted to MWAs are listed in Attachment L, Table 1A, where the "Treatment" column is denoted as "MWA." The terms and conditions of each of these TWAs shall remain unchanged by the conversion except as follows:

(i) the MWA customer had the option of retaining Grandfathered Rights or converting those Grandfathered Rights to Grandfathered TCCs pursuant to Section 17.2.5;

(ii) the rights and obligations under the MWA shall be assignable, in whole or in part, with the transfer of a Generator or rights under a power supply contract to an assignee that satisfies reasonable creditworthiness standards;

(iii) the MWA customer or the assignee will continue to pay the embedded cost-based rate for Transmission Service in accordance with Section 17.4.

(iv) the MWA customer shall have to pay for losses under this ISO OATT in accordance with Section 17.5, and the Transmission Owner shall not charge the MWA customer or the assignee of the MWA for losses to the extent they are provided under this ISO OATT;

(v) the payments under MWAs related to Grandfathered Rights and Grandfathered TCCs do not include the costs of Ancillary Services as provided in Section 17.6, and customers under these agreements will be responsible for Ancillary Services consistent with the provisions of Section 17.6; and

(vi) the corresponding MWA will be terminated to the extent the MWA is to transmit Energy from a Generator, upon the retirement of the associated Generator, the termination of the associated power supply contract, or such other date specified in the MWA by mutual agreement of the parties to the MWA.

17.2.1.2 As long as each MWA customer retains Grandfathered Rights or Grandfathered TCCs, it must maintain all MWAs from each associated Point of Injection of the Generator or the NYCA Interconnection with another Control Area to the corresponding Point of Withdrawal of the Load served by the MWA or at the NYCA Interconnection with another Control Area. The Point of Injection may be designated as the "Point of Receipt," or similar, under the MWA. The Point of Withdrawal may be designated as the "Point of Delivery," or similar, under the MWA.

17.2.2 Third Party TWAs

17.2.2.1 Each existing Third Party TWA, each of which is listed in Attachment L, Table 1A, where the "Treatment" column is denoted as "Third Party TWA" will remain in effect in accordance with its terms and conditions, including provisions governing modification or termination, except that the Third Party TWA customer had the option of:

(i) retaining Grandfathered Rights; or

(ii) converting the Grandfathered Rights to Grandfathered TCCs pursuant to Section 17.2.5; or

(iii) terminating the existing agreement (if the terms and conditions allowed for termination) and obtaining Transmission Service subject to the rates, terms, and conditions of this ISO OATT.

17.2.2.2 As long as each Third Party TWA customer retains Grandfathered Rights or Grandfathered TCCs, it must maintain all Third Party TWAs from each associated Point of Injection of the Generator or the NYCA Interconnection with another Control Area to the corresponding Point of Withdrawal of the Load served by the Third Party TWA or at the NYCA Interconnection with another Control Area.

17.2.2.3 Each Third Party TWA customer, whether it elects Grandfathered TCCs or Grandfathered Rights, shall have the right to inject Energy at the specified Point of Receipt and withdraw it at the specified Point of Delivery in designated amounts without application of a TSC.

17.2.3 Other TWAs Between Transmission Owners

On or around ISO start-up, certain TWAs between the Transmission Owners were terminated. These TWAs are listed in Attachment L, Table 1A, where the "Treatment" column is denoted as "Terminated," and no rights or obligations shall be associated with such terminated TWAs pursuant to this ISO OATT.

17.2.4 Transmission Facilities Agreements

Existing TFAs containing no provisions for transmission service require no modifications. These agreements are listed in Attachment L, Table 2.

TFAs are listed in Attachment L, Table 1A, where the "Treatment" column is denoted as "Facility Agmt - MWA." These TFAs will remain in effect in accordance with their terms and conditions, including any provision governing modification or termination.

17.2.5 Grandfathered Rights and Grandfathered TCCs Created from MWAs, Third Party TWAs, and TFAs

17.2.5.1 Each MWA customer, Third Party TWA customer, and TFA customer (such customers being listed as the "requestor" in Attachment L, Table 1A):

(i) was initially deemed to hold a Grandfathered Right with the Point of Injection, Point of Withdrawal, termination date, and other terms of the ETA which Grandfathered Right shall (unless converted to a Grandfathered TCC) continue in effect pursuant to the terms of the ETA, subject to Section 17.9; and

(ii) was permitted to convert such Grandfathered Right into a Grandfathered TCC until the date that was the earlier of two weeks prior to the first Centralized TCC Auction or six weeks prior to the start-up of the ISO, which Grandfathered TCC shall continue in effect consistent with the terms of the ETA, subject to Section 17.9.

17.2.5.2 Grandfathered Rights may no longer be converted to Grandfathered TCCs. Grandfathered TCCs may not be converted to Grandfathered Rights.

17.2.5.3 For the Third Party TWAs listed in Attachment L, Table 1A, contract numbers 55-62, 65-66, 73-82, 84-92, 98-114, 150-190, each specific individual municipal or cooperative electrical system listed in each such ETA shall be deemed to be the Third Party TWA customer for purposes of holding

Grandfathered Rights or Grandfathered TCCs in specified amounts between specified Points of Injection and Points of Withdrawal. Those Grandfathered Rights or Grandfathered TCCs are the Grandfathered Rights or Grandfathered TCCs of the municipal or cooperative. Whether Grandfathered Rights or Grandfathered TCCs are held by the municipal or cooperative, it thereby waives all rights under the Federal Power Act associated with NYPA's obligation to secure transmission wheeling arrangements on its behalf associated with the Third Party TWA rights elections.

17.2.6 Existing Transmission Capacity for Native Load

Certain transmission capacity associated with the use of a Transmission Owner's own system to serve its own load was designated as Existing Transmission Capacity for Native Load ("ETCNL") as shown on Table 3 of Attachment L.

Such ETCNL shall not be increased above the megawatt (MW) amounts noted in Attachment L, Table 3. The requirements and procedures relating to ETCNL reduction are set forth in Attachment M of the ISO OATT.

17.3 Congestion Terms Applicable to Grandfathered Rights and Grandfathered TCCs Under MWAs, TFAs, and Third Party TWAs

17.3.1 Congestion Charge Relief Associated with Grandfathered Rights

Each holder of Grandfathered Rights has the right to inject power at one specified bus and take power at another specified bus up to amounts reflected in Attachment L, Table 1A, without having to pay the Congestion Component of the TUC, but only to the extent it schedules (in accordance with applicable ISO Procedures) the injection and withdrawal Day-Ahead and is on schedule. If the holder of the Grandfathered Right does not schedule Energy Day-Ahead or inject or withdraw Energy, it will not receive (or pay) any Congestion Rents associated with the Transaction. If the holder of a Grandfathered Right schedules Day-Ahead and/or transacts for a portion of the Grandfathered Rights that are retained, it will not receive any compensation for the unused transmission capacity. If the holder of a Grandfathered Right transmits Energy without scheduling it Day-Ahead (in accordance with applicable ISO Procedures) or exceeds the amounts specified in Attachment L, Table 1A, the customer will pay the real-time TUC for all Energy transmitted under the Transaction exceeding the Day-Ahead schedule or the number of MW of Grandfathered Rights. This TUC will include real-time Congestion Rents.

17.3.2 Congestion Rents Collectible for Grandfathered TCCs

Each holder of Grandfathered TCCs shall receive (or pay, when negative congestion occurs) the Day-Ahead Congestion Rent associated with its Grandfathered TCCs pursuant to Attachment N, but will be subject to the service provisions of the ISO Tariff, including the duty to pay for (i) Congestion Rent, and (ii) Marginal Losses for use of the transmission system in accordance with the provisions of the ISO OATT.

17.4. Obligation to Pay Contractually Agreed Transmission Rates; Relief from TSC

17.4.1 MWA Customers and TFA Customers to Continue to Pay Contractually Agreed Transmission Rates

Each MWA or TFA customer shall continue to pay the Transmission Owner rates set forth in the MWA or TFA. Rates under each MWA or TFA shall be based on embedded cost, and these embedded cost rates may be updated, if allowed for in the terms and conditions of each MWA or TFA. The MWA customer or TFA customer or its assignee shall pay the Transmission Owner directly.

17.4.2 Third Party TWA Customers to Continue to Pay Contractually Agreed Transmission Rates

Subject to Section 17.6, each Third Party TWA customer will pay the Transmission Owner transmission charges in accordance with the terms and conditions of the Third Party TWA, including any provisions governing modification or termination. The Third Party TWA customer or its assignee shall pay the Transmission Owner directly.

17.4.3 Transmission Service Charge Relief

Each MWA, Third Party TWA, or TFA customer, whether it elected Grandfathered TCCs or Grandfathered Rights pursuant to Section 17.2.5, shall have the right to inject Energy at the specified Point of Injection and withdraw it at the specified Point of Withdrawal in designated amounts without application of a TSC, provided that the MWA, Third Party TWA, or TFA customer schedules it pursuant to applicable ISO Procedures.

17. 5. Responsibility For Losses

17.5.1 MWA Customers and TFA Customers to Pay Losses

17.5.1.1 Each MWA customer or TFA customer, irrespective of whether it chose Grandfathered Rights or Grandfathered TCCs under Section 17.2.5, shall pay the ISO for losses under this ISO OATT. The Transmission Owner shall not charge for losses under the MWA or TFA to the extent the losses are provided under this ISO OATT. The MWA customer or TFA customer will pay or receive payment for losses between the Point of Injection and the Point of Withdrawal under the MWA or TFA listed in Attachment L, Table 1A, as calculated in accordance with this ISO OATT.

17.5.1.2 To the extent losses on the Transmission Owner's system are not provided under this ISO OATT, the Transmission Owner may charge for losses unless prohibited from doing so under the MWA or TFA.

17.5.2 Third Party TWA Customers to Pay Losses

17.5.2.1 Each Third Party TWA customer, irrespective of whether it chose Grandfathered Rights or Grandfathered TCCs under Section 17.2.5, shall pay the ISO for losses under the ISO OATT. The Transmission Owner shall not charge for losses under the Third Party TWA to the extent the losses are provided under this ISO OATT. The Third Party TWA customer will pay or receive payment for losses between the Points of Injection and Points of Withdrawal under the Third Party TWA listed in Attachment L, Table 1A, as calculated in accordance with this ISO OATT.

17.5.2.2 To the extent losses on the Transmission Owner's system are not provided under this OATT, the Transmission Owner may charge for losses, unless prohibited from doing so under the Third Party TWA.

17.6 Responsibility for Ancillary Services

Irrespective of whether an ETA is a MWA, Third Party TWA or a TFA, or whether a customer thereunder elected Grandfathered Rights or Grandfathered TCCs, the customer shall be responsible for payment for any applicable Ancillary Services that shall be provided pursuant to this ISO OATT.

17.7 LBMP Transition Period and Payment

At the present time, the Member Systems do not have sufficient data to calculate the LTPP term of the TSC formula. This provision shall only become effective upon the filing of such data and the determination of the LTPP payments with the Commission. Prior to such filing, the LTPP will be set to zero.

A “LBMP Transition Period″ shall be established under which the Investor-Owned Transmission Owners shall be subject to a schedule of fixed monthly transmission payments (“LBMP Transition Period Payments” or “LTPP”). These payments will occur for the period commencing with the start of the first Centralized TCC Auction and continuing for a period of five (5) years following implementation of both the Day-Ahead and Real-Time Markets. The formula for calculating the LTPP is shown below. The LTPP calculation is based upon the differences between each Investor-Owned Transmission Owner’s net transmission revenues and expenses under the current NYPP system and the proposed restructured NYPP system utilizing LBMP. The specific factors include: (1) the amount of transmission revenues/expenses eliminated through the termination of some TWAs including existing net Transmission Fund (“T-Fund”) distributions in effect under the current NYPP pricing mechanism; (2) estimated Congestion Rents to be paid under LBMP; (3) revenues received from the distribution of Net Congestion Rents and the sale of TCCs; and (4) transmission revenues received from off-system sales. The LTPP to be paid or received by the Investor-Owned Transmission Owners during the LBMP Transition Period are designed to offset the net effect of these revenues and expenses.

The LTPP will be calculated once for the entire LBMP Transition Period within thirty (30) days after the initial Centralized TCC Auction. The sum of all LTPPs for the Investor-Owned Transmission Owners shall be zero.

The formula for the calculation of the LTPP for each Investor-Owned Transmission Owner is as follows:

$$\textbf{LTPP} = \textbf{RTA} + \textbf{CR} - \textbf{SR}_1 - \textbf{SR}_2 - \textbf{CRR} - \textbf{ROS}$$

Where:

RTA = Net reduction in revenue resulting from the termination of existing transmission wheeling agreements, effective upon LBMP implementation;

CR = Estimated Congestion Rents to be incurred under LBMP;

SR_1 = Revenues from the Direct Sale of Original Residual TCCs and Grandfathered TCCs by Transmission Owners prior to the first Centralized TCC Auction, which are valued at the Market Clearing Prices from the first Centralized TCC Auction;

SR_2 = Actual revenues from the allocation of TCC sales revenues from the first Centralized TCC Auction;[16]

CRR = Estimated revenues received from the ownership of TCCs, based on the results from the first Centralized TCC Auction and Imputed Revenues from Grandfathered Rights; and

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[16] For the purposes of calculating the LTPP, each Original Residual TCC shall be valued at a weighted average of the prices determined in Stage 1 of the Centralized TCC Auction. The weighted average shall be computed by multiplying the fraction of total transmission capability offered for sale in Stage 1 of the Auction that will be offered for sale in that round, as determined by the Transmission Providers, and the Market Clearing Price of that TCC in that round, summed over all Stage 1 rounds. The price at which Transmission Providers sell Original Residual TCCs through sales prior to the Centralized TCC Auction shall not affect the calculation of the LTPP. NYPA's NTAC (See Attachment H) shall be calculated by valuing their Original Residual TCCs at the greater of the market value of a TCC, as determined by this weighted average of the Market Clearing Prices of that TCC in Stage 1 of the Centralized TCC Auction, or the price at which NYPA sells the Original Residual TCCs through sales prior to the Centralized TCC Auction, if it chooses to do so.

ROS = Transmission revenues received from off-system sales, as reported in FERC Form 1.

All estimates or forecasts used to determine each LTPP are subject to unanimous agreement among the Investor-Owned Transmission Owners; absent unanimous agreement, they may unanimously agree to submit to mediation or arbitration; absent this latter agreement, then each such Transmission Owner reserves its rights under the FPA to justify or protest LTPP estimates or forecasts.

The LTPP will be based on the latest available FERC Form 1 data for transmission revenues and expenses.

17.8 Sale or Other Transfer of Grandfathered Rights and Grandfathered TCCs

17.8.1 Transfers of Grandfathered Rights

An ETA customer will not be permitted to resell or transfer Grandfathered Rights unless permitted in the existing agreements, except as noted in Section 17.2.1.1(ii).

17.8.2 Transfers of Grandfathered TCCs

17.8.2.1 Grandfathered TCCs may be transferred (whether through sale or otherwise) in the same manner in which other types of TCCs may be transferred pursuant to Attachment M; *provided*, *however*, if a Transmission Owner sells Grandfathered TCCs, the Transmission Owner shall do so either through Direct Sales or through Centralized TCC Auctions or Reconfiguration Auctions, as provided in Attachment M of the ISO OATT.

17.8.2.2 To the extent a Grandfathered TCC is transferred (other than in connection with the assignment of the underlying ETA), the relief from the Transmission Service Charge (as provided in Section 17.4.3) and the obligation to pay the transmission charges set forth in an ETA (as provided in Section 17.4.1 and Section 17.4.2) shall continue to apply to the ETA customer, and such rights and obligations shall not transfer with the transfer of the Grandfathered TCC.

17.8.3 Appointment of Settlement Agent is Not a Transfer

A holder of a Grandfathered Right or Grandfathered TCC may appoint the party indicated in Attachment L, Table 1A, in the column labeled “Requestor” to hold the Grandfathered Right or Grandfathered TCC for the ultimate benefit of the ETA customer, and such parties shall be deemed to be the holder of the Grandfathered Right or Grandfathered TCC. The holding by such party shall not be deemed a transfer.

17.9 Basis for Settlements; Procedures for Revising Information Necessary for Grandfathered Right and Grandfathered TCC Settlements

17.9.1 ISO to Make GFR/GFTCC Settlements Based on Information Made Available Through Established Procedures

17.9.1.1 The ISO shall maintain on its website a list of all Accepted Revisions, including the date each such Accepted Revision took effect. The ISO shall also maintain on its website a copy of Attachment L, Table 1A that will be updated from time to time to reflect Accepted Revisions.

17.9.1.2 Notwithstanding other provisions of the ISO Tariffs, but subject to Sections 17.9.1.3, 17.9.1.4, 17.9.1.5 the ISO shall base Settlements pertaining to Grandfathered Rights and Grandfathered TCCs (and conduct Centralized TCC Auctions and administer other processes pertaining to Grandfathered Rights and Grandfathered TCCs) on information listed in Attachment L, Table 1A, and on Accepted Revisions then in effect; provided, however:

(i) the ISO shall administer Reconfiguration Auctions and Centralized TCC Auctions on the basis of information listed in Table 1A and Accepted Revisions in effect thirty (30) or more days prior to the first round of the relevant auction and the ISO shall not include more recent changes; provided, however, see provisions in 17.9.1.3; and

(ii) the ISO shall perform Net Congestion Rent calculations under Attachment N of the ISO OATT on the basis of Table 1A and Accepted Revisions in effect thirty (30) or more days prior to the initial ISO calculation of the related allocation factors and the ISO shall not include more recent changes; and

(iii) the ISO shall process requests for Historic Fixed Price TCCs pursuant to Attachment M, on the basis of information listed in Table 1A and Accepted Revisions in effect thirty (30) or more days prior to the deadline for submitting the documentation necessary to request an Historic Fixed Price TCC; provided, however, for requests for Historic Fixed Price TCCs based on Accepted Revisions in effect fewer than 30 days prior to the deadline or following the deadline for submitting the documentation necessary to request an Historic Fixed Price TCC, see 17.9.1.3.

17.9.1.3 If an Accepted Revision, pursuant to which the ISO may offer an entity an Historic Fixed Price TCC, is in effect fewer than 30 days prior to the deadline or following the deadline for submitting the documentation necessary to request an Historic Fixed Price TCC, the ISO shall:

(i) As provided for in the ISO Transmission Congestion Contracts Manual, use the specified period of time ("reasonable period") to expeditiously determine eligibility of the entity and, if eligible, offer the entity an Historic Fixed Price TCC pursuant to Attachment M and process its request for, or decline of, an Historic Fixed Price TCC;

(ii) Base settlements pertaining to Grandfathered Rights and Grandfathered TCCs pursuant to the terms of the Accepted Revision. Settlements pertaining to Grandfathered TCC or Grandfathered Right will reflect the termination of, or other change in, the Grandfathered TCC or Grandfathered Right provided by the Accepted Revision, except as otherwise provided in 17.9 and Attachment M;

(iii) Hold the Transmission Capacity made available by the Accepted Revision out of Centralized TCC Auctions and Reconfiguration Auctions until it is determined that the party is not eligible for an Historic Fixed Price TCC or declines the Historic Fixed Price TCC, or elects an effective date for the Historic Fixed Price TCC of the first day of the following Capability Period. As appropriate, the transmission capacity made available by the Accepted Revision will be released into the first Reconfiguration Auction or Centralized TCC Auction that occurs 30 days or more after the terms of the Accepted Revision make it available. If the entity elects some or all its Historic Fixed Price TCC, the ISO shall not release Transmission Capacity made available by the Accepted Revision into a Reconfiguration Auction or Centralized TCC Auction to the extent it supports the Historic Fixed Price TCC.

17.9.1.4 If a signatory to the ETA provides notification and documentation pursuant to Section 17.9.3 that supports a change in an ETA or a change in Attachment L information, or entitlement to an Historic Fixed Price TCC, that was effective prior to a Settlement, the ISO shall make adjustments to the Settlement, in accordance with and to the extent permitted by the billing and payment provisions of the ISO OATT.

17.9.1.5 A termination of an ETA based on the occurrence of an event, which event is described in the cells of Attachment L, Table 1A, and a change to information in the cells of Attachment L, Table 1A, which change is related to a footnote to Table 1A that informs, supplements or modifies information in the cells of Table 1A, shall be in effect as an Accepted Revision after the ISO receives written notification of the occurrence of the event or the change to information in the cells of Attachment L, Table 1A from a signatory to the ETA in accordance with the provisions of Section 17.9.3.

17.9.2 Responsibility for Providing Revised Information

The signatories to an ETA shall notify the ISO of any revisions to Table 1A information that may impact Settlements (and TCC related processes), including the termination of an ETA based on the occurrence of an event, in accordance with the provisions of Section 17.9.3. The signatories to an ETA shall also notify the ISO of any revisions to information in the cells of Attachment L, Table 1A, which revision may impact Settlements (and TCC related processes) and which is related to a footnote to Table 1A that informs, supplements, or modifies information in the cells of Table 1A.

17.9.3 Process for Making Accepted Revisions Other than Accepted Revisions Pursuant to Section 17.9.1.4

17.9.3.1 *Non-NYPA/LIPA ETAs (Accepted Revision Due to ETA Amendment)*. For an ETA in which neither NYPA nor LIPA is the provider of service, a proposed revision to Attachment L, Table 1A pursuant to an amendment of the underlying ETA will be in effect as an Accepted Revision as of the start of the second day following the day that (i) the ISO has received a written notification of a change in the ETA from a signatory to the ETA in accordance with ISO Procedures, and (ii) the ISO has received a FERC order approving the change; *provided, however*, settlements and the administration of other processes pertaining to Grandfathered Rights and Grandfathered TCCs will be made in accordance with the provisions of Section 17.9.1.

17.9.3.2 *Non-NYPA/LIPA ETAs (Accepted Revision Not Due to ETA Amendment).* For ETAs in which neither NYPA nor LIPA is the provider of service, a proposed revision to Attachment L, Table 1A to make it consistent with the existing terms of an ETA will be in effect as an Accepted Revision as of the start of the second day following the day that: (i) the ISO has received a written notification of a change in the Table 1A information from a signatory to the ETA in accordance with ISO Procedures and confirmation that a copy of the notification has been provided to all other signatories to the ETA, and a copy thereof, and (ii) the ISO has received FERC orders, copies of the relevant agreement(s) (including amendments thereto), or other information relevant to the change; *provided*, *however*, settlements and the administration of other processes pertaining to Grandfathered Rights and Grandfathered TCCs will be made in accordance with the provisions of Section 17.9.1. If the ISO receives notification from any signatory to the ETA that it objects to the requested change in the information in Table 1A, the ISO will immediately notify the party requesting the change and the ISO will not implement the requested change until the disagreement between the signatories has been resolved pursuant to the dispute resolution provisions of the ETA or by an appropriate legal authority.

17.9.3.3 *NYPA/LIPA ETAs*. For ETAs in which NYPA or LIPA is the provider of service, a proposed revision to Attachment L, Table 1A pursuant to an amendment of a transmission agreement or to make Table 1A consistent with the existing terms of a transmission agreement will be in effect as an Accepted Revision as of the start of the second day following the day that (i) the ISO has received a written notification of a change in the ETA or change in Attachment L information from a signatory to the ETA in accordance with ISO Procedures and confirmation that a copy of the notification has been provided to all other signatories to the ETA, and a copy thereof, and (ii) the ISO has received copies of the relevant agreement(s) (including amendments thereto) or other information relevant to the change; *provided*, *however*, settlements and the administration of other processes pertaining to Grandfathered Rights and Grandfathered TCCs will be in accordance with the provisions of Section 17.9.1. If the ISO receives notification from any signatory to the ETA that it objects to the requested change in the information in Table 1A, the ISO will immediately notify the party requesting the change and the ISO will not implement the requested change until the disagreement between the signatories has been resolved pursuant to the dispute resolution provisions of the ETA or by an appropriate legal authority.

17.9.3.4 *ISO to Notify Market*. The ISO shall provide reasonable notice to all Customers when it receives written notification of a change to Table 1A information pursuant to Section 17.9.1.4 or Sections 17.9.3.1(i), 17.9.3.2(i), or 17.9.3.3(i).

17.9.3.5 *ISO Responsibility for Review*. In receiving written notification of a proposed revision to Attachment L, Table 1A and copies of information related to such change, the ISO will process the Accepted Revision strictly on the basis of the receipt of such information and the representations it receives from the parties to the ETA.

17.9.4 Accepted Revisions to be Incorporated into Attachment L

The ISO shall annually present revisions to Attachment L, Table 1A to stakeholders for filing with the Commission to reflect Accepted Revisions posted on the ISO website; *provided*, *however*, that the ISO shall have no obligation to propose revisions to Table 1A if no Accepted Revisions have been posted on the ISO website.

18 ATTACHMENT L – TRANSMISSION AGREEMENTS & EXISTING TRANSMISSION CAPACITY FOR NATIVE LOAD TABLES

18.1 Transmission Wheeling Agreements

18.1.1 Table 1 A - Long Term Transmission Wheeling Agreements

Table 1A Administrative Rules:

- Accepted Revisions to Attachment L Table 1A are posted on the ISO website.
- ISO shall model contract #5 as follows: Bowline 1 to Zone H for 5 MW and Bowline 2 to Zone H for 5 MW.
- Contracts #49.1 and #49.2 have declining allocations of MWs, as follows:

Contract #49.1		Contract #49.2	
11/18/99 - 11/17/00 = 77 MW	11/18/04 - 11/17/05 = 54 MW	11/18/99 - 11/17/00 = 43 MW	11/18/04 - 11/17/05 = 23 MW
11/18/00 - 11/17/01 = 72 MW	11/18/05 - 11/17/06 = 50 MW	11/18/00 - 11/17/01 = 39 MW	11/18/05 - 11/17/06 = 19 MW
11/18/01 - 11/17/02 = 68 MW	11/18/06 - 11/17/07 = 45 MW	11/18/01 - 11/17/02 = 35 MW	11/18/06 - 11/17/07 = 15 MW
11/18/02 - 11/17/02 = 63 MW	11/18/07 - 11/17/43 = 40 MW	11/18/02 - 11/17/03 = 31 MW	11/18/07 - 6/30/35 = 11 MW
11/18/03 - 11/17/04 = 59 MW		11/18/03 - 11/17/04 = 27 MW	

- One proxy bus in each of the neighboring Control Areas has been designated for any agreement that identifies a POI or POW in that neighboring Control Area. Such Proxy Generator Bus shall be deemed to be the POI or POW for purposes of Settlements. In addition, POIs and POWs referencing a Transmission District (or similar service area designations) shall reference a tranmsision zone. In addition corrections to certain named POIs and POWs are made. These changes are as follows:

POI/POW Designation Listed in Table 1A	POI/POW Modeled in Auctions by ISO
CHG&E	Hudson Valley
Con Ed - North	Millwood
NYSEG - East	Mohawk Valley
NMPC - East	Capital
Mohansic - CE No	Millwood
Con Ed - Mid Hud	Hudson Valley
Con Ed - Cent.	Dunwoodie
Con Edison	New York City
LIPA	Long Island
NYSEG - Cent.	Central
NYSEG - Mech.	Capital
NYSEG - Hudson	Hudson Valley
NYSEG - Brewster	Millwood
NYSEG - North	North
NMPC Cent. Ea.	Mohawk Valley

POI/POW Designation Listed in Table 1A	POI/POW Modeled in Auctions by ISO
O&R	Hudson Valley
RG&E	Genessee or Ginna as listed
NYPA H	Millwood
NMPC - West	West
NYPA C	Central
NMPC - Genessee	Genessee
NMPC - Cent.	Central
NYPA - North	North
NYPA - E	Mohawk Valley
NYSEG - West	West
NYPA West	West
Adirondack	North
Moses 17 18	St. Lawrence
Pleasant Valley 345	Pleasant Valley

- The ISO does not calculate LBMP at Watertown HYD or at Watertown Muni Pl; accordingly the ISO models contract #215 from MHK VL to MHK VL.
- Unless otherwise specified herein, all dates provided in the "Cont./Exp./Termination Date" column shall be deemed to run through and include the end of the last hour of the contract expiration/termination date. All contracts set to expire/terminate upon notice or upon the occurrence of a contingency (e.g., the retirement of a Generator) shall be deemed to have expired/terminated at the end of the last hour of the date provided for in the notice or the date such contingency occurs, provided that the ISO has received evidence satisfactory to the ISO of the delivery of such notice or of the occurrence of such contingency in accordance with Attachment K of the OATT and ISO Procedures.
- Ordinarily, the party with rights to request transmission under an ETA is the Primary Holder of the related Grandfathered TCC or the holder of the related Grandfathered Right. However, where a party has been appointed to act on behalf of another party holding transmission rights under an ETA, the appointed party is indicated in parentheses. Similarly, when a Grandfathered TCC has been transferred but the parties to the ETA have not changed, the holder of the Grandfathered TCC is indicated in parentheses.
- POWs listed in parentheses in the "POW" column indicate that the underlying agreement to which such cell relates provides for redirect rights to such POWs.
- The capacity figures designated under the columns "Sum Cap. Per. MW (ISO)" and "Win Cap. Per. MW (ISO)" denote maximum amounts that are designated for grandfathering treatment but do not constitute rights to use or schedule capacity independent of the provisions of the underlying contracts.

Table 1 A - Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont. Est. Date	Cont. Exp./ Termination Date	Treatment (Refer to Attachment K)	Sum Cap. Per. MW (ISO)	Win Cap. Per. MW (ISO)	Interface Allocations - Summer Period									
		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
1	141	CHG&E	NMPC	Nine Mile Pt #2	101	NMP2	CHG&E	2/14/75	Ret. of Nine Mile Pt. #2	MWA-NMP2	101	101			101		101	101				
2	128	CHG&E	NMPC	Gilboa	100	Gilboa #1	CHG&E	5/10/73	6/30/2002	MWA-Gilboa Contract	100	100						100				
3	N/A	CHG&E	NYPA	Marcy South Facility	300	CHG&E	Con Ed - North	12/7/83	Ret. of Roseton	Facility Agmt. - MWA	300	300							300			
4	26	CHG&E	NYSEG	West Woodbourne	25	NYSEG - East	NMPC - East	6/24/64	Ret. of Nine Mile Pt. #2	Facility Agmt. - MWA	25	25					25					
5	87	Con Edison	NYSEG	Mohansic – Wheeling	10	Bowline	Mohansic - CE No	8/23/83	Ret. of Bowline	Facility Agmt- MWA-Bowline	10	10							10			
8	N/A	Con Edison	NYPA	Gilboa	125	Gilboa #1	Con Ed - Mid Hud	4/1/89	6/30/2004	MWA-Gilboa Contract	125	125						125				
9	N/A	Con Edison	LIPA	Y50 Cable(1)	291	Con Ed - Cent.	Con Edison	4/4/75	Life of the facility	Facility Agmt - MWA	291	291									291	
12.1	142	LIPA	NMPC	Fitzpatrick Delivery - Firm	160/ 124	Fitzpatrick	Con Ed - Mid Hud	2/14/75	Upon 1 year notice from LIPA to NMPC	MWA-Fitzpatrick Contract	160	124			160		160	160				
12.2	117	LIPA	Con Edison	Fitzpatrick Delivery - Firm	103/ 100	Con Ed - Mid Hud	LIPA	7/15/75	Upon mutual agreement between LIPA and Con Edison	MWA-Fitzpatrick Contract	103	100							103	103	103	103
14.1	N/A	LIPA	NYPA	Y49 Cable	307/ 300	Con Ed - Cent.	LIPA	8/26/87	Later of ret. of Bonds or upon mutual agreement	Facility Agmt - MWA	307	300									307	307
14.2	N/A	LIPA	NYPA; Con Edison	Remainder of Interface Agreements (2)	166	Con Ed - Cent.	LIPA		Later of ret. of Bonds or upon mutual agreement	Facility Agmt - MWA	202	202									202	202
16.1	142	LIPA	NMPC	Nine Mile Pt.#2 Delivery	206	NMP2	Con Ed - Mid Hud	2/14/75	Ret. of Nine Mile Pt. #2	MWA-NMP2	206	206			206		206	206				
16.2	117	LIPA	Con Edison	Nine Mile Pt.#2 Delivery	206	Con Ed - Mid Hud	LIPA	4/4/75	Ret. of Nine Mile Pt. #2	MWA-NMP2	206	206							206	206	206	206
17.1	N/A	LIPA	NYPA	Gilboa Delivery	50	Gilboa #1	Con Ed - North	3/31/89	4/30/2015	MWA-Gilboa Contract	50	50						50	50			
17.2	94	LIPA	Con Edison	Gilboa Delivery	50	Con Ed - North	LIPA	3/31/89	4/30/2015	MWA-Gilboa Contract	50	50								50	50	50
19	165	AES Creative Resources	NMPC	Settlement Agreement	298(17)	Kintigh	NYSEG - Cent. (Capital, Hudson Valley, NE Proxy Generator Bus)		10/31/2004	Third Party TWA	298	298	298	298								
20.1	165	NYSEG	NMPC	Remote Load Agmt.	277	Kintigh	NYSEG - Cent.	12/1/52	Ret. of Kintigh (9)	MWA-Kintigh	277	277	277	277								
20.2	165	NYSEG	NMPC	Remote Load Agmt.	277	NYSEG - Cent.	NYSEG - Mech.	12/1/52	Ret. of Kintigh (9)	MWA-Kintigh	277	277			277		277					

Table 1 A - Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont. Est. Date	Cont. Exp./ Termination Date	Treatment (Refer to Attachment K)	Sum Cap. Per. MW (ISO)	Win Cap. Per. MW (ISO)	Interface Allocations - Summer Period									
		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
20.3	165	NYSEG	NMPC	Remote Load Agmt.	205	NYSEG - Mech.	NYSEG - Hudson	12/1/52	Ret. of Kintigh (9)	MWA-NMP2/Kintigh	205	205						205				
20.4	112	NYSEG	Con Edison	Wood Street	205	NYSEG - Hudson	NYSEG - Brewster	3/1/88	4/1/2005	MWA-NMP2/Kintigh	205	205							205			
20.5	165	NYSEG	NMPC	Remote Load Agmt.	187	NMP2	NYSEG - Mech.	12/1/52	Ret. of Nine Mile Pt. #2 (9)	MWA-NMP2	187	187			187		187					
20.6	165	NYSEG	NMPC	Remote Load Agmt.	122	NYSEG - Mech.	CHG&E	12/1/52	Ret. of Nine Mile Pt. #2 (9)	MWA-NMP2/Kintigh	122	122						122				
20.7	22	NYSEG	CHG&E	Fishkill/Sylvan Lake	122	CHG&E	NYSEG - Brewster	7/19/62	Ret. of Nine Mile Pt. #2	MWA-NMP2/Kintigh	122	122							122			
20.8	49	NYSEG	CHG&E	Walden	15	NYSEG - East	NYSEG Hudson	8/1/73	Ret. of Nine Mile Pt. #2	MWA-NMP2/Kintigh	15	15					15	15				
21	26	NYSEG	CHG&E	West Woodbourne	25	NYSEG - East	NMPC - East	6/24/64	Ret. of Nine Mile Pt. #2	Facility Agmt. - MWA	25	25					25					
22	N/A	NYSEG	NYPA	Plattsburgh Export	235/ 225	NYSEG - North	NYSEG - East	5/27/94	6/21/2009	MWA-NUG Contracts	235	225				235						
23	N/A	AES	NYPA	Niagara-Edic (Kintigh)	100	Kintigh	NYSEG - East	12/12/83	8/31/2007	Terminated	100	100										
25	N/A	NYSEG	NYPA	St. Lawrence to Niagara	93	St. Lawrence	NYSEG - East	12/31/61	8/31/2007	MWA-Hydro Contract	93	93				93						
26	115	NMPC	NYSEG	Remote Load Agmt				12/31/52		Terminated												
28	N/A	NMPC	NYPA	Niagara-Edic	126	Niagara	NMPC - Cent. Ea.	11/1/84	6/17/2000	MWA-Hydro Contract	126	126	126	126	126							
29	N/A	NMPC	NYPA	Niagara-Edic	397			11/1/84		Terminated												
30	N/A	NMPC	NYPA	St. Lawrence	104	St. Lawrence	NMPC - Cent. Ea.	2/10/61	8/31/2007	MWA-Hydro Contract	104	104				104						
31.1	N/A	O&R	NYPA	Gilboa	25	Gilboa #1	CHG&E	4/1/89	6/30/2004	MWA-Gilboa Contract	25	25						25				
31.2	51	O&R	CHG&E	Gilboa	25	CHG&E	O&R	4/1/89	8/31/2004	MWA-Gilboa Contract	25	25										
41	32	O&R	CHG&E	E. Delaware Hydro	18	E. Delaware Hydro	O&R	12/31/62	9/27/2006	MWA-Grahmsville	18	18										
45	N/A	RG&E	NYPA	St. Lawrence	55	St. Lawrence	NYPA - E	12/31/61	8/31/2007	MWA-Hydro Contract	55	55				55						
46	N/A	RG&E	NYPA	Niagara - Edic: R&D	65	Niagara	RG&E	11/1/84	8/31/2007	MWA-Hydro Contract	65	65	65									
47	N/A	RG&E	NYPA	Niagara - Edic: Own Load	59	Niagara	RG&E	11/1/84	8/31/2007	MWA-Hydro Contract	59	59	59									
48.1	54	RG&E	NYSEG	Gilboa	30	Ginna	NYSEG - East	5/10/73	6/30/2002	MWA-Gilboa Contract	30	30		30	30							
48.2	54	RG&E	NYPA	Gilboa	30	NYSEG - East	NMPC - East	5/10/73	6/30/2002	MWA-Gilboa Contract	30	30					30					
49.1	176	RG&E	NMPC	Exit Agreement (3)	77 to 40	Ginna	NMPC - East	4/12/73	6/30/2043	MWA	77-40	77-40		77-40	77-40		77-40					

Table 1 A - Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont. Est. Date	Cont. Exp./ Termination Date	Treatment (Refer to Attachment K)	Sum Cap. Per. MW (ISO)	Win Cap. Per. MW (ISO)	Interface Allocations - Summer Period									
		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
49.2	N/A	NMPC	NMPC	Assignment, Assumption, Release, and Termination Agreement	43 to 11	Ginna	Gilboa	10/22/99	6/30/2035	Third Party TWA	43-11	43-11		43-11	43-11		43-11					
55.1	65	NYPA - for SENY	CHG&E	Ashokan	4	Ashokan	E. Fishkill	10/30/81	Upon 5 years' notice by either party	Third Party TWA	4	4							4			
55.2	N/A	NYPA - for SENY (Con Edison)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	4	E. Fishkill	Con Edison	3/10/89; 5/11/00	Upon mutual agreement between NYPA and Con Ed	Third Party TWA	4	4								4	4	
55.3	N/A	NYPA - for SENY	Con Edison	Con Ed Delivery Service Agreement	2	Kensico	E. Fishkill	3/10/89	Upon mutual agreement between NYPA and Con Ed	Third Party TWA	2	2										
55.4	N/A	NYPA - for SENY (Con Edison)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	2	E. Fishkill	Con Edison	3/10/89; 5/11/00	Upon mutual agreement between NYPA and Con Ed	Third Party TWA	2	2								2	2	
56.1	180	NYPA - for SENY	NMPC	Jarvis	4	Jarvis	E. Fishkill	10/29/92	1/10/2013	Third Party TWA	4	4					4	4	4			
56.2	N/A	NYPA - for SENY (Con Edison)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	4	E. Fishkill	Con Edison	3/10/89; 5/11/00	Upon mutual agreement between NYPA and Con Ed	Third Party TWA	4	4								4	4	
57.1	180	NYPA - for SENY	NMPC	Crescent-Vischers	10	Vischers	E. Fishkill	10/29/92	1/10/2013	Third Party TWA	10	10						10	10			
57.2	N/A	NYPA - for SENY (Con Edison)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	10	E. Fishkill	Con Edison	3/10/89; 5/11/00	Upon mutual agreement between NYPA and Con Ed	Third Party TWA	10	10								10	10	
57.3	180	NYPA - for SENY	NMPC	Crescent-Vischers	10	Crescent	E. Fishkill	10/29/92	1/10/2013	Third Party TWA	10	10						10	10			
57.4	N/A	NYPA - for SENY (Con Edison)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	10	E. Fishkill	Con Edison	3/10/89; 5/11/00	Upon mutual agreement between NYPA and Con Ed	Third Party TWA	10	10								10	10	

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Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont. Est. Date	Cont. Exp./ Termination Date	Treatment (Refer to Attachment K)	Sum Cap. Per. MW (ISO)	Win Cap. Per. MW (ISO)	Interface Allocations - Summer Period									
		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
58	96	NYPA - for SENY (Con Edison)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement (11)	912	Indian Pt 3	Con Edison	3/10/89; 5/11/00	Upon mutual agreement between NYPA and Con Ed	Third Party TWA	912	912								912	912	
59.1	N/A	NYPA - for SENY	NYPA	Gilboa	250	Gilboa #1	E. Fishkill	11/24/86	Upon mutual agreement	Third Party TWA	250	250						250	250			
59.2	N/A	NYPA - for SENY (Con Edison)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	250	E. Fishkill	Con Edison	3/10/89; 5/11/00	Upon mutual agreement between NYPA and Con Ed	Third Party TWA	250	250								250	250	
60	N/A	SENY	NYPA	Fitzpatrick	100	Fitzpatrick	NYPA - H	12/31/94	Beyond 12/31/2004	Terminated												
	N/A	SENY	Con Edison	Fitzpatrick	100	Con Ed - North	Con Edison	3/10/89	Beyond 12/31/2004	Terminated												
61.1	N/A	NYPA - for SENY	NYPA	MTA/SENY	10	St. Lawrence	E. Fishkill	5/7/81	7/31/2000	Third Party TWA	10	10				10	10	10	10			
61.2	N/A	NYPA - for SENY (Con Edison)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	10	E. Fishkill	Con Edison	3/10/89; 5/11/00	7/31/2000	Third Party TWA	10	10								10	10	
62.1	N/A	NYPA - for SENY	NYPA	MDA/EDP for CE	139	Fitzpatrick	E. Fishkill	12/31/91	12/31/2013	Third Party TWA	139	139			139		139	139	139			
62.2	N/A	NYPA- for SENY (Con Edison)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	139	E. Fishkill	Con Ed - North	3/10/89; 5/11/00	12/31/2013	Third Party TWA	139	139										
62.3	97, 98	NYPA - for SENY (Con Edison)	Con Edison	MDA/EDP for CE	114	Con Ed - North	Con Edison	12/31/91	12/31/2013	Third Party TWA	114	114								114	114	
65.1	32	Greenport (NYPA)	NYPA	Munis/Coops on Long Island	5	Niagara	Con Ed - North	6/18/76	10/31/2013	Third Party TWA	5	5	5	5	5		5	5	5			
65.2	32	Freeport	NYPA	Munis/Coops on Long Island	38	Niagara	Con Ed - North	6/18/76	10/31/2013	Third Party TWA	38	38	38	38	38		38	38	38			
65.3	32	Rockville Centre	NYPA	Munis/Coops on Long Island	29	Niagara	Con Ed - North	6/18/76	10/31/2013	Third Party TWA	29	29	29	29	29		29	29	29			
65.4	Con Edison OATT	Greenport (NYPA)	Con Edison	Munis on LI (4)	6	Con Ed - North	LIPA	7/30/94	10/31/2013	Third Party TWA	6	6								6	6	6
65.5	Con Edison OATT	Freeport	Con Edison	Munis on LI (4)	37	Con Ed - North	LIPA	7/30/94	10/31/2013	Third Party TWA	37	37								37	37	37
65.6	Con Edison OATT	Rockville Centre	Con Edison	Munis on LI (4)	29	Con Ed - North	LIPA	7/30/94	10/31/2013	Third Party TWA	29	29								29	29	29

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		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
65.7	N/A	Greenport (NYPA)	LIPA	Munis/Coops on LI	5	LIPA	LIPA	4/10/81	10/31/2013	Third Party TWA	5	5										
65.8	N/A	Freeport	LIPA	Munis/Coops on LI	38	LIPA	LIPA	4/10/81	10/31/2013	Third Party TWA	38	38										
65.9	N/A	Rockville Centre	LIPA	Munis/Coops on LI (12)	29	LIPA	LIPA	4/10/81	10/31/2013	Third Party TWA	29	29										
66	134	Festival of Lights	NMPC	Festival of Lights	0.1	Niagara	NMPC - West	Not Available	Not Available	Third Party TWA	0	0										
73	68	NYPA (EDP in O&R)	CHG&E	EDP in O&R	0.3	CHG&E	O&R	12/31/91	Not Available	Third Party TWA	0	0										
74.1	N/A	MDAs on LI (NYPA)	NYPA	MDAs on LI	10	Fitzpatrick	Con Ed - North	12/31/91	6/30/2012	Third Party TWA	10	10			10		10	10	10			
74.2	78	MDAs on LI (NYPA)	Con Edison	MDAs on LI	10	Con Ed - North	Con Ed - Cent.	7/1/85	6/30/2012	Third Party TWA	10	10								10		
74.3	N/A	MDAs on LI (NYPA)	NYPA	MDAs on LI	10	Con Ed - Cent.	LIPA	12/31/91	6/30/2012	Third Party TWA	10	10									10	10
74.4	N/A	Nassau County (NYPA)	LIPA	MDAs on LI	5	LIPA	LIPA	11/14/85	6/30/2012	Third Party TWA	5	5										
74.5	N/A	Suffolk County (NYPA)	LIPA	MDAs on LI	5	LIPA	LIPA	7/21/99 (13)	6/30/2012 (14)	Third Party TWA	5	5										
75.1	N/A	EDP for LI (NYPA)	NYPA	EDP for LI	26	Fitzpatrick	Con Ed - North	8/1/91	6/30/2012	Third Party TWA	26	26			26		26	26	26			
75.2	102	EDP for LI (NYPA)	Con Edison	EDP for LI	26	Con Ed - North	Con Ed - Cent.	8/1/91	6/30/2012	Third Party TWA	26	26								26		
75.3	N/A	EDP for LI (NYPA)	NYPA	EDP for LI	26	Con Ed - Cent.	LIPA	8/1/91	6/30/2012	Third Party TWA	26	26									26	26
75.4	N/A	EDP for LI (NYPA)	LIPA	EDP for LI	19/18	LIPA	LIPA	8/1/91	6/30/2012	Third Party TWA	19	18										
76.1	N/A	Brookhaven (NYPA)	NYPA	Brookhaven	60/68	Fitzpatrick	Con Ed - North	12/31/91	Upon 2 years' notice by either party	Third Party TWA	60	68			60		60	60	60			
76.2	60	Brookhaven (NYPA)	Con Edison	Brookhaven	60/68	Con Ed - North	Con Ed - Cent.	10/1/81	Upon 2 years' notice by either party	Third Party TWA	60	68								60		
76.3	N/A	Brookhaven (NYPA)	NYPA	Brookhaven	60/68	Con Ed - Cent.	LIPA	12/31/91	Upon 2 years' notice by either party	Third Party TWA	60	68									60	60
76.4	N/A	Brookhaven (NYPA)	LIPA	Brookhaven	60/68	LIPA	LIPA	10/1/81	Upon 2 years' notice by either party	Third Party TWA	60	68										
77.1	N/A	Grumman	NYPA	Grumman	0	Fitzpatrick	Con Ed - North	12/31/91	12/31/2001	Third Party TWA	0	0			0		0	0	0			
77.2	66	Grumman	Con Edison	Grumman	0	Con Ed - North	Con Ed - Cent	2/20/85	12/31/2001	Third Party TWA	0	0								0		
77.3	N/A	Grumman	NYPA	Grumman	0	Con Ed - Cent	LIPA	12/31/91	12/31/2001	Third Party TWA	0	0									0	0
77.4	N/A	Grumman	LIPA	Grumman	0	LIPA	LIPA	10/1/81	2 years' notice	Third Party TWA	0	0										

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		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
78	N/A	MDA/EDP to O&R (NYPA)	NYPA	MDA/EDP for O&R	1	Fitzpatrick	O&R	12/31/91	12/31/2003	Third Party TWA	1	1			1		1	1				
79.1	N/A	MDA/EDP to NYSEG (NYSEG)	NYPA	MDA/EDP for NYSEG	38	Fitzpatrick	NYSEG - Cent.	12/31/91	12/31/2009	Third Party TWA	38	38										
79.2	179	MDA/EDP to NYSEG (NYSEG)	NYSEG	MDA/EDP for NYSEG (16)	38	NYSEG - Cent.	NYSEG - Cent.	5/27/94	12/31/2009	Third Party TWA	38	38										
80	249	MDA/EDP to NMPC (NYPA)	NYPA	MDA/EDP for NMPC	46	Fitzpatrick	NMPC-Cent. Ea.	12/31/91	7/27/2013	Third Party TWA	46	46			46							
81	N/A	Industrials to NMPC (NYPA)	NYPA	Industrials to NMPC	68	Fitzpatrick	NYPA - C	12/31/91	Ret. of Fitzpatrick	Third Party TWA	68	68										
82	N/A			Munis/Coops in NMPC	99	Niagara	NMPC-Cent. Ea.				99	99	99	99	99							
82.1	NMPC OATT	Boonville (NYMPA)	NMPC	Munis/Coops in NYS	13	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	12/31/2000	Third Party TWA	13	13										
82.2	NMPC OATT	Frankfort (NYMPA)	NMPC	Munis/Coops in NYS	4	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	12/31/2000	Third Party TWA	4	4										
82.3	NMPC OATT	Ilion (NYMPA)	NMPC	Munis/Coops in NYS	13	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	12/31/2000	Third Party TWA	13	13										
82.4	204	Lake Placid (NYPA)	NMPC	Munis/Coops in NYS	29	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	4/30/2005	Third Party TWA	29	29										
82.5	NMPC OATT	Mohawk (NYMPA)	NMPC	Munis/Coops in NYS	4	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	12/31/2000	Third Party TWA	4	4										
82.6	204	Oneida-Madison (NYPA)	NMPC	Munis/Coops in NYS	1	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	11/01/2003	Third Party TWA	1	1										
82.7	NMPC OATT	Philadelphia (NYMPA)	NMPC	Munis/Coops in NYS	2	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	12/31/2000	Third Party TWA	2	2										
82.8	204	Sherrill (NYPA)	NMPC	Munis/Coops in NYS	12	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	8/31/2007	Third Party TWA	12	12										
82.9	NMPC OATT	Theresa (NYMPA)	NMPC	Munis/Coops in NYS	2	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	12/31/2000	Third Party TWA	2	2										
82.10	204	Tupper Lake (NYPA)	NMPC	Munis/Coops in NYS	19	NMPC - Cent. Ea	NMPC - Cent. Ea.	2/10/61	4/30/2005	Third Party TWA	19	19										
84	N/A			Munis/Coops in NMPC	18	Niagara	NMPC-Genessee				18	18	18									
84.1	NMPC OATT	Akron (NYMPA)	NMPC	Munis/Coops in NYS	8	NMPC-Genessee	NMPC-Genessee	2/10/61	12/31/2000	Third Party TWA	8	8										
84.2	204	Bergen (NMPC)	NMPC	Munis/Coops in NYS	2	NMPC-Genessee	NMPC-Genessee	2/10/61	2/29/2004	Third Party TWA	2	2										
84.3	NMPC OATT	Churchville (NYMPA)	NMPC	Munis/Coops in NYS	4	NMPC-Genessee	NMPC-Genessee	2/10/61	12/31/2000	Third Party TWA	4	4										
84.4	NMPC OATT	Holley (NYMPA)	NMPC	Munis/Coops in NYS	4	NMPC-Genessee	NMPC-Genessee	2/10/61	12/31/2000	Third Party TWA	4	4										
85	N/A			Munis/Coops in NMPC	6	Niagara	NMPC - Cent.				6	6	6	6	6							

Table 1 A - Long Term Transmission Wheeling Agreements

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		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
85.1	NMPC OATT	Green Island (NYMPA)	NMPC	Munis/Coops in NMPC	3	NMPC - Cent.	NMPC - East	12/31/61	10/31/2013	Third Party TWA	3	3					3					
85.2	NMPC OATT	Richmondville (NYMPA)	NMPC	Munis/Coops in NMPC	3	NMPC - Cent.	NMPC - East	12/31/61	10/31/2013	Third Party TWA	3	3					3					
86	N/A			Munis/Coops in NMPC	135	Niagara	NMPC - Cent.				135	135	135	135								
86.1	204	Fairport (NYPA)	NMPC	Munis/Coops in NMPC	77	NMPC - Cent.	NMPC - Cent.	2/10/61	8/31/2007	Third Party TWA	77	77										
86.2	NMPC OATT	Skaneateles (NYMPA)	NMPC	Munis/Coops in NYS	5	NMPC - Cent.	NMPC - Cent.	2/10/61	12/31/2000	Third Party TWA	5	5										
86.3	204	Solvay (NYPA)	NMPC	Munis/Coops in NYS	53	NMPC - Cent.	NMPC - Cent.	2/10/61	8/31/2007	Third Party TWA	53	53										
87	N/A			Munis/Coops in NYSEG	72	Niagara	NYSEG - Cent.				72	72	72	72								
87.1	NYSEG OATT	Bath (NYMPA)	NYSEG	In-State Munis/Coops	13	NYSEG - Cent.	NYSEG - Cent.	2/3/82	2/28/2001	Third Party TWA	13	13										
87.2	NYSEG OATT	Endicott (NYMPA)	NYSEG	In-State Munis/Coops	9	NYSEG - Cent.	NYSEG - Cent.	2/3/82	2/28/2001	Third Party TWA	9	9										
87.3	NYSEG OATT	Greene (NYMPA)	NYSEG	In-State Munis/Coops	7	NYSEG - Cent.	NYSEG - Cent.	2/3/82	2/28/2001	Third Party TWA	7	7										
87.4	NYSEG OATT	Groton (NYMPA)	NYSEG	In-State Munis/Coops	4	NYSEG - Cent.	NYSEG - Cent.	2/3/82	2/28/2001	Third Party TWA	4	4										
87.5	67, 70, 80	Marathon (NYPA)	NYSEG	In-State Munis/Coops	4	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/31/2007	Third Party TWA	4	4										
87.6	67, 70, 80	Penn Yan (NYPA)	NYSEG	In-State Munis/Coops	13	NYSEG - Cent.	NYSEG - Cent.	2/3/82	10/31/2003	Third Party TWA	13	13										
87.7	NYSEG OATT	Silver Springs (NYMPA)	NYSEG	In-State Munis/Coops	1	NYSEG - Cent.	NYSEG - Cent.	2/3/82	2/28/2001	Third Party TWA	1	1										
87.8	67, 70, 80	Steuben (NYPA)	NYSEG	In-State Munis/Coops	13	NYSEG - Cent.	NYSEG - Cent.	2/3/82	10/31/2003	Third Party TWA	13	13										
87.9	67, 70, 80	Watkins Glen (NYPA)	NYSEG	In-State Munis/Coops	6	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/31/2007	Third Party TWA	6	6										
87.10	NYSEG OATT	Castile (NYMPA)	NYSEG	In-State Munis/Coops	2	NYSEG - Cent.	NYSEG - Cent.	2/3/82	2/28/2001	Third Party TWA	2	2										
88	N/A			Munis/Coops in NYSEG	46	Niagara	NYSEG - East				46	46	46	46	46							
88.1	67, 70, 80	Delaware (NYPA)	NYSEG	In-State Munis/Coops	10	NYSEG - East	NYSEG - East	2/3/82	10/31/2003	Third Party TWA	10	10										
88.2	NYSEG OATT	Hamilton (NYMPA)	NYSEG	In-State Munis/Coops	11	NYSEG - East	NYSEG - East	2/3/82	6/30/2003	Third Party TWA	11	11										
88.3	67, 70, 80	Oneida-Madison (NYPA)	NYSEG	In-State Munis/Coops	4	NYSEG - East	NYSEG - East	2/3/82	10/31/2003	Third Party TWA	4	4										
88.4	67, 70, 80	Otsego (NYPA)	NYSEG	In-State Munis/Coops	8	NYSEG - East	NYSEG - East	2/3/82	10/31/2003	Third Party TWA	8	8										
88.5	NYSEG OATT	Sherburne (NYMPA)	NYSEG	In-State Munis/Coops	13	NYSEG - East	NYSEG - East	2/3/82	6/30/2003	Third Party TWA	13	13										

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		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
88.6	N/A	Rouses Point (NYMPA)	NYPA	In-State Munis/Coops	14	Niagara	NYSEG - North	12/31/61	2/28/2001	Third Party TWA	14	14	14	14	14	-14						
88.7	NYSEG OATT	Rouses Point (NYMPA)	NYSEG	In-State Munis/Coops	14	NYSEG - North	NYSEG - North	2/3/82	6/30/2003	Third Party TWA	14	14										
89	N/A	Plattsburgh (NYMPA)	NYPA	Niagara Hydro	103	Niagara	NYPA - North	12/31/61	2/28/2001	Third Party TWA	103	103	103	103	103	-103						
90	N/A	Massena (NYMPA)	NYPA	Niagara Hydro	23	Niagara	NYPA - North	12/31/61	6/30/2003	Third Party TWA	23	23	23	23	23	-23						
91	N/A	NYSEG	NYPA	NYSEG Energy Delivery	30	NYSEG - West	NYPA - North	7/1/92	10/31/2002	Third Party TWA	30	30	30	30	30	-30						
92	N/A	Reynolds (NYPA)	NYPA	Fitzpatrick	17	Fitzpatrick	NYPA - North	7/28/75	Indefinite	Third Party TWA	17	17			17	-17						
98	136	NFTA (NYPA)	NMPC	NFTA	1	St. Lawrence	NYPA - West	7/30/85	7/31/2014	Third Party TWA	1	1	-1	-1	-1	1						
99	159	Expansion Industrials (NYPA)	NMPC	Expansion Industrials	210	Niagara	NMPC - West	2/10/61	6/30/2013	Third Party TWA	210	210										
100	19	Replacement Industrials (NYPA)	NMPC	Replacement Industrials	445	Niagara	NMPC - West	2/10/61	1/1/2013	Third Party TWA	445	445										
101	N/A			Munis/Coops in RG&E	14	Niagara	RG&E				14	14	14									
101.1	RG&E OATT	Angelica (NYMPA)	RG&E	Munis & Coops	2	RG&E	RG&E	12/31/61	2/28/2001	Third Party TWA	2	2										
101.2	RG&E OATT	Spencerport (NYMPA)	RG&E	Munis & Coops	12	RG&E	RG&E	12/31/61	2/28/2001	Third Party TWA	12	12										
102	178	Exelon Generation	NMPC	Sithe Delivery	853	Sithe Independence	Pleasant Vlly	11/5/91	11/14/2014	Third Party TWA	853	853			853		853	853				
103	175	Indeck-Corint h	NMPC	Corinth Delivery	134	Indeck - Corinth	Pleasant Vlly	6/26/91	7/1/2015	Third Party TWA	134	134						134				
104	171	Selkirk Cogen Partners	NMPC	Selkirk Delivery	270	Selkirk II	Pleasant Vlly	12/13/90	8/31/2014	Third Party TWA	270	270						270				
105	172	Lockport Energy LEA (NYSEG)	NMPC	LEA Delivery	100	NEG West LEA Lockport	Gardnvlle	4/11/91	10/8/2007	Third Party TWA	100	100										
106	199	Cornwall Elec	NMPC	Rankin	30	Gardenville F/C	NYPA - E	11/1/89	Ret. of Rankine	Terminated												
107	N/A	NYSEG	NYPA	Out-of-State Wheeling	7	NYSEG - North	NE Proxy Generator Bus	2/4/86	12/31/2009	Third Party TWA	7	7					7					
108.1	N/A	Out-of-State Munis/Coops - NJ (NYPA)	NYPA	Niagara Deliveries	14	Niagara	CHG&E	2/10/61	10/31/2003	Third Party TWA	14	14	14	14	14		14	14				
108.2	68	Out-of-State Munis/Coops - NJ (NYPA)	CHG&E	Out-of-State Munis/Coops	14	CHG&E	O&R	2/28/90	10/31/2003	Third Party TWA	14	14										
108.3	50	Out-of-State Munis/Coops - NJ (NYPA)	O&R	Out-of-State Munis/Coops	14	O&R	PJM Proxy Generator Bus	6/28/85	10/31/2003	Third Party TWA	14	14										

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		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
109.1	N/A	Out-of-State Munis/Coops - NE (NYPA)	NYPA	Niagara Deliveries	89	Niagara	NMPC - Cent. Ea.	2/10/61	10/31/2003	Third Party TWA	89	89	89	89	89							
109.2	138	Out-of-State Munis/Coops - NE (NYPA)	NMPC	Niagara Deliveries	89	NMPC - Cent. Ea.	NE Proxy Generator Bus	2/10/61	10/31/2003	Third Party TWA	89	89					89					
110.1	138	Allegheny Electric Coop. (NYPA)	NMPC	Out-of-State Munis/Coops - PA	28	Niagara	PJM Proxy Generator Bus	7/1/85	10/31/2003	Third Party TWA	28	28										
110.2	NMPC OATT	Allegheny Electric Coop. (NYPA)	NMPC	Out-of-State Munis/Coops - PA	20	Niagara	PJM Proxy Generator Bus	6/30/98	10/31/2003	Third Party TWA	20	20										
110.3	138	Am. Mun. Power- Ohio (NYPA)	NMPC	Out of State Munis/Coops - Ohio	36	Niagara	PJM Proxy Generator Bus	2/10/61	10/31/2003	Third Party TWA	36	36										
110.4	NMPC OATT	Am. Mun. Power- Ohio (NYPA)	NMPC	Out-of- State Munis/Coops - Ohio	28	Niagara	PJM Proxy Generator Bus	12/1/98	12/31/2001	Third Party TWA	28	28										
111.1	N/A	Out-of-State Munis/Coops - VT (NYPA)	NYPA	Niagara Deliveries	14	Niagara	NYPA - E	2/10/61	10/31/2003	Third Party TWA	14	14	14	14	14							
111.2	N/A	Out-of-State Munis/Coops - VT (NYPA)	NYPA	Niagara Deliveries	14	NYPA - E	NE Proxy Generator Bus	2/10/61	10/31/2003	Third Party TWA	14	14					14					
112.1	N/A	Out-of-State Munis/Coops - NE (NYPA)	NYPA	St. Lawrence Deliveries	17	St. Lawrence	NMPC - Cent. Ea.	2/10/61	10/31/2003	Third Party TWA	17	17				17						
112.2	138	Out-of-State Munis/Coops - NE (NYPA)	NMPC	St. Lawrence Deliveries	17	NMPC - Cent. Ea.	NE Proxy Generator Bus	2/10/61	10/31/2003	Third Party TWA	17	17					17					
113.1	N/A	Allegheny Electric Coop. (NYPA)	NYPA	St. Law. Deliveries - PA	20	St. Lawrence	NMPC - West	2/10/61	10/31/2003	Third Party TWA	20	20	-20	-20	-20	20						
113.2	NMPC OATT	Allegheny Electric Coop. (NYPA)	NMPC	St. Law. Deliveries - PA	9	NMPC - West	PJM Proxy Generator Bus	6/30/98	10/31/2003	Third Party TWA	9	9										
113.3	138	Allegheny Electric Coop. (NYPA)	NMPC	St. Law. Deliveries - PA	11	NMPC - West	PJM Proxy Generator Bus	2/10/61	10/31/2003	Third Party TWA	11	11										
113.4	N/A	Am. Mun. Power- Ohio (NYPA)	NYPA	St. Law. Deliveries - Ohio	18	St. Lawrence	NMPC - West	2/10/61	10/31/2003	Third Party TWA	18	18	-18	-18	-18	18						
113.5	NMPC OATT	Am. Mun. Power- Ohio (NYPA)	NMPC	St. Law. Deliveries - Ohio	8	NMPC - West	PJM Proxy Generator Bus	12/1/98	12/31/2001	Third Party TWA	8	8										
113.6	138	Am. Mun. Power- Ohio (NYPA)	NMPC	St. Law. Deliveries - Ohio	10	NMPC - West	PJM Proxy Generator Bus	2/10/61	10/31/2003	Third Party TWA	10	10										

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		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
114	N/A	Out-of-State Munis/Coops - VT (NYPA)	NYPA	St. Lawrence Deliveries	1	St. Lawrence	NE Proxy Generator Bus	2/10/61	10/31/2003	Third Party TWA	1	1				1	1					
150.1	N/A	Out-of-State Munis/Coops - NJ (NYPA)	NYPA	St. Lawrence Deliveries	12	St. Lawrence	CHG&E	2/10/61	10/31/2003	Third Party TWA	12	12				12	12	12				
150.2	68	Out-of-State Munis/Coops - NJ (NYPA)	CHG&E	Out-of-State Munis/Coops	12	CHG&E	O&R	2/28/90	10/31/2003	Third Party TWA	12	12										
150.3	50	Out-of-State Munis- NJ (NYPA)	O&R	Out-of-State Munis/Coops	12	O&R	PJM Proxy Generator Bus	6/28/85	10/31/2003	Third Party TWA	12	12										
151	N/A			Munis/Coops in NMPC	83	Niagara	NMPC - West				83	83										
151.1	NMPC OATT	Andover (NYMPA)	NMPC	Munis/Coops in NMPC	1	NMPC - West	NMPC - West	2/10/61	12/31/2000	Third Party TWA	1	1										
151.2	NMPC OATT	Arcade (NYMPA)	NMPC	Munis/Coops in NMPC	25	NMPC - West	NMPC - West	2/10/61	12/31/2000	Third Party TWA	25	25										
151.3	NMPC OATT	Brocton (NYMPA)	NMPC	Munis/Coops in NMPC	3	NMPC - West	NMPC - West	2/10/61	12/31/2000	Third Party TWA	3	3										
151.4	NMPC OATT	Little Valley (NYMPA)	NMPC	Munis/Coops in NMPC	4	NMPC - West	NMPC - West	2/10/61	12/31/2000	Third Party TWA	4	4										
151.5	204	Mayville (NYPA)	NMPC	Munis/Coops in NMPC	4	NMPC - West	NMPC - West	2/10/61	8/31/2007	Third Party TWA	4	4										
151.6	NMPC OATT	Salamanca (NYMPA)	NMPC	Munis/Coops in NMPC	14	NMPC - West	NMPC - West	2/10/61	12/31/2000	Third Party TWA	14	14										
151.7	NMPC OATT	Springville (NYMPA)	NMPC	Munis/Coops in NMPC	9	NMPC - West	NMPC - West	2/10/61	12/31/2000	Third Party TWA	9	9										
151.8	NMPC OATT	Wellsville (NYMPA)	NMPC	Munis/Coops in NMPC	10	NMPC - West	NMPC - West	2/10/61	12/31/2000	Third Party TWA	10	10										
151.9	204	Westfield (NYPA)	NMPC	Munis/Coops in NMPC	13	NMPC - West	NMPC - West	2/10/61	8/31/2007	Third Party TWA	13	13										
152.1	N/A	Jamestown	NYPA	Jamestown	75	Niagara	NMPC - West	12/31/71	8/31/2001	Third Party TWA	75	75										
152.2	204	Jamestown	NMPC	Jamestown	100	NMPC - West	NMPC - West	2/10/61	8/31/2001	Third Party TWA	100	100										
153	N/A			Fitzpatrick Firm Incremental	2/3	Fitzpatrick	NYSEG - Cent.				2	3										
153.1	67, 70, 80	Penn Yan (NYMPA)	NYSEG	Fitzpatrick Firm Incremental	1/1	NYSEG - Cent.	NYSEG - Cent.	2/3/82	10/31/2003	Third Party TWA	1	1										
153.2	67, 70, 80	Steuben	NYSEG	Fitzpatrick Firm Incremental	0/0	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/21/2007	Third Party TWA	0	0										
153.3	67, 70, 80	Watkins Glen (NYPA)	NYSEG	Fitzpatrick Firm Incremental	1/2	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/31/2007	Third Party TWA	1	2										
153.4	67, 70, 80	Marathon	NYSEG	Fitzpatrick Firm Incremental	0/0	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/21/2007	Third Party TWA	0	0										
154	N/A			Fitzpatrick Firm Incremental	1/6	Fitzpatrick	NYSEG - East				1	6			1							
154.1	67, 70, 80	Delaware (NYPA)	NYSEG	Fitzpatrick Firm Incremental	0/1	NYSEG - East	NYSEG - East	2/3/82	10/31/2003	Third Party TWA	0	1										

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		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
154.2	67, 70, 80	Oneida-Madison (NYPA)	NYSEG	Fitzpatrick Firm Incremental	0/1	NYSEG - East	NYSEG - East	2/3/82	10/31/2003	Third Party TWA	0	1										
154.3	NYSEG OATT	Sherburne (NYMPA)	NYSEG	Incremental EDP	1	NYSEG - East	NYSEG - East	2/3/82	6/31/2003	Third Party TWA	1	1										
154.4	67, 70, 80	Otsego (NYPA)	NYSEG	Fitzpatrick Firm Incremental	0/3	NYSEG - East	NYSEG - East	2/3/82	10/31/2003	Third Party TWA	0	3										
155	N/A			Fitzpatrick Firm Incremental	2/4	Fitzpatrick	NMPC - West				2	4	-2	-2								
155.1	204	Mayville (NYPA)	NMPC	Fitzpatrick Firm Incremental	0/1	NMPC - West	NMPC - West	4/26/94	8/31/2007	Third Party TWA	0	1										
155.2	204	Westfield (NYPA)	NMPC	Fitzpatrick Firm Incremental	0/1	NMPC - West	NMPC - West	4/26/94	8/31/2007	Third Party TWA	0	1										
155.3	NMPC OATT	Arcade (NYMPA)	NMPC	Firm Incremental	1	NMPC - West	NMPC - West	4/26/94	12/31/2000	Third Party TWA	1	1										
155.4	NMPC OATT	Salamanca (NYMPA)	NMPC	Firm Incremental	1	NMPC - West	NMPC - West	4/26/94	12/31/2000	Third Party TWA	1	1										
156	N/A			Fitzpatrick Firm Incremental	0/20	Fitzpatrick	NMPC Central				0	20										
156.1	204	Fairport (NYPA)	NMPC	Fitzpatrick Firm Incremental	0/20	NMPC Central	NMPC - Cent.	4/26/94	8/31/2007	Third Party TWA	0	20										
157	N/A			Fitzpatrick Firm Incremental	2/19	Fitzpatrick	NMPC-Cent. Ea.				2	19			2							
157.1	204	Lake Placid (NYPA)	NMPC	Fitzpatrick Firm Incremental	0/11	NMPC-Cent. Ea	NMPC - Cent. Ea.	4/26/94	4/30/2005	Third Party TWA	0	11										
157.2	204	Sherrill (NYPA)	NMPC	Fitzpatrick Firm Incremental	2/3	NMPC-Cent. Ea	NMPC - Cent. Ea.	4/26/94	8/31/2007	Third Party TWA	2	3										
157.3	204	Tupper Lake (NYPA)	NMPC	Fitzpatrick Firm Incremental	0/5	NMPC-Cent. Ea	NMPC - Cent. Ea.	4/26/94	4/30/2005	Third Party TWA	0	5										
158	N/A	In-State Munis/Coops	NYPA	Fitzpatrick Firm Incremental	0/0	Fitzpatrick	NMPC - Cent.	Not Available	10/31/2013	Third Party TWA	0	0										
158.1	204	Solvay	NMPC	Fitzpatrick Firm Incremental	0/0	NMPC - Cent.	NMPC - Cent.	Not Available	10/31/2013	Third Party TWA	0	0										
160	N/A	In-State Munis/Coops	NYPA	Fitzpatrick Firm Incremental	1/1	Fitzpatrick	NYPA - H		10/31/2013	Third Party TWA	1	1			1		1	1	1			
160.1	N/A	Greenport (NYPA)	LIPA	NYPA Firm Incremental	0/1	LIPA	LIPA		10/31/2013	Third Party TWA	0	1										
161		Munis in NMPC																				
161.1	NMPC OATT	Boonville (NYMPA)	NMPC	Supplemental	1/6	OH Proxy Generator Bus	NMPC - Cent. Ea.	6/1/1998	12/31/2000	Third Party TWA	1	6	1	1	1							
161.2	NMPC OATT	Frankfort (NYMPA)	NMPC	Supplemental	1/2	OH Proxy Generator Bus	NMPC - Cent. Ea.	6/1/1998	12/31/2000	Third Party TWA	1	2	1	1	1							
161.3	NMPC OATT	Ilion (NYMPA)	NMPC	Supplemental	0/2	OH Proxy Generator Bus	NMPC - Cent. Ea.	6/1/1998	12/31/2000	Third Party TWA	0	2	0	0	0							
161.4	NMPC OATT	Mohawk (NYMPA)	NMPC	Supplemental	0/1	OH Proxy Generator Bus	NMPC - Cent. Ea.	6/1/1998	12/31/2000	Third Party TWA	0	1	0	0	0							
161.5	NMPC OATT	Philadelphia (NYMPA)	NMPC	Supplemental	0/1	OH Proxy Generator Bus	NMPC - Cent. Ea.	6/1/1998	12/31/2000	Third Party TWA	0	1	0	0	0							

Table 1 A - Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont. Est. Date	Cont. Exp./ Termination Date	Treatment (Refer to Attachment K)	Sum Cap. Per. MW (ISO)	Win Cap. Per. MW (ISO)	Interface Allocations - Summer Period									
		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
161a	NMPC OATT	Theresa	NMPC	Supplemental	0/0	OH Proxy Bus	NMPC-Cent. Ea	6/1/1998	10/31/2013	Third Party TWA	0	0	0	0	0							
162		Munis in NMPC																				
162.1	NMPC OATT	Akron (NYMPA)	NMPC	Supplemental	1/4	OH Proxy Generator Bus	NMPC - Genessee	6/1/1998	12/31/2000	Third Party TWA	1	4	1									
162.2	NMPC OATT	Churchville (NYMPA)	NMPC	Supplemental	0/1	OH Proxy Generator Bus	NMPC - Genessee	6/1/1998	12/31/2000	Third Party TWA	0	1	0									
162.3	NMPC OATT	Holley (NYMPA)	NMPC	Supplemental	0/2	OH Proxy Generator Bus	NMPC - Genessee	6/1/1998	12/31/2000	Third Party TWA	0	2	0									
163		Munis in NMPC																				
163	NMPC OATT	Richmondville (NYMPA)	NMPC	Supplemental	0/1	OH Proxy Generator Bus	NMPC - East	6/1/1998	10/31/2013	Third Party TWA	0	1	0	0	0		0					
164		Munis in NMPC																				
164	NMPC OATT	Skaneateles (NYMPA)	NMPC	Supplemental	0/2	OH Proxy Generator Bus	NMPC - Cent.	6/1/1998	12/31/2000	Third Party TWA	0	2	0	0								
165		Munis in NYSEG																				
165.1	NYSEG OATT	Bath (NYMPA)	NYSEG	Supplemental	0/7	PJM Proxy Generator Bus	NYSEG - Cent.	6/1/1998	6/30/2003	Third Party TWA	0	7	0	0								
165.2	NYSEG OATT	Endicott (NYMPA)	NYSEG	Supplemental	0/4	PJM Proxy Generator Bus	NYSEG - Cent.	6/1/1998	6/30/2003	Third Party TWA	0	4	0	0								
165.3	NYSEG OATT	Greene (NYMPA)	NYSEG	Supplemental	0/3	PJM Proxy Generator Bus	NYSEG - Cent.	6/1/1998	6/30/2003	Third Party TWA	0	3	0	0								
165.4	NYSEG OATT	Groton (NYMPA)	NYSEG	Supplemental	0/3	PJM Proxy Generator Bus	NYSEG - Cent.	6/1/1998	6/30/2003	Third Party TWA	0	3	0	0								
166a	NYSEG OATT	Castile	NYSEG	Supplemental	0/0	PJM Proxy Generator Bus	NYSEG - Cent.	6/1/1998	6/30/2013	Third Party TWA	0	0	0	0								
166		Munis in NYSEG																				
166.1	NYSEG OATT	Hamilton (NYMPA)	NYSEG	Supplemental	0/3	PJM Proxy Generator Bus	NYSEG - East	6/1/1998	6/30/2003	Third Party TWA	0	3	0	0	0							
166.2	NYSEG OATT	Sherburne (NYMPA)	NYSEG	Supplemental	1/4	PJM Proxy Generator Bus	NYSEG - East	6/1/1998	6/30/2003	Third Party TWA	1	4	1	1	1							
166.3	NYSEG OATT	Rouses Point (NYMPA) (8)	NYSEG	Supplemental	1/5	NYSEG - North	NYSEG - North	6/1/1998	6/30/2003	Third Party TWA	1	5										
167		Munis in RG&E																				
167	RG&E OATT	Spencerport (NYMPA)	RG&E	Supplemental	0/2	RG&E	RG&E	6/1/1998	11/30/2000	Third Party TWA	0	2										
168		Munis in NMPC																				
168.1	NMPC OATT	Arcade (NYMPA)	NMPC	Supplemental	1/13	OH Proxy Generator Bus	NMPC - West	6/1/1998	12/31/2000	Third Party TWA	1	13										
168.2	NMPC OATT	Brocton (NYMPA)	NMPC	Supplemental	1	OH Proxy Generator Bus	NMPC - West	6/1/1998	12/31/2000	Third Party TWA	1	1										

Table 1 A - Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont. Est. Date	Cont. Exp./ Termination Date	Treatment (Refer to Attachment K)	Sum Cap. Per. MW (ISO)	Win Cap. Per. MW (ISO)	Interface Allocations - Summer Period									
		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
168.3	NMPC OATT	Salamanca (NYMPA)	NMPC	Supplemental	1/5	OH Proxy Generator Bus	NMPC - West	6/1/1998	12/31/2000	Third Party TWA	1	5										
168.4	NMPC OATT	Springville (NYMPA)	NMPC	Supplemental	1/4	OH Proxy Generator Bus	NMPC - West	6/1/1998	12/31/2000	Third Party TWA	1	4										
168.5	NMPC OATT	Wellsville (NYMPA)	NMPC	Supplemental	0/3	OH Proxy Generator Bus	NMPC - West	6/1/1998	12/31/2000	Third Party TWA	0	3										
169	NMPC OATT	PG&E Energy Trading	NMPC	PG&E Energy Trading	40	NE Proxy Generator Bus	PJM Proxy Generator Bus	6/1/99	5/31/2000	Third Party TWA	40	40	-40	-40	-40		-40					
172	NMPC OATT	Select Energy NY	NMPC	Select Energy NY	52	Indeck - Illion	PJM Proxy Generator Bus	3/1/99	2/29/2000	Third Party TWA	52	52	-52	-52	-52							
173	NMPC OATT	Select Energy NY	NMPC	Select Energy NY	52	Indeck - Olean	PJM Proxy Generator Bus	3/1/99	2/29/2000	Third Party TWA	52	52										
174	NMPC OATT	NYPA	NMPC	BOC Gases	2.55	Fitzpatrick	NMPC - West	5/23/97	1/1/2010	Third Party TWA	3	3	-3	-3								
175	NMPC OATT	NYPA	NMPC	BOC Gases	14	Fitzpatrick	NMPC - East	5/23/97	1/1/2010	Third Party TWA	14	14			14		14					
176	NMPC OATT	NYPA	NMPC	BOC Gases	0.5	Fitzpatrick	NMPC - East	11/1/97	30 days notice	Third Party TWA	1	1					1					
177	NMPC OATT	NYPA	NMPC	Air Products	13	Fitzpatrick	NMPC - East	5/23/97	1/1/2010	Third Party TWA	13	13			13		13					
179	NMPC OATT	NYPA	NMPC	Norampac Industries	9.1	Fitzpatrick	NMPC - West	3/1/97	1/1/2010	Third Party TWA	9	9	-9	-9								
180	NMPC OATT	NYPA	NMPC	Encore Paper	7.5	Fitzpatrick	NMPC - East	5/23/97	1/1/2010	Third Party TWA	8	8			8		8					
181	NMPC OATT	NYPA	NMPC	Encore Paper	1	Fitzpatrick	NMPC - East	2/15/98	1/1/2010	Third Party TWA	1	1			1		1					
182	N/A	NYPA	NMPC	Norampac Industries	0.2	Fitzpatrick	NMPC - West	6/1/98	1/1/2010	OATT	0	0	0	0								
183	NMPC OATT	NYPA	NMPC	Encore Paper	2	Fitzpatrick	NMPC - East	4/1/99	1/1/2010	Third Party TWA	2	2			2		2					
184	110	Expansion Industrials (NYPA)	NYSEG	Expansion Industrials (16)	38	Niagara	NYSEG - West	12/13/88	6/30/2013	Third Party TWA	38	38										
185	N/A	Alcoa (NYPA)	NYPA	St. Lawrence	239	St. Lawrence	NYPA - North	8/24/81	6/30/2013	Third Party TWA	239	239										
186	N/A	Reynolds (NYPA)	NYPA	St. Lawrence	239	St. Lawrence	NYPA - North	8/24/81	6/30/2013	Third Party TWA	239	239										
187	N/A	General Motors (NYPA)	NYPA	St. Lawrence	12	St. Lawrence	NYPA - North	6/23/92	6/30/2013	Third Party TWA	12	12										
189.1	N/A	NYPA - for SENY	NYPA	Niagara OATT Reservation	422	Niagara	E. Fishkill	7/1/99	12/31/2017	Third Party TWA (6) (7)	422	422	422	422	422		422	422	422			
189.2	N/A	NYPA - for SENY (Con Edison) (5)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	422	E. Fishkill	Con Edison	3/10/89; 5/11/00	12/31/2017	Third Party TWA (7)	422	422								422	422	

Table 1 A - Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont. Est. Date	Cont. Exp./ Termination Date	Treatment (Refer to Attachment K)	Sum Cap. Per. MW (ISO)	Win Cap. Per. MW (ISO)	Interface Allocations - Summer Period									
		Requestor and Primary Holder	Provider	Name	MW (Agmt)	POI	POW						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
190.1	N/A	NYPA - for SENY	NYPA	St. Lawrence OATT Reservation	178	St. Lawrence	E. Fishkill	7/1/99	12/31/2017	Third Party TWA (6) (7)	178	178				178	178	178	178			
190.2	N/A	NYPA - for SENY (Con Edison) (5)	Con Edison	Con Ed Delivery Service Agreement; Fishkill Agreement	178	E. Fishkill	Con Edison	3/10/89; 5/11/00	12/31/2017	Third Party TWA (7)	178	178								178	178	
191	CHG&E OATT	NYPA	CHG&E	Power For Jobs	1	CHG&E	CHG&E	7/1/99	12/31/2003	Third Party TWA	1	1										
194	NMPC OATT	NYPA (NMPC)	NMPC	Power For Jobs	97	Fitzpatrick	NMPC - Cent. East	8/1/99	12/31/2003	Third Party TWA	97	97			97							
195	NMPC OATT	NYPA (NMPC)	NMPC	Power For Jobs	20	Adirondack	NMPC - Cent. East	8/1/99	12/31/2003	Third Party TWA	20	20										
196	NMPC OATT	NYPA (NMPC)	NMPC	Power For Jobs	31	CHG&E	NMPC - East	8/1/99	12/31/2003	Third Party TWA	31	31						-31				
197.1	N/A	NYPA	NYPA	Power For Jobs	1	Fitzpatrick	RG&E	7/1/99	12/31/2003	Third Party TWA	1	1		-1								
197.2	RG&E OATT	NYPA	RG&E	Power For Jobs	1	RG&E	RG&E	7/1/99	12/31/2003	Third Party TWA	1	1										
215	174	Watertown (NMPC)	NMPC	Watertown	1.2	Watertown__ HYD (Mohawk Valley)	Watertown Muni Pl (Mowhawk Valley)	3/19/91	12/31/2040	Third Party TWA	1	1										
216	18	NYPA	NMPC	Adirondack/Marcy	0.5	Adirondack	Marcy	8/26/62	Indefinite	Third Party TWA	0	0										
217	N/A	NYPA - for SENY (15)	Con Edison	Con Ed Delivery Service Agreement	829/865	Poletti	Con Edison	3/10/89	1/31/2010	Third Party TWA	829	865										
218	N/A	NYPA - for SENY (15)	Con Edison	NYPA Load NYC - KIAC	105	KIAC JFK GT2	Con Edison	3/23/93	1/31/2020	Third Party TWA	105	104										

Legend:
MWA - Modified Wheeling Agreement
TWA - Transmission Wheeling Agreement
Cont. Est. Date - Contract Establishment Date

Interface Designations:
DE - Dysinger East
WC - West Central
VE - Volney East
MoS - Moses South
TE - Total East
US - UPNY/SENY
UC - UPNY/Con Ed
MS - Millwood South
DS - Dunwoodie South
CE-LI - Con Ed/LIPA

Footnotes:

(1) - Con Edison has Grandfathered TCCs for 363 MW from Dunwoodie to LIPA via Y-50 and back to Con Edison at the Jamaica Bus consistent with the allocation of transmission capacity under the "Agreement Between Consolidated Edison Company of New York, Inc. and LIPA for Electric Transmission Service." Con Edison provides 72 MW of transmission service to LIPA Munis from Dunwoodie to LIPA. The portion of Grandfathered TCCs actually allocated to Con Edison shall be consistent with the terms of the "Agreement Between Consolidated Edison Company of New York, Inc. and LIPA for Electric Transmission Service."

(2) - Amount of Grandfathered TCCs is equivalent to the balance of the interface rating.

(3) - Previously existing agreements between RG&E and NMPC were replaced by a separate Exit Agreement.

(4) - As amended.

(5) - NYPA's Grandfathered TCCs, allocated to its SENY Governmental load customers, across UPNY/Con Ed, Millwood South and Dunwoodie South will be up to 600 MW, or amounts otherwise available to

NYPA pursuant to the Grandfathered Rights applicable under the Planning & Supply and Delivery Services Agreement between NYPA and Con Edison dated March 1989.
(6) - Subject to NYPA's obtaining non-discriminatory long term firm reservation through 2017 under its OATT.
(7) - NYPA's TCCs allocated to its SENY Governmental Load Customers will terminate on the earlier of December 31, 2017 or when NYPA no longer has an obligation to serve any of the SENY Loads or the retirement or sale of both IP#3 and Poletti.
(8) - Rouses Point must have firm transmission contracts over NYPA's and NMPC's transmission system from OH to NYSEG and pay NYSEG's charges and NYPA's or NMPC's charges for this service.
(9) - Subject to amount and applicable term under Niagara Mohawk's Rate Schedule No. 165.1 accepted in FERC Docket No. ER99-3537.
(11) - Con Edison terminated its purchase of Indian Point3 effective January 1, 2000. At that time, the Con Edison's GFTCCs increased from 800 MW to 912 MW.
(13) - The MDA on LI allotment for service over LIPA's transmission facilities is covered by separate agreements between LIPA and the Suffolk County Electric Agency ("SCEA") and LIPA and the Nassau County Public Utility Agency ("NCPUA"). On July 21, 1999, LIPA and SCEA executed a revised agreement covering SCEA's 5 MW portion of the MDA on LI allotment. NCPUA continues to be governed by the terms of the 11/14/85 agreement.
(14) - LIPA's agreement with NCPUA for its portion of the MDA on LI allotment is effective through the term of NCPUA's NYPA contract, which expires on 10/31/2011. LIPA's agreement with SCEA for its portion of the MDA on LI allotment, by the agreement's terms, expires on 6/30/2012.
(15) - NYPA's Grandfathered Rights were allocated to SENY Governmental Load Customers pursuant to the Grandfathered Rights applicable under the Planning & Supply and Delivery Service Agreement between NYPA and Con Edison dated March 1989. Con Edison has terminated its purchase of Poletti effective January 1, 2000. At that time, the residual amount of available Capacity increased from 765 MW to 865 MW for the Winter Capability Period and from 733 MW to 829 MW for the Summer Capability Period.
(16) - Subject to the settlement or outcome of the Third Party TWA proceeding (FERC Docket Nos. ER97-1523-011, OA97-470-010, and ER97-4234-008) without prejudice to NYSEG's rights in the future.
(17) - Subject to the terms of the Remote Load Wheeling Agreement.

TABLE 2 – Existing Transmission Facility Agreements

	FERC Rate Sch. Designation #	Requestor	Provider	Transmission Facility Agreement Name

TABLE 2 – Existing Transmission Facility Agreements				
23	58	NMPC	RG&E	Station 80
24	36	CHG&E	RG&E	Station 80 Capacitors
25	36	Con Edison	RG&E	Station 80 Capacitors
26	36	LIPA	RG&E	Station 80 Capacitors
27	36	NYSEG	RG&E	Station 80 Capacitors
28	36	NMPC	RG&E	Station 80 Capacitors

TABLE 2– Existing Transmission Facility Agreements				
	FERC Rate Sch. Designation #	Requestor	Provider	Transmission Facility Agreement Name
29	36	O&R	RG&E	Station 80 Capacitors
30	36	RG&E	RG&E	Station 80 Capacitors
31	36	NYPA	RG&E	Station 80 Capacitors
32	128	CHG&E	Con Edison	Ramapo Phase Angle Regulators ("PARs")
33	128	Con Edison	Con Edison	Ramapo PARs
34	128	LIPA	Con Edison	Ramapo PARs
35	128	NYSEG	Con Edison	Ramapo PARs
36	128	NMPC	Con Edison	Ramapo PARs
37	128	O&R	Con Edison	Ramapo PARs
38	128	RG&E	Con Edison	Ramapo PARs
39	128	NYPA	Con Edison	Ramapo PARs

TABLE 3 - Existing Transmission Capacity for Native Load

	Transmission					Est.		Sum	Win	Interface Allocations - Summer Period									
	Requestor	Provider	Name	POI	POW	Date	Code	MW	MW	DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
1	Con Edison	Con Edison	Native Load-Bowline	Bowline (3)	Con Edison	N/A	1	801	801							801	768	584	
2	Con Edison	Con Edison	Native Load-HQ Cap. Purchase	Pleasant Vlly	Con Edison	N/A	1	400	208							400	384	292	
3	Con Edison	Con Edison	Native Load-Gilboa	Pleasant Vlly	Con Edison	N/A	1	125	125							125	120	91	
4	Con Edison	Con Edison	Native Load-Roseton	Roseton-GN1 (4)	Con Edison	N/A	1	480	480							480	461	351	
5	Con Edison	Con Edison	Native Load-Corinth	Pleasant Vlly	Con Edison	N/A	1	134	134							134	129	98	
6	Con Edison	Con Edison	Native Load-Sithe	Pleasant Vlly	Con Edison	N/A	1	837	837							837	803	611	
7	Con Edison	Con Edison	Native Load-Selkirk	Pleasant Vlly	Con Edison	N/A	1	265	265							265	254	193	
8	Con Edison	Con Edison	Native Load-IP2	Indian Pt 2	Con Edison	N/A	1	893	893								893	679	
9	Con Edison	Con Edison	Native Load-IP3	Indian Pt 3	Con Edison	N/A	1	108	108								108	82	
10	Con Edison	Con Edison	Native Load-IP Gas Turbine	IP GT-Buchanan	Con Edison	N/A	1	48	48								48	36	
11	NMPC	NMPC	Native Load -NMP1	NMP1	NMPC - East	N/A	1	610	610			610		610					
12	NMPC	NMPC	Native Load -NMP2	NMP2	NMPC - East	N/A	1	460	460			460		460					
13	NMPC	NMPC	Native Load -Hydro North	Colton	NMPC - East	N/A	1	110	110					110					
14	NYSEG	NYSEG	Native Load-Homer City	PJM Proxy Generator Bus	NYSEG - Cent.	N/A	1	863	863	863	863								
15	NYSEG	NYSEG	Native Load-Homer City	PJM Proxy Generator Bus	NYSEG - West	N/A	1	100	100										
16	NYSEG	NYSEG	Native Load-Allegheny 8&9	PJM Proxy Generator Bus	NYSEG - Cent.	N/A	2	37	37	37	37								
17	NYSEG	NYSEG	Native Load-BCLP	PJM Proxy Generator Bus	NYSEG - Cent.	N/A	2	80	80	80	80								
18	NYSEG	NYSEG	Native Load-LEA (Lockport)	Grdnvlle	NYSEG - Cent.	N/A	2	100	100	100	100								
19	NYSEG	NYSEG	Native Load-Gilboa	Gilboa	NYSEG - Mech	N/A	1	99	99										

Codes: Transmission capacity required:
(1) - to deliver the output of generation resources located out of or across a Member Systems' Transmission District.
(2) - to deliver power purchased under Third Party TWAs (i.e. - NUGs).

Notes:
1. Interface Designations:
DE - Dysinger East
WC - West Central
VE - Volney East
MoS - Moses South
TE - Total East
US - UPNY/SENY
UC - UPNY/Con Ed
MS - Millwood South
DS - Dunwoodie South
CE-LI - Con Ed/LIPA

2. POIs and POWs referencing a service area shall be as follows:

POI/POW Designation Listed in Table 3	POI/POW Modeled in Auctions by ISO
NMPC - East	Capital
Con Ed - Mid Hud	Hudson Valley
Con Edison	New York City
NYSEG - Cent	Central
NYSEG - Mech.	Capital
NYSEG - West	West

3. The ISO shall model ETCNL # 1 as set forth in Attachment M Table 2 of this ISO OATT.
4. The ISO shall model ETCNL # 4 as set forth in Attachment M Table 2 of this ISO OATT.

19 Attachment M - Sale and Award of Transmission Congestion Contracts ("TCCs")

19.1 Overview of the Sales of TCCs

TCCs will be made available through: (i) the Centralized TCC Auction and Reconfiguration Auction, which will be conducted by the ISO; (ii) Direct Sales by the Transmission Owners, which will be non-discriminatory, auditable sales conducted solely on the OASIS in compliance with the applicable requirements and restrictions set forth in Order No. 889 et seq.; (iii) the conversion of transmission Capacity associated with certain Existing Transmission Agreements ("ETAs") pursuant to Section 19.2.1 of this Attachment M; (iv) the award of Non-Historic Fixed Price TCCs pursuant to Section 19.2.2 of this Attachment M; (v) the award of Incremental TCCs pursuant to Section 19.2.4 of this Attachment M; (vi) the conversion of ETCNL into ETCNL TCCs; and (vii) the conversion of RCRRs into RCRR TCCs. TCCs may also be available through resale on the Secondary Markets. Prior to the first Centralized TCC Auction, the NYISO distributed to Transmission Owners Original Residual TCCs, the NYISO designated certain transmission Capacity as ETCNL, and some Transmission Owners converted their Grandfathered Rights into Grandfathered TCCs.

19.1.1 Preservation of Tax-Exempt Financing

Notwithstanding any other provision of this Attachment M, neither the ISO nor the Transmission Owners shall be required to grant, or allow the use of, transmission rights that would jeopardize the tax-exempt status of any Local Furnishing Bond(s), Government Bonds, LIPA Tax-Exempt Bonds or any other tax-exempt debt obligations, or impair the ability of a Transmission Owner to issue future tax-exempt obligations. Transmission Owners advising the ISO that the granting or use of transmission rights would jeopardize the tax-exempt status of any Local Furnishing Bond(s), Government Bonds, LIPA Tax-Exempt Bonds or any other tax-exempt debt obligations, or impair the ability of a Transmission Owner to issue future tax-exempt obligations, shall advise the ISO of the duration of transmission rights that are unavailable pursuant to this section 19.1.1. and shall indicate whether transmission rights with a duration of one month are available or not available pursuant to this section 19.1.1.

19.2 Award of TCCs Other Than Through TCC Auctions: Fixed Price TCCs and Incremental TCCs

19.2.1 Converting Transmission Capacity Associated with Expired, Terminated, or Expiring ETAs Into Historic Fixed Price TCCs

As each ETA in effect on November 19, 1999 that was listed in Table 1A of Attachment L to this OATT (as it may be amended), and that conferred transmission rights on an LSE, expires or terminates, the transmission Capacity associated with it may be used to create Historic Fixed Price TCCs, pursuant to Section 19.2.1 of this Attachment M. When any other ETA terminates, the Grandfathered Rights or Grandfathered TCCs associated with it shall be converted into Residual Transmission Capacity. The revenues associated with the sale or conversion of TCCs created from capacity associated with expired or terminated ETAs shall be allocated among the Transmission Owners as described in Attachment N. All references to "ETAs listed in Table 1A of Attachment L" in this Attachment M shall encompass both those agreements that were previously converted into Grandfathered TCCs and those that were not.

The ISO shall follow the procedures set forth in this Section 19.2.1 prior to the implementation of the End-State Auction process. For purposes of this Section 19.2.1, references to "expired" ETAs shall include ETAs that have been terminated. When determining the Points of Injection, Points of Withdrawal, and MW quantities associated with ETAs listed in Table 1A in effect on November 19, 1999, the ISO shall look to Attachment L of this OATT, as it may be amended, at the time of the conversion.

19.2.1.1 Conversion Rules

Any LSE that had transmission rights under an ETA in effect on November 19, 1999 that was listed in Table 1A of Attachment L to this OATT (as it may be amended), but has since expired, shall have a right to obtain Historic Fixed Price TCCs with the same Point of Injection and Point of Withdrawal associated with that ETA.

Any LSE that currently has transmission rights under an ETA in effect on November 19, 1999 that was listed on Table 1A of Attachment L of the OATT (as it may be amended) but has not yet expired, shall likewise have a right to obtain Historic Fixed Price TCCs with the same Point of Injection and Point of Withdrawal as that ETA after its expiration.

LSEs that are eligible to obtain Historic Fixed Price TCCs shall be able to obtain them for a total duration of up to ten years, except as provided in the following paragraph. The ISO shall offer eligible LSEs Historic Fixed Price TCCs with the same Points of Injection and Points of Withdrawal as shown on Table 1A of Attachment L, as it may be amended, associated with their expired or expiring ETAs and a duration of five or ten years (at the LSE's option) at a price to be determined in accordance with Section 19.2.1.2 below. Prior to the expiration of Historic Fixed Price TCCs with a duration of five years that are created pursuant to the preceding sentence, the ISO shall offer those LSEs that hold such Historic Fixed Price TCCs an option to obtain new Historic Fixed Price TCCs with the same Points of Injection and Points of Withdrawal for one additional five-year term, effective upon the expiration of the original Historic Fixed Price TCCs' five year term, at a new price calculated in accordance with Section 19.2.1.2 below.

LSEs that certify to the ISO that they purchase Energy from the New York Power Authority ("NYPA") under agreements that will expire in 2025 and that have ETAs listed on Table 1A to Attachment L, as it may be amended, that will expire in 2013, which they will use to hedge the congestion costs associated with deliveries under their NYPA agreements, shall have the right to obtain Historic Fixed Price TCCs with the same Points of Injection and Points of Withdrawal as shown on Table 1A of Attachment L to the OATT, as it may be amended, associated with the expiring ETA for a total duration of twelve years. The ISO shall offer Historic Fixed Price TCCs with a duration of five years to LSEs that make the required certification (provided for in this paragraph) at a price to be determined in accordance with Section 19.2.1.2 below. Prior to, but effective upon, the expiration of those Historic Fixed Price TCCs, the ISO shall offer the LSE an option to obtain new Historic Fixed Price TCCs with the same Points of Injection and Points of Withdrawal for one additional seven-year term, effective upon the expiration of the original Historic Fixed Price TCCs, at a new price calculated in accordance with Section 19.2.1.2 below.

To exercise this conversion right, an LSE must notify the ISO, and the Transmission Owner that was (or is) a party to the ETA, in writing, of its decision to obtain Historic Fixed Price TCCs under this provision. That notice must also specify the ETA's expiration or termination date. The LSE must provide this notice prior to a deadline to be established by the ISO. In the case of an ETA that has already expired or been terminated as of the effective date of this Section 19.2.1, or that will expire or be terminated prior to the end of the Winter 2008 Capability Period, the ISO shall set the deadline on a date prior to the beginning of the Autumn 2008 Centralized TCC Auction. In the case of an ETA that will expire or terminate after the end of the 2008 Winter Capability Period, the ISO shall set the deadline on a date prior to the beginning of the Centralized TCC Auction for the Capability Period in which the ETA expires or terminates. The specific deadlines shall be set forth in the ISO Procedures.

When an LSE elects to convert an ETA that: (i) has expired; (ii) is scheduled to expire, prior to November 1, 2008; or (iii) is scheduled to expire later but that is terminated before November 1, 2008, the term of the Historic Fixed Price TCCs that LSE obtains shall begin on November 1, 2008. When an LSE elects to convert any other ETA it may choose to have the term of the Historic Fixed Price TCCs that it obtains begin either on the day after the ETA's expiration or termination, or at the start of the Capability Period following its expiration or termination. If the LSE chooses the latter option, the ISO shall make the transmission Capacity associated with the expired ETA available to support the sale of TCCs in any Reconfiguration Auction(s) held for TCCs valid between the ETA's expiration and the start of the next Capability Period. Nothing in this Section 19.2.1 shall be construed as authorizing the early termination of ETAs before their scheduled expiration dates or as excusing the parties to ETAs of their obligations thereunder.

An LSE that exercises its conversion rights under this Section 19.2.1 may elect to receive a number of Historic Fixed Price TCCs up to one hundred percent of the MW quantity specified for the ETA in Table 1A of Attachment L as it may be amended. In the case of ETAs for which more than one MW quantity is listed in Attachment L, the LSE may elect to receive the higher quantity.

The LSE must submit a written certification to the ISO stating that it expects to: (i) be legally obligated to serve the Load that it historically served under the ETA (or a portion of that Load at least equal to the number of Historic Fixed Price TCCs that it plans to obtain under this Section 19.2.1); and (ii) need the transmission Capacity between the Point of Injection and Point of Withdrawal specified in the ETA to serve that Load. The LSE will not be allowed to obtain Historic Fixed Price TCCs under this Section to the extent that it cannot satisfy either or both of these requirements. That is, the LSE's conversion rights may be wholly or partially terminated to the extent that it anticipates losing all or part of the historic Load, or no longer needing all or part of the transmission Capacity associated with the expired ETA to serve it. Additional information regarding the ISO's certification process shall be set forth in the ISO Procedures.

In addition, if the ISO concludes that an LSE's requested conversion would make existing and valid TCCs infeasible, it will reduce the number of Historic Fixed Price TCCs that the LSE may obtain to the extent necessary to avoid the infeasibility. The reduction procedure will use the same optimization model as the Centralized TCC Auctions, except that the expired or expiring transmission rights subject to conversion will not be represented as fixed injections and withdrawals but will be represented by a bid curve. Additional details shall be specified in the ISO Procedures.

19.2.1.1.1 Special Rules Applicable to LSEs That Were Eligible to Obtain Historic Fixed Price TCCs with a Duration Commencing on November 1, 2008

LSEs that obtained Historic Fixed Price TCCs with a duration of five years commencing on November 1, 2008 shall have a one-time opportunity to elect to replace those Historic Fixed Price TCCs, at no additional cost, with Historic Fixed Price TCCs with a duration of ten years. The ten year duration shall be deemed to have commenced on November 1, 2008. LSEs that elect to replace Historic Fixed Price TCCs under this paragraph shall not be eligible to obtain additional Historic Fixed Price TCCs for an additional five year term at the time that their replacement Historic Fixed Price TCCs expire.

LSEs that were eligible to obtain Historic Fixed Price TCCs with a duration of five years commencing on November 1, 2008, but that opted not to obtain them, shall have a one-time opportunity to obtain Historic Fixed Price TCCs with a duration of ten years. If an LSE makes this election the duration of the Historic Fixed Price TCCs that it obtains will commence at the beginning of a subsequent Capability Period, as specified in the ISO Procedures. An LSE that elects to obtain Historic Fixed Price TCCs under this paragraph shall pay the same price that the ISO originally offered for the same Historic Fixed Price TCCs with a duration of five years, *i.e.*, the price that the ISO calculated under Section 19.2.1.2 for Historic Fixed Price TCCs commencing on November 1, 2008 (including the original historic inflation adjustment) for the LSE in advance of the Autumn 2008 Centralized TCC Auction.

All elections under this Section 19.2.1.1.1 shall be made during an election period specified in the ISO Procedures and shall be subject to all of the notification, certification, feasibility and other requirements established under Section 19.2.1 and the ISO Procedures.

19.2.1.2 Calculating Prices for Historic Fixed Price TCCs

Except as is specifically noted in Section 19.2.1.2 (iii), if an LSE chooses to obtain Historic Fixed Price TCCs pursuant to this Section 19.2.1 it shall pay a base price per MW/year equal to the average of:

(i) the average of the inflation-adjusted market-clearing prices calculated for TCCs with the POI and POW associated with the Historic Fixed Price TCC in the one-year Sub-Auction rounds of each of the four previous Centralized TCC Auctions. The average adjusted market-clearing price will be determined by first calculating the average market-clearing price in the one-year Sub-Auction rounds for each Centralized TCC Auction. One-year Sub-Auction-round market-clearing prices from Centralized TCC Auctions conducted before May 1, 2010 are those from the Stage 1 one-year rounds of the Centralized TCC Auctions. The average market-clearing price for the first, second, and third of the four previous Centralized TCC Auctions will then be adjusted for inflation between: (a) the date that TCCs sold in them went into effect, and (b) the start of the Capability Period during which the TCCs sold in the fourth Centralized Auction went into effect; and

(ii) the inflation-adjusted average annual difference between the Day-Ahead Market Congestion Component at the POW and the POI associated with the TCCs, summed over the hours of the four most recently concluded Capability Periods. The inflation-adjusted average annual difference for a given Historic Fixed Price TCC would be calculated by summing the Day-Ahead Market Congestion Component for the POW associated with that Historic Fixed Price TCC minus the Day-Ahead Market Congestion Component for the POI associated with that Historic Fixed Price TCC over the hours of each month of the four most recently concluded Capability Periods; adjusting each monthly total for inflation between the end of the month in question and the start of the most recently concluded Capability Period; summing those inflation-adjusted monthly totals over those four Capability Periods; and dividing by two.

All inflation calculations referenced in this Section 19.2.1.2 shall be made using the most recently published inflation rates specified in the Personal Consumption Expenditures Implicit Price Deflator published by the Bureau of Economic Analysis of the United States Department of Commerce. A Historic Fixed Price TCC shall not have a price of less than zero. To the extent that the formula in this Section 19.2.1.2 produces a price for a Historic Fixed Price TCC of less than zero, the price shall be zero.

(iii) If an LSE chooses to obtain a Historic Fixed Price TCC with a POW at or inside of Load Zone K (Long Island) pursuant to this Section 19.2.1 and bidding to or from Load Zone K was not permitted in any of the one-year Sub-Auctions of the four previous Centralized TCC Auctions at the time of the price calculation, it shall pay a base price per MW/year equal to the value calculated pursuant to Section 19.2.1.2 (ii).

19.2.1.3 Payment

An LSE that obtains Historic Fixed Price TCCs pursuant to Section 19.2.1 shall be required to pay the ISO the total amount specified in equal annual payments for each year of the Historic Fixed Price TCC's duration. Each annual payment shall entitle the LSE to extend the term of the Historic Fixed Price TCC for an additional year, subject to the provisions of Section 19.2.1.1. Billing for Historic Fixed Price TCCs shall be in accordance with ISO Procedures. To challenge settlement information contained in an invoice, a purchaser of Historic Fixed Price TCCs shall first make payment in full, including any amounts in dispute.

An LSE that obtains Fixed Price TCCs pursuant to this Section 19.2.1 shall be required to pay the ISO the total amount specified in this Section 19.2.1 in equal annual payments for each year of the Fixed Price TCC's duration. Each annual payment shall entitle the LSE to extend the term of the Fixed Price TCC for an additional year, subject to Section 19.2.1.1, above.

An LSE that fails to make any required annual payment for its Historic Fixed Price TCCs shall permanently surrender those Historic Fixed Price TCCs for that year and for all subsequent years (and shall not have a right to renew for additional term(s)), provided however that the ISO shall provide a one week cure period to an LSE that has failed to make the required annual payment for its Historic Fixed Price TCCs before the LSE has its Historic Fixed Priced TCCs permanently surrendered, pursuant to ISO Procedures.

19.2.2 Awards of Non-Historic Fixed Price TCCs

19.2.2.1 Initial Purchase of Non-Historic Fixed Price TCCs

LSEs may be eligible to purchase Non-Historic Fixed Price TCCs, at prices established pursuant to Section 19.2.2.3.1. below if, pursuant to ISO Procedures, they submit a completed Notice of Intent to Purchase specifying the quantity of Non-Historic Fixed Price TCCs they intend to obtain under this Section 19.2.2.1 by Load Zone Point of Withdrawal. The LSE shall also indicate for each Load Zone potential Points of Injection for their Non-Historic Fixed Price TCCs. The LSE must provide its completed Notice of Intent to Purchase prior to the deadline established by the ISO. The LSE's completed Notice of Intent to Purchase shall also include a written certification. The written certification shall state that the LSE: (i) expects to be legally obligated to serve Load in each identified Load Zone in an amount and for a term that equals or exceeds the sum of the number of Non-Historic Fixed Price TCCs that it intends to obtain under this Section 19.2.2.1 with a Point of Withdrawal in that Load Zone and the number of Grandfathered TCCs, Grandfathered Rights and Historic Fixed Price TCCs, in effect for the same term, that are held by or on behalf of the LSE with Points of Withdrawal in that Load Zone; and (ii) has served Load in the identified Load Zone in the most recently concluded Capability Period. The LSE will not be allowed to obtain Non-Historic Fixed Price TCCs under this Section to the extent that it does not satisfy either or both of these requirements prior to the deadline established by the ISO for this submittal. Additional information regarding the Notice of Intent to Purchase, including the written certification included therein, shall be set forth in the ISO Procedures.

The NYISO shall notify each LSE requesting a Notice of Intent to Purchase of the number of Non-Historic Fixed Price TCCs which the LSE is eligible to purchase by Load Zone Point of Withdrawal.

19.2.2.1.1 Availability

A percentage of the transmission Capacity that is available, pursuant to Section 19.8.3 of this Attachment M, to support the purchase of TCCs in any Centralized TCC Auction during which Non-Historic Fixed Price TCCs may be obtained shall be available to support the purchase of Non-Historic Fixed Price TCCs. The final decision concerning the percentage of the transmission Capacity that will be available to support the purchase of Non-Historic Fixed Price TCCs will be made by the ISO and shall not exceed five percent. The scaling factor for the allocation of Non-Historic Fixed Price TCCs during the period of any Centralized TCC Auction shall equal the percentage of available transmission Capacity that has not yet been made available to support the sale of TCCs in previous rounds of that Centralized TCC Auction, divided by the percentage of available transmission Capacity that will be made available to support Non-Historic Fixed Price TCCs that may be purchased during the period of the Centralized TCC Auction.

19.2.2.1.2 Limits on Availability

The ISO may limit the availability of Non-Historic Fixed Price TCCs for initial purchase, by Load Zone, based on each LSE’s average hourly load in that Load Zone and number of Grandfathered Rights and TCCs, Historic Fixed Price TCCs and other Non-Historic Fixed Price TCCs with POWs in that Load Zone held by or on behalf of the LSE.

In no event shall an LSE be eligible to purchase new Non-Historic Fixed Price TCCs with a Point of Withdrawal in a Load Zone for which the number of Grandfathered TCCs, Grandfathered Rights, Non-Historic and Historic Fixed Price TCCs held by or on behalf of the LSE with a Point of Withdrawal in that Load Zone equals or exceeds the average hourly load of the LSE in that Load Zone. Additional details shall be specified in the ISO Procedures.

Non-Historic Fixed Price TCCs may be offered by the ISO periodically, but no less frequently than every other year. They will be offered, if at all, with an initial term of two years. Renewal terms for Non-Historic Fixed Price TCCs shall be one year.

19.2.2.2 Renewal

LSEs may be eligible to renew Non-Historic Fixed Price TCCs at a new price calculated in accordance with Section 19.2.2.3.1 below if, pursuant to ISO Procedures, they submit a completed Notice of Intent to Renew specifying the Non-Historic Fixed Price TCC they intend to renew (by Point of Injection, Point of Withdrawal and quantity). The LSE must provide this notice prior to a deadline to be established by the ISO. The LSE's Notice of Intent to Renew shall also include a written certification stating that the LSE: (i) expects to be legally obligated to serve Load in each identified Load Zone in an amount and for a term that equals or exceeds the number of Non-Historic Fixed Price TCCs that it intends to renew under this Section 19.2.2.2 with a Point of Withdrawal in that Load Zone given the number of Grandfathered TCCs, Grandfathered Rights and Historic Fixed Price TCCs, in effect for the same term, that are held by or on behalf of the LSE with Points of Withdrawal in that Load Zone; and (ii) needs the transmission Capacity between the Point of Injection and Point of Withdrawal specified in the Non-Historic Fixed Price TCC to serve its Load. In no event shall an LSE be eligible to renew Non-Historic Fixed Price TCCs with a Point of Withdrawal in a Load Zone if the number of these Non-Historic Fixed Price TCCs when added to the number of Grandfathered TCCs, Grandfathered Rights, Historic Fixed Price TCCs and Non-Historic Fixed Price TCCs held by or on behalf of the LSE with a Point of Withdrawal in that Load Zone equals or exceeds the average hourly load of the LSE in that Load Zone.

In no event shall the ISO offer renewals that would extend a Non-Historic Fixed Price TCC for a total term of more than ten years,

19.2.2.3 Provisions affecting the Initial Purchase and the Renewal of Non-Historic Fixed Price TCCs

19.2.2.3.1 Pricing

Non-Historic Fixed Price TCCs intended to be purchased or renewed shall be priced for the initial or renewal term based on the market-clearing price calculated in the first round of the Sub-Auction of the Centralized TCC Auction conducted immediately subsequent to receipt of the completed Notice of Intent to Purchase or Notice of Intent to Renew in which TCCs with the same term as the Non-Historic Fixed Price TCCs being purchased or renewed were offered for sale, as established in ISO procedures. Such market-clearing prices shall have been calculated for a TCC with the same purchase or renewal term respectively (in years), and POI and POW, that is associated with the Non-Historic Fixed Price TCC. A Non-Historic Fixed Price TCC shall not have a purchase or renewal price of less than zero. To the extent that the formula in this Section 19.2.2.3.1 produces a purchase or renewal price for a Non-Historic Fixed Price TCC of less than zero, the price shall be zero.

19.2.2.3.2 Purchase or Renewal

The ISO shall provide to each LSE, that submitted a completed Notice of Intent to Purchase or a Notice of Intent to Renew, the purchase or renewal price of the Non-Historic Fixed Price TCCs identified in the LSE's completed Notice of Intent or Purchase or completed Notice of Intent to Renew, as appropriate. Within a period to be established by the ISO, following this notification, the purchasing or renewing LSE shall nominate the Non-Historic Fixed Price TCCs by Point of Injection and Point of Withdrawal that it has chosen to purchase or renew, provided that the availability of Non-Historic Fixed Price TCCs with a Point of Withdrawal in a Load Zone shall be limited by the lesser of the number of Non-Historic Fixed Price TCCs indicated as available by the ISO for that LSE with a Point of Withdrawal in that Load Zone or the number of

Non-Historic Fixed Price TCCs identified in the LSE's completed Notice of Intent to Purchase or Notice of Intent to Renew with a Point of Withdrawal in that Load Zone. The ISO may establish a deadline by which the ISO must receive the LSE's nominations of which Non-Historic Fixed Price TCCs it wishes to purchase or renew. An LSE that chooses not to renew its Non-Historic Fixed Price TCCs forfeits its entitlement to further renewals of that Non-Historic Fixed Price TCC.

If the ISO concludes that awarding the Non-Historic Fixed Price TCCs nominated by LSEs for purchase would make existing and valid TCCs infeasible, it will reduce the number of Non-Historic Fixed Price TCCs that an LSE can purchase to the extent necessary to avoid infeasibility. Such reduction shall use the same optimization model as the Centralized TCC Auctions, except that the nominated TCCs will not be represented as fixed injections and withdrawals but will be represented by a bid curve, pursuant to ISO Procedures.

Non-Historic Fixed Price TCCs shall become effective with the first day of the Capability Period immediately following their purchase or renewal.

19.2.2.3.3 Payment

An LSE that obtains Non-Historic Fixed Price TCCs pursuant to Section 19.2.2 shall be required to pay the ISO the total amount specified in annual payments for each year of the initial term of the Non-Historic Fixed Price TCC's and for each year of the renewal term of the Non-Historic Fixed Price TCC. Billing for Non-Historic Fixed Price TCCs shall be in accordance with ISO Procedures. To challenge settlement information contained in an invoice, a purchaser of Non-Historic Fixed Price TCCs shall first make payment in full, including any amounts in dispute.

An LSE that fails to make the required annual payment for the initial or any renewal term of its Non-Historic Fixed Price TCC shall, notwithstanding any provision in this OATT to the contrary, permanently surrender its right to future renewals of those Non-Historic Fixed Price TCCs and shall not have a right to renew for additional term(s), pursuant to ISO Procedures.

19.2.3 Miscellaneous Provisions Affecting Historic and Non-Historic Fixed Price TCCs

The ISO shall post the following information promptly after awarding Fixed Price TCCs: (i) the quantity of TCCs awarded (in MW); (ii) the Point of Injection and Point of Withdrawal for each Fixed Price TCC awarded; and (iii) the price paid for each Fixed Price TCC.

If an LSE acquires Load from another LSE that holds Fixed Price TCCs, it may request that the Fixed Price TCCs be reassigned to follow the transferred Load. In such case, the quantity of the Fixed Price TCCs that transfers to the assignee shall be equal to: (i) the amount of transferred Load divided by total Load associated with those Fixed Price TCCs, (ii) multiplied by the quantity of the Fixed Price TCCs held by the LSE losing Load between the same Point of Injection and Point of Withdrawal; provided however, that no Fixed Price TCC will transfer under this paragraph if the calculation above indicates that less than one Fixed Price TCC will transfer. If at least one Fixed Price TCC would transfer pursuant to this paragraph, the quantity of reassigned Fixed Price TCCs shall be rounded down to the nearest whole number of Fixed Price TCCs. An LSE that is reassigned Fixed Price TCCs under this paragraph shall hold such Fixed Price TCCs for the remainder of their term, and have rights of renewal as provided in Sections 19.2.1 and 19.2.2, provided it makes all required payments.

An LSE that has met all required payment and collateral obligations for its Fixed Price TCC, including LSEs that have transferred Load to a new LSE, may reassign, reconfigure, or sell its Fixed Price TCCs for any period of time for which its Fixed Price TCC is valid. Such assignment, reconfiguration, or sale shall not include renewal rights otherwise associated with the Fixed Price TCC, which renewal rights will remain with the LSE to which the Fixed Price TCCs were originally awarded, provided however that renewal rights associated with Fixed Price TCCs that are reassigned to follow the transferred Load shall be reassigned to follow the transferred Load. To the extent that Fixed Price TCCs are created pursuant to Section 19.2.1 or 19.2.2, the transmission Capacity that supports them shall not be available for sale in the Centralized TCC Auctions until those Fixed Price TCCs expire.

All rights and obligations that apply to an LSE in connection with obtaining and holding Fixed Price TCCs as provided for in Sections 19.2.1, 19.2.2 and 19.2.3, shall also be applicable to an ETA Agent, except as the context otherwise requires (for example, an ETA Agent cannot obtain Fixed Price TCCs on its own behalf).

The ISO shall establish a dispute period following the conclusion of the Centralized TCC Auction during the conduct of which Fixed Price TCCs are awarded, challenges to awards of Fixed Price TCCs may be made and mistakes in the calculation of Fixed Price TCC prices may be corrected. Notice of the dispute period established by the ISO and of procedures to be employed in bringing a dispute or correcting a Fixed Price TCC price shall be provided by the ISO on its OASIS.

Following the resolution of challenges, if any, to the award of Fixed Price TCCs, or mistakes in the calculation of Fixed Price TCC prices, raised during the dispute period, charges and payments for Fixed Price TCCs awarded shall be final as provided in the award notices provided by the ISO and shall not be subject to revision.

19.2.3.1 Responsibilities of LSEs that Obtain Fixed Price TCCs

To obtain a Fixed Price TCC under Section 19.2.1 or 19.2.2 of this Attachment M an LSE must submit such information to the ISO regarding its creditworthiness as the ISO may require. Each such LSE must also: (i) comply with the applicable deadlines established by the ISO under Sections 19.2.1, 19.2.2 and 19.2.3; (ii) satisfy all ISO credit requirements; and (iii) pay the price determined pursuant to Section 19.2.1 or 19.2.2.3.1, as appropriate.

19.2.4 Awards of Incremental TCCs

19.2.4.1 Overview

The ISO shall follow the procedures set forth in this Section 19.2.4 to determine awards of Incremental TCCs to any person or entity that requests them in connection with the funding or construction of new transmission facilities or transmission facility improvements that increase the Transfer Capability of the New York State Transmission System.

These procedures shall only apply to requests for awards that are submitted on or after November 1, 2008 and not to: (i) requests for awards that are pending as of that date; (ii) or to Incremental TCC award determinations that were made by the ISO on or prior to that date; neither shall these procedures interfere with the completion of requests for awards that are pending as of that date or require that award determinations made by the ISO prior to that date be reopened. Award determinations that were made prior to November 1, 2008 or that were pending as of that date shall remain effective as described in the ISO's Automated Market System.

Throughout this Section 19.2.4: (i) any change to, reconfiguration of, and/or construction of new transmission facilities or other transmission facility improvements that are potentially eligible for an award of Incremental TCCs shall be referred to as an "Expansion;" and (ii) a person or entity that is pursuing an Expansion and requesting Incremental TCCs shall be referred to as an "Expander."

The ISO shall not award Incremental TCCs: (i) when the ISO cannot calculate the effect on Transfer Capability associated with an Expansion in the Day-Ahead Market with reasonable certainty; (ii) for Expansions that involve controllable transmission facilities that are under the operational control of a Control Area operator other than the ISO; or (iii) to the extent that an Expansion's impact on Transfer Capability is solely dependent on a Generator's operating state. Additional information concerning eligibility for Incremental TCC awards shall be set forth in the ISO Procedures. The ISO shall not award Incremental TCCs before the provisions of Section 19.2.4.5.2 have all been fulfilled.

The ISO shall also follow the procedures in this Section 19.2.4 to determine whether "Partial Outage Incremental TCCs" should be created in connection with final awards of Incremental TCCs.

19.2.4.2 Requests for Incremental TCC Awards

An Expander pursuing an Expansion and seeking an Incremental TCC award shall submit a request for an award to the ISO. A request for an Incremental TCC award must be submitted prior to the associated Expansion's expected commercial operation date. A request for an Incremental TCC award shall not be deemed to be complete, and shall not be considered by the ISO, unless it includes all of the information and satisfies all of the technical requirements required by this Section 19.2.4 and by the ISO Procedures. Prior to submitting its request for a non-binding estimate, an Expander must have: (i) completed all of the engineering studies that are required under the ISO OATT, including Attachments X, S, and Z; and (ii) obtained all permits and regulatory approvals necessary to commence construction. If an Expansion is subject to the Class Year study requirements under Attachment S of the ISO OATT then the Expander must have accepted its Class Year cost allocation and posted the security required under Attachment S.

As part of its request for an award, an Expander shall request that the ISO prepare one or more non-binding estimates of an Expansion's impact on Transfer Capability between one or more POI/POW combinations. The ISO shall be required to prepare up to three non-binding estimates with respect to an Expansion. Additional rules governing requests for non-binding estimates shall be set forth in the ISO Procedures.

An Expander that is not subject to Section 20.2.5 of Attachment N to the ISO OATT that requests an Incremental TCC award associated with an Expansion that will consist of multiple transmission facilities that might separately be taken out of service or derated in connection with the outage of an External transmission facility must provide additional information regarding partial outage states, as specified in the ISO Procedures, as part of its request. The ISO will use this information to analyze the creation of Partial Outage Incremental TCCs.

19.2.4.3 Non-Binding Estimates

The ISO shall provide non-binding estimates of Incremental TCCs that might be awarded between different POI/POW combinations that are identified in a complete request for a non-binding estimate. The ISO shall only prepare non-binding estimates if the associated Expansion is expected to enter commercial operation within the current or next like Capability Period.

The ISO shall estimate whether, and to what extent, Incremental TCCs may be created by analyzing whether an Expansion will actually increase Transfer Capability with respect to the entire set of POI/POW combinations included in a request for a non-binding estimate. Incremental TCCs shall not be created for Transfer Capability that the ISO determines would exist on the system even in the absence of an Expansion. The ISO shall make these determinations using an Optimal Power Flow model that is updated and modified as necessary to represent the state of the New York State Transmission system both with and without the Expansion associated with the request for a non-binding estimate. If an Expansion is intended to increase voltage or transient stability limits the ISO shall conduct transfer limit studies as necessary to confirm the Expansion's impact on interface limits as specified in the ISO Procedures. Additional detail concerning the Optimal Power Flow model to be used by the ISO shall be set forth in the ISO Procedures. The ISO shall not be bound by the findings of previous engineering studies, conducted under the ISO OATT or otherwise, regarding the impact of an Expansion on Transfer Capability when preparing non-binding estimates (or when determining awards under Section 19.2.4.5).

If the ISO estimates that Incremental TCCs would be created by an Expansion it shall separately estimate the quantity of Incremental TCCs that would be created for both the Summer and Winter Capability Periods.

19.2.4.4 Partial Outage Incremental TCCs

The ISO shall use the additional information submitted by certain Expanders regarding partial outage states pursuant to Section 19.2.4 to determine whether Partial Outage Incremental TCCs shall be created. Partial Outage Incremental TCCs shall not be awarded. They shall only be used to determine day-ahead outage charges, implemented through settlements for Day-Ahead Market Congestion Rents associated with Expansions that are partially out of service, or that are derated due to the outage of an External transmission facility, in connection with the calculation of outage charges under Section 19.2.4.9.

Partial Outage Incremental TCCs shall be created to the extent that the ISO finds, as part of its determination of final Incremental TCC awards pursuant to Section 19.2.4.5, that a revised set of Incremental TCCs would exist between a given POI/POW combination regardless of whether a portion of the associated Expansion is out of service or derated as a result of the outage of an External transmission facility. Partial Outage Incremental TCCs may be created between POI/POW combinations that differ from those for which the ISO may determine that Incremental TCCs would be available in a non-binding estimate or in any award of Incremental TCCs.

If the ISO determines that Partial Outage Incremental TCCs may be created as the result of an Expansion it shall separately calculate the number that would be created for the Summer and Winter Capability Periods.

19.2.4.5 Incremental TCC Awards

The ISO shall respond to complete requests for Incremental TCC awards by determining: (i) whether, and to what extent, Incremental TCCs should be awarded for the POI/POW combinations selected by the Expander; and (ii) whether, and to what extent, Partial Outage Incremental TCCs should be created. An Expander may select all of the POI/POW combinations that were analyzed in any one of the non-binding estimates prepared by the ISO under Section 19.2.4.3 to be included in the award determination. It may not select the POI/POW combinations from more than one non-binding estimate or select fewer than all of the POI/POW combinations that were analyzed in any one non-binding estimate.

The ISO shall determine both temporary and final awards using an Optimal Power Flow model that is updated and modified as necessary to represent the state of the New York State Transmission system both with and without the Expansion, and to represent any of the

Expansion's partial outage states, at the time that an award is determined. The ISO shall determine whether, and to what extent, Incremental TCCs shall be awarded by analyzing whether an Expansion will actually increase Transfer Capability with respect to the entire set of POI/POW combinations included in a request for an award. Incremental TCCs shall not be awarded for Transfer Capability that the ISO determines would exist on the system even in the absence of an Expansion. If an Expansion is intended to increase voltage or transient stability limits the ISO shall conduct transfer limit studies as necessary to confirm the Expansion's impact on interface limits as specified in the ISO Procedures. The ISO shall make separate determinations for temporary and final awards of Incremental TCCs.

The ISO shall only determine or make an Incremental TCC award if the associated Expansion is expected to enter commercial operation within the current or next like Capability Period.

The ISO shall only determine, award, or create Incremental TCCs (including, for purposes of this paragraph, Partial Outage Incremental TCCs) in whole number MW quantities. If the ISO determines that an Expansion will create one or more non-whole number quantity Incremental TCCs, the ISO shall round each non-whole number Incremental TCC to a whole number in a manner that minimizes the risk of infeasibility caused by rounding with respect to the entire Incremental TCC award.

If the ISO determines that Incremental TCCs should be awarded, it shall make separate awards for the Summer and Winter Capability Periods.

19.2.4.5.1 Temporary Awards

If the ISO determines that Incremental TCCs should be awarded in connection with an Expansion and the Expansion goes into commercial operation during a Capability Period, the

ISO shall make a temporary award of Incremental TCCs as soon as reasonably possible after notice that the Expansion has entered commercial operation has been provided in writing to the ISO pursuant to the ISO Procedures. Temporary awards of Incremental TCCs shall terminate at the end of the last day before a final award of Incremental TCCs becomes effective. In the case of an Expansion that enters commercial operation less than 90 days before the beginning of a Capability Period, the temporary award that is effective during the Summer Capability Period (or any portion thereof) may differ from the temporary award that is effective during the Winter Capability Period (or any portion thereof). The quantity of Incremental TCCs included in a temporary award may differ from the quantity included in any of the non-binding estimate(s) associated with the Expansion and/or in the final award.

19.2.4.5.2 Final Awards

Awards of Incremental TCCs shall be final on the date by which the following are fulfilled: (i) an Expansion has actually entered commercial operation; (ii) written notice has been provided to the ISO pursuant to the ISO Procedures; and (iii) the ISO has determined the final award using an Optimal Power Flow analysis that reflects the results of the most recently completed Centralized TCC Auction. The quantity of Incremental TCCs included in a final award may differ from the quantity included in the temporary award, or in the non-binding estimate(s), associated with the Expansion.

Incremental TCCs included in final awards shall become effective on the first day of the first Capability Period following the date that the award became final. If, however: (i) the associated Expansion enters commercial operation fewer than ninety days before the end of a Capability Period then the Incremental TCCs included in a final award shall become effective on the first day of the next like Capability Period after the associated Expansion enters commercial operation; or (ii) the associated Expansion results in an increase to a limit that must be approved by the Operating Committee, and the Operating Committee's approval is granted fewer than ninety days before the end of a Capability Period, then the final award shall become effective on the first day of the next like Capability Period following the Operating Committee's approval.

If more than one Expansion enters commercial operation in the same Capability Period, the ISO shall make its final award determinations, and shall make final Incremental TCC awards, in the same order as the Expansions actually enter commercial operation.

19.2.4.6 Acceptance of Incremental TCC Awards

An Expander may elect to accept or reject a temporary or final award of Incremental TCCs in its entirety. Partial acceptances shall not be permitted. Deadlines for confirming the acceptance or rejection of an award shall be specified in the ISO Procedures.

An Expander that elects to accept a final award of Incremental TCCs shall inform the ISO, no later than the time that it accepts its final award, of the awarded Incremental TCCs' duration. Incremental TCCs shall have a duration of no less than twenty and no more than fifty years, starting on the date that the final award becomes effective, provided that their duration may not exceed the expected operating life of the associated Expansion. The ISO shall record the existence and duration of the Incremental TCCs in the Automated Market System.

If an Expander fails to accept a final award of Incremental TCCs and to specify the award's duration by the deadline established in the ISO Procedures it will forfeit its right to collect Day-Ahead Market Congestion Rent payments in connection with the Incremental TCCs until it confirms its acceptance in the manner specified in the ISO Procedures.

19.2.4.7 Attributes of Incremental TCCs

Incremental TCCs, but not partial outage Incremental TCCs, shall have the same attributes as other TCCs and shall be subject to the same rules under the ISO Tariffs, except as specifically provided in this Section 19.2.4.

19.2.4.8 Restrictions on Transfers of Incremental TCCs

19.2.4.8.1 Secondary Market transfers of fewer than all of the Incremental TCCs associated with a given Expansion that were included in a final award shall not be allowed with the exception of allowable Secondary Market transfers as provided in Section 19.2.4.8.2;, an Expander may only make Secondary Market transfers of all of the Incremental TCCs for all of the POI/POW combinations that were included in a final award for a given Expansion. This restriction shall not prohibit the sale of fewer than all of the Incremental TCCs included in a final award through a Centralized TCC Auction or a Reconfiguration Auction. Secondary Market transfers of Incremental TCCs shall be made pursuant to the provisions of OATT Section 19.6.2. Transferees of Incremental TCCs that choose to become Primary Holders shall be subject to all existing ISO credit requirements and may be subject to any future credit requirements that may be applied to TCCs with a duration longer than one year.

19.2.4.8.2 An Expander may make a Secondary Market transfer pursuant to OATT Section 19.6.2 of fewer TCCs than all of the Incremental TCCs finally awarded for a given Expansion for which it is the Primary Holder provided that the Expander received a single final award of Incremental TCCs for the Expansion which award specified the same POI and the same POW combination. To comply with the requirement of a single final award with the same POI and POW, POIs or POWs that represent individual units of a Generator comprised of a group of generating units shall be deemed the same POI or POW.

A Secondary Market transfer by an Expander of all or a portion of its Incremental TCCs awarded for a given Expansion, pursuant to Sections 19.2.4.8.2 and 19.6.2, that is an assignment of the Incremental TCCs shall also operate as an assignment of the annual option to terminate the assigned Incremental TCCs, available pursuant to Section 19.2.4.9.

Incremental TCCs that are awarded pursuant to a temporary award may not be sold or transferred through a Secondary Market transfer, through a Centralized TCC Auction, through a Reconfiguration Auction, or otherwise.

19.2.4.9 Early Termination of Incremental TCCs

An Expander or its assignee shall have an annual option to terminate Incremental TCCs for which it is the Primary Holder and which were finally awarded to the Expander for a given Expansion. This annual option extends only to the entire portfolio of Incremental TCCs held by the Expander or its assignee for a given Expansion; early termination of a partial award of Incremental TCCs for a given Expansion held by a Expander or its assignee shall not be permitted. The annual option to terminate Incremental TCCs shall expire: i) with the early termination of those Incremental TCCs pursuant to this paragraph; ii) with the Expander's assignment of those Incremental TCCs; or iii) with a Secondary Market transfer of all or a portion of those Incremental TCCs, which expiration would apply only to the transferred portion of the Incremental TCCs and only for the duration of the Secondary market transfer.

To terminate its Incremental TCCs, the Expander, or the Expander's assignee, shall provide a notice of early termination and a proposed expiration date by Certified, Return-Receipt U.S. Mail, or by a reputable commercial courier service employing a parcel tracking system to the ISO at least one year in advance of the proposed early termination date which notice shall be irrevocable. The termination date for Incremental TCCs that were subject to a notice of early termination shall be the last day of a Capability Period which date occurs no earlier than one year after the notice of proposed early termination has been received by the ISO.

19.2.4.9.1 Upon receiving the notice of an early termination, the ISO shall promptly notice the market of the effective date of the early termination. To ensure that Centralized TCC Auctions following a notice of early termination start with a simultaneously feasible security constrained Power Flow, the ISO may: i) update its ISO Procedures to include prohibited bid points or combinations of prohibited bid points at which TCCs with durations of longer than one year may not be available in a future Centralized TCC Auction or Reconfiguration Auction, as a result of the notice of early termination; and / or ii) rather than effectuate the termination date, require that the Incremental TCC award proposed for early termination be apportioned such that the Incremental TCCs terminate in portions over as many as 12 months, beginning with the initial termination date. To terminate Incremental TCCs in portions over as many as 12 months, the ISO shall establish up to two additional termination dates following the initial termination date, and assign Incremental TCCs to each termination date, which additional termination dates shall fall at the end of the Capability Period(s) that follow the initial termination date.

Any prohibition on bid points resulting from a notice of early termination of Incremental TCCs in order to avoid infeasibility shall expire as of the first Capability Period following the last termination date of the Incremental TCCs.

19.2.4.10 Outage Charges

Any person or entity that is not subject to Section 20.2.5 of Attachment N to the ISO OATT and that owns an Expansion (or a portion of an Expansion) associated with a temporary or final award of Incremental TCCs, or has been assigned Incremental TCCs by an Expander, shall pay an outage charge to the ISO for any hour in the Day-Ahead Market during which the Expansion associated with the Incremental TCCs is modeled to be wholly or partially out of service. All outage charges shall be implemented through the billing of Day-Ahead Market Congestion Rents to the person or entity responsible for paying the outage charge and, as such, will be credits to Day-Ahead Market Congestion Rents in the ISO settlement system.

Outage charges shall be determined as follows:

- If the entire Expansion is modeled as out of service in the Day-Ahead Market; the outage charge shall be equal to the Day-Ahead Market Congestion Rent payment for all of the Incremental TCCs associated with the entire Expansion.
- If one or more portions of an Expansion are modeled as out of service in the Day-Ahead Market, or derated by the outage of an External Transmission facility, and Partial Outage Incremental TCCs have not been created, the outage charge shall be equal to the Day-Ahead Market Congestion Rent payment for all of the Incremental TCCs associated with the entire Expansion.
- If one or more portions of an Expansion are modeled as out of service in the Day-Ahead Market or are caused to be out of service or derated by the outage of an External

transmission facility, and Partial Outage Incremental TCCs have been created for such an out-of-service state or derating, the outage charge shall be calculated as follows:

Outage charge = A – B

where:

- "A" is the sum, over all different POI and POW combinations associated with the Incremental TCCs for an Expansion, of the product of (i) the Congestion Component at the POW minus the Congestion Component at the POI; and (ii) the number of Incremental TCCs between that POI and POW associated with the Expansion, and
- "B" is the sum, over all different POI and POW combinations associated with the Partial Outage Incremental TCCs for that out-of-service state or derating of the Expansion, of the product of: (i) the Congestion Component at the POW minus the Congestion Component at the POI; and (ii) the number of Partial Outage Incremental TCCs between that POI and POW associated with that out-of-service state or derating of the Expansion.

19.2.4.11 Incremental TCCs for System Deliverability Upgrades

In accordance with Section 25.7.2 of Attachment S of the ISO OATT, the Transmission Owner(s) responsible for constructing a System Deliverability Upgrade shall be the entity(ies) to submit requests for awards of Incremental TCCs pursuant to this Section 19.2.4 for each System Deliverability Upgrade, which will constitute the Expansion for purposes of each such request. The ISO shall evaluate each such request in accordance with the requirements of this Section 19.2.4 to determine any applicable temporary and/or final Incremental TCC awards for each System Deliverability Upgrade, including any Partial Outage Incremental TCCs relating thereto. Unless otherwise specified herein, Incremental TCCs resulting from System Deliverability Upgrades will be subject to the same requirements as Incremental TCCs awarded to any other

Expansion pursuant to this Section 19.2.4, including the payment of any outage charges pursuant to Section 19.2.4.10 of this Attachment M.

If the ISO determines that a System Deliverability Upgrade is eligible to receive an award of Incremental TCCs, including any Partial Outage Incremental TCCs relating thereto, the ISO will allocate the determined award among the applicable Developers eligible to receive Incremental TCCs related to the System Deliverability Upgrade and/or the Transmission Owner(s) responsible for constructing the System Deliverability Upgrade in accordance with the requirements of Section 25.7.2 of Attachment S of the ISO OATT. Each Developer eligible to receive Incremental TCCs related to the System Deliverability Upgrade shall be provided the right to elect to receive its respective portion of such Incremental TCCs pursuant to Section 19.2.4.6 of this Attachment M. To the extent necessary to facilitate the potential for transfers to subsequent Developers that pay for the use of Headroom pursuant to Attachment S of the ISO OATT on a System Deliverability Upgrade that has been awarded Incremental TCCs, Incremental TCCs that are declined by a Developer will be deemed reserved. Incremental TCCs that are declined by a Developer and not otherwise deemed reserved will be deemed permanently terminated.

If subsequent Developers pay for the use of Headroom pursuant to Attachment S of the ISO OATT on a System Deliverability Upgrade that has been awarded Incremental TCCs, such subsequent Developers will be provided a right to elect to receive any applicable Incremental TCCs to which they may be eligible to receive in accordance with Sections 25.7.2 and 25.7.12 of Attachment S of the ISO OATT. Incremental TCCs to be made available to subsequent Developers will, as applicable, be obtained by the ISO by reducing the Incremental TCCs related to the System Deliverability Upgrade that were previously: (i) awarded to the Developers that initially paid for the System Deliverability Upgrade; (ii) awarded to the Transmission Owner(s) responsible for constructing the System Deliverability Upgrade; and/or (iii) deemed reserved as a result of prior declination and/or termination, in accordance with the requirements of Section 25.7.2 of Attachment S of the ISO OATT. Incremental TCCs that were previously deemed reserved and are transferred to a subsequent Developer will become effective on the first day of the Capability Period that commences following the next Centralized TCC Auction conducted after the subsequent Developer makes the necessary Headroom payment and elects to receive its proportionate share of Incremental TCCs. Incremental TCCs that are declined by a subsequent Developer will be deemed permanently terminated.

Any Developer that elects to receive Incremental TCCs related to a System Deliverability Upgrade shall have the right to terminate its Incremental TCCs in accordance with Section 19.2.4.9 of this Attachment M. Incremental TCCs terminated by a Developer that initially paid for a System Deliverability Upgrade will, to the extent necessary to facilitate the potential for transfers to subsequent Developers that pay for the use of Headroom pursuant to Attachment S of the ISO OATT on a System Deliverability Upgrade that has been awarded Incremental TCCs, be deemed reserved. Incremental TCCs that are terminated by a Developer that initially paid for a System Deliverability Upgrade and not otherwise deemed reserved will be deemed permanently terminated. Incremental TCCs terminated by a subsequent Developer that paid for the use of Headroom on a System Deliverability Upgrade will be deemed permanently terminated.

Notwithstanding anything to the contrary in this Section 19.2.4, Incremental TCCs awarded as a result of System Deliverability Upgrades may not be sold or transferred through a Centralized TCC Auction, Reconfiguration Auction or the Secondary Market. Incremental TCCs related to a System Deliverability Upgrade that are deemed reserved as a result of prior declination or termination will not be considered as active or valid for the period during which they remain deemed reserved. Incremental TCCs related to a System Deliverability Upgrade that were previously deemed reserved as a result of prior declination or termination will be deemed permanently terminated when the Headroom on the System Deliverability Upgrade ceases to exist or is otherwise reduced to zero in accordance with Section 25.8.7.4 of Attachment S of the ISO OATT.

19.3 Allocation of Residual Transmission Capacity As Original Residual TCCs

Before the first Centralized TCC Auction, the ISO calculated the Residual Transmission Capacity across each transmission Interface in both the Summer and Winter Capability Periods from the Operating Study Power Flow dispatch and allocated the Residual Transmission Capacity across Interfaces to individual Transmission Owners in the form of Original Residual TCCs in accordance with the Interface MW-Mile Methodology. The Original Residual TCCs allocated to individual Transmission Owners are shown in Table 3.

The ISO's allocation of Original Residual TCCs to Transmission Owners shall remain the same for at least the duration of the LBMP Transition Period. At the conclusion of the LBMP Transition Period, the Transmission Owners will review this methodology and shall have the sole discretion to modify by unanimous vote, the procedure to be used to allocate Residual Transmission Capacity across Interfaces in the form of Original Residual TCCs, and to determine the duration of all such Original Residual TCCs allocated.

Original Residual TCCs for each Interface will constitute point-to-point TCCs, each from a Point of Injection in one Load Zone to a Point of Withdrawal in another Load Zone.

Transmission Owners will be required to sell Original Residual TCCs, not previously sold in a Direct Sale, through a Centralized TCC Auction. Primary Holders of Original Residual TCCs shall inform the ISO of all Direct Sales of those TCCs, including the identity of the buyer.

19.4 Reservation of Transmission Capacity in a Centralized TCC Auction through ETCNL TCCs

19.4.1 Subject to the limitations set forth in Section 19.4.2 of this Attachment M, a Transmission Owner with a set of ETCNL designated from a Point of Injection to a Point of Withdrawal, as detailed in Table 2 of this Attachment M, shall have a right prior to each Centralized TCC Auction to convert into an ETCNL TCC each megawatt of transmission Capacity of that set of ETCNL not used to support the sale of existing TCCs that are valid for any part of the duration of any TCCs to be sold in the Centralized TCC Auction and that remains after any reduction pursuant to Section 19.8.2 of this Attachment M.

Each ETCNL TCC will have a duration of 6 months and will have the same POI and POW as the original set of ETCNL converted into ETCNL TCCs.

If a Transmission Owner fails to exercise its right to convert a megawatt of ETCNL into an ETCNL TCC in the manner and by the date specified in this Section 19.4, the Transmission Owner shall forfeit its right to convert ETCNL into ETCNL TCCs for the Centralized TCC Auction. Any ETCNL not converted to ETCNL TCCs shall remain valid as ETCNL, and shall be released for the Centralized TCC Auction pursuant to the provisions of this Attachment M.

19.4.2 Notwithstanding any other provisions of this Section 19.4, a Transmission Owner shall not convert into ETCNL TCCs an amount greater than the Capacity Reservation Cap of the transmission Capacity of each set of the Transmission Owner's ETCNL; *provided, however*, that if (i) a Transmission Owner has a set of ETCNL from one POI and one or more sets of ETCNL from another POI, each of which are in the same Load Zone, and (ii) each of these sets of ETCNL has the same POW, then there shall be no maximum amount of transmission Capacity from a single set of ETCNL that a Transmission Owner shall have a right to convert into ETCNL TCCs, but a Transmission Owner shall not convert into ETCNL TCCs an amount greater than the Capacity Reservation Cap of the total transmission Capacity of all of the Transmission

Owner's sets of ETCNL with that POW.

ETCNL may be converted only into whole ETCNL TCCs. If the Capacity Reservation Cap multiplied by the transmission Capacity of a set of ETCNL or by the total transmission Capacity of multiple sets of ETCNL, as the case may be pursuant to this Section 19.4.2, does not yield a whole number, then the number of ETCNL TCCs that a Transmission Owner may convert from ETCNL will be reduced to the nearest integer and the number of megawatts of ETCNL that a Transmission Owner may not convert to ETCNL TCCs will be increased to the nearest integer.

19.4.3 The ISO shall determine the Capacity Reservation Cap prior to each Centralized TCC Auction, and shall post the Capacity Reservation Cap on its website. The Capacity Reservation Cap shall be any amount less than or equal to five percent (5%).

19.4.4 Before each Centralized TCC Auction, the ISO shall, subsequent to performing the reduction process pursuant to Section 19.8.2 of this Attachment M, determine the number of megawatts of transmission Capacity from each of the Transmission Owner's sets of ETCNL that the Transmission Owner shall have a right to convert into ETCNL TCCs. The ISO shall notify each Transmission Owner of the ISO's determination with regard to its ETCNL in a written notice to be received by the Transmission Owner on or before the date specified in the timeline for the relevant Centralized TCC Auction posted on the ISO's website, as that timeline may be revised from time to time.

19.4.5 A Transmission Owner may exercise its right to convert its ETCNL into ETCNL TCCs by notifying the ISO of the number of megawatts of transmission Capacity from each of the Transmission Owner's sets of ETCNL that the Transmission Owner elects to convert to ETCNL TCCs. The Transmission Owner shall make the notification in a written notice to be received by the ISO on or before the date specified in the timeline for the relevant Centralized

TCC Auction posted on the ISO's website, as that timeline may be revised from time to time. After receipt by the ISO, the Transmission Owner's notification shall not be modified or revoked, except by permission of the ISO.

19.5 Reservation of Transmission Capacity in a Centralized TCC Auction through RCRR TCCs

19.5.1 Before each Centralized TCC Auction, the ISO shall, subsequent to performing the reduction process pursuant to Section 19.8.2 of this Attachment M, determine the number of RCRRs between each of the following contiguous pairs of Load Zones within the NYCA that the ISO shall allocate to Transmission Owners: West – Genesee; Genesee – Central; North – Mohawk Valley; Central - Mohawk Valley; Mohawk Valley – Capital; Capital - Hudson Valley; Hudson Valley – Millwood; Millwood – Dunwoodie; Dunwoodie - New York City; Dunwoodie - Long Island.

The ISO shall determine the number of RCRRs that the ISO shall allocate for each of these Load Zone pairs by maximizing the number of RCRRs between each Load Zone pair that are simultaneously feasible with all TCCs and Grandfathered Rights listed in Section 19.8.2 (i), and Table 1 ETCNL/TCCs that remain~~s~~ after reduction pursuant to Section 19.8.2 of this Attachment M.

To do so, the ISO will use the same optimization model that is used in determining the award of TCCs in a Centralized TCC Auction, and will represent each TCC and Grandfathered Right listed in Section 19.8.2 (i), Table 1 ETCNL/TCCs remaining after reduction pursuant to Section 19.8.2, and a large number of RCRRs in the model as fixed injections and withdrawals. The Centralized TCC Auction software will determine the maximum number of RCRRs for each Load Zone pair by maximizing the area under the bid curve $Bids_j$ as expressed by the following formula, subject to the constraint that the injections and withdrawals corresponding to the TCCs, Grandfathered Rights listed in Section 19.8.2 (i) and Table 1 ETCNL/TCCs remaining after reduction pursuant to Section 19.8.2, and potential RCRRs must correspond to a simultaneously feasible Power Flow:

$$\sum_{j \in N} \int_0^{A_j} Bids_j$$

Where,

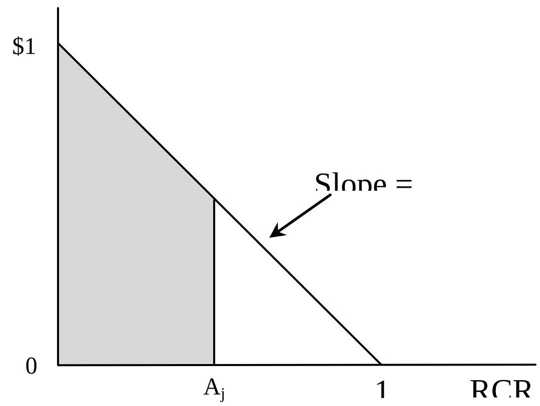
j = A Load Zone pair

N = The set of all Load Zone pairs for which the ISO shall calculate RCRRs

A_j = The number of RCRRs defined between Load Zone pair *j*

$Bids_j$ = The line that intersects the y-axis at $1/TCC and which intersects the x-axis at 1 MW, as illustrated in the bid curve illustrated below.

Bid Curve $Bids_j$ for $RCRR_j$



The ISO shall determine the POI and POW of each RCRR by assigning the POI and POW that the ISO expects, based on the ISO's review of historical and other information available to the ISO, to produce positive Congestion payments to a Transmission Owner that converts the RCRR into an RCRR TCC for the majority of the duration, in hours, of the longest duration TCCs to be sold in the relevant Centralized TCC Auction.

19.5.2 The ISO shall allocate RCRRs between each Load Zone pair to each Transmission Owner in an amount equal to the product of (i) the number of RCRRs between the Load Zone pair for the Centralized TCC Auction as calculated pursuant to Section 19.5.1 of this Attachment M, and (ii) the Transmission Owner's allocation factor for that Load Zone pair, which shall be calculated pursuant to the following formula:

$$\text{Allocation Factor}_{\text{t,j}} = \frac{\sum_{a \in A} \left(\text{Interface Revenue}_{t,j,a}\right)}{\sum_{\substack{t \in T \\ a \in A}} \left(\text{Interface Revenue}_{t,j,a}\right)}$$

Where,

Allocation $\text{Factor}_{t,j}$	=	The allocation factor used by the ISO to allocate a share of RCRRs between Load Zone pair *j* to Transmission Owner *t* for a Centralized TCC Auction
Interface $\text{Revenue}_{t,j,a}$	=	The revenue from the sale of TCCs (excluding those TCCs for which revenue is allocated to a Transmission Owner pursuant to Sections 20.3.3 through 20.3.5 of Attachment N) associated with the Interface between Load Zone pair *j* in Centralized TCC Auction *a* assigned to Transmission Owner *t*

t	=	A Transmission Owner
T	=	The set of all Transmission Owners
a	=	A Centralized TCC Auction
A	=	The set of Centralized TCC Auctions beginning with the Centralized TCC Auction held for the 2000 Summer Capability Period and ending with the Centralized TCC Auction held for the 2003-2004 Winter Capability Period
j	=	A Load Zone pair.

19.5.3 Subject to the limitations set forth in Section 19.5.4 of this Attachment M, a Transmission Owner allocated an RCRR pursuant to Section 19.5.2 of this Attachment M shall have a right prior to each Centralized TCC Auction to convert each RCRR into an RCRR TCC. Each RCRR TCC will have a duration of 6 months and will have the same POW and POI as the RCRR from which it was converted. If a Transmission Owner fails to exercise its right to convert an RCRR into an RCRR TCC in the manner and by the date specified in this Section 19.5.0, the Transmission Owner shall forfeit the RCRR. Each RCRR shall be valid only for the Centralized TCC Auction for which it was allocated.

19.5.4 Notwithstanding any other provisions of this Section 19.5.0, a Transmission Owner shall not convert an amount greater than the Capacity Reservation Cap of the Transmission Owner's RCRRs into RCRR TCCs.

RCRRs may be converted only into whole RCRR TCCs. If the Capacity Reservation Cap multiplied by the number of RCRR does not yield a whole number, then the number of RCRR TCCs that a Transmission Owner shall have a right to convert from RCRRs will be reduced to the nearest integer and the number of RCRRs that a Transmission Owner shall not have a right to convert to RCRR TCCs will be increased to the nearest integer.

19.5.5 Before each Centralized TCC Auction, the ISO shall, subsequent to performing the reduction process pursuant to Section 19.8.2 of this Attachment M, determine the number of RCRRs that each Transmission Owner shall have a right to convert to RCRR TCCs. The ISO shall notify each Transmission Owner of the ISO’s determination with regard to its RCRRs in a written notice to be received by the Transmission Owner on or before the date specified in the timeline for the relevant Centralized TCC Auction posted on the ISO’s website, as that timeline may be revised from time to time.

19.5.6 A Transmission Owner may exercise its right to convert its RCRRs into RCRR TCCs by notifying the ISO of the number of the Transmission Owner’s RCRRs that the Transmission Owner elects to convert to RCRR TCCs. The Transmission Owner shall make the notification in a written notice, in accordance with ISO Procedures, to be received by the ISO on or before the date specified in the timeline for the relevant Centralized TCC Auction posted on the ISO’s website, as that timeline may be revised from time to time. After receipt by the ISO, the Transmission Owner’s notification shall not be modified or revoked, except by permission of the ISO.

19.5.7 A Transmission Owner shall not transfer (by sale or otherwise) its RCRR TCC except through a Centralized TCC Auction or Reconfiguration Auction, and shall not sell its RCRR TCC through Direct Sales or through Secondary Markets.

19.6 Direct Sale of TCCs by Transmission Owners directly over the OASIS ("Direct Sale")

19.6.1 Direct Sales

Transmission Owners may sell their Original Residual TCCs, ETCNL, and Grandfathered TCCs directly to buyers through a Direct Sale. Sellers and potential buyers shall communicate all offers to sell and buy TCCs, through a Direct Sale, solely over the ISO's OASIS. Buyers and Sellers of TCCs by Direct Sale will have the responsibility to report their TCC transactions to the ISO, whereupon the ISO will post them on the OASIS. Provisions governing Primary Holder status and responsibilities otherwise applicable to TCCs shall be applicable to TCCs acquired through a Direct Sale.

During the Direct Sale process, the Transmission Owner electing to use Direct Sale shall have the sole discretion to accept or reject an offer to purchase TCCs. Each Transmission Owner shall develop and apply a non-discriminatory method for choosing the winning offers consistent with FERC Order No. 889, et seq., and may establish eligibility requirements that shall be no more stringent than those set forth in Section 2.14 of this Tariff. The Transmission Owner shall post information regarding the results of the Direct Sale on the ISO's OASIS promptly after the Direct Sale is completed. The information shall include: (i) the amount of TCCs sold (in MW); (ii) the Point of Injection and Point of Withdrawal for each TCC sold; and (iii) the price paid for each TCC.

Each Transmission Owner may retain its Grandfathered TCCs. If it sells Grandfathered TCCs, a Transmission Owner shall do so through Direct Sales or through Centralized TCC Auctions or Reconfiguration Auctions for periods not extending beyond the termination date of those TCCs. Payment for TCCs purchased in a Direct Sale shall be in accordance with the terms and conditions of the agreement between the buyer and seller.

19.6.2 Secondary Market for TCCs

After the conclusion of each auction, all Primary Holders may sell their TCCs in the Secondary Markets, unless otherwise provided in this Attachment M. However, the ISO shall make all Settlements with Primary Holders. Buyers in a Secondary Market that elect to become Primary Holders must meet the eligibility criteria in Section 19.7 of this Attachment M. Buyers and Sellers of TCCs in the Secondary Market will have the responsibility to report their TCC transactions to the ISO, whereupon the ISO will post them on the OASIS.

19.7 Primary Holders

Parties that purchase TCCs at the close of the Centralized TCC Auction or Reconfiguration Auction, that convert their ETAs to Historic Fixed Price TCCs, buyers of Non-Historic Fixed Price TCCs, buyers in the Secondary Market that meet the eligibility criteria listed herein, and Expanders (as defined in Section 19.2.4.1) accepting a Temporary or Final Award of Incremental TCCs become Primary Holders of those TCCs. The ISO shall make all TCC settlements with Primary Holders. When selling TCCs, Transmission Owners are considered Primary Holders of those TCCs. A Primary Holder of a TCC which sells that TCC through a Direct Sale continues to be the Primary Holder of that TCC unless the buyer elects to become the Primary Holder of that TCC.

Primary Holders must meet the following eligibility criteria; (i) register as Transmission Customers and otherwise comply with all applicable registration requirements established in ISO Procedures; (ii) comply with all applicable credit requirements as set forth in Attachment K of the ISO Services tariff; and (iii) submit a statement signed by the buyer, representing that the buyer is financially able and willing to pay for the TCCs it proposes to purchase as well as all other obligations associated with the purchase of such TCCs, including without limitation, Congestion Rent due pursuant to this Tariff.

Where a buyer electing to become a Primary Holder fails to meet the eligibility criteria or the above financial criteria (as determined by the ISO), or fails to provide information required by the ISO, the seller of the TCCs in a Direct Sale shall be the Primary Holder with respect to those TCCs.

19.8 Auctions for TCCs

19.8.1 Overview

The ISO will conduct Centralized TCC Auctions before each Capability Period. Winning bidders in each such auction will purchase TCCs that will be valid for one or more Capability Periods, beginning with the first Capability Period that begins after the conclusion of the auction. The ISO will also conduct Reconfiguration Auctions each month. Winning bidders in each such auction will purchase TCCs valid for one or more calendar months within the same Capability Period, beginning with the calendar month that begins after the conclusion of the auction.

19.8.2 Description of the Reduction Process For Reducible ETCNL/GFTCCs

Before each Centralized TCC Auction, the ISO shall ensure that all of the following correspond to a simultaneously feasible security constrained Power Flow: (i) existing TCCs and Grandfathered Rights that are valid for any part of the duration of any TCCs to be sold in the Centralized TCC Auction, including but not limited to Fixed Price TCCs that were created pursuant to Section 19.2.1 or 19.2.2.of this Attachment M and Incremental TCCs awarded pursuant to Section 19.2.4 of this Attachment M; Grandfathered TCCs not subject to reduction and Original Residual TCCs to the extent not previously used to support the purchase of TCCs that are valid for any part of the duration of any TCCs to be sold in the Centralized TCC Auction (henceforth “TCCs and Grandfathered Rights listed in Section 19.8.2 (i)”); and (ii) ETCNL (to the extent not previously used to support the purchase of TCCs that are valid for any part of the duration of any TCCs to be sold in the Centralized TCC Auction) and Grandfathered TCCs subject to reduction as listed in Table 1 of this Attachment M (henceforth “Table 1 ETCNL/TCCs”). In some cases, the total set of all the TCCs, Grandfathered Rights, and Table 1 ETCNL/TCCs listed in (i) through (ii) above may not correspond to a simultaneously feasible

Power Flow in some period of time. In such cases, Table 1 ETCNL/TCCs, will be reduced for that period in order to make the total set of TCCs and Grandfathered Rights listed in Section 19.8.2 (i), and Table 1 ETCNL/TCCs remaining after reduction correspond to a simultaneously feasible Power Flow.

This reduction procedure will use the same optimization model that will be used in the Centralized TCC Auction to determine the amount by which Table 1 ETCNL/TCCs will be reduced. Each of the TCCs and Grandfathered Rights listed in Section 19.8.2 (i) above will be represented in the Centralized TCC Auction model by a fixed injection of 1 MW at its Point of Injection, and a fixed withdrawal of 1 MW at its Point of Withdrawal. In addition, Table 1 ETCNL/TCCs will be represented in the model, but they will be represented in such a way as to allow their reduction. To do so, bids for each Table 1 ETCNL/TCC will consist of a line which intersects the y-axis at $1/TCC (or any other value selected by the ISO, so long as that value is constant for each bid curve for all of these Table 1 ETCNL/TCCs) and which intersects the x-axis at 1 MW. An example of the bid curve B_j for a representative Table 1 ETCNL/TCC is illustrated in the diagram below.

The TCC auction software will determine the amount of each Table 1 ETCNL/TCC that will remain after reduction, which is designated as A_j in the diagram. The objective function that the TCC auction software will use to determine these coefficients A_j will be to maximize:

$$\sum_{j \in N} \int_0^{A_j} \mathrm{B}_j$$

Where:

N = The set of Table 1 ETCNL/TCCs

j = Any individual Table 1 ETCNL/TCC

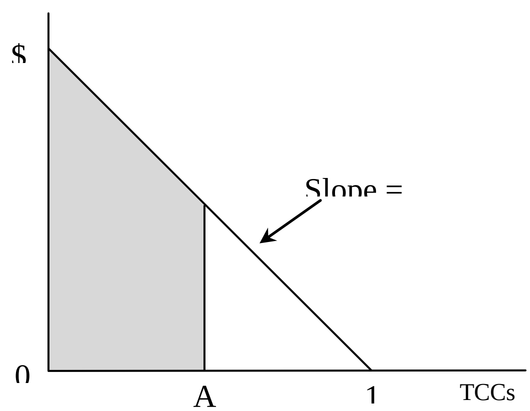
A_j = Any amount of each Table 1 ETCNL/TCC(j) remaining

B_j = As defined by the diagram

subject to the constraint that injections and withdrawals corresponding to the TCCs and Grandfathered Rights listed in Section 19.8.2(i) and Table 1 ETCNL/TCCs remaining after reduction must be simultaneously feasible in a Power Flow.

As a result, the objective function will maximize the area under the bid curve for each Table 1 ETCNL/TCC that remains after reduction, summed over all Table 1 ETCNL/TCCs, subject to the simultaneous feasibility constraint. This area for one Table 1 ETCNL/TCC is illustrated in the following diagram:

Bid Curve B_j for TCCj



The ISO shall apply this methodology as follows:

19.8.2.1 first, on the Table 1 ETCNL/TCCs (prior to the conversion of any ETCNL to ETCNL TCCs), and

19.8.2.2 second, on the Table 1 ETCNL/TCCs remaining after conversion into ETCNL TCCs of ETCNL included in such Table 1 ETCNL/TCCs.

For purpose of the second reduction, a holder of ETCNL may elect to disaggregate the ETCNL in accordance with ISO Procedures prior to conducting the reduction process. If a

Transmission Owner elects to have its ETCNL disaggregated, the number of MW of ETCNL allocated to that Transmission Owner specifying each Load Zone as its POW shall be replaced by the same number of MW of ETCNL, specifying the same POI as the original ETCNL, but specifying various buses within that Load Zone as the POWs, as determined in accordance with ISO Procedures.

To the extent more than one model is used in a given Centralized TCC Auction (*e.g.*, to reflect different summer / winter ratings), the ISO shall retest the Table 1 ETCNL/TCCs remaining after reduction so as to avoid reducing the Table 1 ETCNL/TCCs more than is necessary to prevent infeasibility in a given Sub-Auction. However, any Table 1 ETCNL/TCC that is deemed infeasible in one Centralized TCC Auction may be deemed reduced and not eligible for retesting in a subsequent Centralized TCC Auction.

19.8.3 Transmission Capacity Sold in Centralized Auctions for TCCs

Transmission Owners with ETCNL will release that transmission Capacity to support the sale of TCCs in each Centralized TCC Auction, unless the Transmission Owner has converted the ETCNL into ETCNL TCCs pursuant to Section 19.4 of this Attachment M. Transmission Owners which have not sold their Original Residual TCCs through a Direct Sale on the OASIS prior to the Centralized TCC Auction, shall sell them through the Centralized TCC Auction. Transmission Owners may retain their Grandfathered TCCs. If it sells Grandfathered TCCs, a Transmission Owner shall do so either through Direct Sales or through Centralized TCC Auctions or Reconfiguration Auctions.

Capacity associated with the termination of ETAs in effect on November 19, 1999, listed in Table 1A of Attachment L to this OATT (as it may be amended), that conferred transmission rights on an LSE and is not used to create Historic Fixed Price TCCs, pursuant to Section 19.2.1 of this Attachment M shall be converted into Residual Transmission Capacity.

In each Centralized TCC Auction, the following transmission Capacity not required to support already-outstanding TCCs or Grandfathered Rights and not withheld pursuant to Section 19.1.1 of this Attachment M shall be available to support TCCs that can be purchased in that Centralized TCC Auction:

19.8.3.1 following any reduction pursuant to Section 19.8.2 of this Attachment M, all of the transmission Capacity associated with ETCNL (a) that the Transmission Owners do not sell through a Direct Sale in advance of the Centralized TCC Auction, (b) that the Transmission Owners do not convert to ETCNL TCCs, and (c) that has not been used to support the sale of existing TCCs that are valid for any part of the duration of any TCCs sold in the Centralized TCC Auction;

19.8.3.2 all of the transmission Capacity associated with Original Residual TCCs, that the Transmission Owners do not sell through a Direct Sale in advance of the Centralized TCC Auction and that has not been used to support the sale of existing TCCs that are valid for any part of the duration of any TCCs sold in the Centralized TCC Auction;

19.8.3.3 all of the transmission Capacity associated with TCCs offered for sale by TCC Primary Holders; and

19.8.3.4 any Residual Transmission Capacity.

19.8.4 Centralized TCC Auctions

TCCs with durations of 6 months and 1 year shall be available in each Centralized TCC Auction. TCCs with durations of 2 years, 3 years, 4 years, or 5 years may also be available in the Centralized TCC Auction, at the ISO's discretion.

The final decision concerning the percentage of the transmission Capacity that will be available in the Centralized TCC Auction to support TCCs of different durations will be made by the ISO. The ISO will conduct a polling process to assess the market demand for TCCs with different durations, which it will take into consideration when making this determination. The ISO may elect not to sell any TCCs with one or more of the above durations. However, all transmission Capacity not associated with ETAs or outstanding TCCs or not reserved through conversion of ETCNL to ETCNL TCCs or RCRRs to RCRR TCCs must be available to support TCCs of some duration sold in the Centralized TCC Auction.

The Centralized TCC Auction will consist of a series of Sub-Auctions, which will be conducted consecutively. In each Sub-Auction, TCCs of a single duration will be available (*e.g.*, only TCCs with a five-year duration might be available in one Sub-Auction). Sub-Auctions will be conducted in decreasing order of the length of the period for which TCCs sold in the Sub-Auction are valid. Therefore, if the ISO were to determine that five years would be the maximum length of TCCs available in the Centralized TCC Auction, then the Sub-Auction for TCCs with a duration of five years would be held first. All TCCs sold in the 5-year TCC Sub-Auction (other than those offered for sale in the next Sub-Auction, as described in Section 19.9.1) would then be modeled as fixed injections and withdrawals in the next Sub-Auction, in which TCCs of the next longest duration, as determined by the ISO (*e.g.*, four years), would be available for purchase. Following that Sub-Auction, TCCs sold in either of the first two Sub-Auction (other than those offered for sale in the next Sub-Auction) would then be modeled as fixed injections and withdrawals in the third Sub-Auction (*e.g.*, a Sub-Auction for TCCs with a duration of three years), etc.

Each Sub-Auction shall normally consist of at least four rounds unless the Transmission Owners that are subject to Attachment N of this Tariff unanimously consent to fewer rounds. The ISO shall have the authority to determine the percentage of the available transmission Capacity that will be available to support TCCs sold in each round of each Sub-Auction such that all of the transmission Capacity offered for sale in that Sub-Auction shall be offered by the last round of that Sub-Auction. The ISO shall announce these percentages before the Sub-Auctions. The "scaling factor" for each round shall equal the percentage of available transmission Capacity that has not yet been made available to support the sale of TCCs in previous rounds, divided by the percentage of available transmission Capacity that will be made available to support the sale of TCCs in that round.

The ISO shall also determine the maximum duration of TCCs sold in the Centralized TCC Auction, and whether the TCCs sold in the Centralized TCC Auction shall be separately available for purchase as on-peak and off-peak TCCs. (For purposes of this Attachment, the on-peak period will include the hours from 7 a.m. to 11 p.m. Prevailing Eastern Time Monday through Friday. The remaining hours in each week will be included in the off-peak period.)

19.8.5 Reconfiguration Auctions

A Reconfiguration Auction is an auction in which TCCs with a duration of one or more months within the same Capability Period may be offered and purchased. This will allow Market Participants to purchase and sell short-term TCCs. Reconfiguration Auctions will also capture short-term changes in transmission Capacity. The ISO will conduct Reconfiguration Auctions monthly and TCCs purchased in Reconfiguration Auctions will be valid for the applicable month or months following the Reconfiguration Auction. A Reconfiguration Auction will consist of a single round. Any Primary Holder of a TCC that is valid for a month in which TCCs are being sold in the Reconfiguration Auction, including a purchaser of a TCC in a Centralized TCC Auction that has not sold that TCC and a Transmission Owner that is the Primary Holder of an ETCNL TCC or a Member System that is the Primary Holder of a RCRR TCC, may offer that TCC for sale in a Reconfiguration Auction; provided however that the sale of TCCs in a Reconfiguration Auction shall be subject to the limitations and prohibitions set forth in this ISO OATT including the limitation on the sale or transfer of Fixed Price TCCs and the limitation on the sale or other transfer of Incremental TCCs. The transmission Capacity used to support these TCCs, as well as any other transmission Capacity not required to support already-outstanding TCCs or Grandfathered Rights, will be available to support TCCs purchased in the Reconfiguration Auction.

Transmission Capacity made available for transmission rights in durations of no more than one month pursuant to Section 19.1.1 shall be released in Reconfiguration Auctions.

19.9 Procedures for Sales of TCCs in Each Auction

19.9.1 Auction Structure

TCCs may be offered for sale in each Sub-Auction round of the Centralized TCC Auction.

TCCs purchased in any round of any Sub-Auction may be resold in a subsequent round of that Centralized TCC Auction. For example, the purchaser of a 5-year TCC purchased in the 5 year Sub-Auction may release a 4-year TCC with the same Point of Injection and Point of Withdrawal for sale in the 4-year Sub-Auction. Similarly, that purchaser could instead release a corresponding 3-year TCC for sale in the 3-year Sub-Auction.

The following holders of TCCs may offer to sell TCCs in any round of a Sub-Action appropriate to their duration (i) Primary Holders who did not sell those TCCs in a Direct Sale or in a previous round of the Centralized TCC Auction ; (ii) purchasers of TCCs in previous rounds of that Centralized TCC Auction or in previous auctions who have not subsequently sold those TCCs through an auction; and (iii) purchasers of TCCs through a Direct Sale who qualify to become Primary Holders and have not already sold those TCCs through an auction or through a Direct Sale, provided however that the sale of TCCs shall be subject to the limitations and prohibitions set forth in this ISO OATT including the limitation on the sale or transfer of Fixed Price TCCs and the limitation on the sale or other transfer of Incremental TCCs.

19.9.1.1 Bid Requirements

Bidders shall submit Bids into the Centralized TCC Auction in accordance with this Attachment M and ISO Procedures. Bidders shall submit Bids such that the sum of the value of its Bids shall not exceed that bidder’s ability to pay for TCCs, as determined by ISO Procedures.

19.9.1.2 Bidding Rounds

Bidders shall be awarded TCCs in each round of the Centralized TCC Auction and shall be charged the market-clearing price for that round, as determined by the ISO in accordance with Section 19.9.5of this Attachment M, for all TCCs they purchase.

19.9.1.3 Reconfiguration Auctions

All rules stated in this Section 19.9 for the auction rounds of a Centralized TCC Auction shall also apply to Reconfiguration Auctions unless otherwise stated or the context otherwise requires it. The scaling factor for the single round of a Reconfiguration Auction shall be one.

19.9.2 Responsibilities of the ISO

The ISO shall establish the auction rules and procedures consistent with this Tariff. The ISO shall conduct the Optimal Power Flows in each round of the Centralized TCC Auction. The ISO will verify that the Optimal Power Flows calculated in each round of the Centralized TCC Auction corresponds to a simultaneously feasible Power Flow as described in Section 19.9.7 of this Attachment M. The ISO shall notify the Transmission Owners if: (1) the Optimal Power Flow results calculated are inaccurate; or (2) the Optimal Power Flow is not calculated in accordance with the correct procedure.

Additionally, the ISO will determine the information pertaining to the auction to be made available to Centralized TCC Auction participants over the OASIS and publish information on its OASIS accordingly. The ISO may develop a list of POIs and POWs between which TCCs may not be purchased and shall post such list on its OASIS. The ISO will identify the details to be included in development of the auction software and arrange for development of the software.

The ISO will apply the credit requirements established in this ISO OATT and Attachment K of the NYISO Services Tariff to Primary Holders of TCCs and to bidders in the Centralized TCC Auctions and Reconfiguration Auctions.

The ISO shall not reveal the Bid Prices submitted by any bidder in the Centralized TCC Auction until three months after the Bids were submitted. When these Bid Prices are posted, the names of the bidders shall not be publicly revealed, but the data shall be posted in a way that permits third parties to track each individual bidder's Bids over time.

The ISO will settle all Centralized TCC Auctions and Reconfiguration Auctions, and will settle all Congestion settlements related to the Day-Ahead Market, pursuant to Attachment N.

19.9.3 Additional Responsibilities of the ISO

The ISO shall be capable of completing the Centralized TCC Auction within the time frame specified in this Attachment M.

The ISO will establish an auditable information system to facilitate analysis and acceptance or rejection of Bids, and to provide a record of all Bids and the award of Fixed Price TCCs. The ISO shall also provide all necessary assistance in the resolution of disputes that arise from questions regarding the acceptance, rejection, award and recording of Bids, or the award of Fixed Price TCCs, pursuant to Sections 19.2.1 or 19.2.2.above. The ISO will establish a system to communicate auction-related information to all auction participants between rounds of the Centralized TCC Auction. (This last requirement will not apply to single-round auctions.)

The ISO will receive Bids to buy TCCs from any entity that meets the eligibility criteria established in this ISO OATT and will implement the auction bidding rules previously established by the ISO. In accordance with ISO Procedures, the ISO shall unbundle TCCs in accordance with a request made by a Transmission Customer awarded a TCC. Unbundling

TCCs shall consist of replacing that TCC with an equivalent set of TCCs. In all cases, the amount payable to (or by) the Primary Holder of such a set of TCCs will be equal to the amount payable to (or by) the Primary Holder of the original TCC.

The ISO will be required to solve Optimum Power Flows for the NYS Transmission System; properly utilize an Optimum Power Flow program to determine the set of winning Bids for each round of the Centralized TCC Auction; and calculate the market-clearing price of all TCCs at the conclusion of each round of the Centralized TCC Auction, in the manner described in this Attachment M.

19.9.4 Responsibilities of each Bidder

To qualify to submit Bids and offers in a Centralized TCC Auction, a party shall register as a Customer or Transmission Customer and shall otherwise comply with all applicable registration requirements established in ISO Procedures. All Customers and Transmission Customers seeking to submit Bids and offers in a Centralized TCC Auction shall comply with all applicable credit requirements as set forth in Attachment K of the NYISO Services Tariff.

Each bidder shall submit Bids to purchase and sell TCCs into the Centralized TCC Auction in accordance with this Attachment M and ISO Procedures. Each bidder shall submit the following information with its Bids to purchase TCCs: (i) the number of TCCs for which an offer to purchase is made, (ii) the Bid Price (in $/TCC) which represents the maximum amount the bidder is willing to pay for the TCC (Bid Prices may be negative, indicating that a bidder would have to be paid in order to accept a TCC); (iii) the location of the Point of Injection and the Point of Withdrawal for the TCC to which the Bid applies (these locations may be any locations for which the ISO calculates an LBMP and which is otherwise available as a TCC POI or POW); and (iv) if the auction is a Balance-of-Period, the month(s) for which the bidder is bidding. Additionally, if the ISO offers TCCs for sale that are valid in sub-periods (e.g., on-peak or off-peak TCCs), this information must also be provided by the Bidder.

Each bidder must submit such information to the ISO regarding the bidder's or LSE's creditworthiness as the ISO may require, along with a statement signed by the bidder, or LSE representing that the bidder or LSE is financially able and willing to pay for the TCCs for which it is bidding. The aggregate value of the Bids submitted by any bidder into the Centralized TCC Auction shall not exceed that bidder's ability to pay or the maximum value of Bids that bidder is permitted to place, as determined by the ISO (based on an analysis of that bidder's creditworthiness).

19.9.5 Selection of Winning Bids and Determination of the Market Clearing Price

The ISO shall determine the winning set of Bids in each round of the Centralized TCC Auction as follows: (i) the ISO shall use an Optimal Power Flow program with the initial assumptions identified by the ISO; (ii) the Optimal Power Flow shall use the same Reference Bus and system security constraints assumptions as used by the ISO subject to ISO Procedures; (iii) the ISO shall select the set of Bids that maximizes the value of the TCCs awarded to the winning bidders; (iv) the aggregate market value of the TCCs awarded to each bidder shall not exceed that bidder's ability to pay, since each bidder is not allowed to Bid more than its ability to pay as determined by the ISO; and (v) the selected set of Bids must be simultaneously feasible as described in this Attachment M.

In the Centralized TCC Auction, if the ISO elects to perform separate auctions for on-peak and off-peak TCCs, the procedure used to select winning Bids in an on-peak auction will not depend on winning Bids selected in an off-peak auction; nor shall the procedure used to select winning Bids in an off-peak auction depend on winning Bids selected in an on-peak auction.

The market clearing price for each TCC in each round of a Centralized TCC Auction shall be determined using a similar algorithm to that used to determine LBMPs (refer to Attachment J and ISO Procedures). For a Balance-of-Period Auction, if an awarded TCC has a duration of more than one month, the market-clearing price for such multi-month TCC will equal the sum of the market-clearing prices for one-month TCCs with the same Point of Injection and Point of Withdrawal, which in aggregate cover the same period for which the multi-month TCC is valid.

19.9.6 Settlements, Billing, Payment, and Disputes

Each bidder must pay the market-clearing price for each TCC it is awarded in the Centralized TCC Auction.

Charges for TCCs awarded in an auction, shall be billed upon completion of the Centralized TCC Auction or Reconfiguration Auction process through the delivery of an award notice by the ISO. The ISO shall establish a dispute period which follows the conclusion of the Centralized TCC Auction or Reconfiguration Auction during which challenges to awards may be made and mistakes in the calculation of market clearing prices may be corrected. Notice of the dispute period established by the ISO and of procedures to be employed in bringing a dispute or correcting a market clearing price shall be provided by the ISO on its OASIS.

Following the resolution of challenges, if any, to Centralized TCC Auction or Reconfiguration Auction awards, or mistakes in the calculation of market-clearing prices, raised during the dispute period, charges and payments for TCCs awarded or sold in the Centralized

TCC Auction and Reconfiguration Auction shall be final as provided in the award notices provided by the ISO and shall not be subject to revision.

19.9.7 Simultaneous Feasibility

The set of winning Bids selected in each round of a Sub-Auction shall correspond to a simultaneously feasible Power Flow.

The Power Flow must be able to accommodate in each round injections and withdrawals corresponding to each of the following TCCs and Grandfathered Rights: (i) TCCs not offered for sale in that round, including Grandfathered TCCs, Original Residual TCCs, or any other existing TCCs whether purchased in a previous auction, an earlier round of the current Centralized TCC Auction or otherwise acquired that are valid for any part of the duration of any TCCs to be sold in that round (or in the case of a Balance-of-Period Auction are valid for the relevant month at issue), as well as TCCs offered for sale in that round but not awarded that are valid for any part of the duration of any TCCs to be sold in that round (or in the case of a Balance-of-Period Auction are valid for the relevant month at issue); (ii) Grandfathered Rights; and (iii) TCCs awarded in the current round. Each injection and withdrawal associated with Bids for TCCs will be multiplied by a scaling factor which apportions the transmission Capacity available among each of the rounds.

A set of injections and withdrawals shall be judged simultaneously feasible if it would not cause any thermal, voltage, or stability violations within the NYCA for base case conditions or any monitored contingencies.

When performing Power Flows for the purpose of determining simultaneous feasibility, injections for TCCs that specify a Load Zone as the Point of Injection will be modeled as a set of injections at each Load bus in the Load Zone containing the Point of Injection equal to the product of the number of TCCs and the ratio of Load served at each bus to Load served in the Load Zone, based on the bus Loads used in calculating zonal LBMPs.

When performing the above Power Flows, withdrawals for TCCs that specify a Load Zone as the Point of Withdrawal will be modeled as a set of withdrawals at each Load bus in the Load Zone containing the Point of Withdrawal equal to the product of the number of TCCs and the ratio of the Load served at each bus to the total Load served in the Load Zone based on the ISO's estimate of the bus Loads used in calculating the Zonal LBMPs.

The Power Flow simulations shall take into consideration the effects of parallel flows on the transmission Capacity of the NYS Transmission System when determining which sets of injections and withdrawals are simultaneously feasible.

19.9.8 Information to be Made Available to Bidders

The ISO shall provide over the ISO's OASIS the expected non-simultaneous Total Transfer Capability for each Interface (as displayed on the OASIS).

The ISO shall make the following information available before each Centralized TCC Auction or Reconfiguration Auction:

19.9.8.1 for each Generator bus, external bus and Load Zone for the previous ten (10) Capability Periods, if available, (a) the monthly average Congestion Component of the Day-Ahead LBMP, relative to the Reference Bus, and (b) the monthly average Marginal Losses Component of the Day-Ahead LBMP, relative to the Reference Bus;

19.9.8.2 for the previous two Capability Periods, data from which the following can be determined: (a) the flow for each of the closed Interfaces in the Day-Ahead

Market, and (b) the number of hours that the most limiting facilities were physically constrained in the Day-Ahead;

19.9.8.3 subject to a Transmission Customer's completion of a non-disclosure agreement in the form required by ISO procedures: (a) Power Flow data to be used as the starting point for the Centralized TCC Auction or Reconfiguration Auction, including all assumptions, (b) all limits associated with transmission facilities, contingencies, thermal, voltage and stability to be monitored as constraints in the Optimum Power Flow determination;

19.9.8.4 (a) assumptions made by the ISO relating to transmission maintenance outage schedules, and (b) the ISO summer and winter operating study results (non-simultaneous Interface Transfer Capabilities); and

19.9.8.5 on its website no fewer than five (5) business days prior to the date on which a Centralized TCC Auction will begin, the number of megawatts of each set of ETCNL that each Transmission Owner has elected to convert to ETCNL TCCs for the Centralized TCC Auction and the RCRRs that each Member System has elected to convert to RCRR TCCs for the Centralized TCC Auction.

The ISO shall make the following information available with respect to each Centralized TCC Auction or Reconfiguration Auction:

19.9.8.6 between each round of bidding during the Centralized TCC Auction, for all bidders bidding in subsequent rounds, the market-clearing price, stated relative to the Reference Bus for each Generator bus, External bus and Load Zone; and

19.9.8.7 for each TCC awarded in each round: (a) the number of TCCs awarded, (b) the Point of Injection and Point of Withdrawal for that TCC, (c) the market-clearing price for the TCC, (d) the auction participant awarded the TCC, and (e) if the auction is a Balance-of-Period Auction, the month(s) for which the awarded TCCs are valid.

Items 19.9.8.1, 19.9.8.2, 19.9.8.3, 19.9.8.4(b), and 19.9.8.6 above shall be made available separately for on-peak and off-peak periods, if on-peak and off-peak TCCs will be separately available for purchase in the upcoming auction.

If the auction is a Balance-of-Period Auction, items 19.9.8.4(a) and 19.9.8.6 above shall be made available separately for each month covered by the auction.

The ISO will make available information about Secondary Market transactions, and all sales of TCCs by Direct Sale, to the extent received by the ISO.

19.10 End-State Auctions for TCCs

Upon the completion of more sophisticated auction software, the ISO will perform an End-State Centralized TCC Auction, which will permit the Bids submitted by auction participants to determine the lengths of the TCCs sold in the End-State Centralized TCC Auction. The End-State Centralized TCC Auction will be held annually. The date for the first End-State Centralized TCC Auction shall be determined by the ISO. The period during which each TCC sold in an End-State Centralized TCC Auction is valid shall begin on the beginning date of a Capability Period, and shall conclude on the ending date of a Capability Period.

The ISO will determine the maximum duration and minimum duration of the TCCs available in the End-State Centralized TCC Auctions. The ISO shall have the authority to determine the percentage of the available transmission Capacity that will be sold in each round of the End-State Centralized TCC Auction. The ISO shall announce these percentages before the End-State Centralized TCC Auction. The ISO shall also determine the periods for which TCCs will be sold in End-State Centralized TCC Auctions (*e.g.,* TCCs valid during on-peak and off-peak periods, or TCCs valid during Winter and Summer Capability Periods). The ISO may elect to vary the duration or the periods for which TCCs will be available from one End-State Centralized TCC Auction to the next End-State Centralized TCC Auction.

The End-State Centralized TCC Auction will not include separate Sub-Auctions for TCCs of different durations. Instead, TCCs of each permitted duration will be allocated as the result of the operation of a single auction. If, for example, a Market Participant wishes to purchase a TCC beginning in the Summer Capability Period of 2003, and ending in the Winter Capability Period of 2004-2005, it would submit a single Bid for this TCC. If that Bid is a winning Bid, the bidder would be awarded a TCC valid for the entire two year-long period; if the

Bid is a losing Bid, the bidder would not receive the TCC for any portion of this period. The ISO will not specify in advance the portion of system transmission Capacity that will be used to create TCCs of differing durations. Rather, the durations of TCCs awarded will be determined as part of the objective of the End-State Centralized TCC Auction, and will depend on the Bids submitted by participants in the End-State Centralized TCC Auction.

In a given round of the End-State Centralized TCC Auction, the market-clearing price determined for a TCC that is valid for multiple Capability Periods will equal the sum of the market-clearing prices for shorter-term TCCs with the same Point of Injection and Point of Withdrawal, which in aggregate cover the same period for which the longer-term TCC is valid. (For example, the price of a TCC that is valid from May 2001 through April 2003 would equal the sum of the prices in that round for (1) TCCs valid from May 2001 through April 2002 and (2) TCCs valid from May 2002 through April 2003.)

The End-State Centralized TCC Auction will include multiple rounds of bidding, as described elsewhere in this Attachment M.

Transmission Capacity that can be used to support TCCs sold in End-State Centralized TCC Auctions shall include all transmission Capacity except that necessary to support the following: Original Residual TCCs that the Transmission Owners sell directly in advance of the End-State Centralized TCC Auction; any TCCs previously allocated (either in an auction or through other means) that have not been offered for sale in the End-State Centralized TCC Auction; and transmission Capacity needed to support Grandfathered Rights.

The End-State Centralized TCC Auction will allow reconfiguration of the TCCs sold in the previous auctions. An entity holding a five-year TCC, for example, may release a TCC for some or all of the period for which that TCC is valid for sale in the End-State Centralized TCC

Auction.

If necessary, the ISO may elect to conduct a semi-annual auction to sell six-month TCCs between annual End-State Centralized TCC Auctions. The transmission Capacity that can be used to support TCCs purchased in this semi-annual auction shall include the portion of the transmission Capacity sold in the previous End-State Centralized TCC Auction as six-month TCCs, as well as any other outstanding TCC whose Primary Holder elects to release it for sale in this semi-annual auction.

Table 1 - TCC Reservations Subject to MW Reduction

					Sum	Win	Interface Allocations _ Summer Period									
	Reservation Holder	Name	From	To	MW	MW	DE	WC	VE	MoS	TE	US	UC	MS	DS	CE_LI
1	Con Edison	Bowline	Bowline	Con Edison	801	801							801	768	584	
2	Con Edison	ST4 HQ	–Pleasant Valley	Con Edison	400	208							400	384	292	
3	Con Edison	Gilboa	Pleasant Valley	Con Edison	125	125							125	120	91	
4	Con Edison	Roseton	Roseton_GN1	Con Edison	480	480							480	461	351	
5	Con Edison	Corinth	–Pleasant Valley	Con Edison	134	134							134	129	98	
6	Con Edison	Sithe	–Pleasant Valley	Con Edison	837	837							837	803	611	
7	Con Edison	Selkirk	Pleasant Valley	Con Edison	265	265							265	254	193	
8	Con Edison	IP2	Indian Pt 2	Con Edison	893	893								893	679	
9	Con Edison	IP3	Indian Pt 3	Con Edison	108	108								108	82	
10	Con Edison	IP Gas Turbine	IP GT_Buchanan	Con Edison	48	48								48	36	
11	NMPC	NMP1	NMP1	NMPC _ East	610	610			610		610					
12	NMPC	NMP2	NMP2	NMPC _ East	460	460			460		460					
13	NMPC	Hydro North	Colton	NMPC _ East	110	110					110					
14	NYSEG	Homer City	PJM Proxy Generator Bus	NYSEG _ Cent.	863	863	863	863								
15	NYSEG	Homer City	PJM Proxy Generator Bus	NYSEG _ West	100	100										
16	NYSEG	Allegheny 8&9	PJM Proxy Generator Bus	NYSEG _ Cent.	37	37	37	37								
17	NYSEG	BCLP	PJM Proxy Generator Bus	NYSEG _ Cent.	80	80	80	80								
18	NYSEG	LEA (Lockport)	Gardenville	NYSEG _ Cent.	100	100	100	100								
19	NYSEG	Gilboa	Gilboa	NYSEG _ Mech	99	99										
20	SENY (2) (4)	Niagara OATT Reservation	Niagara	Con Edison	422	422	422 (3)	422 (3)	422 (3)		422 (3)	422 (3)	422 (3)	422 (3)	422 (3)	
21	SENY (2) (4)	St. Lawrence OATT Reserv.	St. Lawrence	Con Edison	178	178				178 (3)	178 (3)	178 (3)	178 (3)	178 (3)	178 (3)	

Notes: 1. Interface Designations:

DE - Dysinger East	WC - West Central	VE - Volney East	MoS - Moses South
TE - Total East	US - UPNY/SENY	UC - UPNY/Con Ed	MS - Millwood South
DS - Dunwoodie South	CE-LI - Con Ed/LILCO		

2. Subject to NYPA's obtaining non-discriminatory long term firm reservation through 2017 under their OATT.
3. NYPA's TCCs allocated to their SENY Governmental Load Customers, across UPNY/Con Ed, Millwood South and Dunwoodie South will be up to 600 MW, or amounts otherwise available to NYPA pursuant to the grandfathered rights applicable under the Planning & Supply and Delivery Services Agreement between NYPA and Con Edison dated March 1989.
4. NYPA's TCCs allocated to their SENY Governmental Load Customers will terminate on the earlier of December 31, 2017 or when NYPA no longer has an obligation to serve any SENY Loads or the retirement or sale of both IP#3 and Poletti.

TABLE 2- ETCNL Data for Converting ETCNL to ETCNL TCCs					
	Holder of ETCNL	**Name of Set of ETCNL**	**Point of Injection**	**Point of Withdrawal**	**Transmission Capacity (MW)**
1.	Con Edison	Native Load-Bowline	Bowline #1/Bowline #2	Millwood Zone	16 (Bowline #1)/17 (Bowline #2)
2.	Con Edison	Native Load-Bowline	Bowline #1/Bowline #2	Dunwoodie Zone	92(Bowline #1)/92 (Bowline #2)
3.	Con Edison	Native Load-Bowline	Bowline #1/Bowline #2	NYC Zone	292(Bowline #1)/292 (Bowline #2)
4.	Con Edison	Native Load- HQ Capacity Purchase	Pleasant Valley	Millwood Zone	16 (summer)/8 (winter)
5.	Con Edison	Native Load- HQ Capacity Purchase	Pleasant Valley	Dunwoodie Zone	92 (summer)/48 (winter)
6.	Con Edison	Native Load- HQ Capacity Purchase	Pleasant Valley	NYCZone	292 (summer)/152 (winter)
7.	Con Edison	Native Load - Gilboa	Pleasant Valley	Millwood Zone	5
8.	Con Edison	Native Load - Gilboa	Pleasant Valley	Dunwoodie Zone	29
9.	Con Edison	Native Load - Gilboa	Pleasant Valley	NYC Zone	91
10.	Con Edison	Native Load - Roseton	Roseton #1/Roseton #2	Millwood Zone	9 (Roseton #1)/10 (Roseton #2)
11.	Con Edison	Native Load - Roseton	Roseton #1/Roseton #2	Dunwoodie Zone	55 (Roseton #1)/55 (Roseton #2)
12.	Con Edison	Native Load - Roseton	Roseton #1/Roseton #2	NYC Zone	175 (Roseton #1)/176 (Roseton #2)
13.	Con Edison	Native Load - Corinth	Pleasant Valley	Millwood Zone	5
14.	Con Edison	Native Load - Corinth	Pleasant Valley	Dunwoodie Zone	31
15.	Con Edison	Native Load - Corinth	Pleasant Valley	NYC Zone	98
16.	Con Edison	Native Load - Sithe	Pleasant Valley	Millwood Zone	34
17.	Con Edison	Native Load - Sithe	Pleasant Valley	Dunwoodie Zone	192
18.	Con Edison	Native Load - Sithe	Pleasant Valley	NYC Zone	611
19.	Con Edison	Native Load - Selkirk	Pleasant Valley	Millwood Zone	11
20.	Con Edison	Native Load - Selkirk	Pleasant Valley	Dunwoodie Zone	61
21.	Con Edison	Native Load - Selkirk	Pleasant Valley	NYC Zone	193
22.	Con Edison	Native Load - IP2	Indian Pt 2	Dunwoodie Zone	214
23.	Con Edison	Native Load - IP2	Indian Pt 2	NYC Zone	679
24.	Con Edison	Native Load - IP3	Indian Pt 3	Dunwoodie Zone	26
25.	Con Edison	Native Load - IP3	Indian Pt 3	NYC Zone	82
26.	Con Edison	Native Load - IP Gas Turbine	Indian Pt.-GT Buchanan	Dunwoodie Zone	12
27.	Con Edison	Native Load - IP Gas Turbine	Indian Pt.-GT Buchanan	NYC Zone	36
28.	NMPC	Native Load - NMP1	Nine Mile Pt. #1	Capital Zone	610
29.	NMPC	Native Load - NMP2	Nine Mile Pt. #2	Capital Zone	460
30.	NMPC	Native Load - Hydro North	Colton Hydro	Capital Zone	110
31.	NYSEG	Native Load - Homer City	PJM Proxy Bus	Central Zone	863
32.	NYSEG	Native Load - Homer City	PJM Proxy Bus	West Zone	100
33.	NYSEG	Native Load - Allegheny 8&9	PJM Proxy Bus	Central Zone	37
34.	NYSEG	Native Load - BCLP	PJM Proxy Bus	Central Zone	80
35.	NYSEG	Native Load - LEA (Lockport)	Gardenville	Central Zone	100
36.	NYSEG	Native Load - Gilboa	Gilboa	Capital Zone	99

TABLE 3- LIST OF ORIGINAL RESIDUAL TCCS			
Primary Holder of Original Residual TCCs	**Point of Injection**	**Point of Withdrawal**	**Number of Original Residual TCCs**
NYSEG	West	Genesee	16
NMPC	West	Genesee	23
NYPA	West	Genesee	28
RG&E	West	Genesee	3

20 Attachment N – Congestion Settlements Related to the Day-Ahead Market and TCC Auction Settlements

20.1 Overview and Definitions

20.1.1 Overview

This Attachment N describes the Congestion settlements related to the Day-Ahead Market and the settlements related to Centralized TCC Auctions and Reconfiguration Auctions. Congestion Rent settlements for Real-Time Market Energy Transactions or Bilateral Transactions scheduled in the Real-Time Market are not addressed in this Attachment N.

Section 20.2 addresses the Congestion settlements related to each hour of the Day-Ahead Market. These settlements include, as applicable pursuant to this Attachment N, charges or payments for Congestion Rents for Energy Transactions in the Day-Ahead Market and for Bilateral Transactions scheduled in the Day-Ahead Market, and settlements with Primary Holders of TCCs. In addition, these settlements include, as applicable pursuant to this Attachment N, O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Congestion Rent Surplus Payments, and U/D Congestion Rent Surplus Payments. The ISO shall allocate to Transmission Owners the net of all of these settlements as Net Congestion Rents as described in this Attachment N.

Section 20.3 addresses the settlements in each round of each Centralized TCC Auction and in each Reconfiguration Auction. These settlements include, as applicable pursuant to this Attachment N, charges or payments to purchasers of TCCs, charges or payments to Primary Holders selling TCCs, payments to Transmission Owners in a Centralized TCC Auction for ETCNL released into the Centralized TCC Auction, and payments to Transmission Owners for Original Residual TCCs that are released into the Centralized TCC Auction. In addition, these settlements include, as applicable pursuant to this Attachment N, O/R-t-S Auction Revenue Shortfall Charges, U/D Auction Revenue Shortfall Charges, O/R-t-S Auction Revenue Surplus Payments, and U/D Auction Revenue Surplus Payments. The ISO shall allocate to Transmission

Owners the net of all of these settlements as Net Auction Revenue as described in this Attachment N.

Section 20.4 addresses the allocation of revenue from the initial award and annual renewals of Historic Fixed Price TCCs. The ISO shall allocate such revenues to Transmission Owners as described in this Attachment N.

Section 20.5 addresses the allocation of revenue from initial awards and renewals of Non-Historic Fixed Price TCCs. The ISO shall allocate such revenues to Transmission Owners as described in this Attachment N.

Provisions of this Attachment N applicable to a transmission facility outage or return-to-service shall not apply to a transmission facility derating or uprating. Charges and payments under this Attachment N shall be made to a Transmission Owner for a transmission facility derating or uprating only as specified in Sections 20.2.4.3 and 20.3.6.3.

This Attachment N shall not apply to the obligation to pay an outage charge which obligation attaches to persons or entities not otherwise subject to Section 20.2.5 of this Attachment N that own an Expansion (or a portion of an Expansion) associated with a temporary or final award of Incremental TCCs or which has been assigned Incremental TCCs related to an Expansion which Expansion is modeled as wholly or partially out of service for any hour in the Day-Ahead Market which obligation to pay to the ISO an outage charge shall be determined pursuant to Attachment M to the ISO OATT.

20.1.2 Defined Terms Used in Attachment N

Capitalized terms used in this Attachment N shall have the meaning specified below in this Section 20.1.2, and capitalized terms used in this Attachment N but not defined below shall have the meaning given to them in Section 1 of the ISO OATT:

Actual Qualifying Auction Derating: As defined in Section 20.3.6.3.1.

Actual Qualifying Auction Outage: As defined in Section 20.3.6.2.1.

Actual Qualifying Auction Return-to-Service: As defined in Section 20.3.6.2.1.

Actual Qualifying Auction Uprating: As defined in Section 20.3.6.3.1.

Actual Qualifying DAM Derating: As defined in Section 20.2.4.3.1.

Actual Qualifying DAM Outage: As defined in Section 20.2.4.2.1.

Actual Qualifying DAM Return-to-Service: As defined in Section 20.2.4.2.1.

Actual Qualifying DAM Uprating: As defined in Section 20.2.4.3.1.

Auction Constraint Residual: The dollar value associated with a Constraint that is binding for a round of a 6-month Sub-Auction of a Centralized TCC Auction or a given month covered by a Reconfiguration Auction, which is calculated pursuant to Section 20.3.6.1.

Auction Status Change: Any of the following: Qualifying Auction Outage, Qualifying Auction Derating, Qualifying Auction Return-to-Service, or Qualifying Auction Uprating.

Centralized TCC Auction Interface Uprate/Derate Table: The interface derate table posted on the ISO website prior to a given Centralized TCC Auction specifying the impact on transfer limits of Qualifying DAM Outages and Qualifying DAM Returns-to-Service for a Sub-Auction of a Centralized TCC Auction.

DAM Constraint Residual: The dollar value associated with a Constraint that is binding for an hour of the Day-Ahead Market, which is calculated pursuant to Section 20.2.4.1.

DAM Status Change: Any of the following: Qualifying DAM Outage, Qualifying DAM Derating, Qualifying DAM Return-to-Service, or Qualifying DAM Uprating.

DCR Allocation Threshold: Five thousand dollars ($5,000), except that this amount shall be reduced for any given month to the extent necessary so that the sum of all DAM Constraint Residuals for the month (for all binding constraints and for all hours of the month) that are less than the DCR Allocation Threshold is not greater than either two hundred and fifty thousand dollars ($250,000) or five percent (5%) of the sum of all DAM Constraint Residuals for the month (for all binding constraints and for all hours of the month) that would have been calculated if the DCR Allocation Threshold were set equal to zero.

Deemed Qualifying Auction Derating: As defined in Section 20.3.6.3.1.

Deemed Qualifying Auction Outage: As defined in Section 20.3.6.2.1.

Deemed Qualifying Auction Return-to-Service: As defined in Section 20.3.6.2.1.

Deemed Qualifying Auction Uprating: As defined in Section 20..3.6.3.1.

Deemed ISO-Directed Auction Status Change: Any of the following: (1) an Actual Qualifying Auction Return-to-Service for a given month covered by a Reconfiguration Auction that occurs for a transmission facility that, in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month), was a Qualifying Auction Outage that qualified as an ISO-Directed Auction Status Change; (2) an Actual Qualifying Auction Uprating for a given month covered by a Reconfiguration Auction that occurs as a result of an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service of a transmission facility that, in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month), qualified as a Qualifying Auction Outage or Qualifying Auction Return-to-Service that was an ISO-Directed Auction Status Change; or (3) an Actual Qualifying Auction Derating for a given month covered by a Reconfiguration Auction that occurs as a result of an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service of a transmission facility that, in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month), qualified as an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service that was an ISO-Directed Auction Status Change.

Deemed ISO-Directed DAM Status Change: Any of the following: (1) an Actual Qualifying DAM Return-to-Service for an hour of the Day-Ahead Market that occurs for a transmission facility that, for the month that contains the relevant hour in the last Reconfiguration Auction held for TCCs valid for the relevant hour (or if no Reconfiguration Auction was held for TCCs valid during the relevant hour, then the last 6-month Sub-Auction of a Centralized TCC Auction held for TCCs valid for the relevant hour), was an Actual Qualifying Auction Outage that qualified as an ISO-Directed Auction Status Change; (2) an Actual Qualifying DAM Uprating for an hour of the Day-Ahead Market that occurs for a transmission facility that, for the month that contains the relevant hour in the last Reconfiguration Auction held for TCCs valid for the relevant hour (or if no Reconfiguration Auction was held for TCCs valid during the relevant hour, then the last 6-month Sub-Auction of a Centralized TCC Auction held for TCCs valid for the relevant hour), qualified as an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service that was an ISO-Directed Auction Status Change; or (3) an Actual Qualifying DAM Derating for an hour of the Day-Ahead Market that occurs for a transmission facility that, for the month that contains the relevant hour in the last Reconfiguration Auction held for TCCs valid for the relevant hour (or if no Reconfiguration Auction was held for TCCs valid during the relevant hour, then the last 6-month Sub-Auction of a Centralized TCC Auction held for TCCs valid for the relevant hour), qualified as an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service that was an ISO-Directed Auction Status Change. (The terms "Actual Qualifying Auction Outage" and "ISO-Directed Auction Status Change" shall, if not defined in this Section 20.1.2, have the meaning given in the ISO's March 17, 2006, filing.)

Deemed Qualifying DAM Derating: As defined in Section 20.2.4.3.1.

Deemed Qualifying DAM Outage: As defined in Section 20.2.4.2.1.

Deemed Qualifying DAM Return-to-Service: As defined in Section 20.2.4.2.1.

Deemed Qualifying DAM Uprating: As defined in Section 20.2.4.3.1.

ISO-Directed Auction Status Change: Either of the following: (1) an Actual Qualifying Auction Outage for a given month covered by a Reconfiguration Auction or a round of a Centralized TCC Auction that is directed by the ISO or results from an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service directed by the ISO; or (2) an Actual Qualifying Auction Derating or an Actual Qualifying Auction Uprating for a given month covered by a Reconfiguration Auction or a round of a Centralized TCC Auction that results from an Actual Qualifying Auction Outage directed by the ISO.

ISO-Directed DAM Status Change: Either of the following: (1) an Actual Qualifying DAM Outage for an hour of the Day-Ahead Market that is directed by the ISO or results from an Actual Qualifying DAM Outage or an Actual Qualifying DAM Return-to-Service directed by the ISO; or (2) an Actual Qualifying DAM Derating or an Actual Qualifying DAM Uprating for an hour of the Day-Ahead Market that results from an Actual Qualifying DAM Outage directed by the ISO.

Normally Out-of-Service Equipment: Transmission facilities that are normally operated as out-of-service by mutual agreement of the transmission facility owner and the ISO and that appear on the list of such equipment posted on the ISO website.

Outage/Return-to-Service Auction Constraint Residual ("O/R-t-S Auction Constraint Residual"): The portion of an Auction Constraint Residual that is deemed to be attributable to Qualifying Auction Outages or Qualifying Auction Returns-to-Service, which O/R-t-S Auction Constraint Residual shall be calculated pursuant to Section 20.3.6.1.

Outage/Return-to-Service Auction Revenue Shortfall Charge ("O/R-t-S Auction Revenue Shortfall Charge"): A charge to a Transmission Owner that is created as a result of the allocation of an O/R-t-S Auction Constraint Residual pursuant to Section 20.3.6.2.

Outage/Return-to-Service Auction Revenue Surplus Payment ("O/R-t-S Auction Revenue Surplus Payment"): A payment to a Transmission Owner that is created as a result of the allocation of an O/R-t-S Auction Constraint Residual pursuant to Section 20.3.6.2.

Outage/Return-to-Service Congestion Rent Shortfall Charge ("O/R-t-S Congestion Rent Shortfall Charge"): A charge to a Transmission Owner that is created as a result of the allocation of an O/R-t-S DAM Constraint Residual pursuant to Section 20.2.4.2.

Outage/Return-to-Service Congestion Rent Surplus Payment ("O/R-t-S Congestion Rent Surplus Payment"): A payment to a Transmission Owner that is created as a result of the allocation of an O/R-t-S DAM Constraint Residual pursuant to Section 20.2.4.2.

Outage/Return-to-Service DAM Constraint Residual ("O/R-t-S DAM Constraint Residual"): The portion of a DAM Constraint Residual that is deemed to be attributable to

Qualifying DAM Outages or Qualifying DAM Returns-to-Service, which O/R-t-S DAM Constraint Residual shall be calculated pursuant to Section 20.2.4.1.

Qualifying Auction Derating: As defined in Section 20.3.6.3.1.

Qualifying Auction Outage: As defined in Section 20.3.6.2.1.

Qualifying Auction Return-to-Service: As defined in Section 20.3.6.2.1.

Qualifying Auction Uprating: As defined in Section 20.3.6.3.1.

Qualifying DAM Derating: As defined in Section 20.2.4.3.1.

Qualifying DAM Outage: As defined in Section 20.2.4.2.1.

Qualifying DAM Return-to-Service: As defined in Section 20.2.4.2.1.

Qualifying DAM Uprating: As defined in Section 20.2.4.3.1.

Reconfiguration Auction Interface Uprate/Derate Table: The interface derate table posted on the ISO website prior to a Reconfiguration Auction specifying the impact on transfer limits of Qualifying DAM Outages and Qualifying DAM Returns-to-Service for the month(s) covered by the Reconfiguration Auction.

Uprate/Derate Auction Constraint Residual ("U/D Auction Constraint Residual"): The portion of an Auction Constraint Residual that is deemed to be attributable to Qualifying Auction Deratings or Qualifying Auction Upratings, which U/D Auction Constraint Residual shall be calculated pursuant to Section 20.3.6.1.

Uprate/Derate Auction Revenue Shortfall Charge ("U/D Auction Revenue Shortfall Charge"): A charge to a Transmission Owner that is created as a result of the allocation of a U/D Auction Constraint Residual pursuant to Section 20.3.6.3.

Uprate/Derate Auction Revenue Surplus Payment ("U/D Auction Revenue Surplus Payment"): A payment to a Transmission Owner that is created as a result of the allocation of a U/D Auction Constraint Residual pursuant to Section 20.3.6.3.

Uprate/Derate Congestion Rent Shortfall Charge ("U/D Congestion Rent Shortfall Charge"): A charge to a Transmission Owner that is created as a result of the allocation of a U/D DAM Constraint Residual pursuant to Section 20.2.4.3.

Uprate/Derate Congestion Rent Surplus Payment ("U/D Congestion Rent Surplus Payment"): A payment to a Transmission Owner that is created as a result of the allocation of a U/D DAM Constraint Residual pursuant to Section 20.2.4.3.

Uprate/Derate DAM Constraint Residual ("U/D DAM Constraint Residual"): The portion of a DAM Constraint Residual that is deemed to be attributable to a Qualifying DAM Derating or a Qualifying DAM Uprating, which U/D DAM Constraint Residual shall be calculated pursuant to Section 20.2.4.1.

For purposes of this Attachment N, the term “transmission facility” shall mean any transmission line, phase angle regulator, transformer, series reactor, circuit breaker, or other type of transmission equipment.

For the purposes of this Attachment N, a “constraint” shall refer to a monitored transmission facility and a transmission facility that is out of service in the contingency being evaluated (including the base case).

For purposes of this Attachment N: (i) a set of injections and withdrawals corresponds to a set of TCCs and Grandfathered Rights if the quantity of Energy injected at each location matches the number of TCCs and Grandfathered Rights specifying that location as a POI, and the quantity of Energy withdrawn at each location matches the number of TCCs and Grandfathered Rights specifying that location as a POW; and (ii) a TCC corresponds to ETCNL if it has the same POI and POW as the ETCNL.

All references in this Attachment N to sections shall be construed to be references to a section of this Attachment N.

20.2 Congestion Settlements Related to the Day-Ahead Market

20.2.1 Overview of Congestion Settlements Related to the Day-Ahead Market; Calculation of Net Congestion Rents

Overview of DAM Related Congestion Settlements. For each hour *h* of the Day-Ahead Market, the ISO shall settle all Congestion settlements related to the Day-Ahead Market. These Congestion settlements include, as applicable pursuant to the provisions of this Attachment N: (i) Congestion Rent charges or payments for Energy Transactions in the Day-Ahead Market and Bilateral Transactions scheduled in the Day-Ahead Market; (ii) Congestion payments or charges to Primary Holders of TCCs; (iii) O/R-t-S Congestion Rent Shortfall Charges and U/D Congestion Rent Shortfall Charges; and (iv) O/R-t-S Congestion Rent Surplus Payments and U/D Congestion Rent Surplus Payments. Each of these settlements is represented by a variable in Formula N-1.

Calculation of Net Congestion Rents for an Hour. In each hour *h* of the Day-Ahead Market, the ISO shall calculate Net Congestion Rents pursuant to Formula N-1.

Formula N-1

$$NetCongestionRents_h = (Congestion\ Rents_h - TCC\ Payments_h - O/R\text{-}t\text{-}S\&U/D\ CRSC\&CRSP_h)$$

Where,

$NetCongestionRents_h$	=	The total Net Congestion Rents for hour *h* of the Day-Ahead Market
h	=	An hour of the Day-Ahead Market
$Congestion\ Rents_h$	=	The sum of Congestion Rents for (i) Energy Transactions scheduled in hour *h* of the Day-Ahead Market, and (ii) Bilateral Transactions scheduled in hour *h* of the Day-Ahead Market, each as calculated pursuant to Section 20.2.2
$TCC\ Payments_h$	=	The sum for all TCCs of all payments and charges made pursuant to Section 20.2.3 to Primary Holders of TCCs in hour *h*

O/R-t-S&U/D $CRSC\&CRSP_h$	=	The sum of all O/R-t-S Congestion Rent Shortfall Charges (O/R-t-S $CRSC_{a,t,h}$), U/D Congestion Rent Shortfall Charges (U/D $CRSC_{a,t,h}$), O/R-t-S Congestion Rent Surplus Payments (O/R-t-S $CRSP_{a,t,h}$), and U/D Congestion Rent Surplus Payments (U/D $CRSP_{a,t,h}$) for all Transmission Owners *t* (which sum is calculated for each Transmission Owner as $NetDAMAllocations_{t,h}$ pursuant to Formula N-14), reduced by any zeroing out of such charges or payments pursuant to Section 20.2.4.5

The ISO shall allocate the Net Congestion Rents calculated in each hour to Transmission Owners pursuant to Section 20.2.5.

20.2.2 Congestion Rents Charged in the Day-Ahead Market

In each hour of the Day-Ahead Market, the ISO shall collect or pay Congestion Rents through Energy Transactions in the Day-Ahead Market and through Bilateral Transactions scheduled in the Day-Ahead Market.

Day-Ahead Market Energy Transactions. The ISO shall charge or pay Congestion Rents as part of the Congestion Component of the LBMP applicable to Energy injections and withdrawals scheduled in the Day-Ahead Market, as described in Attachment J of this Tariff. The total Congestion Rents for all Energy Transactions scheduled in the Day-Ahead Market in hour *h* are calculated pursuant to Formula N-2.

Formula N-2

$$\sum_{W} MWh_{W,h} * CCPOW_{W,h} - \sum_{I} MWh_{I,h} * CCPOI_{I,h}$$

Where,

$MWh_{W,h}$	=	Energy, in MWh, scheduled to be withdrawn in hour *h* pursuant to Day-Ahead Market schedule *W*
$CCPOW_{W,h}$	=	Congestion Component, in $/MWh, at the Point of Withdrawal for Energy withdrawn in hour *h* pursuant to schedule *W*
$MWh_{I,h}$	=	Energy, in MWh, scheduled to be injected in hour *h* pursuant to Day-Ahead Market schedule *I*

$CCPOI_{I,h}$ = Congestion Component, in \$/MWh, at the Point of Injection for Energy injected in hour *h* pursuant to schedule *I*.

Bilateral Transactions. The ISO shall charge or pay Congestion Rents as part of the Transmission Usage Charge applied to Bilateral Transaction *B* scheduled in the Day-Ahead Market, as described in Section 2.7.2.2 of this Tariff. Total Congestion Rents for all Bilateral Transactions scheduled in the Day-Ahead Market in hour *h* are calculated pursuant to Formula N-3.

Formula N-3

$$\sum_{B} MWh_{B,h} * CCTUC_{B,h}$$

Where,

$MWh_{B,h}$ = Energy, in MWh, of Bilateral Transaction *B* scheduled in the Day-Ahead Market in hour *h*

$CCTUC_{B,h}$ = Congestion Component of the TUC, in \$/MWh, for scheduled Bilateral Transaction *B*, in hour *h*, which is equal to $CCPOW_{B,h}$ - $CCPOI_{B,h.}$

$CCPOW_{B,h}$ = Congestion Component, in \$/MWh, at the Point of Withdrawal for Energy withdrawn in hour *h* pursuant to Bilateral Transaction *B*

$CCPOI_{B,h}$ = Congestion Component, in \$/MWh, at the Point of Injection for Energy injected in hour *h* pursuant to Bilateral Transaction *B*.

20.2.3 Congestion Payments Made To Primary Holders

For each hour *h* of the Day-Ahead Market, the ISO shall charge or pay Congestion payments to the Primary Holders, as follows:

Formula N-4

$$Congestion\ Payment\ (\$/\text{hr}) = (CCPOW - CCPOI) * TCCMW$$

Where,

CCPOW = Congestion Component (\$/MWh) at the Point of Withdrawal (POW)

CCPOI = Congestion Component (\$/MWh) at the Point of Injection (POI)

TCCMW = The number of TCCs in MW from POI to POW.

(See Attachment J for the calculation of the Congestion Component of the LBMP price at either the POI or the POW.)

The ISO shall pay Primary Holders for the Congestion payments from revenues collected from: (i) Congestion Rents, (ii) O/R-t-S Congestion Rent Shortfall Charges and U/D Congestion Rent Shortfall Charges, and (iii) Net Congestion Rents in accordance with Section 20.2.5.

20.2.4 Charges and Payments to Transmission Owners for DAM Outages and Returns-to-Service

The ISO shall charge O/R-t-S Congestion Rent Shortfall Charges and U/D Congestion Rent Shortfall Charges and pay O/R-t-S Congestion Rent Surplus Payments and U/D Congestion Rent Surplus Payments pursuant to this Section 20.2.4. To do so, the ISO shall calculate the DAM Constraint Residual for each binding constraint for each hour of the Day-Ahead Market and then determine the amount of each DAM Constraint Residual that is O/R-t-S DAM Constraint Residual and the amount that is U/D DAM Constraint Residual, as specified in Section 20.2.4.1. The ISO shall use the O/R-t-S DAM Constraint Residual to allocate O/R-t-S Congestion Rent Shortfall Charges and O/R-t-S Congestion Rent Surplus Payments to Transmission Owners pursuant to Sections 20.2.4.2 and 20.2.4.4, each of which shall be subject to being reduced to zero pursuant to Section 20.2.4.5. The ISO shall use the U/D DAM Constraint Residual to allocate U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments to Transmission Owners pursuant to Sections 20.2.4.3 and 20.2.4.4, each of which shall be subject to being reduced to zero pursuant to Section 20.2.4.5.

20.2.4.1 Measuring the Impact of DAM Outages and Returns-to-Service: Calculation of DAM Constraint Residuals and Division of DAM Constraint Residuals into O/R-t-S DAM Constraint Residuals and U/D DAM Constraint Residuals

For each hour *h* of the Day-Ahead Market, the ISO shall identify all constraints that are binding in the Power Flow solution for the final schedules for hour *h* of the Day-Ahead Market. For each binding constraint *a* identified for each hour *h*, the ISO shall calculate the DAM Constraint Residual, $DCR_{a,h}$, using Formula N-5; *provided, however*, where $DCR_{a,h}$ calculated using Formula N-5 is not greater than the DCR Allocation Threshold or less than the negative of the DCR Allocation Threshold, then $DCR_{a,h}$ shall be set equal to zero.

Formula N-5

$$DCR_{a,h} = ShadowPrice_{a,h} * \begin{bmatrix} (FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction}) \\ +(UprateDerate_{a,h} * SCUCSignChange_{a,h}) \\ +(UnsoldCapacity_{a,h,RA} * SCUCSignChange_{a,h}) \end{bmatrix}$$

Where,

$DCR_{a,h}$ = The DAM Constraint Residual, in dollars, for binding constraint *a* in hour *h* of the Day-Ahead Market

$ShadowPrice_{a,h}$ = The Shadow Price, in dollars/MWh, of binding constraint *a* in hour *h* of the Day-Ahead Market, which Shadow Price is calculated in a manner so that if relaxation of constraint *a* would permit a reduction in the associated Bid Production Cost, $ShadowPrice_{a,h}$ is negative

$FLOW_{a,h,DAM}$ = The Energy flow, in MWh, on binding constraint *a* for hour *h* for a set of injections and withdrawals that corresponds (as described in Section 20.1.2 of this Attachment N) to the set of TCCs and Grandfathered Rights represented for the month that contains hour *h* in the solution to the most recent auction in which TCCs valid in hour *h* were sold (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction), which Energy flow will be determined using Shift Factors produced in scheduling hour *h* of the Day-Ahead Market applied to these injections and withdrawals and the phase angle regulator schedules fixed for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*

$FLOW_{a,h,TCC\ Auction}$ = The Energy flow, in MWh, on binding constraint *a* for hour *h* determined as described in the definition of $FLOW_{a,h,DAM}$ above, except that the Shift Factors applied will be those produced in a simulated run of SCUC (run using the Transmission System model for the month that contains hour *h* used in the most recent auction in which TCCs valid in hour *h* were sold);

provided, *however*, special rules (1) through (3) below shall instead be used to calculate $FLOW_{a,h,TCC\ Auction}$ if they apply, and rule (4) below shall be used to calculate $FLOW_{a,h,TCC\ Auction}$ if $FLOW_{a,h,TCC\ Auction}$ cannot be calculated using any other rule set forth in this definition of $FLOW_{a,h,TCC\ Auction}$ because a simulated run of SCUC does not produce

Shift Factors to calculate $FLOW_{a,h,TCC\ Auction}$:

(1) in the event that a maintenance contingency is binding in the Day-Ahead Market but was not applied for the month that contains hour *h* in the most recent auction in which TCCs valid in hour *h* were sold, $FLOW_{a,h,TCC\ Auction}$ shall be equal to the Energy flow in MWh on the monitored transmission facility of binding constraint *a* for the contingency resulting in the highest flows on constraint *a* for the month that contains hour *h* in the most recent auction in which TCCs valid in hour *h* were sold, which Energy flow shall be calculated using the set of injections and withdrawals that corresponds (as described in Section 20.1.2 of this Attachment N) to the set of TCCs and Grandfathered Rights represented for the month that contains hour *h* in the solution to that auction (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction) and using Shift Factors from a simulated run of SCUC as first set forth in this definition of $FLOW_{a,h,TCC\ Auction}$

(2) in the event that the monitored transmission facility for constraint *a* was modeled as out-of-service for the month that contains hour *h* in the most recent auction in which TCCs valid in hour *h* were sold and that transmission facility returns to service for hour *h* of the Day-Ahead Market, $FLOW_{a,h,TCC\ Auction}$ shall be equal to:

(i) the rating limit, in MWh, for the monitored transmission facility of binding constraint *a* applicable in hour *h* of the Day-Ahead Market, multiplied by

(ii) negative $SCUCSignChange_{a,h}$

(3) in the event that the transmission facility that is the contingency element for constraint *a* was modeled as out-of-service for the month that contains hour *h* in the most recent auction in which TCCs valid in hour *h* were sold and that

transmission facility returns to service for hour *h* of the Day-Ahead Market, $FLOW_{a,h,TCC\ Auction}$ shall be equal to the Energy flow, in MWh, on the monitored transmission facility of binding constraint *a* for the contingency resulting in the highest flows on the monitored transmission facility of constraint *a* for the month that contains hour *h* in the most recent auction in which TCCs valid in hour *h* were sold, which Energy flow shall be calculated using the set of injections and withdrawals that corresponds (as described in Section 20.1.2 of this Attachment N) to the set of TCCs and Grandfathered Rights represented for the month that contains hour *h* in the solution to that auction (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction) and using Shift Factors from a simulated run of SCUC as first set forth in this definition of $FLOW_{a,h,TCC\ Auction}$

(4) in the event that a simulated run of SCUC does not produce Shift Factors to calculate $FLOW_{a,h,TCC\ Auction}$, $FLOW_{a,h,TCC\ Auction}$ shall be equal to:

(i) the Energy flow on constraint *a* as determined for the month that contains hour *h* in the most recent auction in which TCCs valid in hour *h* were sold, multiplied by

(ii) $OPF/SCUCAdjust_a$

$UprateDerate_{a,h}$ = Zero, except that in the event of a Qualifying DAM Uprating or Qualifying DAM Derating for constraint *a* in hour *h* that is included for the month that contains hour *h* in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*), $UprateDerate_{a,h}$ shall equal the interface uprating or derating impact reflected in such table. Notwithstanding the definition above, $UprateDerate_{a,h}$ shall always equal zero in the event that the monitored transmission facility for binding constraint *a* in the Day-Ahead Market was modeled as out-of-service for the month that contains hour *h* in the most recent auction in which TCCs valid in hour *h* were sold and that transmission facility returns to service for hour *h*.

$UnsoldCapacity_{a,h,RA}$ = Zero, except that if $ShadowPrice_{a,h}$ * [($FLOW_{a,h,DAM}$ – $FLOW_{a,h,TCCAuction}$) + ($UprateDerate_{a,h}$ * $SCUCSignChange_{a,h}$)] is less than zero, then $UnsoldCapacity_{a,h,RA}$ shall be equal to the lesser of (1) the amount of transmission Capacity for constraint *a* that was available for sale for the month that contains hour *h* in the most recent auction in which TCCs valid in hour *h* were sold but which transmission Capacity was not sold; or (2) the absolute value of ($FLOW_{a,h,DAM}$ – $FLOW_{a,h,TCCAuction}$) + ($UprateDerate_{a,h}$ * $SCUCSignChange_{a,h}$).

$SCUCSignChange_{a,h}$ = 1 if $ShadowPrice_{a,h}$ is greater than zero; otherwise, -1.

$OPF/SCUCAdjust_a$ = 1 if the directional orientation of constraint *a* used by the ISO in SCUC is the same as that used by the ISO in the Optimal Power Flow program used to select winning Bids for the month that contains hour *h* in the most recent auction in which TCCs valid in hour *h* were sold; otherwise, -1.

Following calculation of the DAM Constraint Residual for each constraint *a* for each hour *h*, the ISO shall calculate the amount of each O/R-t-S DAM Constraint Residual and the amount of each U/D DAM Constraint Residual for each constraint *a* for each hour *h*. The amount of each O/R-t-S DAM Constraint Residual for hour *h* and for constraint *a* shall be determined by applying Formula N-6. The amount of each U/D DAM Constraint Residual for hour *h* and for constraint *a* shall be determined by applying Formula N-7.

Formula N-6

$$O/R\text{-}t\text{-}S\ DCR_{a,h} = DCR_{\mathrm{a,h}} * \left[\frac{(FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction})}{(FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction}) + (UprateDerate_{a,h} * SCUCSignChange_{a,h})} \right]$$

Where,

O/R-t-S $DCR_{a,h}$ = The amount of the O/R-t-S DAM Constraint Residual, in dollars, for hour *h* and for constraint *a*

and each of the other variables are as defined in Formula N-5.

Formula N-7

$$U/D\ \ DCR_{a,h} = DCR_{\mathrm{a,h}} \left[\frac{(UprateDerate_{a,h} * SCUCSignChange_{a,h})}{} \right]$$

$$* \quad \overline{(FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction}) + (UprateDerate_{a,h} * SCUCSignChange_{a,h})}$$

Where,

U/D $DCR_{a,h}$ = The amount of the U/D DAM Constraint Residual for hour *h* for constraint *a* and each of the other variables are as defined in Formula N-5.

20.2.4.2 Charges and Payments for the Direct Impact of DAM Outages and Returns-to-Service

The ISO shall use O/R-t-S DAM Constraint Residuals to allocate O/R-t-S Congestion Rent Shortfall Charges and O/R-t-S Congestion Rent Surplus Payments, as the case may be, among Transmission Owners pursuant to this Section 20.2.4.2. Each O/R-t-S Congestion Rent Shortfall Charge and each O/R-t-S Congestion Rent Surplus Payment allocated to a Transmission Owner pursuant to this Section 20.2.4.2 is subject to being set equal to zero pursuant to Section 20.2.4.5.

20.2.4.2.1 Identification of Outages and Returns-to-Service Qualifying for Charges and Payments

For each hour of the Day-Ahead Market, the ISO shall identify each Qualifying DAM Outage and each Qualifying DAM Return-to-Service, as described below. The Transmission Owner responsible, as determined pursuant to Section 20.2.4.4, for a Qualifying DAM Outage or Qualifying DAM Return-to-Service shall be allocated an O/R-t-S Congestion Rent Shortfall Charge or an O/R-t-S Congestion Rent Surplus Payment pursuant to Sections 20.2.4.2.2 or 20.2.4.2.3.

20.2.4.2.1.1 Definition of Qualifying DAM Outage

A "**Qualifying DAM Outage**" shall be defined to mean either an Actual Qualifying DAM Outage or a Deemed Qualifying DAM Outage. For purposes of this Attachment N, "*o*" shall refer to a single Qualifying DAM Outage.

An "**Actual Qualifying DAM Outage**" shall be defined as a transmission facility that, for a given hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the facility exists but is not modeled as in-service for the Day-Ahead Market for hour *h*;

(ii) the facility existed and was modeled as in-service for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment for the month that contains hour *h* at the time of the last auction held for TCCs valid for hour *h*.

A "**Deemed Qualifying DAM Outage**" shall be defined as a transmission facility that, for a given hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*;

(ii) the facility existed but was not modeled as in-service in the Day-Ahead Market in hour *h* as a result of a DAM Status Change or external event described in Section 20.2.4.4.3 for which responsibility was assigned pursuant to Section 20.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.2.4.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*;

(iii) the facility was not Normally Out-of-Service Equipment for the month that contains hour *h* at the time of the last auction held for TCCs valid for hour *h*.

A transmission facility shall not qualify as an Actual Qualifying DAM Outage if the facility is modeled as in-service for hour *h* of the Day-Ahead Market as a result of a

Transmission Owner's use of spare or alternative transmission equipment to bring the facility back in-service so long as the Transmission Owner has notified the ISO in advance of or contemporaneously with the use of such spare or alternative equipment and the estimated duration of its use.

20.2.4.2.1.2 Definition of Qualifying DAM Return-to-Service

A "**Qualifying DAM Return-to-Service**" shall be defined to mean either an Actual Qualifying DAM Return-to-Service or a Deemed Qualifying DAM Return-to-Service. For purposes of this Attachment N, "*o*" shall refer to a single Qualifying DAM Return-to-Service.

An "**Actual Qualifying DAM Return-to-Service**" shall be defined as a transmission facility that, for a given hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the facility exists and is modeled as in-service in the Day-Ahead Market for hour *h*;

(ii) the facility existed but was not modeled as in-service for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment for the month that contains hour *h* at the time of the last auction held for TCCs valid for hour *h*.

A "**Deemed Qualifying DAM Return-to-Service**" shall be defined as a transmission facility that, for a given hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*;

(ii) the facility existed but was not modeled as in-service in the Day-Ahead Market for hour *h* as a result of a DAM Status Change or external event described in Section 20.2.4.4.3 for which responsibility is assigned pursuant to Section 20.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.2.4.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment for the month that contains hour *h* at the time of the last auction held for TCCs valid for hour *h*.

20.2.4.2.2 Allocation of an O/R-t-S DAM Constraint Residual When Only One Transmission Owner is Responsible for All of the Relevant Outages and Returns-to-Service

This Section 20.2.4.2.2 describes the allocation of an O/R-t-S DAM Constraint Residual for a given hour and a given constraint when only one Transmission Owner is responsible, as determined pursuant to Section 20.2.4.4, for all of the Qualifying DAM Outages and all of the Qualifying DAM Returns-to-Service for that hour that contribute to that constraint.

If the same Transmission Owner is responsible, as determined pursuant to Section 20.2.4.4, for all of the Qualifying DAM Outages *o* and Qualifying DAM Returns-to-Service *o* for hour *h* that contribute to constraint *a*, then the ISO shall allocate the O/R-t-S DAM Constraint Residual for that hour and that constraint, O/R-t-S $DCR_{a,h}$, to that Transmission Owner in the form of either: (i) an O/R-t-S Congestion Rent Shortfall Charge in the amount of O/R-t-S $DCR_{a,h}$ if O/R-t-S $DCR_{a,h}$ is negative, or (ii) an O/R-t-S Congestion Rent Surplus Payment in the amount of O/R-t-S $DCR_{a,h}$ if O/R-t-S $DCR_{a,h}$ is positive.

20.2.4.2.3 Allocation of an O/R-t-S DAM Constraint Residual When More Than

One Transmission Owner is Responsible for the Relevant Outages and Returns-to-Service

This Section 20.2.4.2.3 describes the allocation of an O/R-t-S DAM Constraint Residual for a given hour and a given constraint when more than one Transmission Owner is responsible, as determined pursuant to Section 20.2.4.4, for the Qualifying DAM Outages and the Qualifying DAM Returns-to-Service for that hour that contribute to that constraint.

If more than one Transmission Owner is responsible, as determined pursuant to Section 20.2.4.4, for the Qualifying DAM Outages and the Qualifying DAM Returns-to-Service for hour *h* that contribute to constraint *a*, the ISO shall allocate the O/R-t-S DAM Constraint Residual for constraint *a* for hour *h*, O/R-t-S $DCR_{a,h}$, in the form of an O/R-t-S Congestion Rent Shortfall Charge or O/R-t-S Congestion Rent Surplus Payment to the Transmission Owners responsible for the Qualifying DAM Outages *o* and Qualifying DAM Returns-to-Service *o* for hour *h* by first determining the net total impact on the constraint for hour *h* of all Qualifying DAM Outages and Qualifying DAM Returns-to-Service for hour *h* with an impact on the Energy flow across that constraint of 1 MWh or more by applying Formula N-8, and then applying either Formula N-9 or Formula N-10, as specified herein, to assess O/R-t-S Congestion Rent Shortfall Charges and O/R-t-S Congestion Rent Surplus Payments.

Formula N-8

$$O/R\text{-}t\text{-}S\ NetDAMImpact_{a,h} = \left(\sum_{for\ all\ o \in O_h} FlowImpact_{a,h,o} * ShadowPrice_{a,h}\right) * OPF/SCUCAdjust_a$$

Where,

O/R-t-S $NetDAMImpact_{a,h}$ = The net impact, in dollars, on constraint *a* in hour *h* of all Qualifying DAM Outages and Qualifying DAM Returns-to-Service for hour *h* having an impact of more than 1 MWh on Energy flow across constraint *a*; *provided, however*, O/R-t-S $NetDAMImpact_{a,h}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula N-8

$\text{FlowImpact}_{a,h,o}$ = The Energy flow impact of a Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o*, in MWh, on binding constraint *a* determined for hour *h*, which shall either:

(a) if Qualifying DAM Outage *o* is a Deemed Qualifying DAM Outage, be equal to the negative of $\text{FlowImpact}_{a,h,o}$ calculated for the corresponding Deemed Qualifying DAM Return-to-Service as described in part (b) of this definition of $\text{FlowImpact}_{a,h,o}$; or

(b) if Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* is an Actual Qualifying DAM Outage, an Actual Qualifying DAM Return-to-Service, or a Deemed Qualifying DAM Return-to-Service, be calculated pursuant to the following formula:

$$FlowImpact_{a,h,o} = One\text{-}OffFlow_{a,h,o} - BaseCaseFlow_{a,h}$$

Where,

$\text{BaseCaseFlow}_{a,h}$ = The Energy flow on binding constraint *a* resulting from a Power Flow or similar analysis using (1) the set of injections and withdrawals corresponding (as described in Section 20.1.2 of this Attachment N) to the TCCs and Grandfathered Rights represented for the month that contains hour *h* in the solution to the most recent auction in which TCCs valid in hour *h* were sold (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction); (2) the phase angle regulator schedules determined in the Optimal Power Flow solution for the month that contains hour *h* for the final round of the last auction held for TCCs valid in hour *h*; and (3) the Transmission System model for the month that contains hour *h* in the last auction held for TCCs valid in hour *h*;

$\text{One-OffFlow}_{a,h,o}$ = Either

(1) if Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* is an Actual Qualifying DAM Outage or an Actual Qualifying DAM Return-to-Service, the Energy flow on binding constraint *a* resulting from a Power Flow or similar analysis using each element of the base case data set used in the calculation of $\text{BaseCaseFlow}_{a,h}$ above (*provided, however*, if a transmission facility was modeled as free-flowing in hour *h* of the Day-Ahead Market because of the

outage of any transmission facility, the ISO shall appropriately adjust the phase angle regulator schedules and related variables to model the transmission facility as free flowing), but in each case with the Transmission System model modified so as to, as the case may be, either (i) model as out-of-service Actual Qualifying DAM Outage *o*, or (ii) model as in-service Actual Qualifying DAM Return-to-Service *o*; or

(2) if Qualifying DAM Return-to-Service *o* is a Deemed Qualifying DAM Return-to-Service, the Energy flow on binding constraint *a* resulting from a Power Flow or similar analysis using each element of the base case data set used in the calculation of $\text{BaseCaseFlow}_{a,h}$ above (*provided*, *however*, if a transmission facility was modeled as free-flowing in hour *h* of the Day-Ahead Market because of the outage of any transmission facility, the ISO shall appropriately adjust the phase angle regulator schedules and related variables to model the transmission facility as free flowing), but with the Transmission System model modified so as to model as in-service the transmission facility that is Deemed Qualifying DAM Return-to-Service *o*

provided, however, where the absolute value of $\text{FlowImpact}_{a,h,o}$ calculated using the procedures set forth above is less than 1 MWh, then $\textit{FlowImpact}_{a,h,o}$ shall be set equal to zero;

provided further, $\text{FlowImpact}_{a,h,o}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula N-8

O_h = The set of all Qualifying DAM Outages *o* and Qualifying DAM Returns-to-Service *o* in hour *h*

and the variables $\text{ShadowPrice}_{a,h}$ and OPF/SCUCAdjust_a are defined as set forth in Formula N-5.

After calculating O/R-t-S $\text{NetDAMImpact}_{a,h}$ pursuant to Formula N-8, the ISO shall determine whether O/R-t-S $NetDAMImpact_{a,h}$ for constraint *a* in hour *h* has a different sign than O/R-t-S $DCR_{a,h}$ for constraint *a* in hour *h*. If the sign is different, the ISO shall (i) recalculate O/R-t-S $NetDAMImpact_{a,h}$ pursuant to Formula N-8 after setting equal to zero each $FlowImpact_{a,h,o}$ for which $FlowImpact_{a,h,o}$ * $ShadowPrice_{a,h}$ * $OPF/SCUCAdjust_{a}$ has a different sign than O/R-t-S $DCR_{a,h}$, and then (ii) use this recalculated O/R-t-S $NetDAMImpact_{a,h}$ and reset value of $FlowImpact_{a,h,o}$ to allocate O/R-t-S Congestion Rent Shortfall Charges and O/R-t-S Congestion Rent Surplus Payments pursuant to Formula N-9 or Formula N-10, as specified below.

If the absolute value of the net impact (O/R-t-S $NetDAMImpact_{a,h}$) on constraint *a* of all Qualifying DAM Outages and Qualifying DAM Returns-to-Service for hour *h* as calculated using Formula N-8 (or recalculated pursuant to Formula N-8 using a reset value of $FlowImpact_{a,h,o}$ as described in the prior paragraph) is greater than the absolute value of the O/R-t-S DAM Constraint Residual (O/R-t-S $DCR_{a,h}$), in dollars, for constraint *a* in hour *h*, then the ISO shall allocate the O/R-t-S DAM Constraint Residual in the form of an O/R-t-S Congestion Rent Shortfall Charge, O/R-t-S $CRSC_{a,t,h}$, or O/R-t-S Congestion Rent Surplus Payment, O/R-t-S $CRSP_{a,t,h}$, by using Formula N-9. If the absolute value of the net impact (O/R-t-S $NetDAMImpact_{a,h}$) on constraint *a* of all Qualifying DAM Outages and Qualifying DAM Returns-to-Service for hour *h* as calculated using Formula N-8 (or recalculated pursuant to Formula N-8 using a reset value of $FlowImpact_{a,h,o}$ as described in the prior paragraph) is less than or equal to the absolute value of the O/R-t-S DAM Constraint Residual (O/R-t-S $DCR_{a,h}$), in dollars, for constraint *a* in hour *h*, then the ISO shall allocate the O/R-t-S DAM Constraint Residual in the form of an O/R-t-S Congestion Rent Shortfall Charge or O/R-t-S Congestion Rent Surplus Payment by using Formula N-10.

Formula N-9

$$O/R\text{-}t\text{-}S\,Allocation_{a,t,h} = \left(\frac{\sum_{\substack{o \in O_h \\ and\ q=t}} \left(FlowImpact_{a,h,o} * Responsibility_{h,q,o}\right)}{\sum_{for\ all\ o \in O_h} FlowImpact_{a,h,o}} \right) * O/R\text{-}t\text{-}S\,DCR_{a,h}$$

Where,

O/R-t-S $Allocation_{a,t,h}$ = Either an O/R-t-S Congestion Rent Shortfall Charge or an O/R-t-S Congestion Rent Surplus Payment, as specified in (a) and (b) below:

(a) If O/R-t-S $Allocation_{a,t,h}$ is negative, then O/R-t-S $Allocation_{a,t,h}$ shall be an O/R-t-S Congestion Rent Shortfall Charge, O/R-t-S $CRSC_{a,t,h}$, charged to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market; or

(b) If O/R-t-S $Allocation_{a,t,h}$ is positive, then O/R-t-S $Allocation_{a,t,h}$ shall be an O/R-t-S Congestion Rent Surplus Payment, O/R-t-S $CRSP_{a,t,h}$, paid to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market

$Responsibility_{h,q,o}$ = The amount, as a percentage, of responsibility borne by Transmission Owner *q* (which shall include the ISO when it is deemed a Transmission Owner for the purpose of applying Sections 20.2.4.4.2, 20.2.4.4.3, or 20.2.4.4.4) for Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* in hour *h*, as determined pursuant to Section 20.2.4.4

and the variable O/R-t-S $DCR_{a,h}$ is defined as set forth in Formula N-6 and the variables $FlowImpact_{a,h,o}$ and O_h are defined as set forth in Formula N-8.

Formula N-10

$$O/R\text{-}t\text{-}S\,Allocation_{a,t,h} = \left(\sum_{\substack{o \in O_h \\ and\ q=t}} FlowImpact_{a,h,o} * ShadowPrice_{a,h} * Responsibility_{h,q,o} \right) * OPF/SCUCAdjust_a$$

Where,

the variables $ShadowPrice_{a,h}$ and $OPF/SCUCAdjust_a$ are defined as set forth in Formula N-5, the variables O/R-t-S $Allocation_{a,t,h}$ and $Responsibility_{h,q,o}$ are defined as set forth in Formula N-9, and the variables $FlowImpact_{a,h,o}$ and O_h are defined as set forth in Formula N-8.

20.2.4.3 Charges and Payments for the Secondary Impact of DAM Outages and Returns-to-Service

The ISO shall use U/D DAM Constraint Residuals to allocate U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments, as the case may be, among Transmission Owners pursuant to this Section 20.2.4.3. Each U/D Congestion Rent Shortfall Charge and each U/D Congestion Rent Surplus Payment allocated to a Transmission Owner pursuant to this Section 20.2.4.3 is subject to being set equal to zero pursuant to Section 20.2.4.5.

20.2.4.3.1 Identification of Upratings and Deratings Qualifying for Charges and Payments

For each hour of the Day-Ahead Market and for each constraint, the ISO shall identify each Qualifying DAM Derating and each Qualifying DAM Uprating, as described below. The Transmission Owner responsible, as determined pursuant to Section 20.2.4.4, for the Qualifying DAM Derating shall be allocated a U/D Congestion Rent Shortfall Charge and the Transmission Owner responsible, as determined pursuant to Section 20.2.4.4, for the Qualifying DAM Uprating shall be allocated a U/D Congestion Rent Surplus Payment pursuant to Section 20.2.4.3.2.

20.2.4.3.1.1 Definition of Qualifying DAM Derating

A "**Qualifying DAM Derating**" shall be defined to mean either an Actual Qualifying DAM Derating or a Deemed Qualifying DAM Derating. For purposes of this Attachment N, "*r*" shall refer to a single Qualifying DAM Derating.

An "**Actual Qualifying DAM Derating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* and hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the constraint has a lower rating in hour *h* than it would have if all transmission facilities were modeled as in-service in hour *h*;

(ii) this lower rating is in whole or in part the result of an Actual Qualifying DAM Outage *o* or an Actual Qualifying DAM Return-to-Service *o* for hour *h*;

(iii) this lower rating resulting from Actual Qualifying DAM Outage *o* or Actual Qualifying DAM Return-to-Service *o* for hour *h* was not modeled for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating is included for the month that contains hour *h* in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); and

(v) the constraint is binding in the Day-Ahead Market for hour *h*.

A "**Deemed Qualifying DAM Derating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* and hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the constraint has a lower rating in hour *h* than it would have if all transmission facilities were modeled as in-service in hour *h*;

(ii) this lower rating is in whole or in part the result of a Deemed Qualifying DAM Outage *o* or Deemed Qualifying DAM Return-to-Service *o* for hour *h*;

(iii) the lower rating resulting from Deemed Qualifying DAM Outage *o* or Deemed Qualifying DAM Return-to-Service *o* for hour *h* was modeled for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*, but responsibility for Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* resulting in the lower rating for hour *h* is assigned pursuant to Section 20.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.2.4.4) other than the Transmission Owner responsible for the lower rating for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating is included for the month that contains hour *h* in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); and

(v) the constraint is binding in the Day-Ahead Market for hour *h*.

20.2.4.3.1.2 Definition of Qualifying DAM Uprating

A "**Qualifying DAM Uprating**" shall be defined to mean either an Actual Qualifying DAM Uprating or a Deemed Qualifying DAM Uprating. For purposes of this Attachment N, "*r*" shall refer to a single Qualifying DAM Uprating.

An "**Actual Qualifying DAM Uprating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* in hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the constraint has a higher rating for hour *h* than it would have absent an Actual Qualifying DAM Outage *o* or Actual Qualifying DAM Return-to-Service *o* for hour *h*;

(ii) this higher rating resulting from Actual Qualifying DAM Outage *o* or Actual Qualifying Return-to-Service *o* for hour *h* was not modeled for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*;

(iii) this higher rating is included for the month that contains hour *h* in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); and

(iv) the constraint is binding in the Day-Ahead Market for hour *h*.

A "**Deemed Qualifying DAM Uprating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* and hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the constraint has a lower rating in hour *h* than it would have if all transmission facilities were modeled as in-service in hour *h*;

(ii) this lower rating is in whole or in part the result of a Deemed Qualifying DAM Outage *o* or Deemed Qualifying DAM Return-to-Service *o* for hour *h*;

(iii) this lower rating resulting from Deemed Qualifying DAM Outage *o* or Deemed Qualifying DAM Return-to-Service *o* for hour *h* was modeled for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*, but responsibility for Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* resulting in the lower rating for hour *h* is assigned pursuant to Section 20.2.4.4 to a Transmission Owner (including the ISO when it is deemed a

Transmission Owner for the purpose of applying Section 20.2.4.4) other than the Transmission Owner responsible for the lower rating for the month that contains hour *h* in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating for hour *h* is included for the month that contains hour *h* in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); and

(v) the constraint is binding in the Day-Ahead Market for hour *h*.

20.2.4.3.2 Allocation of U/D DAM Constraint Residuals

This Section 20.2.4.3.2 describes the allocation of U/D DAM Constraint Residuals to Qualifying DAM Deratings and Qualifying DAM Upratings.

When there are Qualifying DAM Deratings or Qualifying DAM Upratings for constraint *a* in hour *h*, the ISO shall allocate a U/D DAM Constraint Residual in the form of a U/D Congestion Rent Shortfall Charge, U/D $CRSC_{a,t,h}$, or U/D Congestion Rent Surplus Payment, U/D $CRSP_{a,t,h}$, by first determining the net total impact on the constraint for hour *h* of all Qualifying DAM Upratings r and Qualifying DAM Deratings *r* for constraint *a* in hour *h* pursuant to Formula N-11 and then applying either Formula N-12 or Formula N-13, as specified herein, to assess U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments.

Formula N-11

$$U/D\ NetDAMImpact_{a,h} = \left(\sum_{for\ all\ r \in R_{a,h}} RatingChange_{a,h,r} * ShadowPrice_{a,h} \right) * SCUCSignChange_{a,h}$$

Where,

U/D $NetDAMImpact_{a,h}$ = The net impact, in dollars, on constraint *a* of all Qualifying DAM Upratings and Qualifying DAM Deratings for constraint *a* in hour *h*; *provided, however*, U/D $NetDAMImpact_{a,h}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula N-11

$RatingChange_{a,h,r}$ = Either

(a) If Qualifying DAM Derating *r* or Qualifying DAM Uprating *r* is a Deemed Qualifying DAM Derating or a Deemed Qualifying DAM Uprating, $RatingChange_{a,h,r}$ shall be equal to the amount, in MWh, of the decrease or increase in the rating of binding constraint *a* in hour *h* resulting from a Deemed Qualifying DAM Return-to-Service or Deemed Qualifying DAM Outage for constraint *a* in hour *h*, as shown for the month that contains hour *h* in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); or

(b) If Qualifying DAM Derating *r* or Qualifying DAM Uprating *r* is an Actual Qualifying DAM Derating or an Actual Qualifying DAM Uprating, $RatingChange_{a,h,r}$ shall be equal to the amount, in MWh, of the decrease or increase in the rating of binding constraint *a* in hour *h* resulting from an Actual Qualifying DAM Return-to-Service or an Actual Qualifying DAM Outage for constraint *a* in hour *h*, as shown for the month that contains hour *h* in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); *provided, however*, $\text{RatingChange}_{a,h,r}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula N-11

$R_{a,h}$ = The set of all Qualifying DAM Deratings *r* or Qualifying DAM Upratings *r* for binding constraint *a* in hour *h*

and the variables $\text{SCUCSignChange}_{a,h}$ and $\text{ShadowPrice}_{a,h}$ are defined as set forth in Formula N-5.

After calculating U/D $\text{NetDAMImpact}_{a,h}$ pursuant to Formula N-11, the ISO shall determine whether U/D $\text{NetDAMImpact}_{a,h}$ for constraint *a* in hour *h* has a different sign than U/D $\text{DCR}_{a,h}$ for constraint *a* in hour *h*. If the sign is different, the ISO shall (i) recalculate U/D $\text{NetDAMImpact}_{a,h}$ pursuant to Formula N-11 after setting equal to zero each $\text{RatingChange}_{a,h,r}$ for which $\text{RatingChange}_{a,h,r}$ * $\text{ShadowPrice}_{a,h}$ * $\text{SCUCSignChange}_{a,h}$ has a different sign than U/D $\text{DCR}_{a,h}$, and then (ii) use this recalculated U/D $\text{NetDAMImpact}_{a,h}$ and reset value of $\text{RatingChange}_{a,h,r}$ to allocate U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments pursuant to Formula N-12 or Formula N-13, as specified below.

If the absolute value of the net impact (U/D $\text{NetDAMImpact}_{a,h}$) on constraint *a* of all Qualifying DAM Deratings and Qualifying DAM Upratings for constraint *a* in hour *h* as calculated using Formula N-11 (or recalculated pursuant to Formula N-11 using a reset value of $\text{RatingChange}_{a,h,r}$ as described in the prior paragraph) is greater than the absolute value of the

U/D DAM Constraint Residual (U/D $DCR_{a,h}$) for constraint *a* in hour *h*, then the ISO shall allocate the U/D DAM Constraint Residual in the form of a U/D Congestion Rent Shortfall Charge, U/D $CRSC_{a,t,h}$, or U/D Congestion Rent Surplus Payment, U/D $CRSP_{a,t,h}$, by using Formula N-12. If the absolute value of the net impact (U/D $NetDAMImpact_{a,h}$) on constraint *a* of all Qualifying DAM Deratings and Qualifying DAM Upratings for constraint *a* in hour *h* as calculated using Formula N-11 (or recalculated pursuant to Formula N-11 using a reset value of $RatingChange_{a,h,r}$ as described in the prior paragraph) is less than or equal to the absolute value of the U/D DAM Constraint Residual (U/D $DCR_{a,h}$) for constraint *a* in hour *h*, then the ISO shall allocate the U/D DAM Constraint Residual in the form of a U/D Congestion Rent Shortfall Charge, U/D $CRSC_{a,t,h}$, or U/D Congestion Rent Surplus Payment, U/D $CRSP_{a,t,h}$, by using Formula N-13.

Formula N-12

$$U/D\,Allocation_{a,t,h} = \left(\frac{\sum_{\substack{r \in R_{a,h} \\ and\ q=t}} \left(RatingChange_{a,h,r} * Responsibility_{h,q,r}\right)}{\sum_{for\ all\ r \in R_{a,h}} RatingChange_{a,h,r}} \right) * U/D\,DCR_{a,h}$$

Where,

U/D $Allocation_{a,t,h}$ = Either a U/D Congestion Rent Shortfall Charge or a U/D Congestion Rent Surplus Payment, as specified in (a) and (b) below:

(a) If U/D $Allocation_{a,t,h}$ is negative, then U/D $Allocation_{a,t,h}$ shall be a U/D Congestion Rent Shortfall Charge, U/D $CRSC_{a,t,h}$, charged to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market; or

(b) If U/D $Allocation_{a,t,h}$ is positive, then U/D $Allocation_{a,t,h}$ shall be a U/D Congestion Rent Surplus Payment, U/D $CRSP_{a,t,h}$, paid to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market

$Responsibility_{h,q,r}$ = The amount, as a percentage, of responsibility borne by Transmission Owner *q* (which shall include the ISO when it is deemed a Transmission Owner for the purpose of applying Sections 20.2.4.4.2, 20.2.4.4.3, or

20.2.4.4.4) for Qualifying DAM Derating *r* or Qualifying DAM Uprating *r* in hour *h*, as determined pursuant to Section 20.2.4.4

and the variable U/D $DCR_{a,h}$ is defined as set forth in Formula N-7 and the variables $RatingChange_{a,h,r}$ and $R_{a,h}$ are defined as set forth in Formula N-11.

Formula N-13

$$U/D\ Allocation_{a,t,h} = \left(\sum_{\substack{r \in R_{a,h} \\ and\ q=t}} RatingChange_{a,h,r} * ShadowPrice_{a,h} * Responsibility_{h,q,r} \right) * SCUCSignChange_{a,h}$$

Where,

the variables $ShadowPrice_{a,h}$ and $SCUCSignChange_{a,h}$ are defined as set forth in Formula N-5, the variables U/D $Allocation_{a,t,h}$ and $Responsibility_{h,q,r}$ are defined as set forth in Formula N-12, and the variables $RatingChange_{a,h,r}$ and $R_{a,h}$ are defined as set forth in Formula N-11.

20.2.4.4 Assigning Responsibility for Outages, Returns-to-Service, Deratings, and Upratings

20.2.4.4.1 General Rule for Assigning Responsibility; Presumption of Causation

Unless the special rules set forth in Sections 20.2.4.4.2 through 20.2.4.4.4 apply, a Transmission Owner shall for purposes of this Section 20.2.4 be deemed responsible for a DAM Status Change to the extent that the Transmission Owner has caused the DAM Status Change by changing the in-service or out-of-service status of its transmission facility; *provided, however*, that where a DAM Status Change results from a change to the in-service or out-of-service status of a transmission facility owned by more than one Transmission Owner, responsibility for such DAM Status Change shall be assigned to each owning Transmission Owner based on the percentage of the transmission facility that is owned by the Transmission Owner (as determined in accordance with Section 20.2.4.6.1) during the hour for which the DAM Status Change occurred. For the sake of clarity, a Transmission Owner may, by changing the in-service or out-of-service status of its transmission facility, cause a DAM Status Change of another transmission facility if the Transmission Owner's change in the in-service or out-of-service status of its transmission facility causes (directly or as a result of Good Utility Practice) a change in the in-service or out-of-service status of the other transmission facility.

The Transmission Owner that owns a transmission facility that qualifies as a DAM Status Change shall be deemed to have caused the DAM Status Change of that transmission facility unless (i) the Transmission Owner that owns the facility informs the ISO that another Transmission Owner caused the DAM Status Change or that responsibility is to be shared among Transmission Owners in accordance with Sections 20.2.4.4.2, 20.2.4.4.3, or 20.2.4.4.4, and no party disputes such claim; (ii) in case of a dispute over the assignment of responsibility, the ISO determines a Transmission Owner other than the owner of the transmission facility caused the DAM Status Change or that responsibility is to be shared among Transmission Owners in accordance with Sections 20.2.4.4.2, 20.2.4.4.3, or 20.2.4.4.4; or (iii) FERC orders otherwise.

20.2.4.4.2 Shared Responsibility For Outages, Returns-to-Service, and Ratings Changes Directed by the ISO or Caused by Facility Status Changes Directed by the ISO

A Transmission Owner shall not be responsible for any DAM Status Change that qualifies as an ISO-Directed DAM Status Change or Deemed ISO-Directed DAM Status Change. Instead, the ISO shall allocate any revenue impacts resulting from a DAM Status Change that qualifies as an ISO-Directed DAM Status Change or Deemed ISO-Directed DAM Status Change as part of Net Congestion Rents for hour *h*. To do so, the ISO shall be treated as a Transmission Owner when allocating DAM Constraint Residuals pursuant to Section 20.2.4.2 and Section 20.2.4.3, and any DAM Status Change that qualifies as an ISO-Directed DAM Status Change or Deemed ISO-Directed DAM Status Change shall be attributed to the ISO when performing the calculations described in Section 20.2.4.2 and Section 20.2.4.3; *provided, however*, any O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment allocable to the ISO pursuant to this Section 20.2.4.4.2 shall ultimately be allocated to the Transmission Owners as Net Congestion Rents pursuant to Section 20.2.5.

Responsibility for a Qualifying DAM Return-to-Service or Qualifying DAM Uprating that is directed by the ISO but does not qualify as a Deemed ISO-Directed DAM Status Change shall be assigned to the Transmission Owner that was responsible for the Qualifying Auction Outage or Qualifying Auction Derating for the month that contains the relevant hour in the last Reconfiguration Auction held for TCCs valid for the relevant hour (or if no Reconfiguration Auction was held for TCCs valid in the relevant hour, the last 6-month Sub-Auction of a Centralized TCC Auction held for TCCs valid for the relevant hour).

20.2.4.4.3 Shared Responsibility for External Events

A Transmission Owner shall not be responsible for a DAM Status Change occurring inside the NYCA that is caused by a change in the in-service or out-of-service status or rating of a transmission facility located outside the NYCA. Instead, the ISO shall allocate any revenue impacts resulting from a DAM Status Change caused by such an event outside the NYCA as part of Net Congestion Rents for hour *h*. To do so, the ISO shall be treated as a Transmission Owner when allocating DAM Constraint Residuals pursuant to Section 20.2.4.2 and Section 20.2.4.3 and any DAM Status Change caused by such an event outside the NYCA shall be attributed to the ISO when performing the calculations described in Section 20.2.4.2 and Section 20.2.4.3; *provided, however,* any O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus

Payment allocable to the ISO pursuant to this Section 20.2.4.4.3 shall ultimately be allocated to the Transmission Owners as Net Congestion Rents pursuant to Section 20.2.5.

20.2.4.5 Exceptions: Setting Charges and Payments to Zero

20.2.4.5.1 Zeroing Out of Charges and Payments When Outages and Deratings Lead to Net Payments or Returns-to-Service and Upratings Lead to Net Charges

The ISO shall use Formula N-14 to calculate the total O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Congestion Rent Surplus Payments, and U/D Congestion Rent Surplus Payments, $\text{NetDAMAllocations}_{t,h}$, for Transmission Owner *t* in hour *h*. Based on this calculation, the ISO shall set equal to zero all O/R-t-S $\text{CRSC}_{a,t,h}$, U/D $\text{CRSC}_{a,t,h}$, O/R-t-S $\text{CRSP}_{a,t,h}$, and U/D $\text{CRSP}_{a,t,h}$ (each as defined in Formula N-14) for Transmission Owner *t* for all constraints for hour *h* if (i) $\text{NetDAMAllocations}_{t,h}$ is positive and Transmission Owner *t* is not responsible (as determined pursuant to Section 20.2.4.4) for any Qualifying DAM Returns-to-Service or Qualifying DAM Upratings during hour *h*, or (ii) $\text{NetDAMAllocations}_{t,h}$ is negative and Transmission Owner *t* is not responsible (as determined pursuant to Section 20.2.4.4) for any Qualifying DAM Outages or Qualifying DAM Deratings during hour *h*; *provided, however*, the ISO shall not set equal to zero pursuant to this Section 20.2.4.5.1 any O/R-t-S $\text{CRSC}_{a,t,h}$, U/D $\text{CRSC}_{a,t,h}$, O/R-t-S $\text{CRSP}_{a,t,h}$, or U/D $\text{CRSP}_{a,t,h}$ arising from an ISO-Directed DAM Status Change or Deemed ISO-Directed DAM Status Change described in Section 20.2.4.4.2, an external event described in Section 20.2.4.4.3, or an event occurring during a transitional period as described in Section 20.2.4.4.4.

Formula N-14

$$NetDAMAllocations_{t,h} = \sum_{for\ all\ a} \left(O/R\text{-}t\text{-}S\ CRSC_{a,t,h} + U/D\,\mathrm{CRSC}_{a,t,h} + O/R\text{-}t\text{-}S\ CRSP_{\mathrm{a,t,h}} + U/D\ CRSP_{\mathrm{a,t,h}} \right)$$

Where,

$NetDAMAllocations_{t,h}$ = The total of the O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Congestion Rent Surplus Payments, and U/D Congestion Rent Surplus Payments allocated to Transmission Owner *t* in hour *h*

O/R-t-S $CRSC_{a,t,h}$ = An O/R-t-S Congestion Rent Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market, calculated pursuant to Section 20.2.4.2

U/D $CRSC_{a,t,h}$ = A U/D Congestion Rent Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market, calculated pursuant to Section 20.2.4.3

O/R-t-S $CRSP_{a,t,h}$ = An O/R-t-S Congestion Rent Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market, calculated pursuant to Section 20.2.4.2

U/D $CRSP_{a,t,h}$ = A U/D Congestion Rent Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market, calculated pursuant to Section 20.2.4.3.

20.2.4.5.2 Zeroing Out of Charges and Payments Resulting from Formula Failure

Notwithstanding any other provision of this Attachment N, the ISO shall set equal to zero any O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment allocated to a Transmission Owner for an hour of the Day-Ahead Market if either:

(i) data necessary to compute such a charge or payment, as specified in the formulas set forth in Section 20.2.4, is not known by the ISO and cannot be computed by the ISO (in interpreting this clause, equipment failure shall not preclude computation by the ISO unless necessary data is irretrievably lost); or

(ii) both (a) the charge or payment is clearly and materially inconsistent with cost causation principles; and (b) this inconsistency is the result of factors not taken into account in the formulas used to calculate the charge or payment;

provided, however, if the amount of charges or payments set equal to zero as a result of the unknown data or inaccurate formula is greater than twenty five thousand dollars ($25,000) in any given month or greater than one hundred thousand dollars ($100,000) over multiple months, the ISO will inform the Transmission Owners of the identified problem and will work with the Transmission Owners to determine if an alternative allocation method is needed and whether it will apply to all months for which the intended formula does not work. Alternate methods would be subject to market participant review and subsequent filing with FERC, as appropriate.

For the sake of clarity, the ISO shall not pursuant to this Section 20.2.4.5.2 set equal to zero any O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment that fails to meet these conditions, even if another O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment is set equal to zero pursuant to this Section 20.2.4.5.2 in the same hour of the Day-Ahead Market.

20.2.4.6 Information Requirements

20.2.4.6.1 Information Regarding Facility Ownership

A Transmission Owner shall be responsible for informing the ISO of any change in the ownership of a transmission facility. The ISO shall allocate responsibility for DAM Status Changes based on the transmission facility ownership information available to it at the time of initial settlement.

20.2.4.6.2 Calculation of Settlements Without DCR Allocation Threshold

One month each year, the ISO shall, for informational purposes only, calculate the DAM Constraint Residuals for each constraint for each hour without applying the DCR Allocation Threshold and shall calculate all O/R-t-S Congestion Rent Shortfall Charges, O/R-t-S Congestion Rent Surplus Payments, U/D Congestion Rent Shortfall Charges, and U/D

Congestion Rent Surplus Payments. Before choosing the month for which it will perform these calculations, the ISO will consult with the Transmission Owners.

20.2.5 Allocation of Net Congestion Rents to Transmission Owners

The Net Congestion Rents for each hour of month *m* shall be summed over the month, so that positive and negative values net to a monthly total, NCR_m. The ISO shall allocate NCR_m each month to the Transmission Owners by allocating to each Transmission Owner *t* an amount equal to the product of (i) NCR_m, and (ii) the allocation factor for Transmission Owner *t* for month *m*, as calculated pursuant to Formula N-15.

Formula N-15

$$AllocationFactor_{t,m} = \frac{\left(\begin{array}{c} OriginalResidual_{t,m} + ETCNL_{t,m} + NARs_{t,m} \\ +GFR\&GFTCC_{t,m} + HFPTCC_{t,m} + NHFPTCC_{t,m} \end{array}\right)}{\sum_{q \in T} \left(\begin{array}{c} OriginalResidual_{q,m} + ETCNL_{q,m} + NARs_{q,m} \\ +GFR\&GFTCC_{q,m} + HFPTCC_{q,m} + NHFPTCC_{q,m} \end{array}\right)}$$

Where,

Allocation $Factor_{t,m}$	=	The allocation factor used by the ISO to allocate a share of the Net Congestion Rents to Transmission Owner *t* for month *m*
Original $Residual_{q,m}$	=	The sum of the one-month portion of the revenue imputed to the Direct Sale and the sale in any Centralized TCC Auction Sub-Auction of Original Residual TCCs held by Transmission Owner *q* that are valid in month *m*. The one-month portion of the revenue imputed to the Direct Sale of these Original Residual TCCs shall be the market-clearing price of the TCCs valid in month *m* in the last Reconfiguration Auction held for TCCs valid in month *m* (or one-sixth of the average market-clearing price in the rounds of the 6-month Sub-Auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for TCCs valid in month *m*). The one-month portion of the revenue imputed to the sale in any Centralized TCC Auction Sub-Auction of these Original Residual TCCs shall be calculated by dividing the revenue received from the sale of these Original Residual TCCs in the Centralized TCC Auction Sub-Auction by the duration in months of the TCCs sold in that Centralized TCC Auction Sub-Auction.

$ETCNL_{q,m}$ = The sum of the one-month portion of the revenue imputed to the Direct Sale of Transmission Owner *q*'s ETCNL or for its ETCNL released in the Centralized TCC Auction Sub-Auction held for TCCs valid for month *m*. The one-month portion of the revenue imputed for ETCNL released in any Centralized TCC Auction shall be calculated by dividing the revenue received in a Centralized TCC Auction Sub-Auction from the sale of the ETCNL by the duration in months of the TCCs corresponding (as described in Section 20.1.2 of this Attachment N) to the ETCNL sold in the Centralized TCC Auction Sub-Auction. The one-month portion of the revenue imputed to the Direct Sale of ETCNL shall be the market-clearing price of the TCCs valid in month *m* corresponding (as described in Section 20.1.2 of this Attachment N) to that ETCNL in the last Reconfiguration Auction held for TCCs valid in month *m* (or one-sixth of the average market-clearing price of such TCCs in the rounds of the 6-month Sub-Auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for TCCs valid in month *m*).

$NARs_{q,m}$ = The one-month portion of the Net Auction Revenues Transmission Owner *q* has received in Centralized TCC Auction Sub-Auctions and all Reconfiguration Auctions held for TCCs valid for month *m* (which shall not include any revenue from the sale of Original Residual TCCs). The one-month portion of the revenues shall be calculated by summing (i) the revenue Transmission Owner *q* received from the allocation of Net Auction Revenue pursuant to Section 20.3.7 in each Centralized TCC Auction Sub-Auction for TCCs valid in month *m*, divided in each case by the duration in months of the TCCs sold in the Centralized TCC Auction Sub-Auction and the sum of the revenue Transmission Owner *q* received from the allocation of that portion of Net Auction Revenue pursuant to Section 20.3.7 related to month *m* for all Reconfiguration Auctions held for TCCs valid in month *m* (or, to the extent TCC auction revenues were allocated pursuant to a different methodology, the amount of such revenues allocated to Transmission Owner *q*), minus (ii) the sum of $NetAuctionAllocations_{t,n}$ as calculated pursuant to Formula N-27 (as adjusted for any charges or payments that are zeroed out) for Transmission Owner *q* for all 6-month Sub-Auction rounds *n* of all Centralized TCC Auctions held for TCCs valid in month *m*, divided in each case by the duration in months of the TCCs sold in each Centralized TCC Auction Sub-Auction (or, to the extent that the revenue impact of transmission facility outages, returns-to-service, upratings, and deratings were settled pursuant to a different methodology, the net of such revenue impacts for Transmission Owner *q*), minus (iii) the sum of the portion of $NetAuctionAllocations_{t,n}$ as calculated pursuant to Formula N-27 and as adjusted for any charges or payments that are zeroed out for Transmission Owner *q* for month *m* for all Reconfiguration Auctions held for TCCs valid in month *m* (or, to the extent that the revenue impact of transmission facility outages, returns-to-service, upratings, and deratings were settled pursuant to a different methodology, the net of such revenue impacts for Transmission Owner *q*).

$GFR\&GFTCC_{q,m}$ = The one-month portion of the imputed value of Grandfathered TCCs and Grandfathered Rights held by Transmission Owner *q*, valued at their market-clearing prices for month *m* in the last Reconfiguration Auction for TCCs valid in month *m* (or one-sixth of the average market clearing price for rounds in the 6-month Sub-Auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for TCCs valid in month *m*), provided that Transmission Owner *q* is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in month *m*.

$HFPTCC_{q,m}$ = The one-month portion of the Historic Fixed Price TCC revenues that Transmission Owner *q* has received for Historic Fixed Price TCCs valid for month *m*, valued at the sum of the share of revenues received by Transmission Owner *q* pursuant to Section 20.4 of this Attachment N for all Historic Fixed Price TCCs valid for month *m*, divided by twelve; provided, however that the value shall be zero for all Historic Fixed Price TCCs that took effect on or before November 1, 2016.

$NHFPTCC_{q,m}$ = The one-month portion of the Non-Historic Fixed Price TCC revenues that Transmission Owner *q* has received for Non-Historic Fixed Price TCCs valid for month *m*, valued at the sum of the share of revenues received by Transmission Owner *q* pursuant to Section 20.5 of this Attachment N for all Non-Historic Fixed Price TCCs valid for month *m*, divided by: (i) twenty-four in the case of Non-Historic Fixed Price TCC revenues received by Transmission Owner *q* related to initial awards of Non-Historic Fixed Price TCCs valid for month *m*; or (ii) twelve in the case of Non-Historic Fixed Price TCC revenues received by Transmission Owner *q* related to renewals of Non-Historic Fixed Price TCCs valid for month *m*; provided, however that the value shall be zero for all Non-Historic Fixed Price TCCs that took effect on or before May 1, 2017.

t = Transmission Owner *t*

T = The set of all Transmission Owners *q*.

For purposes of Formula N-15, variables subscripted by *t* shall be calculated for

Transmission Owner t in the same manner as variables subscripted by q are calculated for Transmission Owner q.

Each Transmission Owner's share of Net Congestion Rents allocated pursuant to this Section 20.2.5 shall be incorporated into its TSC or NTAC, as the case may be.

20.3 Settlement of TCC Auctions

20.3.1 Overview of TCC Auction Settlements; Calculation of Net Auction Revenue

Overview of TCC Auction Settlements. For each round *n* of a Centralized TCC Auction and for each Reconfiguration Auction *n*, the ISO shall settle all settlements for round *n* or for Reconfiguration Auction *n*. These settlements include, as applicable pursuant to the provisions of this Attachment N: (i) the market-clearing price charged or paid to purchasers of TCCs; (ii) payments to Transmission Owners that released ETCNL; (iii) payments or charges to Primary Holders selling TCCs; (iv) payments to Transmission Owners that released Original Residual TCCs; (v) O/R-t-S Auction Revenue Shortfall Charges and U/D Auction Revenue Shortfall Charges; and (vi) O/R-t-S Auction Revenue Surplus Payments and U/D Auction Revenue Surplus Payments. Each of these settlements is represented by a variable in Formula N-16.

Calculation of Net Auction Revenues for a Round or a Reconfiguration Auction. In each Centralized TCC Auction round *n* and in each Reconfiguration Auction *n*, the ISO shall calculate Net Auction Revenue pursuant to Formula N-16.

Formula N-16

$$Net\ Auction\ Revenue_n = \begin{bmatrix} TCC\ Auction\ Revenue_n \\ -ETCNL_n \\ -Primary\ Holder\ TCCs\ Sold_n \\ -Original\ Residual\ TCCs_n \\ -O/R\text{-}t\text{-}S\&U/D\ ARSC\&ARSP_n \end{bmatrix}$$

Where,

n	=	A round of a Centralized TCC Auction (which may be either a round of a 6-month Sub-Auction or a round of a Sub-Auction in which TCCs with a duration greater than 6 months are sold) or a Reconfiguration Auction, as the case may be
Net Auction Revenue_n	=	Net Auction Revenue for the round *n* of a Centralized TCC Auction or for Reconfiguration Auction *n*, as the case may be

TCC Auction Revenue_n	=	The gross amount of revenue that the ISO collects from the award of TCCs to purchasers in round *n* or in Reconfiguration Auction *n*, which results from the charges and payments allocated pursuant to Section 20.3.2
ETCNL_n	=	Either (i) if round *n* is a round of a Centralized TCC Auction, the total of all payments that the ISO makes to Transmission Owners releasing ETCNL into the round pursuant to Section 20.3.3; or (ii) for Reconfiguration Auction *n*, 0
Primary Holder TCCs Sold_n	=	The net of the total payments and charges the ISO allocates to Primary Holders selling TCCs in round *n* or in Reconfiguration Auction *n* pursuant to Section 20.3.4
Original Residual TCCs_n	=	Either (i) if round *n* is a round of a Centralized TCC Auction, the total payments the ISO makes in round *n* pursuant to Section 20.3.5 to Transmission Owners that release into round *n* Original Residual TCCs; or (ii) for Reconfiguration Auction *n*, 0
O/R-t-S&U/D $\text{ARSC\&ARSP}_n$	=	Either (i) if round *n* is a round of a Centralized TCC Auction in which 6-month TCCs are sold, the sum of the total O/R-t-S Auction Revenue Shortfall Charges, U/D Auction Revenue Shortfall Charges, O/R-t-S Auction Revenue Surplus Payments, and U/D Auction Revenue Surplus Payments (calculated as $\text{NetAuctionAllocations}_{t,n}$ pursuant to Formula N-27) for all Transmission Owners *t*, reduced by any zeroing out of such charges or payments pursuant to Section 20.3.6.5; (ii) if round *n* is a round of a Centralized TCC Auction Sub-Auction in which TCCs with durations longer than 6 months are sold, 0; or (iii) for Reconfiguration Auction *n*, the sum of the total O/R-t-S Auction Revenue Shortfall Charges(O/R-t-S $\text{ARSC}_{a,t,n}$), U/D Auction Revenue Shortfall Charges (U/D $\text{ARSC}_{a,t,n}$), O/R-t-S Auction Revenue Surplus Payments (O/R-t-S $\text{ARSP}_{a,t,n}$), and U/D Auction Revenue Surplus Payments (U/D $\text{ARSP}_{a,t,n}$) for all Transmission Owners *t* (which sum is calculated for each Transmission Owner as $\text{NetAuctionAllocations}_{t,n}$ pursuant to Formula N-27), reduced by any zeroing out of such charges or payments pursuant to Section 20.3.6.5

The ISO shall allocate the Net Auction Revenue calculated in each round of a Centralized TCC Auction Sub-Auction and in each Reconfiguration Auction to Transmission Owners pursuant to Section 20.3.7.

20.3.2 Charges for TCCs Purchased

All bidders awarded TCCs in round *n* of a Centralized TCC Auction or in

Reconfiguration Auction *n* shall pay or be paid the market clearing price in round *n* or in Reconfiguration Auction *n*, as determined pursuant to Attachment M of this Tariff, for the TCCs purchased. For a Balance-of-Period Auction, if an awarded TCC has a duration of more than one month, the market-clearing price for such multi-month TCC will equal the sum of the market-clearing prices for one-month TCCs with the same Point of Injection and Point of Withdrawal, which in aggregate cover the same period for which the multi-month TCC is valid.

20.3.3 Payments for ETCNL

The ISO shall, in each round of a Centralized TCC Auction in which ETCNL is released, pay the market clearing price determined in that round for TCCs that correspond (as described in Section 20.1.2 of this Attachment N) to that ETCNL to the Transmission Owner that releases the ETCNL.

If a Transmission Owner releases ETCNL for sale in a round of the Centralized TCC Auction, and the market-clearing price for those TCCs corresponding (as described in Section 20.1.2 of this Attachment N) to that ETCNL in that round is negative, the value of those TCCs will not be included in the determination of payments to the Transmission Owners for ETCNL released into the Centralized TCC Auction. If the market-clearing price is negative for TCCs corresponding (as described in Section 20.1.2 of this Attachment N) to any ETCNL, the value will be set to zero for purposes of allocating auction revenues from the sale of ETCNL. If the total value of the auction revenues available for payment to the Transmission Owners for ETCNL and Original Residual TCCs released into the Centralized TCC Auction is insufficient to fund payments at market-clearing prices, the total payments to each Transmission Owner for ETCNL and Original Residual TCCs will be reduced proportionately. Notwithstanding any other provision in this Tariff, ETCNL that is offered in any Centralized TCC Auction and that is assigned a negative market-clearing price or value shall not give rise to a payment obligation by the Transmission Owner that released it.

20.3.4 Payments to Primary Holders Selling TCCs; Distribution of Revenues from Sale of Certain Grandfathered TCCs (excluding ETCNL) in a Centralized TCC Auction

The ISO shall distribute to or collect from each Primary Holder of a TCC selling that TCC in the Centralized TCC Auction or Reconfiguration Auction the market-clearing price of that TCC in the round of the Centralized TCC Auction or in the Reconfiguration Auction in which that TCC was sold. For a Balance-of-Period Auction, if a TCC sold has a duration of more than one month, the market-clearing price for such multi-month TCC will equal the sum of the market-clearing prices for one-month TCCs with the same Point of Injection and Point of Withdrawal, which in aggregate cover the same period for which the multi-month TCC was sold.

In the event a Grandfathered TCC is terminated by mutual agreement of the parties to the grandfathered ETA (or, in the case of Grandfathered TCCs, if any, associated with those rate schedules to which footnote 9 of Attachment L pertains, terminated by mutual agreement or otherwise) prior to the conditions specified within Attachments K and L, then the ISO shall distribute the revenues from the sale of the TCCs that correspond to the terminated Grandfathered TCCs in a round of a Centralized TCC Auction directly back to the Transmission Owner identified in Attachment L, until such time as the conditions specified within Attachments K and L are met. Upon such time that the conditions within Attachments K and L are met, the ISO shall allocate the revenues from the sale of the TCCs that correspond to terminated Grandfathered TCCs in the Centralized TCC Auction as Net Auction Revenues in accordance with Section 20.3.7 of this Attachment.

20.3.5 Allocation of Revenues from the Sale of Original Residual TCCs

If a Transmission Owner releases an Original Residual TCC for sale in a round of the Centralized TCC Auction, and the market-clearing price for those TCCs in that round is negative, the value of those TCCs will not be included in the determination of payments to the Transmission Owners for Original Residual TCCs released into the Centralized TCC Auction. If the market-clearing price is negative for any Original Residual TCC, the value will be set to zero for purposes of allocating auction revenues from the sale of Original Residual TCCs. If the total value of the auction revenues available for payment to the Transmission Owners for Original Residual TCCs and ETCNL released into the Centralized TCC Auction is insufficient to fund payments at market-clearing prices, the total payments to each Transmission Owner for Original Residual TCCs and ETCNL will be reduced proportionately. This proportionate reduction would include a reduction in payments reflecting a proportionate reduction in the auction value of Original Residual TCCs sold in a Direct Sale. Notwithstanding any other provision in this Tariff, Original Residual TCCs that are offered in any Centralized TCC Auction and that are assigned a negative market-clearing price or value shall not give rise to a payment obligation by the Transmission Owner that released them.

20.3.6 Charges and Payments to Transmission Owners for Auction Outages and Returns-to-Service

The ISO shall charge O/R-t-S Auction Revenue Shortfall Charges and U/D Auction Revenue Shortfall Charges and pay O/R-t-S Auction Revenue Surplus Payments and U/D Auction Revenue Surplus Payments pursuant to this Section 20.3.6. To do so, the ISO shall calculate the Auction Constraint Residual for each constraint for each round *n* of a Centralized TCC Auction 6-month Sub-Auction or for each month covered by Reconfiguration Auction *n*, as the case may be, pursuant to Section 20.3.6.1 and then determine the amount of each Auction Constraint Residual that is O/R-t-S Auction Constraint Residual and the amount that is U/D Auction Constraint Residual, as specified in Section 20.3.6.1. The ISO shall use the O/R-t-S Auction Constraint Residual to allocate O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments to Transmission Owners pursuant to Sections 20.3.6.2 and 20.3.6.4, each of which shall be subject to being reduced to zero pursuant to Section 20.3.6.5. The ISO shall use the U/D Auction Constraint Residual to allocate U/D Auction Revenue Shortfall Charges and U/D Auction Revenue Surplus Payments to Transmission Owners pursuant to Sections 20.3.6.3 and 20.3.6.4, each of which shall be subject to being reduced to zero pursuant to Section 20.3.6.5.

The ISO shall not calculate an Auction Constraint Residual, O/R-t-S Auction Constraint Residual, or U/D Auction Constraint Residual for any rounds of a Centralized TCC Auction except for rounds of the 6-month Sub-Auction.

20.3.6.1 Measuring the Impact of Auction Outages and Returns-to-Service: Calculation of Auction Constraint Residuals and Division of Auction Constraint Residuals into O/R-t-S Auction Constraint Residuals and U/D Auction Constraint Residuals

The ISO shall identify all constraints that are binding in the final Optimal Power Flow solution for round *n* of a 6-month Sub-Auction of a Centralized TCC Auction or for each month covered by Reconfiguration Auction *n*, as the case may be. For each binding constraint *a* and for each -round *n* of a 6-month Sub-Auction of a Centralized TCC Auction or month covered by Reconfiguration Auction *n*, the ISO shall calculate the Auction Constraint Residual, $ACR_{a,n}$, using Formula N-17; *provided, however*, the ISO shall recalculate $ACR_{a,n}$ using Formula N-18 if (i) $ACR_{a,n}$ is positive based on the calculation using Formula N-17, and (ii) constraint *a* was not binding in the Power Flow used to determine the Energy flow on constraint *a* in calculating the variable $FLOW_{a,n,basecase}$ in Formula N-17.

Formula N-17

$$ACR_{a,n} = ShadowPrice_{a,n} * \begin{bmatrix} (FLOW_{a,n,actual} - FLOW_{a,n,basecase}) \\ +(ISORatingChange_{a,n} * OPFSignChange_{a,n}) \end{bmatrix} * \%Sold_n$$

Where,

$ACR_{a,n}$ = The Auction Constraint Residual, in dollars, for binding constraint *a* in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*

$ShadowPrice_{a,n}$ = The Shadow Price, in dollars/MW-*p*, of binding constraint *a* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*, where *p* is a one-month period for the relevant month covered by Reconfiguration Auction *n* and *p* is a six-month period for round *n* of a 6-month Sub-Auction, which Shadow Price is calculated in a manner so that if relaxation of constraint *a* would permit an increase in the objective function used for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* as described in Attachment M of this Tariff, then $ShadowPrice_{a,n}$ is positive

$FLOW_{a,n,actual}$ = The Energy flow, in MW-*p*, on binding constraint *a* resulting from a Power Flow using, as the case may be:

(a) For a given month covered by Reconfiguration Auction *n*, (i) the Transmission System model for the relevant month for Reconfiguration Auction *n*, (ii) the set of TCCs and Grandfathered Rights represented in the solution to Reconfiguration Auction *n* for the relevant month (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction), and (iii) the phase angle regulator schedules determined in the Optimal Power Flow solution for the relevant month covered by for Reconfiguration Auction *n*; or

(b) For round *n* of a 6-month Sub-Auction, (i) the Transmission System model for round *n*, (ii) the set of TCCs (scaled appropriately) and Grandfathered Rights represented in the solution to round *n* (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction), and (iii) the phase angle regulator schedules produced in the Optimal Power Flow solution for round *n*

$FLOW_{a,n,basecase}$= The Energy flow, in MW-*p*, on binding constraint *a* produced in, as the case may be:

(a) For a given month covered by Reconfiguration Auction *n*, a Power Flow using the following base case data set: (i) the Transmission System model for the relevant month for Reconfiguration Auction *n*, (ii) the set of TCCs and Grandfathered Rights for the relevant month represented in the solution to the last Reconfiguration Auction held for TCCs valid during the relevant month, or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the final round of the last 6-month Sub-Auction held for TCCs valid during the relevant month, (including those pre-existing TCCs and Grandfathered Rights for the relevant month represented as fixed injections and withdrawals in that auction), and (iii) the phase angle regulator schedules determined in the Optimal Power Flow solution for the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the final round of the last 6-month Sub-Auction held for TCCs valid during the relevant month); or (b) For round *n* of a 6-month Sub-Auction, a Power Flow run using the following base case data set: (i) the Transmission System model for the actual 6-month Sub-Auction, and (ii) the base case set of TCCs (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in the simulated auction) and the phase angle regulator schedules produced in a single simulated TCC auction administered for all rounds of the 6-month Sub-Auction using the

Transmission System model for the actual 6-month Sub-Auction modified so as to model as in-service all transmission facilities that were out-of-service in the Transmission System model used for the Sub-Auction and model as fully rated all transmission facilities that were derated in the Transmission System model used for the Sub-Auction, the pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in the Sub-Auction, and all bids to purchase and offers to sell made into all rounds of the Sub-Auction that includes round *n*

$ISORatingChange_{a,n}$ =The total change in the rating of constraint *a* for round *n* or for a given month covered by Reconfiguration Auction *n* resulting from ISO-Directed Auction Status Changes or Deemed ISO-Directed Auction Status Changes described in Section 20.3.6.4.2, external events described in Section 20.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for round *n* or the relevant month covered by Reconfiguration Auction *n*, which shall be calculated as follows:

(a) For a given month covered by Reconfiguration Auction *n*, zero, except that in the event of a change in the rating of constraint *a* resulting from ISO-Directed Auction Status Changes or Deemed ISO-Directed Auction Status Changes described in Section 20.3.6.4.2, external events described in Section 20.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for the relevant month covered by Reconfiguration Auction *n*, $ISORatingChange_{a,n}$ shall be equal to: (1) the rating limit, in MW-*p*, of constraint *a* as shown in the Reconfiguration Auction Interface Uprate/Derate Table for the relevant month in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the rating limit, in MW-*p*, of constraint *a* as shown in the Centralized TCC Auction Interface

Uprate/Derate Table for last Centralized TCC Auction held for TCCs valid during the relevant month), minus (2) the rating limit, in MW-*p*, of constraint *a* resulting from ISO-Directed Auction Status Changes or Deemed ISO-Directed Auction Status Changes described in Section 20.3.6.4.2, external events described in Section 20.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for the relevant month covered by Reconfiguration Auction *n* as shown in the Reconfiguration Auction Interface Uprate/Derate Table applicable for the relevant month in Reconfiguration Auction *n*

(b) For round *n* of a 6-month Sub-Auction, zero, except that in the event of a change in the rating of a transmission facility resulting from ISO-Directed Auction Status Changes or Deemed ISO-Directed Auction Status Changes described in Section 20.3.6.4.2, external events described in Section 20.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for round *n*, $\text{ISORatingChange}_{a,n}$ shall be equal to: (1) the rating limit, in MW-*p*, of constraint *a* in a case where all transmission facilities are in-service and fully rated as shown in the Centralized TCC Auction Interface Uprate/Derate Table applicable for round *n*, minus (2) the rating limit, in MW-*p*, of constraint *a* resulting from ISO-Directed Auction Status Changes or Deemed ISO-Directed Auction Status Changes described in Section 20.3.6.4.2, external events described in Section 20.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for round *n* as shown in the Centralized TCC Auction Interface

Uprate/Derate Table applicable for round *n*

$OPFSignChange_{a,n}$= 1 if $ShadowPrice_{a,n}$ is greater than zero; otherwise, -1

$\%Sold_n$ = Either (i) for round *n* of a 6-month Sub-Auction, the percentage of transmission Capacity sold in round *n*, divided by the percentage of transmission Capacity sold in all rounds of the Sub-Auction of which round *n* is a part; or (ii) for a given month covered by Reconfiguration Auction *n*, 1.

Formula N-18

$$ACR_{a,n} = ShadowPrice_{a,n} * \begin{bmatrix} (FLOW_{a,n,actual} - FLOW_{a,n,basecase}) \\ +(ISORatingChange_{a,n} * OPFSignChange_{a,n}) \\ -\left(UnsoldCapacity_{a,n,PriorAuction} * OPFSignChange_{a,n}\right) \end{bmatrix} * \%Sold_n$$

Where,

$UnsoldCapacity_{a,n,PriorAuction}$ = Either:

(a) For a given month covered by Reconfiguration Auction *n*, the rating limit for binding constraint *a* for the relevant month applied in the model used in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last Centralized TCC Auction held for TCCs valid during the relevant month), minus the Energy flow, in MW-*p*, on binding constraint *a* for the relevant month produced in the Optimal Power Flow in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last round of that the last Centralized TCC Auction held for TCCs valid during the relevant month); or

(b) For round *n* of a 6-month Sub-Auction, the rating limit for binding constraint *a* applied in the model used in the simulated auction run to determine $FLOW_{a,n,basecase}$ in Formula N-17, minus the Energy flow, in MW-*p*, on binding constraint *a* produced in the Optimal Power Flow in the simulated auction run to determine $FLOW_{a,n,basecase}$ in Formula N-17

and each of the other variables is as set forth in Formula N-17; *provided, however,* if $ACR_{a,n}$ is less than zero when calculated using this Formula N-18, $ACR_{a,n}$ shall be set equal to zero.

Following calculation of the Auction Constraint Residual for each constraint *a* for each round *n* of a 6-month Sub-Auction or each month covered by Reconfiguration Auction *n*, the ISO shall calculate the amount of each O/R-t-S Auction Constraint Residual and the amount of each U/D Auction Constraint Residual for each constraint *a* for each round *n* of a 6-month Sub-Auction or each month covered by Reconfiguration Auction *n*, as the case may be. The amount of each O/R-t-S Auction Constraint Residual for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be, for constraint *a* shall be determined by applying Formula N-19. The amount of each U/D Auction Constraint Residual for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be, for constraint *a* shall be determined by applying Formula N-20.

Formula N-19

$$O/R\text{-}t\text{-}S\,ACR_{a,n} = ACR_{a,n} * \left[\frac{(FLOW_{a,n,actual} - FLOW_{a,n,basecase}) + (TotalRatingChange_{a,n} * OPFSignChange_{a,n})}{(FLOW_{a,n,actual} - FLOW_{a,n,basecase}) + (ISORatingChange_{a,n} * OPFSignChange_{a,n})}\right]$$

Where:

O/R-t-S $ACR_{a,n}$ = The amount of the O/R-t-S Auction Constraint Residual for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be, for constraint *a*

$TotalRatingChange_{a,n}$ = The total change in the rating of constraint *a*, which shall be calculated as follows:

(a) For a given month covered by Reconfiguration Auction *n*, $TotalRatingChange_{a,n}$ shall be equal to (1) the rating limit, in MW-*p*, of constraint *a* for the relevant month in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last Centralized TCC Auction held for TCCs valid during the relevant month), minus (2) the rating limit, in MW-*p*, of constraint *a* applicable for the relevant month in Reconfiguration Auction *n*

(b) For round *n* of a 6-month Sub-Auction, $TotalRatingChange_{a,n}$ shall be equal to (1) the rating limit, in MW-*p*, of constraint *a* in a case where all transmission facilities are in-service and fully rated, minus (2) the rating limit, in MW-*p*, of constraint *a* in round *n*

and the variable $ACR_{a,n}$ is as calculated pursuant to Formula N-17 or, if required, pursuant to Formula N-18, and each of the other variables are as defined in Formula N-17.

Formula N-20

$$U/D\,ACR_{a,n} = ACR_{a,n} * \left[\frac{-\left(TotalRatingChange_{a,n} - ISORatingChange_{a,n}\right) * \ OPFSignChange_{a,n}}{\left(FLOW_{a,n,actual} - FLOW_{a,n,basecase}\right) + \left(ISORatingChange_{a,n} * OPFSignChange_{a,n}\right)}\right]$$

Where,

$U/D\ ACR_{a,n}$ = The amount of the U/D Auction Constraint Residual for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be, for constraint *a*

and the variable $ACR_{a,n}$ is as calculated pursuant to Formula N-17 or, if required, pursuant to Formula N-18, the variable $TotalRatingChange_{a,n}$ is defined as set forth in Formula N-19 and each of the other variables are defined as set forth in Formula N-17.

20.3.6.2 Charges and Payments for the Direct Impact of Auction Outages and Returns-to-Service

The ISO shall use O/R-t-S Auction Constraint Residuals to allocate O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments, as the case may be, among Transmission Owners pursuant to this Section 20.3.6.2. Each O/R-t-S Auction Revenue

Shortfall Charge and each O/R-t-S Auction Revenue Surplus Payment allocated to a Transmission Owner pursuant to this Section 20.3.6.2 is subject to being set equal to zero pursuant to Section 20.3.6.5.

20.3.6.2.1 Identification of Outages and Returns-to-Service Qualifying for Charges and Payments

For each round of a 6-month Sub-Auction or each month covered by a Reconfiguration Auction, as the case may be, the ISO shall identify each Qualifying Auction Outage and each Qualifying Auction Return-to-Service, as described below. The Transmission Owner responsible, as determined pursuant to Section 20.3.6.4, for the Qualifying Auction Outage or Qualifying Auction Return-to-Service shall be allocated an O/R-t-S Auction Revenue Shortfall Charge or an O/R-t-S Auction Revenue Surplus Payment pursuant to Sections 20.3.6.2.2 or 20.3.6.2.3.

20.3.6.2.1.1 Definition of Qualifying Auction Outage

A "**Qualifying Auction Outage**" (which term shall apply to round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be) shall be defined to mean either an Actual Qualifying Auction Outage or a Deemed Qualifying Auction Outage. For purposes of this Attachment N, "*o*" shall refer to a single Qualifying Auction Outage.

An "**Actual Qualifying Auction Outage**" (which term shall apply to round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be) shall be defined as a transmission facility that, for a given round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be:

(a) For a given month covered by Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed and was modeled as in-service for the relevant month in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month); and

(ii) the facility exists but is not modeled as in-service in the relevant month for Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment for the relevant month at the time of the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month); or

(b) For round *n* of a 6-month Sub-Auction, meets each of the following requirements:

(i) the facility exists but is not modeled as in-service for round *n* of a 6-month Sub-Auction; and

(ii) the facility was not Normally Out-of-Service Equipment at the time of stage 1 round *n* of that 6-month Sub-Auction.

A "**Deemed Qualifying Auction Outage**" (which term shall apply only to a given month covered by Reconfiguration Auction *n*) shall be defined as a transmission facility that, for the relevant month covered by Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service for the relevant month in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month);

(ii) the facility existed but was not modeled as in-service for the relevant month in Reconfiguration Auction *n* as a result of an Auction Status Change or external event described in Section 20.3.6.4.3 in the relevant month covered by Reconfiguration Auction *n* for which responsibility was assigned pursuant to Section 20.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.3.6.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service for the relevant month in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month);

(iii) the facility was not Normally Out-of-Service Equipment for the relevant month at the time of the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month).

20.3.6.2.1.2 Definition of Qualifying Auction Return-to-Service

A "**Qualifying Auction Return-to-Service**" shall be defined to mean either an Actual Qualifying Auction Return-to-Service or a Deemed Qualifying Auction Return-to-Service. For purposes of this Attachment N, "*o*" shall refer to a single Qualifying Auction Return-to-Service.

An "**Actual Qualifying Auction Return-to-Service**" shall be defined as a transmission facility that, for a given month covered by Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service in the relevant month for the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month); and

(ii) the facility exists and is modeled as in-service for the relevant month in Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment for the relevant month at the time of the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month).

Notwithstanding any other provision of this Attachment N, a transmission facility returning to service for round *n* of a 6-month Sub-Auction shall not be an Actual Qualifying Auction Return-to-Service for that round *n* and shall not qualify a Transmission Owner for an O/R-t-S Auction Revenue Shortfall Charge or O/R-t-S Auction Revenue Surplus Payment for that round *n*.

A "**Deemed Qualifying Auction Return-to-Service**" shall be defined as a transmission facility that, for a given month covered by Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service for the relevant month in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month);

(ii) the facility existed but was not modeled as in-service for the relevant month in Reconfiguration Auction *n* as a result of an Auction Status Change or external event described in Section 20.3.6.4.3 in the relevant month covered by Reconfiguration Auction *n* for which responsibility was assigned pursuant to Section 20.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.3.6.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service in the relevant month for the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month); and

(iii) the facility was not Normally Out-of-Service Equipment for the relevant month at the time of the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month).

20.3.6.2.2 Allocation of an O/R-t-S Auction Constraint Residual When Only One Transmission Owner is Responsible for All of the Relevant Outages and

Returns-to-Service

This Section 20.3.6.2.2 describes the allocation of an O/R-t-S Auction Constraint Residual for a given round of a 6-month Sub-Auction or a given month covered by a Reconfiguration Auction, as the case may be, and a given constraint when only one Transmission Owner is responsible, as determined pursuant to Section 20.3.6.4, for all of the Qualifying Auction Outages and all of the Qualifying Auction Returns-to-Service for that round of a 6-month Sub-Auction or the relevant month covered by that Reconfiguration Auction that contribute to that constraint.

If the same Transmission Owner is responsible, as determined pursuant to Section 20.3.6.4, for all of the Qualifying Auction Outages *o* and Qualifying Auction Returns-to-Service *o* for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n* that contribute to constraint *a*, then the ISO shall allocate the O/R-t-S Auction Constraint Residual for that round *n* of a 6-month Sub-Auction or that month covered by Reconfiguration Auction *n* and that constraint, O/R-t-S $ACR_{a,n}$, to that Transmission Owner in the form of either (i) an O/R-t-S Auction Revenue Shortfall Charge in the amount of O/R-t-S $ACR_{a,n}$ if O/R-t-S $ACR_{a,n}$ is negative, or (ii) an O/R-t-S Auction Revenue Surplus Payment in the amount of O/R-t-S $ACR_{a,n}$ if O/R-t-S $ACR_{a,n}$ is positive.

20.3.6.2.3 Allocation of an O/R-t-S Auction Constraint Residual When More Than One Transmission Owner is Responsible for the Relevant Outages and Returns-to-Service

This Section 20.3.6.2.3 describes the allocation of an O/R-t-S Auction Constraint Residual for a given round of a 6-month Sub-Auction or a given month covered by a Reconfiguration Auction, as the case may be, and a given constraint when more than one Transmission Owner is responsible, as determined pursuant to Section 20.3.6.4, for the

Qualifying Auction Outages and the Qualifying Auction Returns-to-Service for the round of a 6-month Sub-Auction or the relevant month covered by the Reconfiguration Auction that contribute to the constraint.

If more than one Transmission Owner is responsible, as determined pursuant to Section 20.3.6.4, for the Qualifying Auction Outages and the Qualifying Auction Returns-to-Service for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction n that contribute to constraint a, the ISO shall allocate the O/R-t-S Auction Constraint Residual for constraint a for round *n* of a 6-month Sub-Auction or for the relevant month covered by Reconfiguration Auction *n*, O/R-t-S $ACR_{a,n}$, in the form of an O/R-t-S Auction Revenue Shortfall Charge or O/R-t-S Auction Revenue Surplus Payment to the Transmission Owners responsible for the Qualifying Auction Outages *o* and Qualifying Auction Returns-to-Service *o* for round *n* of a 6-month Sub-Auction or the relevant month covered by Reconfiguration Auction *n* by first determining the net total impact on the constraint of all Qualifying Auction Outages and Qualifying Auction Returns-to Service for round *n* of a 6-month Sub-Auction or the relevant month covered by Reconfiguration Auction *n* with an impact on the Energy flow across that constraint of 1 MW-*p* or more by applying Formula N-21, and then applying either Formula N-22 or Formula N-23, as specified herein, to assess O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments.

Formula N-21

$$O/R\text{-}t\text{-}SNetAuctionImpact_{a,n} = \sum_{for\ all\ o \in O_n} FlowImpact_{a,n,o} * ShadowPrice_{a,n}$$

Where,

$O/R\text{-}t\text{-}SNetAuctionImpact_{a,n}$ = The net impact, in dollars, for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be, on constraint *a* of all Qualifying Auction Outages and Qualifying Auction Returns-to-Service for -round *n* of a 6-month Sub-Auction or the relevant month covered by Reconfiguration Auction *n* having an impact of more than 1 MW-*p* on Energy flow across constraint *a; provided, however,* O/R-t-SNetAuctionImpact$_{a,n}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula N-21

FlowImpact$_{a,n,o}$ = The Energy flow impact, in MW-*p*, of a Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* on binding constraint *a* determined for a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, which shall either:

(a) if Qualifying Auction Outage *o* is a Deemed Qualifying Auction Outage, be equal to the negative of FlowImpact$_{a,n,o}$ calculated for the corresponding Deemed Qualifying Auction Return-to-Service as described in part (b) of this definition of FlowImpact$_{a,n,o}$, or

(b) if Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* is an Actual Qualifying Auction Outage, an Actual Qualifying Auction Return-to-Service, or a Deemed Qualifying Auction Return-to-Service, be calculated pursuant to the following formula:

$$FlowImpact_{a,n,o} = BaseCaseFlow_{a,n} - One\text{-}OffFlow_{a,n,o}$$

Where,

BaseCaseFlow$_{a,n}$ = Either, as the case may be:

(i) for a given month covered by Reconfiguration Auction *n*, the Energy flow on constraint *a* resulting from a Power Flow using (1) the set of injections and withdrawals corresponding (as described in Section 20.1.2 of this Attachment N) to the actual TCCs and Grandfathered Rights for the relevant month represented in the solution to the last Reconfiguration Auction held for TCCs valid during the relevant month, or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month, (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction); (2) the phase angle regulator schedules determined in the Optimal Power Flow solution for the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the final round of the last 6-month Sub-Auction held for TCCs valid during the relevant month); and (3) the Transmission System model for the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month); or

(ii) for any round of a 6-month Sub-Auction, the Energy flow on constraint *a* resulting from a Power Flow run using the following base case data set: (1) the Transmission System model for the actual 6-month Sub-Auction, modified so as to model as in-service all transmission facilities that were out-of-service for the actual 6-month Sub-Auction, and (2) the set of injections and withdrawals corresponding (as described in Section 20.1.2 of this Attachment N) to the base case set of TCCs (including those pre-existing TCCs and Grandfathered Rights that are represented as fixed injections and withdrawals in the 6-month Sub-Auction) and the phase angle regulator schedules produced in the Optimal Power Flow used to calculate the Energy flow on constraint *a* for round *n* of a 6-month Sub-Auction, as described in the definition of $FLOW_{a,n,basecase}$ in Formula N-17

$One\text{-}OffFlow_{a,n,o}$ = Either

(i) if Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* is an

Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service, the Energy flow on constraint *a* resulting from a Power Flow using each element of the base case data set used in the calculation of $\text{BaseCaseFlow}_{a,n}$ above (*provided, however,* if a transmission facility was modeled as free-flowing in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*, as the case may be, because of the outage of any transmission facility, the ISO shall appropriately adjust the phase angle regulator schedules and related variables to model the transmission facility as free flowing), but in each case with the Transmission System model modified so as to, as the case may be, either (i) model as out-of-service Actual Qualifying Auction Outage *o*, or (ii) model as in-service Actual Qualifying Auction Return-to-Service *o*; or

(ii) if Qualifying Auction Return-to-Service *o* is a Deemed Qualifying Auction Return-to-Service, the Energy flow on constraint *a* resulting from a Power Flow using each element of the base case data set used in the calculation of $\text{BaseCaseFlow}_{a,n}$ above (*provided,* however, if a transmission facility was modeled as free-flowing in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*, as the case may be, because of the outage of any transmission facility, the ISO shall appropriately adjust the phase angle regulator schedules and related variables to model the transmission facility as free flowing), but with the Transmission System model modified so as to model as in-service the facility that is Deemed Qualifying Auction Return-to-Service *o*;

provided, however, where the absolute value of $\text{FlowImpact}_{a,n,o}$ calculated using the procedures set forth above is less than 1 MW-*p*, then $\text{FlowImpact}_{a,n,o}$

shall be set equal to zero *provided further*, $\text{FlowImpact}_{a,n,o}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula N-21

O_n = The set of all Qualifying Auction Outages *o* and Qualifying Auction Returns-to-Service *o* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*

p = A one-month period for a given month covered by Reconfiguration Auction *n*, or a six-month period for round *n* of a 6-month Sub-Auction

and the variable $\text{ShadowPrice}_{a,n}$ is defined as set forth in Formula N-17.

After calculating O/R-t-S $\text{NetAuctionImpact}_{a,n}$ pursuant to Formula N-21, the ISO shall determine whether O/R-t-S $\text{NetAuctionImpact}_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n* has a different sign than O/R-t-S $\text{ACR}_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or in the relevant month covered by Reconfiguration Auction *n*. If the sign is different, the ISO shall (i) recalculate O/R-t-S $\text{NetAuctionImpact}_{a,n}$ pursuant to Formula N-21 after setting equal to zero each $\text{FlowImpact}_{a,n,o}$ for which $\text{FlowImpact}_{a,n,o}$ * $\text{ShadowPrice}_{a,n}$ has a different sign than O/R-t-S $\text{ACR}_{a,n}$, and then (ii) use this recalculated O/R-t-S $\text{NetAuctionImpact}_{a,n}$ and reset value of $\text{FlowImpact}_{a,n,o}$ to allocate O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments pursuant to Formula N-22 or Formula N-23, as specified below.

If the absolute value of the net impact (O/R-t-S $\text{NetAuctionImpact}_{a,n}$) on constraint *a* of all Qualifying Auction Outages and Qualifying Auction Returns-to-Service for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n* as calculated using Formula N-21 (or recalculated pursuant to Formula N-21 using a reset value of $\text{FlowImpact}_{a,n,o}$ as described in the prior paragraph) is greater than the absolute value of the O/R-t-S Auction Constraint Residual (O/R-t-S $\text{ACR}_{a,n}$) for constraint *a* in round *n* of a 6-month Sub-Auction or in the relevant month covered by Reconfiguration Auction *n*, as the case may be, then the ISO shall allocate the O/R-t-S Auction Constraint Residual in the form of an O/R-t-S Auction Revenue Shortfall Charge, O/R-t-S $ARSC_{a,t,n}$, or O/R-t-S Auction Revenue Surplus Payment, O/R-t-S $ARSP_{a,t,n}$, by using Formula N-22. If the absolute value of the net impact (O/R-t-S $NetAuctionImpact_{a,n}$) on constraint *a* of all Qualifying Auction Outages and Qualifying Auction Returns-to-Service for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n* as calculated using Formula N-21 (or recalculated pursuant to Formula N-21 using a reset value of $FlowImpact_{a,n,o}$ as described in the prior paragraph) is less than or equal to the absolute value of the O/R-t-S Auction Constraint Residual (O/R-t-S $ACR_{a,n}$) for constraint *a* in round *n* of a 6-month Sub-Auction or in the relevant month covered by Reconfiguration Auction *n*, as the case may be, then the ISO shall allocate the O/R-t-S Auction Constraint Residual in the form of an O/R-t-S Auction Revenue Shortfall Charge, O/R-t-S $ARSC_{a,t,n}$, or O/R-t-S Auction Revenue Surplus Payment, O/R-t-S $ARSP_{a,t,n}$, by using Formula N-23.

Formula N-22

$$O/R\text{-}t\text{-}S\ Allocation_{a,t,n} = \left(\frac{\sum_{\substack{o \in O_n \\ and\ q=t}} \left(FlowImpact_{a,n,o} * Responsibility_{n,q,o}\right)}{\sum_{for\ all\ o \in O_n} FlowImpact_{a,n,o}} \right) * O/R\text{-}t\text{-}S\ ACR_{a,n}$$

Where,

O/R-t-S $Allocation_{a,t,n}$ = Either an O/R-t-S Auction Revenue Shortfall Charge or an O/R-t-S Auction Revenue Surplus Payment, as specified in (a) and (b) below:

(a) If O/R-t-S $Allocation_{a,t,n}$ is negative, then O/R-t-S $Allocation_{a,t,n}$ shall be an O/R-t-S Auction Revenue Shortfall Charge, O/R-t-S $ARSC_{a,t,n}$, charged to Transmission Owner *t* for binding constraint *a* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction; or

(b) If O/R-t-S $Allocation_{a,t,n}$ is positive, then O/R-t-S $Allocation_{a,t,n}$ shall be an O/R-t-S Auction Revenue Surplus Payment, O/R-t-S

$ARSP_{a,t,n}$, paid to Transmission Owner *t* for binding constraint *a* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction

$Responsibility_{n,q,o}$ = The amount, as a percentage, of responsibility borne by Transmission Owner *q* (which shall include the ISO when it is deemed a Transmission Owner for the purpose of applying Sections 20.3.6.4.2 or 20.3.6.4.3) for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, as determined pursuant to Section 20.3.6.4

and the variable O/R-t-S $ACR_{a,n}$ is defined as set forth in Formula N-19 and the variables $FlowImpact_{a,n,o}$ and O_n are defined as set forth in Formula N-21.

Formula N-23

$$O/R\text{-}t\text{-}S\,Allocation_{a,t,n} = \sum_{\substack{o \in O_n \\ and\ q=t}} FlowImpact_{a,n,o} * ShadowPrice_{a,n} * Responsibility_{n,q,o}$$

Where,

the variable $ShadowPrice_{a,n}$ is defined as set forth in Formula N-17, the variables O/R-t-S $Allocation_{a,t,n}$ and $Responsibility_{n,q,o}$ are defined as set forth in Formula N-22, and the variables $FlowImpact_{a,n,o}$ and O_n are defined as set forth in Formula N-21.

20.3.6.3 Charges and Payments for the Secondary Impact of Auction Outages and Returns-to-Service

The ISO shall use U/D Auction Constraint Residuals to allocate U/D Auction Revenue Shortfall Charges and U/D Auction Revenue Surplus Payments, as the case may be, among Transmission Owners pursuant to this Section 20.3.6.3. Each U/D Auction Revenue Shortfall Charge and each U/D Auction Revenue Surplus Payment allocated to a Transmission Owner pursuant to this Section 20.3.6.3 is subject to being set equal to zero pursuant to Section 20.3.6.5.

20.3.6.3.1 Identification of Upratings and Deratings Qualifying for Charges and

Payments

For each constraint for each round of a 6-month Sub-Auction or each month covered by a Reconfiguration Auction, the ISO shall identify each Qualifying Auction Derating and each Qualifying Auction Uprating, as described below. The Transmission Owner responsible, as determined pursuant to Section 20.3.6.4, for a Qualifying Auction Derating or Qualifying Auction Uprating shall be allocated a U/D Auction Revenue Shortfall Charge or a U/D Auction Revenue Surplus Payment, as the case may be, pursuant to Section 20.3.6.3.2.

20.3.6.3.1.1 Definition of Qualifying Auction Derating

A "**Qualifying Auction Derating**" (which term shall apply to round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be) shall be defined to mean an Actual Qualifying Auction Derating or a Deemed Qualifying Auction Derating. For purposes of this Attachment N, "*r*" shall refer to a single Qualifying Auction Derating.

An "**Actual Qualifying Auction Derating**" (which term shall apply to round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*, as the case may be) shall be defined as a change in the rating of a constraint that, for a given constraint *a* and a given round *n* or a given month covered by Reconfiguration Auction *n* meets each of the following requirements:

For a given month covered by Reconfiguration Auction *n*:

(i) the constraint has a lower rating in the relevant month covered by Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service for the relevant month in Reconfiguration Auction *n*;

(ii) this lower rating is in whole or in part the result of an Actual Qualifying Auction

Outage *o* or an Actual Qualifying Auction Return-to-Service *o* for the relevant month covered by Reconfiguration Auction *n*;

(iii) the lower rating resulting from Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for the relevant month covered by Reconfiguration Auction *n* was not modeled in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month);

(iv) this lower rating for the relevant month is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint was binding in the relevant month covered by Reconfiguration Auction *n*.

For round *n* of a 6-month Sub-Auction:

(i) the constraint has a lower rating in round *n* of the 6-month Sub-Auction than that constraint would have in a case where all transmission facilities are in-service and fully rated;

(ii) this lower rating is the result of an Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for round *n* of the 6-month Sub-Auction;

(iii) this lower rating is included in the Centralized TCC Auction Interface Uprate/Derate Table in effect for round *n* of the 6-month Sub-Auction; and

(iv) the constraint is binding in round *n* of the 6-month Sub-Auction.

A "**Deemed Qualifying Auction Derating**" (which term shall apply to a given month covered by Reconfiguration Auction *n*) shall be defined as a change in the rating of a constraint that, for a given constraint *a* and a given month covered by Reconfiguration Auction *n* meets each of the following requirements:

(i) the constraint has a lower rating in the relevant month covered by Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service for the relevant month in Reconfiguration Auction *n*;

(ii) this lower rating is in whole or in part the result of a Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for the relevant month covered by Reconfiguration Auction *n*;

(iii) this lower rating resulting from Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for the relevant month covered by Reconfiguration Auction *n* was modeled in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month), but responsibility for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* resulting in the lower rating for the relevant month covered by Reconfiguration Auction *n* is assigned pursuant to Section 20.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.3.6.4) other than the Transmission Owner responsible for the lower rating in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month);

(iv) this lower rating is included for the relevant month in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint is binding in the relevant month covered by Reconfiguration Auction *n*.

20.3.6.3.1.2 Definition of Qualifying Auction Uprating

A "**Qualifying Auction Uprating**" shall be defined to mean either an Actual Qualifying Auction Uprating or a Deemed Qualifying Auction Uprating. For purposes of this Attachment N, "*r*" shall refer to a single Qualifying Auction Uprating.

An "**Actual Qualifying Auction Uprating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* and a given month covered by Reconfiguration Auction *n*, as the case may be, meets each of the following requirements:

(i) the constraint has a higher rating for the relevant month covered by Reconfiguration Auction *n* than it would have absent an Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for the relevant month covered by Reconfiguration Auction *n*;

(ii) this higher rating resulting from Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for the relevant month covered by Reconfiguration Auction *n* was not modeled in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month);

(iii) this higher rating in the relevant month covered by Reconfiguration Auction *n* is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(iv) the constraint is binding in the relevant month covered by Reconfiguration Auction *n*.

Notwithstanding any other provision of this Attachment N, a transmission facility uprating for a round of a 6-month Sub-Auction shall not be a Qualifying Auction Uprating and shall not qualify a Transmission Owner for a U/D Auction Revenue Shortfall Charge or U/D Auction Revenue Surplus Payment.

A "**Deemed Qualifying Auction Uprating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* and a given month covered by Reconfiguration Auction *n*, as the case may be, meets each of the following requirements:

(i) the constraint has a lower rating in the relevant month covered by Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service for the relevant month in Reconfiguration Auction *n*;

(ii) this lower rating is in whole or in part the result of a Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for the relevant month covered by Reconfiguration Auction *n*;

(iii) this lower rating resulting from Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for the relevant month covered by Reconfiguration Auction *n* was modeled in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month), but responsibility for Qualifying

Auction Outage *o* or Qualifying Auction Return-to-Service *o* resulting in the lower rating for the relevant month covered by Reconfiguration Auction *n* is assigned pursuant to Section 20.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.3.6.4) other than the Transmission Owner responsible for the lower rating in the last Reconfiguration Auction held for TCCs valid during the relevant month (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month);

(iv) this lower rating in the relevant month covered by Reconfiguration Auction *n* is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint is binding in the relevant month covered by Reconfiguration Auction *n*.

20.3.6.3.2 Allocation of U/D Auction Constraint Residuals

This Section 20.3.6.3.2 describes the allocation of U/D Auction Constraint Residuals to Qualifying Auction Deratings and Qualifying Auction Upratings.

When there are Qualifying Auction Deratings or Qualifying Auction Upratings in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction for constraint *a*, the ISO shall allocate a U/D Auction Constraint Residual in the form of a U/D Auction Revenue Shortfall Charge, U/D $ARSC_{a,t,n}$, or U/D Auction Revenue Surplus Payment, U/D $ARSP_{a,t,n}$, by first determining the net total impact on the constraint for the round *n* of a 6-month Sub-Auction or the relevant month covered by Reconfiguration Auction *n* of all Qualifying Auction Deratings *r* and Qualifying Auction Upratings *r* for constraint *a* in the relevant month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction pursuant to Formula N-24 and then applying either Formula N-25 or Formula N-26, as specified herein, to assess U/D Auction Revenue Shortfall Charges and U/D Auction Revenue Surplus Payments.

Formula N-24

$$U/D\ NetAuctionImpact_{a,n} = \left(\sum_{r \in R_{a,n}} RatingChange_{a,n,r} * ShadowPrice_{a,n} \right) * OPFSignChange_{a,n}$$

Where,

U/D NetAuctionImpact$_{a,n}$ = The net impact, in dollars, on constraint *a* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction of all Qualifying Auction Deratings or Qualifying Auction Upratings for constraint *a* in the relevant month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction; *provided*, *however*, U/D NetAuctionImpact$_{a,n}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula N-24

RatingChange$_{a,n,r}$= Either:

(a) If Qualifying Auction Derating *r* or Qualifying Auction Uprating *r* is a Deemed Qualifying Auction Derating or a Deemed Qualifying Auction Uprating, RatingChange$_{a,n,r}$ shall be equal to the amount, in MW-*p*, of the decrease or increase in the rating of binding constraint *a* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction resulting from a Deemed Qualifying Auction Outage or Deemed Qualifying Auction Return-to-Service for constraint *a* in the relevant month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, which in the case of the relevant month covered by Reconfiguration Auction *n* shall be as shown in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*, and which in the case of round *n* of a 6-month Sub-

Auction shall be as shown in the Centralized TCC Auction Interface Uprate/Derate Table in effect for round *n* of a 6-month Sub-Auction; or

(b) If Qualifying Auction Derating *r* or Qualifying Auction Uprating *r* is an Actual Qualifying Auction Derating or an Actual Qualifying Auction Uprating, $\text{RatingChange}_{a,n,r}$ shall be equal to the amount, in MW-*p*, of the decrease or increase in the rating of binding constraint *a* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction resulting from an Actual Qualifying Auction Outage or Actual Qualifying Auction Return-to-Service for constraint *a* in the relevant month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, which in the case of the relevant month covered by Reconfiguration Auction *n* shall be as shown in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*, and which in the case of round *n* of a 6-month Sub-Auction shall be as shown in the Centralized TCC Auction Interface Uprate/Derate Table in effect for round *n* of a 6-month Sub-Auction;

provided, however, $\text{RatingChange}_{a,n,r}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula N-24

$R_{a,n}$ = The set of all Qualifying Auction Deratings *r* or Qualifying Auction Upratings *r* for binding constraint *a* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction

and the variables $\text{ShadowPrice}_{a,n}$ and $\text{OPFSignChange}_{a,n}$ are defined as set forth in Formula N-17.

After calculating U/D $\text{NetAuctionImpact}_{a,n}$ pursuant to Formula N-24, the ISO shall determine whether U/D $\text{NetAuctionImpact}_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n* has a different sign than U/D

$ACR_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or in the relevant month covered by Reconfiguration Auction *n*. If the sign is different, the ISO shall (i) recalculate U/D $NetAuctionImpact_{a,n}$ pursuant to Formula N-24 after setting equal to zero each $RatingChange_{a,n,r}$ for which $RatingChange_{a,n,r}$ * $ShadowPrice_{a,n}$ * $OPFSignChange_{a,n}$ has a different sign than U/D $ACR_{a,n}$, and then (ii) use this recalculated U/D $NetAuctionImpact_{a,n}$ and reset value of $RatingChange_{a,n,r}$ to allocate U/D Auction Revenue Shortfall Charges and U/D Auction Revenue Surplus Payments pursuant to Formula N-25 or Formula N-26, as specified below.

If the absolute value of the net impact (U/D $NetAuctionImpact_{a,n}$) on constraint *a* for a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction of all Qualifying Auction Deratings or Qualifying Auction Upratings for constraint *a* in the relevant month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction as calculated using Formula N-24 (or recalculated pursuant to Formula N-24 using a reset value of $RatingChange_{a,n,r}$ as described in the prior paragraph) is greater than the absolute value of the U/D Auction Constraint Residual (U/D $ACR_{a,n}$) for constraint *a* in the relevant month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, as the case may be, then the ISO shall allocate the U/D Auction Constraint Residual in the form of a U/D Auction Revenue Shortfall Charge, U/D $ARSC_{a,t,n}$, or U/D Auction Revenue Surplus Payment, U/D $ARSP_{a,t,n}$, by using Formula N-25. If the absolute value of the net impact (U/D $NetAuctionImpact_{a,n}$) on constraint *a* for a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction of all Qualifying Auction Deratings or Qualifying Auction Upratings for constraint *a* in the relevant month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction as calculated using Formula N-24 (or recalculated pursuant to Formula N-24 using a reset value of $RatingChange_{a,n,r}$ as described in the prior paragraph) is less than or equal to the absolute value of the U/D Auction Constraint Residual (U/D $ACR_{a,n}$) for constraint *a* in the relevant month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, as the case may be, then the ISO shall allocate the U/D Auction Constraint Residual in the form of a U/D Auction Revenue Shortfall Charge, U/D $ARSC_{a,t,n}$, or U/D Auction Revenue Surplus Payment, U/D $ARSP_{a,t,n}$, by using Formula N-26.

Formula N-25

$$U/D\,Allocation_{a,t,n} = \left(\frac{\sum_{\substack{r \in R_{a,n} \\ and\ q=t}} \left(RatingChange_{a,n,r} * Responsibility_{n,q,r} \right)}{\sum_{for\ all\ r \in R_{a,n}} RatingChange_{a,n,r}} \right) * U/D\,ACR_{a,n}$$

Where,

U/D $Allocation_{a,t,n}$ = Either a U/D Auction Revenue Shortfall Charge or a U/D Auction Revenue Surplus Payment, as specified in (a) and (b) below:

(a) If U/D $Allocation_{a,t,n}$ is negative, then U/D $Allocation_{a,t,n}$ shall be a U/D Auction Revenue Shortfall Charge, U/D $ARSC_{a,t,n}$, charged to Transmission Owner *t* for binding constraint *a* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction; or

(b) If U/D $Allocation_{a,t,n}$ is positive, then U/D $Allocation_{a,t,n}$ shall be a U/D Auction Revenue Surplus Payment, U/D $ARSP_{a,t,n}$, paid to Transmission Owner *t* for binding constraint *a* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction

$Responsibility_{n,q,r}$ = The amount, as a percentage, of responsibility borne by Transmission Owner *q* (which shall include the ISO when it is deemed a Transmission Owner for the purpose of applying Sections 20.3.6.4.2 or 20.3.6.4.3) for Qualifying Auction Derating *r* or Qualifying Auction Uprating *r* in a given month covered by Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, as determined pursuant to Section 20.3.6.4

and the variable U/D $ACR_{a,n}$ is defined as set forth in Formula N-20 and the variables $RatingChange_{a,n,r}$ and $R_{a,n}$ are defined as set forth in Formula N-24.

Formula N-26

$$U/D\,Allocation_{a,t,n} = \sum_{\substack{r \in R_{a,n} \\ and\ q=t}} RatingChange_{a,n,r} * ShadowPrice_{a,n} * Responsibility_{n,q,r}$$

Where,

the variables U/D $Allocation_{a,t,n}$ and $Responsibility_{n,q,r}$ are defined as set forth in Formula N-25, the variable $ShadowPrice_{a,n}$ is defined as set forth in Formula N-17, and the variables $RatingChange_{a,n,r}$ and $R_{a,n}$ are defined as set forth in Formula N-24.

20.3.6.4 Assigning Responsibility for Outages, Returns-to-Service, Deratings, and Upratings

20.3.6.4.1 General Rule for Assigning Responsibility; Presumption of Causation

Unless the special rules set forth in Sections 20.3.6.4.2 or 20.3.6.4.3 apply, a Transmission Owner shall for purposes of this Section 20.3.6 be deemed responsible for an Auction Status Change to the extent that the Transmission Owner has caused the Auction Status Change by changing the in-service or out-of-service status of its transmission facility; *provided, however*, that where an Auction Status Change results from a change to the in-service or out-of-service status of a transmission facility owned by more than one Transmission Owner, responsibility for such Auction Status Change shall be assigned to each owning Transmission Owner based on the percentage of the transmission facility that is owned by the Transmission Owner (as determined in accordance with Section 20.3.6.6.3). For the sake of clarity, a Transmission Owner may, by changing the in-service or out-of-service status of its transmission facility, cause an Auction Status Change of another transmission facility if the Transmission Owner’s change in the in-service or out-of-service status of its transmission facility causes (directly or as a result of Good Utility Practice) a change in the in-service or out-of-service status of the other transmission facility.

The Transmission Owner that owns a transmission facility that qualifies as an Auction

Status Change shall be deemed to have caused the Auction Status Change of that transmission facility unless (i) the Transmission Owner that owns the facility informs the ISO that another Transmission Owner caused the Auction Status Change or that responsibility is to be shared among Transmission Owners in accordance with Sections 20.3.6.4.2 or 20.3.6.4.3, and no party disputes such claim; (ii) in case of a dispute over the assignment of responsibility, the ISO determines a Transmission Owner other than the owner of the transmission facility caused the Auction Status Change or that responsibility is to be shared among Transmission Owners in accordance with Section 20.3.6.4.2 or Section 20.3.6.4.3; or (iii) FERC orders otherwise.

20.3.6.4.2 Shared Responsibility For Outages, Returns-to-Service, and Ratings Changes Directed by the ISO or Caused by Facility Status Changes Directed by the ISO

A Transmission Owner shall not be responsible for any Auction Status Change that qualifies as an ISO-Directed Auction Status Change or Deemed ISO-Directed Auction Status Change. Instead, the ISO shall allocate any revenue impacts resulting from an Auction Status Change that qualifies as an ISO-Directed Auction Status Change or Deemed ISO-Directed Auction Status Change as part of Net Auction Revenues for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*. To do so, the ISO shall be treated as a Transmission Owner when allocating Auction Constraint Residuals pursuant to Section 20.3.6.2 and Section 20.3.6.3, and any Auction Status Change that qualifies as an ISO-Directed Auction Status Change or Deemed ISO-Directed Auction Status Change shall be attributed to the ISO when performing the calculations described in Section 20.3.6.2 and Section 20.3.6.3; *provided, however*, any O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment allocable to the ISO pursuant to this Section 20.3.6.4.2 shall ultimately be allocated to the

Transmission Owners as Net Auction Revenues pursuant to Section 20.3.7.

Responsibility for a Qualifying Auction Return-to-Service or Qualifying Auction Uprating that is directed by the ISO but does not qualify as a Deemed ISO-Directed Auction Status Change shall be assigned to the Transmission Owner that was responsible for the Qualifying Auction Outage or Qualifying Auction Derating in the last Reconfiguration Auction held for TCCs valid during the a given month covered by Reconfiguration Auction *n* (or if no Reconfiguration Auction was held for TCCs valid during the relevant month, then the last 6-month Sub-Auction held for TCCs valid during the relevant month).

The ISO shall not direct that a transmission facility be modeled as in-service or out-of-service for purposes of a given month covered by a Reconfiguration Auction without the unanimous consent of the Transmission Owner(s), if any, that will be allocated a resulting O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment in accordance with this Section 20.3.6.4.2.

20.3.6.4.3 Shared Responsibility for External Events

A Transmission Owner shall not be responsible for an Auction Status Change occurring inside the NYCA that is caused by a change in the in-service or out-of-service status or rating of a transmission facility located outside the NYCA. Instead, the ISO shall allocate any revenue impacts resulting from an Auction Status Change caused by such an event outside the NYCA as part of Net Auction Revenues for round *n* of a 6-month Sub-Auction or a given month covered by Reconfiguration Auction *n*. To do so, the ISO shall be treated as a Transmission Owner when allocating Auction Constraint Residuals pursuant to Section 20.3.6.2 and Section 20.3.6.3 and any Auction Status Change caused by such an event outside the NYCA shall be attributed to the

ISO; *provided, however*, any O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment allocable to the ISO pursuant to this Section 20.3.6.4.3 shall ultimately be allocated to the Transmission Owners as Net Auction Revenues pursuant to Section 20.3.7.

20.3.6.5 Exceptions: Setting Charges and Payments to Zero

20.3.6.5.1 Zeroing Out of Charges and Payments When Outages and Deratings Lead to Net Payments or Returns-to-Service and Upratings Lead to Net Charges

The ISO shall use Formula N-27 to calculate the total O/R-t-S Auction Revenue Shortfall Charges, U/D Auction Revenue Shortfall Charges, O/R-t-S Auction Revenue Surplus Payments, and U/D Auction Revenue Surplus Payments, $\text{NetAuctionAllocations}_{t,n}$, for Transmission Owner *t* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*, as the case may be. Based on this calculation, the ISO shall set equal to zero all O/R-t-S $\text{ARSC}_{a,t,n}$, U/D $\text{ARSC}_{a,t,n}$, O/R-t-S $\text{ARSP}_{a,t,n}$, and U/D $\text{ARSP}_{a,t,n}$ (each as defined in Formula N-27) for Transmission Owner *t* for all constraints for round *n* of a 6-month Sub-Auction or the relevant month covered by Reconfiguration Auction *n*, as the case may be, if (i) $\text{NetAuctionAllocations}_{t,n}$ is positive and Transmission Owner *t* is not responsible (as determined pursuant to Section 20.3.6.4) for any Qualifying Auction Returns-to-Service or Qualifying Auction Upratings in round *n* of a 6-month Sub-Auction or in the relevant month covered by Reconfiguration Auction *n*, as the case may be, or (ii) $\text{NetAuctionAllocations}_{t,n}$ is negative and Transmission Owner *t* is not responsible (as determined pursuant to Section 20.3.6.4) for any Qualifying Auction Outages or Qualifying Auction Deratings in round *n* of a 6-month Sub-Auction or in the relevant month covered by Reconfiguration Auction *n*, as the case may be; *provided, however,* the ISO shall not set equal to zero pursuant to this Section 20.3.6.5.1 any

O/R-t-S $ARSC_{a,t,n}$, U/D $ARSC_{a,t,n}$, O/R-t-S $ARSP_{a,t,n}$, or U/D $ARSP_{a,t,n}$ arising from an ISO-Directed Auction Status Change or Deemed ISO-Directed Auction Status Change described in Section 20.3.6.4.2 or external events described in Section 20.3.6.4.3.

Formula N-27

$$NetAuctionAllocations_{t,n} = \sum_{for\ all\ a} \left(O/R\text{-}t\text{-}S\ ARSC_{a,t,n} + U/D\ ARSC_{a,t,n} + O/R\text{-}t\text{-}S\ ARSP_{a,t,n} + U/D\ ARSP_{a,t,n} \right)$$

Where,

$NetAuctionAllocations_{t,n}$ = The total of the O/R-t-S Auction Revenue Shortfall Charges, U/D Auction Revenue Shortfall Charges, O/R-t-S Auction Revenue Surplus Payments, and U/D Auction Revenue Surplus Payments allocated to Transmission Owner *t* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*

O/R-t-S $ARSC_{a,t,n}$ = An O/R-t-S Auction Revenue Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.2

U/D $ARSC_{a,t,n}$ = A U/D Auction Revenue Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.3

O/R-t-S $ARSP_{a,t,n}$ = An O/R-t-S Auction Revenue Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.2

U/D $ARSP_{a,t,n}$ = A U/D Auction Revenue Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in round *n* of a 6-month Sub-Auction or in a given month covered by Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.3.

20.3.6.5.2 Zeroing Out of Charges and Payments Resulting from Formula Failure

Notwithstanding any other provision of this Attachment N, the ISO shall set equal to zero any O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment allocated to a Transmission Owner for a given month covered by a Reconfiguration Auction or a round of a Centralized TCC Auction if either:

(i) data necessary to compute such a charge or payment, as specified in the formulas set forth in Section 20.3.6, is not known by the ISO and cannot be computed by the ISO (in interpreting this clause, equipment failure shall not preclude computation by the ISO unless necessary data is irretrievably lost); or

(ii) both (a) the charge or payment is clearly and materially inconsistent with cost causation principles; and (b) this inconsistency is the result of factors not taken into account in the formulas used to calculate the charge or payment;

provided, however, if the amount of charges or payments set equal to zero as a result of the unknown data or inaccurate formula is greater than twenty five thousand dollars ($25,000) in any given month or greater than one hundred thousand dollars ($100,000) over multiple months, the ISO will inform the Transmission Owners of the identified problem and will work with the Transmission Owners to determine if an alternative allocation method is needed and whether it will apply to all months for which the intended formula does not work. Alternate methods would be subject to market participant review and subsequent filing with FERC, as appropriate.

For the sake of clarity, the ISO shall not pursuant to this Section 20.3.6.5.2 set equal to zero any O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment that fails to meet these conditions, even if another O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment is set equal to zero pursuant to this Section 20.3.6.5.2 in the same round of a Centralized TCC Auction or the same month covered by a Reconfiguration Auction, as the case may be.

20.3.6.6 Information Requirements

20.3.6.6.1 Posting of Uprate/Derate Tables

Prior to each Reconfiguration Auction, the ISO shall post on its website the Reconfiguration Auction Interface Uprate/Derate Table, which table shall specify the expected impact (at the time of the Reconfiguration Auction based on all information available to the ISO) of all transmission facility outages and returns-to-service on interface transfer limits for the month(s) for which TCCs are to be sold in the Reconfiguration Auction.

Prior to each Centralized TCC Auction, the ISO shall post on its website the Centralized TCC Auction Interface Uprate/Derate Table, which table shall specify the expected impact (at the time of the Centralized TCC Auction based on all information available to the ISO) of all transmission facility outages and returns-to-service on interface transfer limits for the period for which TCCs are to be sold in each Sub-Auction of the Centralized TCC Auction.

20.3.6.6.2 Posting of List of Normally Out-of-Service Equipment

The ISO shall maintain on its website a list of Normally Out-of-Service Equipment and update such list prior to each Reconfiguration Auction and each Centralized TCC Auction.

20.3.6.6.3 Information Regarding Facility Ownership

A Transmission Owner shall be responsible for informing the ISO of any change in the ownership of a transmission facility. The ISO shall allocate responsibility for Auction Status Changes based on the transmission facility ownership information available to it at the time of initial settlement.

20.3.7 Allocation of Net Auction Revenue to Transmission Owners

In Centralized TCC Auction round *n* or in a given month covered by Reconfiguration Auction *n*, as the case may be, the ISO shall use the Facility Flow-Based Methodology to allocate Net Auction Revenue to each Transmission Owner *t* in an amount equal to the product of (i) the Facility Flow-Based Methodology coefficient, $FFB_{t,n}$, and (ii) the Net Auction Revenue for the round or for the relevant month covered by the Reconfiguration Auction; *provided, however,* where the Net Auction Revenue is negative for a given month covered by a Reconfiguration Auction, the ISO shall allocate Net Auction Revenue to each Transmission Owner *t* in an amount equal to the product of (i) the negative Net Auction Revenue coefficient, $NNAR_{t,n}$, and (ii) the negative Net Auction Revenue for the relevant month covered by Reconfiguration Auction.

Calculation of Facility Flow-Based Methodology Coefficient. The Facility Flow-Based Methodology coefficient for Transmission Owner *t* for Centralized TCC Auction round *n* or a given month covered by Reconfiguration Auction *n* is calculated pursuant to Formula N-28.

Formula N-28

$$FFB_{t,n} = \frac{\sum_{l \in L_{t,n}} \left| \left(FLOW_{l,n} - FLOW_{l,IC}\right) * \left(Price_{y,l} - Price_{x,l}\right) * Share_{n,t,l} \right|}{\sum_{l \in L_n} \left| \left(FLOW_{l,n} - FLOW_{l,IC}\right) * \left(Price_{y,l} - Price_{x,l}\right) \right|}$$

Where,

$FFB_{t,n}$ = The Facility Flow-Based Methodology coefficient for Transmission Owner *t* for Centralized TCC Auction round *n* or a given month covered by Reconfiguration Auction *n*, as the case may be

L_n = The set of all transmission facilities owned by Transmission Owners that are modeled in the Transmission System model for round *n* or for a given month covered by Reconfiguration Auction *n*, as the case may be

$L_{t,n}$ = The set of all transmission facilities owned by Transmission Owner *t* that are modeled in the Transmission System model applied in round *n* or in a given month covered by Reconfiguration Auction *n*, as the case may be

l = A transmission facility from bus *x* to bus *y*

$FLOW_{l,n}$ = The Energy flow, in MW-*p*, on transmission facility *l* from the set of TCCs (as scaled appropriately) and Grandfathered Rights represented in the solution to round *n* or to a given month covered by Reconfiguration Auction *n*, as the case may be (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction).

$FLOW_{l,IC}$ = The Energy flow, in MW-*p*, on transmission facility *l* from (i) the set of pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in administering the TCC auction held for round *n* or a given month covered by Reconfiguration Auction *n*, as the case may be, (ii) ETCNL not sold in prior Centralized TCC Auctions, prior rounds of the Centralized TCC Auction that includes round *n* or through a Direct Sale, and (iii) Original Residual TCCs not sold in prior Centralized TCC Auctions, prior rounds of the Centralized TCC Auction that includes round *n* or through a Direct Sale

$Price_{y,l}$ = The market-clearing price at bus *y* on transmission facility *l* in the Optimal Power Flow solution to round *n* or a given month covered by Reconfiguration Auction *n*, as the case may be

$Price_{x,l}$ = The market-clearing price at bus *x* on transmission facility *l* in the Optimal Power Flow solution to round *n* or a given month covered by Reconfiguration Auction *n*, as the case may be

$Share_{n,t,l}$ = The percentage of transmission facility *l* owned by Transmission Owner *t* on the effective date of the TCCs sold in round *n* or in a given month covered by Reconfiguration Auction *n*

p = A one-month period for a given month covered by a Reconfiguration Auction *n*, or the effective period of TCCs sold in round *n*.

Calculation of Negative Net Auction Revenue Coefficient. The negative Net Auction Revenue coefficient for Transmission Owner *t* for a given month covered by Reconfiguration Auction *n* is calculated pursuant to Formula N-29.

Formula N-29

$$NNAR_{t,n} = \frac{\begin{pmatrix} OriginalResidual_{t,n} + ETCNL_{t,n} + NARs_{t,n} \\ +GFR\&GFTCC_{t,n} + HFPTCC_{t,n} + NHFPTCC_{t,n} \end{pmatrix}}{\sum_{q \in T} \begin{pmatrix} OriginalResidual_{q,n} + ETCNL_{q,n} + NARs_{q,n} \\ +GFR\&GFTCC_{q,n} + HFPTCC_{q,n} + NHFPTCC_{q,n} \end{pmatrix}}$$

Where,

$NNAR_{t,n}$ = The negative Net Auction Revenue coefficient for Transmission Owner *t* for a given month covered by Reconfiguration Auction *n*

Original $Residual_{q,n}$ = The sum of the one-month portion of the revenue imputed to the Direct Sale and the sale in any Centralized TCC Auction Sub-Auction of

Original Residual TCCs held by Transmission Owner *q* that are valid during a given month covered by Reconfiguration Auction *n*. The one-month portion of the revenue imputed to the Direct Sale of these Original Residual TCCs shall be one-sixth of the average market-clearing price in the rounds of the 6-month Sub-Auction of the last Centralized TCC Auction held for TCCs valid during the relevant month covered by Reconfiguration Auction *n*. The one-month portion of the revenue imputed to the sale in any Centralized TCC Auction Sub-Auction of these Original Residual TCCs shall be calculated by dividing the revenue received from the sale of these Original Residual TCCs in the Centralized TCC Auction Sub-Auction by the duration in months of the TCCs sold in that Centralized TCC Auction Sub-Auction

$ETCNL_{q,n}$ = The sum of the one-month portion of the revenue imputed to the Direct Sale of Transmission Owner *q*'s ETCNL or for its ETCNL released in the Centralized TCC Auction Sub-Auction held for TCCs valid for a given month covered by Reconfiguration Auction *n*. The one-month portion of the revenue imputed for ETCNL released in any Centralized TCC Auction Sub-Auction shall be calculated by dividing the revenue received in a Centralized TCC Auction Sub-Auction from the sale of the ETCNL by the duration in months of the TCCs corresponding (as described in Section 20.1.2 of this Attachment N) to the ETCNL sold in the Centralized TCC Auction Sub-Auction. The one-month portion of the revenue imputed to the Direct Sale of ETCNL shall be one-sixth of the average market-clearing price of the TCCs corresponding (as described in Section 20.1.2 of this Attachment N) to that ETCNL in the rounds of the 6-month Sub-Auction of the last Centralized TCC Auction held for TCCs valid during the relevant month covered by Reconfiguration Auction *n*.

$NARs_{q,n}$ = The one-month portion of the Net Auction Revenues Transmission Owner *q* has received in Centralized TCC Auction Sub-Auctions and all Reconfiguration Auctions held for TCCs valid for a given month covered by Reconfiguration Auction *n* (which shall not include any revenue from the sale of Original Residual TCCs). The one-month portion of the revenues shall be calculated by summing (i) the revenue Transmission Owner *q* received in each Centralized TCC Auction Sub-Auction from the allocation of Net Auction Revenue pursuant to Section 20.3.7, divided by the duration in months of the TCCs sold in the Centralized TCC Auction Sub-Auction and the sum of the revenue Transmission Owner *q* received from the allocation of that portion of Net Auction Revenue pursuant to Section 20.3.7 related to month *m* for all Reconfiguration Auctions held for TCCs valid in month *m* (or, to the extent TCC auction revenues were allocated pursuant to a different methodology, the amount of such revenues allocated to Transmission Owner *q*), minus (ii) the sum of $NetAuctionAllocations_{t,n}$ as calculated pursuant to Formula N-27 (as adjusted for any charges or payments that are zeroed out) for Transmission Owner *q* for all rounds *n* of a 6-month

Sub-Auction for all Centralized TCC Auctions held for TCCs valid in the relevant month covered by Reconfiguration Auction *n*, divided in each case by the duration in months of the TCCs sold in each Centralized TCC Auction Sub-Auction (or, to the extent that the revenue impact of transmission facility outages, returns-to-service, upratings, and deratings were settled pursuant to a different methodology, the net of such revenue impacts for Transmission Owner *q*), minus (iii) the sum of the portion of $NetAuctionAllocations_{t,n}$ as calculated pursuant to Formula N-27 and as adjusted for any charges or payments that are zeroed out for Transmission Owner *q* for the relevant month covered by Reconfiguration Auction *n* for all Reconfiguration Auctions held for TCCs valid in month *m* (or, to the extent that the revenue impact of transmission facility outages, returns-to-service, upratings, and deratings were settled pursuant to a different methodology, the net of such revenue impacts for Transmission Owner *q*).

$GFR\&GFTCC_{q,n}$ = The one-month portion of the imputed value of Grandfathered TCCs and Grandfathered Rights held by Transmission Owner *q*, valued at one-sixth of the market-clearing price in the last Centralized TCC Auction held for TCCs valid during a given month covered by Reconfiguration Auction *n*, provided that Transmission Owner *q* is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in the relevant month covered by Reconfiguration Auction *n*.

$HFPTCC_{q,n}$ = The one-month portion of the Historic Fixed Price TCC revenues that Transmission Owner *q* has received for Historic Fixed Price TCCs valid during a given month covered by Reconfiguration Auction *n*, valued at the sum of the share of revenues received by Transmission Owner *q* pursuant to Section 20.4 of this Attachment N for all Historic Fixed Price TCCs valid in the relevant month covered by Reconfiguration Auction *n*, divided by twelve; provided, however that the value shall be zero for all Historic Fixed Price TCCs that took effect on or before November 1, 2016.

$NHFPTCC_{q,n}$ = The one-month portion of the Non-Historic Fixed Price TCC revenues that Transmission Owner *q* has received for Non-Historic Fixed Price TCCs valid during a given month covered by Reconfiguration Auction *n*, valued at the sum of the share of revenues received by Transmission Owner *q* pursuant to Section 20.5 of this Attachment N for all Non-Historic Fixed Price TCCs valid in the relevant month covered by Reconfiguration Auction *n*, divided by: (i) twenty-four in the case of Non-Historic Fixed Price TCC revenues received by Transmission Owner *q* related to initial awards of Non-Historic Fixed Price TCCs valid in the relevant month covered by Reconfiguration Auction *n*; or (ii) twelve in the case of Non-Historic Fixed Price TCC revenues received by Transmission Owner *q* related to renewals of Non-Historic Fixed Price TCCs valid in the relevant month covered by Reconfiguration

Auction *n*; provided, however that the value shall be zero for all Non-Historic Fixed Price TCCs that took effect on or before May 1, 2017.

t	=	Transmission Owner *t*
T	=	The set of all Transmission Owners *q*.

For purposes of Formula N-29, variables subscripted by *t* shall be calculated for Transmission Owner *t* in the same manner as variables subscripted by *q* are calculated for Transmission Owner *q*.

For a Balance-of-Period Auction, the ISO shall sum the share of Net Auction Revenues allocated to each Transmission Owner across the month(s) covered by the auction to determine each Transmission Owner's aggregate share of Net Auction Revenues for such auction. The ISO shall also provide each Transmission Owner information regarding their respective share of Net Auction Revenues for each month covered by the Balance-of-Period Auction.

Each Transmission Owner's share of Net Auction Revenues allocated pursuant to this Section 20.3.7 shall be incorporated into its TSC or NTAC, as the case may be.

20.4 Allocation of Historic Fixed Price TCC Revenues

20.4.1 Defined Terms and Overview

20.4.1.1 Defined Terms

1. **Set of Historic Fixed Price TCCs (HFPTCCs):** Historic Fixed Price TCCs that have the same POI and POW and which take, or took, effect in the same Capability Period.

20.4.1.2 Overview

The ISO shall allocate the revenues from the initial award and renewal of Historic Fixed Price TCCs as follows:

1. following the effective date of this Section 20.4, the ISO shall allocate to the Transmission Owners the revenue paid by LSEs for Historic Fixed Price TCCs that took effect on or before November 1, 2016 by using the methodology described in this Section 20.4 and by using the data and results of the last Centralized TCC Auction completed prior to the respective Capability Period in which each such Historic Fixed Price TCC took effect; and
2. following the completion of each Centralized TCC Auction after the effective date of this Section 20.4, the ISO shall allocate to the Transmission Owners the revenue paid by LSEs for Historic Fixed Price TCCs that take effect in the Capability Period immediately following such Centralized TCC Auction using the methodology described in this Section 20.4 and by using the data and results of the last Centralized TCC Auction completed prior to the respective Capability Period in which each such Historic Fixed Price TCC takes effect.

To do so, for each Set of HFPTCCs, the ISO shall:

1. determine the Historic Fixed Price TCC revenue deemed to be associated with each

round of the one-year Sub-Auction of the relevant Centralized TCC Auction pursuant to Section 20.4.2 of this Attachment N;

2. determine the applicable Historic Fixed Price TCC facility flow-based methodology coefficient for each Transmission Owner for each round of the one-year Sub-Auction of the relevant Centralized TCC Auction pursuant to Section 20.4.3 of this Attachment N; and
3. allocate, among the Transmission Owners, the Historic Fixed Price TCC revenue deemed to be associated with each round of the one-year Sub-Auction of the relevant Centralized TCC Auction in accordance with Section 20.4.4 of this Attachment N.

20.4.2 Calculation of Historic Fixed Price TCC Revenue Deemed to be Associated with a Round of a One-Year Sub-Auction

For each Set of HFPTCCs, the ISO shall calculate the revenue deemed to be associated with a round of the one-year Sub-Auction for the relevant Centralized TCC Auction in accordance with Formula N-30.

Formula N-30

$$HFPTCCRevenue_{s,n} = \left[\sum_{k \in s} HFPTCCPmt_{k,s}\right] * RoundPct_n$$

Where,

$\text{HFPTCCRevenue}_{s,n}$	= For Set of HFPTCCs *s*, the Historic Fixed Price TCC revenue that is deemed to be associated with round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction
s	= A Set of HFPTCCs
$\text{HFPTCCPmt}_{k,s}$	= The revenue received for each Historic Fixed Price TCC *k* that is part of Set of HFPTCCs *s*, as payable by an LSE in accordance with Section 19.2.1.3 of Attachment M of this Tariff
RoundPct_n	= The percentage of transmission capacity made available for round *n* of the relevant Centralized TCC Auction to support the sale of one-year TCCs, calculated as the ratio of (i) the percentage of transmission

capacity made available to support the sale of one-year TCCs in round *n* of the relevant Centralized TCC Auction; to (ii) the percentage of transmission capacity made available to support the sale of one-year TCCs in the one-year Sub-Auction of the relevant Centralized TCC Auction, each as determined by the ISO prior to the relevant Centralized TCC Auction.

20.4.3 Calculation of Historic Fixed Price TCC Facility Flow-Based Methodology Coefficient

For each Set of HFPTCCs, the ISO shall use the Historic Fixed Price TCC facility flow-based methodology coefficient to allocate, among the Transmission Owners, the Historic Fixed Price TCC revenue deemed to be associated with a round of the one-year Sub-Auction for the relevant Centralized TCC Auction. The applicable coefficient for each Set of HFPTCCs and each round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction shall be calculated in accordance with Formula N-31.

Formula N-31

$$HFPTCCFFB_{t,s,n} = \frac{\sum_{L \in L_{t,n}} \left| \left(1YrFlow_{L,n} - ModlYrFlow_{L,n,s}\right)\left(Price_{y,L,n} - Price_{x,L,n}\right) * Share_{n,t,L} \right|}{\sum_{L \in L_n} \left| \left(1YrFlow_{L,n} - ModlYrFlow_{L,n,s}\right)\left(Price_{y,L,n} - Price_{x,L,n}\right) \right|}$$

Where,

$HFPTCCFFB_{t,s,n}$	= For Set of HFPTCCs *s*, the Historic Fixed Price TCC facility flow-based methodology coefficient for Transmission Owner *t* for round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction
s	= As defined in Formula N-30
L_n	= The set of all transmission facilities owned by Transmission Owners that are modeled in the Transmission System model for round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction
$L_{t,n}$	= The set of all transmission facilities owned by Transmission Owner *t* that are modeled in the Transmission System model for round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction
L	= A transmission facility from bus *x* to bus *y*
$1YrFlow_{L,n}$	= The Energy flow on transmission facility *L* in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant

Centralized TCC Auction that includes all injections and withdrawals corresponding (as described in Section 20.1.2 of this Attachment N) to the set of TCCs (including Fixed Price TCCs) and Grandfathered Rights represented in such Optimal Power Flow

$Mod1YrFlow_{L,n,s}$ = The Energy flow on transmission facility *L* in a Power Flow that includes all injections and withdrawals corresponding (as described in Section 20.1.2 of this Attachment N) to the set of TCCs (including Fixed Price TCCs) and Grandfathered Rights represented in the solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction, except for the injections and withdrawals corresponding to Set of HFPTCCs *s*. For purposes of this Power Flow: (i) the phase angle settings for optimized phase angle regulators, as identified in ISO Procedures, will be set equal to the phase angle settings for such phase angle regulators as determined in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction, but the schedules for such phase angle regulators will be allowed to vary from the schedules determined in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction; and (ii) for all other phase angle regulators internal to the NYCA or on external borders, as identified in ISO Procedures, the schedules for such phase angle regulators will be set equal to the schedules as determined in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction, but the phase angle settings for such phase angle regulators will be allowed to vary from the phase angle settings determined in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction. Notwithstanding anything to the contrary herein, if the Power Flow results in Energy flow on transmission facility *L* that violates any limit applicable to the amount of Energy that may flow on transmission facility *L* for round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction, the ISO shall adjust the resulting value of the Energy flow on transmission facility *L*, as determined by the Power Flow, to avoid consideration of such incremental flows above the applicable limit for transmission facility *L* and use such adjusted Energy flow value for purposes of calculating $HFPTCCFFB_{t,s,n}$

$Price_{y,L,n}$ = The market-clearing price at bus *y* on transmission facility *L* in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction. Notwithstanding anything to the contrary herein, for Historic Fixed Price TCCs with a POW on Long Island that took effect on November 1, 2013 and remained valid through October 31, 2014, the applicable market-clearing price at bus *y* on transmission facility *L* shall be the sum of (i) the market-clearing prices at bus *y* on transmission facility *L* determined in the Optimal Power Flow solution for each of the Reconfiguration Auctions for

November 2013 through April 2014; and (ii) the weighted average market-clearing price at bus *y* on transmission facility *L* determined from the Optimal Power Flow solution for each of the six-month Sub-Auction rounds for the Centralized TCC Auction that included six-month TCCs valid for the Summer 2014 Capability Period (*i.e.*, May 1, 2014 through October 31, 2014)

$Price_{x,L,n}$ = The market-clearing price at bus *x* on transmission facility *L* in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction. Notwithstanding anything to the contrary herein, for Historic Fixed Price TCCs with a POW on Long Island that took effect on November 1, 2013 and remained valid through October 31, 2014, the applicable market-clearing price at bus *x* on transmission facility *L* shall be the sum of (i) the market-clearing prices at bus *x* on transmission facility *L* determined in the Optimal Power Flow solution for each of the Reconfiguration Auctions for November 2013 through April 2014; and (ii) the weighted average market-clearing price at bus *x* on transmission facility *L* determined from the Optimal Power Flow solution for each of the six-month Sub-Auction rounds for the Centralized TCC Auction that included six-month TCCs valid for the Summer 2014 Capability Period (*i.e.*, May 1, 2014 through October 31, 2014)

$Share_{n,t,L}$ = The percentage of transmission facility *L* owned by Transmission Owner *t* on the effective date of the TCCs sold in round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction

20.4.4 Allocation of Historic Fixed Price TCC Revenue Deemed to be Associated with a Round of a One-Year Sub-Auction

For each Set of HFPTCCs, each Transmission Owner's share of the Historic Fixed Price TCC revenue deemed to be associated with a round of the one-year Sub-Auction for the relevant Centralized TCC Auction shall be calculated in accordance with Formula N-32.

Formula N-32

$$HFPTCCRevAlloc_{t,s,n} = HFPTCCRevenue_{s,n} * HFPTCCFFB_{t,s,n}$$

Where,

$HFPTCCRevAlloc_{t,s,n}$ = For Set of HFPTCCs *s*, the Historic Fixed Price TCC revenue deemed to be associated with round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction that is allocated to Transmission Owner *t*

s = As defined in Formula N-30

$HFPTCCRevenue_{s,n}$ = As defined in Formula N-30

$HFPTCCFFB_{t,s,n}$ = As defined in Formula N-31.

Each Transmission Owner’s share of Historic Fixed Price TCC revenue allocated pursuant to this Section 20.4 shall be incorporated into, or otherwise accounted for as part of, its TSC, or NTAC or other applicable rate mechanism under the ISO Tariffs used to assess charges for Transmission Service provided by the Transmission Owner pursuant to this Tariff, as the case may be.

20.5 Allocation of Non-Historic Fixed Price TCC Revenues

20.5.1 Defined Terms and Overview

20.5.1.1 Defined Terms

Set of Non-Historic Fixed Price TCCs ("NHFPTCCs"): Non-Historic Fixed Price TCCs that have the same POI and POW, same duration and which take, or took, effect in the same Capability Period.

20.5.1.2 Overview

The ISO shall allocate the revenues from the initial award and renewal of Non-Historic Fixed Price TCCs as follows:

1. following the effective date of this Section 20.5, the ISO shall allocate to the Transmission Owners the revenue paid by LSEs for Non-Historic Fixed Price TCCs that took effect on or before May 1, 2017 by using the methodology described in this Section 20.5 and by using the applicable data and results of the last Centralized TCC Auction completed prior to the respective Capability Period in which each such Non-Historic Fixed Price TCC took effect; and
2. following the completion of each Centralized TCC Auction after the effective date of this Section 20.5, the ISO shall allocate to the Transmission Owners any revenue paid by LSEs for Non-Historic Fixed Price TCCs that take effect in the Capability Period immediately following such Centralized TCC Auction using the methodology described in this Section 20.5 and by using the applicable data and results of such Centralized TCC Auction.

To do so, for each Set of NHFPTCCs, the ISO shall:

1. determine the Non-Historic Fixed Price TCC revenue deemed to be associated with: (i) the applicable rounds of the two-year Sub-Auction of the relevant

Centralized TCC Auction pursuant to Section 20.5.2 of this Attachment N in the case of revenue related to initial awards of Non-Historic Fixed Price TCCs; or (ii) each round of the one-year Sub-Auction of the relevant Centralized TCC Auction pursuant to Section 20.5.2 of this Attachment N in the case of revenue related to renewals of Non-Historic Fixed Price TCCs;

2. determine the applicable Non-Historic Fixed Price TCC facility flow-based methodology coefficient for each Transmission Owner for: (i) the applicable rounds of the two-year Sub-Auction of the relevant Centralized TCC Auction pursuant to Section 20.5.3 of this Attachment N in the case of revenue related to initial awards of Non-Historic Fixed Price TCCs; or (ii) each round of the one-year Sub-Auction of the relevant Centralized TCC Auction pursuant to Section 20.5.3 of this Attachment N in the case of revenue related to renewals of Non-Historic Fixed Price TCCs; and

3. allocate, among the Transmission Owners, the Non-Historic Fixed Price TCC revenue deemed to be associated with: (i) the applicable rounds of the two-year Sub-Auction of the relevant Centralized TCC Auction pursuant to Section 20.5.4 of this Attachment N in the case of revenue related to initial awards of Non-Historic Fixed Price TCCs; or (ii) each round of the one-year Sub-Auction of the relevant Centralized TCC Auction in accordance with Section 20.5.4 of this Attachment N in the case of revenue related to renewals of Non-Historic Fixed Price TCCs.

20.5.2 Calculation of Non-Historic Fixed Price TCC Revenue Deemed to be Associated with Sub-Auction Rounds

For each Set of NHFPTCCs, the ISO shall calculate the revenue deemed to be associated with: (i) an applicable round of the two-year Sub-Auction of the relevant Centralized TCC Auction in accordance with Formula N-33 in the case of revenue related to initial awards of Non-Historic Fixed Price TCCs; or (ii) each round of the one-year Sub-Auction for the relevant Centralized TCC Auction in accordance with Formula N-33 in the case of revenue related to renewals of Non-Historic Fixed Price TCCs.

Formula N-33

$$NHFPTCCRevenue_{s,n} = \left[\sum_{k \in s} NHFPTCCPmt_{k,s}\right] * RoundPct_n$$

Where,

$NHFPTCCRevenue_{s,n}$	= (a) <u>For Initial Awards</u>: For Set of NHFPTCCs *s*, the Non-Historic Fixed Price TCC revenue that is deemed to be associated with round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction; provided, however, that no such revenue shall be deemed to be associated with the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction (b) <u>For Renewals</u>: For Set of NHFPTCCs *s*, the Non-Historic Fixed Price TCC revenue that is deemed to be associated with round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction
s	= A Set of NHFPTCCs
$NHFPTCCPmt_{k,s}$	= The revenue received for each Non-Historic Fixed Price TCC *k* that is part of Set of NHFPTCCs *s*, as payable by an LSE in accordance with Section 19.2.2.3.3 of Attachment M of this Tariff
$RoundPct_n$	= (a) <u>For Initial Awards</u>: The percentage of transmission capacity made available for round *n* of the relevant Centralized TCC Auction to support the sale of two-year TCCs, calculated as the ratio of (i) the percentage of transmission capacity made available to support the sale of two-year TCCs in round *n* of the relevant Centralized TCC Auction; to (ii) the total percentage of transmission capacity made available to support the sale of two-year TCCs in all rounds other than the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction, each as determined by the ISO prior to the relevant Centralized TCC Auction. Notwithstanding anything to the contrary herein, the NYISO shall not include the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction or the percentage of transmission capacity made available to support the sale of two-year TCCs in such round in conducting the calculations

described above

(b) For Renewals: The percentage of transmission capacity made available for round *n* of the relevant Centralized TCC Auction to support the sale of one-year TCCs, calculated as the ratio of (i) the percentage of transmission capacity made available to support the sale of one-year TCCs in round *n* of the relevant Centralized TCC Auction; to (ii) the total percentage of transmission capacity made available to support the sale of one-year TCCs in the relevant Centralized TCC Auction, each as determined by the ISO prior to the relevant Centralized TCC Auction

20.5.3 Calculation of Non-Historic Fixed Price TCC Facility Flow-Based Methodology Coefficient

For each Set of NHFPTCCs, the ISO shall use the Non-Historic Fixed Price TCC facility flow-based methodology coefficient to allocate, among the Transmission Owners, the Non-Historic Fixed Price TCC revenue deemed to be associated with: (i) an applicable round of the two-year Sub-Auction of the relevant Centralized TCC Auction (*i.e.*, round *n*) in accordance with Formula N-34 in the case of revenue related to initial awards of Non-Historic Fixed Price TCCs; or (ii) each round of the one-year Sub-Auction for the relevant Centralized TCC Auction (*i.e.*, round *n*) in accordance with Formula N-34 in the case of revenue related to renewals of Non-Historic Fixed Price TCCs.

Formula N-34

$$NHFPTCCFFB_{t,s,n} = \frac{\sum_{L \in L_{t,n}} \left| \left(AuctionFlow_{L,n} - ModAuctionFlow_{L,n,s}\right)\left(Price_{y,L,n} - Price_{x,L,n}\right) * Share_{n,t,L} \right|}{\sum_{L \in L_n} \left| \left(AuctionFlow_{L,n} - ModAuctionFlow_{L,n,s}\right)\left(Price_{y,L,n} - Price_{x,L,n}\right) \right|}$$

Where,

$NHFPTCCFFB_{t,s,n}$ = (a) For Initial Awards: For Set of NHFPTCCs *s*, the Non-Historic Fixed Price TCC facility flow-based methodology coefficient for Transmission Owner *t* for round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction; provided, however, that the NYISO shall not determine coefficient values for the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction

(b) For Renewals: For Set of NHFPTCCs *s*, the Non-Historic Fixed Price TCC facility flow-based methodology coefficient for Transmission Owner *t* for round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction

s	= As defined in Formula N-33
L_n	= (a) For Initial Awards: The set of all transmission facilities owned by Transmission Owners that are modeled in the Transmission System model for round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction; provided, however, that the NYISO shall not utilize data and information for the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction (b) For Renewals: The set of all transmission facilities owned by Transmission Owners that are modeled in the Transmission System model for round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction
$L_{t,n}$	= (a) For Initial Awards: The set of all transmission facilities owned by Transmission Owner *t* that are modeled in the Transmission System model for round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction; provided, however, that the NYISO shall not utilize data and information for the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction (b) For Renewals: The set of all transmission facilities owned by Transmission Owner *t* that are modeled in the Transmission System model for round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction
L	= A transmission facility from bus *x* to bus *y*
$\text{AuctionFlow}_{L,n}$	= (a) For Initial Awards: The Energy flow on transmission facility *L* in the Optimal Power Flow solution to round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction that includes all injections and withdrawals corresponding (as described in Section 20.1.2 of this Attachment N) to the set of TCCs (including Fixed Price TCCs) and Grandfathered Rights represented in such Optimal Power Flow; provided, however, that the NYISO shall not utilize data and information for the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction (b) For Renewals: The Energy flow on transmission facility *L* in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction that includes all injections and withdrawals corresponding (as described in Section 20.1.2 of this Attachment N) to the set of TCCs (including Fixed Price TCCs) and Grandfathered Rights represented in such Optimal Power Flow
$\text{ModAuctionFlow}_{L,n,s}$	= (a) For Initial Awards: The Energy flow on transmission facility *L* in a Power Flow that includes all injections and withdrawals

corresponding (as described in Section 20.1.2 of this Attachment N) to the set of TCCs (including Fixed Price TCCs) and Grandfathered Rights represented in the solution to round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction, except for the injections and withdrawals corresponding to Set of NHFPTCCs *s*; provided, however, that the NYISO shall not utilize data and information for the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction. For purposes of this Power Flow: (i) the phase angle settings for optimized phase angle regulators, as identified in ISO Procedures, will be set equal to the phase angle settings for such phase angle regulators as determined in the Optimal Power Flow solution to round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction, but the schedules for such phase angle regulators will be allowed to vary from the schedules determined in the Optimal Power Flow solution to round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction; and (ii) for all other phase angle regulators internal to the NYCA or on external borders, as identified in ISO Procedures, the schedules for such phase angle regulators will be set equal to the schedules as determined in the Optimal Power Flow solution to round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction, but the phase angle settings for such phase angle regulators will be allowed to vary from the phase angle settings determined in the Optimal Power Flow solution to round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction. Notwithstanding anything to the contrary herein, if the Power Flow results in Energy flow on transmission facility *L* that violates any limit applicable to the amount of Energy that may flow on transmission facility *L* for round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction, the ISO shall adjust the resulting value of the Energy flow on transmission facility *L*, as determined by the Power Flow, to avoid consideration of flows that would otherwise violate the applicable limit for transmission facility *L* and use such adjusted Energy flow value for purposes of calculating $NHFPTCCFFB_{t,s,n}$

(b) For Renewals: The Energy flow on transmission facility *L* in a Power Flow that includes all injections and withdrawals corresponding (as described in Section 20.1.2 of this Attachment N) to the set of TCCs (including Fixed Price TCCs) and Grandfathered Rights represented in the solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction, except for the injections and withdrawals corresponding to Set of NHFPTCCs *s*. For purposes of this Power Flow: (i) the phase angle settings for optimized phase angle regulators, as identified in ISO Procedures, will be set equal to the phase angle settings for such phase angle regulators as determined in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction, but the schedules for such phase angle regulators will be allowed to vary from the schedules determined in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction; and (ii) for all other phase angle regulators internal to the NYCA or on external borders, as identified in ISO Procedures, the schedules for such phase angle regulators will be set equal to the schedules as determined in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction, but the phase angle settings for such phase angle regulators will be allowed to vary from the phase angle settings determined in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction. Notwithstanding anything to the contrary herein, if the Power Flow results in Energy flow on transmission facility *L* that violates any limit applicable to the amount of Energy that may flow on transmission facility *L* for round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction, the ISO shall adjust the resulting value of the Energy flow on transmission facility *L*, as determined by the Power Flow, to avoid consideration of flows that would otherwise violate the applicable limit for transmission facility *L* and use such adjusted Energy flow value for purposes of calculating $\mathrm{NHFPTCCFFB}_{t,s,n}$

$\mathrm{Price}_{y,L,n}$ = (a) For Initial Awards: The market-clearing price at bus *y* on transmission facility *L* in the Optimal Power Flow solution to round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction; provided, however, that the NYISO shall not utilize data and information for the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction

(b) For Renewals: The market-clearing price at bus *y* on transmission facility *L* in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction

$\mathrm{Price}_{x,L,n}$ = (a) For Initial Awards: The market-clearing price at bus *x* on transmission facility *L* in the Optimal Power Flow solution to round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction; provided, however, that the NYISO shall not utilize data and information for the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction

(b) For Renewals: The market-clearing price at bus *x* on transmission facility *L* in the Optimal Power Flow solution to round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction

$\mathrm{Share}_{n,t,L}$ = (a) For Initial Awards: The percentage of transmission facility *L* owned by Transmission Owner *t* on the effective date of the TCCs sold in round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction; provided, however, that the NYISO shall not utilize data and information for the first round of the two-year

Sub-Auction of the relevant Centralized TCC Auction

(b) For Renewals: The percentage of transmission facility *L* owned by Transmission Owner *t* on the effective date of the TCCs sold in round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction

20.5.4 Allocation of Non-Historic Fixed Price TCC Revenue

For each Set of NHFPTCCs, each Transmission Owner's share of the Non-Historic Fixed Price TCC revenue deemed to be associated with: (i) an applicable round of the two-year Sub-Auction of the relevant Centralized TCC Auction shall be calculated in accordance with Formula N-35 in the case of revenue related to initial awards of Non-Historic Fixed Price TCCs; or (ii) each round of the one-year Sub-Auction for the relevant Centralized TCC Auction shall be calculated in accordance with Formula N-35 in the case of revenue related to renewals of Non-Historic Fixed Price TCCs.

Formula N-35

$$NHFPTCCRevAlloc_{t,s,n} = NHFPTCCRevenue_{s,n} * NHFPTCCFFB_{t,s,n}$$

Where,

$\mathrm{NHFPTCCRevAlloc}_{t,s,n}$	= (a) For Initial Awards: For Set of NHFPTCCs *s*, the Non-Historic Fixed Price TCC revenue deemed to be associated with round *n* of the two-year Sub-Auction of the relevant Centralized TCC Auction that is allocated to Transmission Owner *t*; provided, however, that no such revenue shall be deemed to be associated with the first round of the two-year Sub-Auction of the relevant Centralized TCC Auction (b) For Renewals: For Set of NHFPTCCs *s*, the Non-Historic Fixed Price TCC revenue deemed to be associated with round *n* of the one-year Sub-Auction of the relevant Centralized TCC Auction that is allocated to Transmission Owner *t*
s	= As defined in Formula N-33
$\mathrm{NHFPTCCRevenue}_{s,n}$	= As defined in Formula N-33
$\mathrm{NHFPTCCFFB}_{t,s,n}$	= As defined in Formula N-34.

Each Transmission Owner's share of Non-Historic Fixed Price TCC revenue allocated pursuant to this Section 20.5 shall be incorporated into, or otherwise accounted for as part of, its TSC, or NTAC or other applicable rate mechanism under the ISO Tariffs used to assess charges for Transmission Service provided by the Transmission Owner pursuant to this Tariff, as the case may be.

21 Attachment O - Service Agreement for Network Integration Transmission Service

1.0 This Service Agreement, dated as of _____________, 20__, is entered into, by and between the New York System Operator ("ISO") and ________________________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the ISO to have a valid request for Network Transmission Service under the Tariff and to have satisfied the conditions for service imposed by this Tariff.

3.0 Service under this Agreement shall commence on the later of: (1) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this Agreement shall terminate on such date as mutually agreed upon by the parties.

4.0 The ISO agrees to provide and the Transmission Customer agrees to pay for Network Transmission Service in accordance with the provisions of this Tariff, including the Network Operating Agreement (which is incorporated herein by reference), and this Service Agreement as they may be amended from time to time.

5.0 Any notice or request to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

New York Independent System Operator
3890 Carman Road
Guilderland, New York 12303

Transmission Customer:

____

____

____

6.0 This Tariff for Network Integration Transmission Service is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

New York Independent System Operator

By: ___________________________ ___________________ ____________
Name Title Date

Transmission Customer

By: ___________________________ ___________________ ____________
Name Title Date

CERTIFICATION

I, _____________________________________, certify that I am a duly authorized officer of

_____________________________________ (Transmission Customer) and that

_____________________________________ (Transmission Customer) will not request service

under this Service Agreement to assist an Eligible Customer to avoid the reciprocity provision of

this Open Access Transmission Tariff.

____
(Name)

____
(Title)

Subscribed and sworn before me

this _______ day of ________________, 20___.

____
(Notary Public)

My Commission expires: _____/_____/_____

SPECIFICATION FOR NETWORK

INTEGRATION TRANSMISSION SERVICE

1 Term of Transaction:____

Start Date: ____

Termination Date: ____

2 Description of Capacity and/or Energy to be transmitted within the NYCA (including electric control area in which the transaction originates).

3 Network Resources: ____

4 Network Load: ____

5 Designation of party subject to reciprocal service obligation: ______________________

6 Name(s) of any Intervening Systems providing transmission service:________________

7 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of this Tariff.)

7.1 Embedded Cost Transmission Charge:________________________________

7.2 Facilities Study Charge:____

7.3 Direct Assignment Facilities Charge: ______________________________

7.4 Ancillary Services Charge: _____________________________________

7.5 Other Supporting Facilities Charge: ______________________________

22 Attachment P – This section is reserved for future use

23 Attachment Q – Procedures for Reserving and Correcting Erroneous Energy and Ancillary Services Prices

These provisions shall control the reservation and correction of Energy and Ancillary Services prices that are posted on OASIS and used in ISO settlements. The ISO shall review market clearing prices calculated for Energy and Ancillary Services and shall correct any price it determines not to have been calculated in accordance with the ISO tariffs as established in this Attachment Q.

23.1 Market Clearing Price Errors Requiring Correction

To be deemed a price that does not require correction, an Energy and Ancillary Service clearing price must be: (i) calculated correctly according to the relevant provision(s) of the ISO tariffs; (ii) based on the appropriate price-setting resource (*i.e.*, the marginal resource, except as otherwise provided by the ISO tariffs); and (iii) posted to the OASIS before the reservation deadline.

23.1.1 Calculation Errors

A calculation error occurs when, notwithstanding the selection of the correct price-setting unit, an Energy or Ancillary Service market clearing price is computed in a manner that is inconsistent with the ISO tariffs. In addition, a calculation error occurs when no price is calculated or a correctly calculated price is not timely posted to OASIS. Subject to the deadlines established in Section C of this Attachment Q, the ISO shall correct a price that it determines to have resulted from a calculation error.

23.1.2 Errors in Selecting the Price-Setting Resource

The ISO shall schedule, commit, and dispatch supply resources on a least total bid production cost basis. An Energy or Ancillary Services market clearing price must be based on the appropriate price-setting resource (*i.e.*, the marginal resource, unless otherwise provided by the tariffs). Subject to the deadlines established in Section C of this Attachment Q, the ISO shall correct a price that it determines to have resulted from an error in selecting the appropriate price-setting resource.

23.2 Methodology for Correcting Prices

The ISO shall recalculate an erroneous price in accordance with the relevant provision(s) of the ISO tariffs. In the event that the ISO cannot practicably recalculate an erroneous price, due to the unavailability of necessary data or otherwise, the ISO shall determine a price as close as reasonably possible to the price that should have resulted from the operation of the relevant tariff provisions consistent with system conditions by drawing as appropriate from: (i) prices calculated for electrically similar points, (ii) prices in surrounding intervals, (iii) Real-Time Commitment prices, (iv) Day-Ahead Market prices, or (v) Real-Time Dispatch prices for the affected interval(s).

In the event of a catastrophic failure of the ISO's price calculation software, the ISO shall provide notice of the problem to the Commission and Transmission Customers as soon as possible, but in no event later than the next business day. Within two additional business days, the ISO shall inform the Commission and Transmission Customers regarding the nature of the problem and the schedule for determining the procedures to be used by the ISO to construct prices. Following consultation with Transmission Customers regarding the procedures to be used, the ISO shall construct prices as close as possible to the prices that should have resulted from the application of the market rules established in the tariffs to prevailing system conditions.

23.3 Deadlines for Price Corrections

The ISO shall provide notice reserving a potentially erroneous real-time price not later than 17:00 of the calendar day following the operating day for which the price was calculated. The ISO shall provide notice reserving a potentially erroneous Day-Ahead price prior to the start of the operating day for which the price was calculated.

The ISO shall correct a price it has timely reserved and determines to be erroneous and shall provide notice of the correction as soon as possible, but not later than three days after the price reservation deadline. Whenever possible, the ISO will make price corrections prior to the reservation deadline and will provide notice of those corrections along with the reservation notices.

Erroneous prices not reserved and corrected within these timeframes shall not be corrected by the ISO except as directed by the Commission or a court of competent jurisdiction. Nothing herein shall be construed to restrict any stakeholder's right to seek redress from the Commission in accordance with the Federal Power Act.

23.4 Reporting Requirements

In the event that the ISO corrects a price, it shall provide Transmission Customers with supporting tariff references and information regarding:

(i) the affected price intervals;

(ii) the affected LBMP zone(s); or the affected Ancillary Service(s);

(iii) the type of pricing error (either a calculation error or an error in selecting the price-setting resource);

(iv) a description of the nature of the pricing error;

(v) a description of the underlying cause of the pricing error; and

(vi) the price correction method used.

The ISO shall provide this information to Transmission Customers as soon as possible but within ten days following the price correction unless extraordinary circumstances necessitate additional time to provide this information, in which case the ISO shall provide this information as soon as possible, but no later than 30 days following the price correction.

The ISO shall provide quarterly reports to Transmission Customers regarding the cause of each error requiring correction and steps taken or planned by the ISO to eliminate or diminish the incidence of the error in the future. In its quarterly reports, the ISO shall also detail any price errors of which it becomes aware after the deadlines for reservation or correction of the price error.

23.5 Liability

The ISO shall not be liable for errors of commission or omission relating to price errors that are left uncorrected by operation of these rules except in cases of gross negligence or intentional misconduct.

24 Attachment R – Cost Allocation and Measurement and Verification Methodologies for Demand Reductions Arising Under the Incentivized Day-Ahead Economic Load Curtailment Program

Under the Incentivized Day-Ahead Economic Load Curtailment Program – also referred to in the ISO Tariffs and ISO Procedures as the Day-Ahead Demand Response Program – ("Program" or "DADRP"), costs incurred by the ISO in covering Demand Reduction Providers' Curtailment Initiation Costs and making Demand Reduction Incentive Payments for scheduled and verified Demand Reductions are to be recovered under Schedule 1. Measurement and verification of actual Demand Reductions scheduled under the Program shall be conducted in accordance with subsections 24.2, 24.3, and 24.4.

24.1 Cost Allocation Methodology for Payments to Demand Reduction Providers under the Program Recovered Pursuant to Schedule 1

The "Schedule 1 Program Costs" for scheduled and verified Demand Reductions shall be allocated to Transmission Customers, pursuant to the methodology set forth below, on the basis of their Load Ratio Shares and in proportion to the probability, given historical transmission congestion patterns, that a particular Demand Reduction will benefit them by reducing Energy costs in their Load Zones or "Composite Load Zones" (see below). Loads served by Bilateral Transactions associated with the NYPA Western New York Power Program, formerly known as the NYPA Replacement Power and Expansion Power Programs, shall be excluded from the allocation of these costs.

More specifically, Schedule 1 Program Costs shall be allocated to Transmission Customers each Billing Period as follows:

a) Schedule 1 Program Costs shall initially be attributed to the Load Zone where the Generator Bus that was used to bid the Demand Reduction associated with them is located.

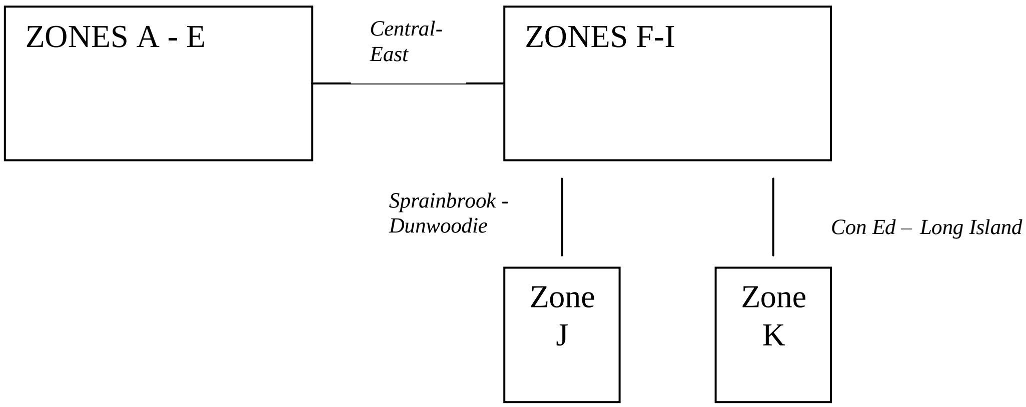
b) In determining whether and how Transmission Customers located in particular Load Zones, or Composite Load Zones, have benefited from the Demand Reduction, and how much they shall be required to pay a share of the associated Schedule 1 Program Costs, the ISO shall account for the effects of congestion at the most frequently constrained NYCA interfaces. When none of these interfaces are constrained Transmission Customers in all Load Zones shall be deemed to have benefited from the Demand Reduction and shall pay a share of the associated Schedule 1 Program Costs. When one or more of the most frequently constrained NYCA interfaces is constrained, then Transmission Customers located in a Load Zone, or Composite Load Zone, that is upstream of the constrained interface, shall be deemed to have benefited from an upstream Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. Similarly, when one or more of the interfaces is congested, Transmission Customers located in a Load Zone, or Composite Load Zone, that is downstream of a constrained interface, shall be deemed to have benefited from a downstream Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. By contrast, Transmission Customers that are “separated” from a Demand Reduction by a constrained interface shall be deemed not to have benefited from it and shall not be required to pay a share of the associated Schedule 1 Program Costs.

c) The ISO shall determine the extent of congestion at the most frequently constrained interfaces using a series of equations that calculate the static probability that: (i) no constraints existed in the transmission system serving the Load Zone or Composite Load Zone; (ii) the Composite Load Zone was upstream of a constraint and curtailment pursuant to the Program occurred upstream; and (iii) the Composite Load Zone was downstream of a constraint and curtailment pursuant to the Program occurred downstream.

Costs shall be allocated to each Transmission Customer that is deemed to have benefited from the scheduled and verified Demand Reduction on a Load Ratio Share basis, using Real-Time metered hourly Load data.

d) The three most frequently constrained interfaces are currently the “Central-East” interface, which divides western from eastern New York State, the Sprainbrook-Dunwoodie interface, which divides New York City and Long Island from the rest of New York State, and the Consolidated Edison Company (“ConEd”) - Long Island interface (including the Y49/Y50 lines), which divides New York City from Long Island. Given these limiting interfaces, four Composite Load Zones currently exist, *i.e.*, West of Central-East (Load Zones A, B, C, D, E,), East Upstate Excluding New York City and Long Island (Load Zones F, G, H, I), New York City (Load Zone J), and Long Island (Load Zone K). The geographic configuration of these Composite Load Zones is depicted in the illustration below.

Relationship Between Frequently Constrained Interfaces and Composite Load Zones



Based on these factors, Schedule 1 Program Costs shall be allocated to Transmission Customers as follows:

For Transmission Customer m in Load Zones A-E:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ **'no constraints**
$a_2 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E) +$ **'Central East const**
$a_3 * (cost_A+\ldots+cost_I+cost_K) * load_m / (load_A+\ldots+load_I+load_K) +$ **'NYC constraint**
$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J) +$ **'LI constraint**
$a_5 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E) +$ **'Cent East + NYC**
$a_6 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E) +$ **'Cent East + LI**
$a_7 * (cost_A+\ldots+cost_I) * load_m / (load_A+\ldots+load_I) +$ **'NYC + LI**
$a_8 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E)$ **'Cent East + NYC + LI**

For Transmission Customer m in Load Zones F-I:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ **'no constraints**
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +$ **'Central East const**
$a_3 * (cost_A+\ldots+cost_I+cost_K) * load_m / (load_A+\ldots+load_I+load_K) +$ **'NYC constraint**
$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J) +$ **'LI constraint**
$a_5 * (cost_F+\ldots+cost_I+cost_K) * load_m / (load_F+\ldots+load_I+load_K) +$ **'Cent East + NYC**
$a_6 * (cost_F+\ldots+cost_J) * load_m / (load_F+\ldots+load_J) +$ **'Cent East + LI**
$a_7 * (cost_A+\ldots+cost_I) * load_m / (load_A+\ldots+load_I) +$ **'NYC + LI**
$a_8 * (cost_F+\ldots+cost_I) * load_m / (load_F+\ldots+load_I)$ **'Cent East + NYC + LI**

For Transmission Customer m in Load Zone J:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ **'no constraints**
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +$ **'Central East const**
$a_3 * cost_J * load_m / load_J +$ **'NYC constraint**

a_4 * $(cost_A+\ldots+cost_J)$ * $load_m$ / $(load_A+\ldots+load_J)$ + **'LI constraint**
a_5 * $cost_J$ * $load_m$ / $load_J$ + **'Cent East + NYC**
a_6 * $(cost_F+\ldots+cost_J)$ * $load_m$ / $(load_F+\ldots+load_J)$ + **'Cent East + LI**
a_7 * $cost_J$ * $load_m$ / $load_J$ + **'NYC + LI**
a_8 * $cost_J$ * $load_m$ / $load_J$ **'Cent East + NYC + LI**

For Transmission Customer m in Load Zone K:

a_1 * $(cost_A+\ldots+cost_K)$ * $load_m$ / $(load_A+\ldots+load_K)$ + **'no constraints**
a_2 * $(cost_F+\ldots+cost_K)$ * $load_m$ / $(load_F+\ldots+load_K)$ + **'Central East const**
a_3 * $(cost_A+\ldots+cost_I+cost_K)$ * $load_m$ / $(load_A+\ldots+load_I+load_K)$ + **'NYC constraint**
a_4 * $cost_K$ * $load_m$ / $load_K$ + **'LI constraint**
a_5 * $(cost_F+\ldots+cost_I+cost_K)$ * $load_m$ / $(load_F+\ldots+load_I+load_K)$ + **'Cent East + NYC**
a_6 * $cost_K$ * $load_m$ / $load_K$ + **'Cent East + LI**
a_7 * $cost_K$ * $load_m$ / $load_K$ + **'NYC + LI**
a_8 * $cost_K$ * $load_m$ / $load_K$ **'Cent East + LI + NYC**

In all cases, the variables are:

a_1 = fraction of time when no constraints exist
a_2 = fraction of time when Central East interface alone is constraining
a_3 = fraction of time when Sprainbrook-Dunwoodie interface alone is constraining
a_4 = fraction of time when Con Ed-Long Island (including the Y49/Y50 lines) interfaces are constraining, but Central East and Sprainbrook-Dunwoodie interfaces are not constraining
a_5 = fraction of time when Central East and Sprainbrook-Dunwoodie interfaces are constraining
a_6 = fraction of time when Central East, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining
a_7 = fraction of time when Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining
a_8 = fraction of time when Central East, Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining

$cost_{A\ldots K}$ = revenue deficiencies due to DADRP Demand Reductions in Load Zones A…K, calculated on an hourly basis
$load_m$ = real-time Load for Transmission Customer m, calculated on a hourly basis, excluding the hourly Loads served by Bilateral Transactions associated with the NYPA Western New York Power Program, up to the level of hourly output produced by the specific supply resource associated with the Western New York Power Program Bilateral Transactions
$load_{A\ldots K}$ = real-time Loads for all Transmission Customers in Load Zones A…K, calculated on an hourly basis, excluding the hourly Loads served by Bilateral Transactions associated with the NYPA Western New York Power Program, up to the level of hourly output produced by the specific supply resource associated with the Western New York Power Program Bilateral Transactions

24.2 Measurement of Actual Demand Reduction Scheduled in the Program

The measured amount of Demand Reduction supplied by a Demand Reduction Provider under the Program shall be the difference between the Demand Reduction Provider's baseline load for each scheduled hour, which shall be calculated in accordance with section 24.2.1 and ISO Procedures, and the actual metered hourly load for each scheduled hour.

24.2.1 Methodology for the Calculating the Economic Customer Baseline Load for a Resource Scheduled to Reduce Load Under the Program

The ISO shall employ two different calculation methodologies of the Economic Customer Baseline Load ("ECBL") for scheduled Demand Reductions, depending on whether the Demand Reduction is scheduled on a weekend or a weekday.

24.2.1.1 Definitions

Adjusted Weekday ECBL: For each hour of the scheduled Demand Reduction, the Adjusted Weekday ECBL shall be equal to the ECBL multiplied by the ECBL In-Day Adjustment Factor calculated for the scheduled Demand Reduction period.

ECBL In-Day Adjustment Factor: The ECBL In-Day Adjustment shall be an adjustment factor that is applied to the ECBL for each hour of the scheduled Demand Reduction period.

a) Calculate the ECBL In-Day Adjustment by dividing the average of the metered load for the two hours of the ECBL In-Day Adjustment Period on the day of the scheduled Demand Reduction by the average of the ECBL for the same two hours.

b) The ECBL In-Day Adjustment Factor shall be limited to a minimum of 0.8 and a maximum of 1.2.

ECBL In-Day Adjustment Period: The ECBL Adjustment Period is the time prior to the scheduled Demand Reduction period that is used to determine the ECBL In-Day Adjustment. The hours to be used in the ECBL Adjustment Period shall be the two consecutive hours that occur four hours prior to the first hour of the scheduled Demand Reduction period, provided that the hours are part of the same calendar day.

To determine the two hours of the ECBL In-Day Adjustment Period:

a) The fourth hour before the first hour of the scheduled Demand Reduction period shall be the first hour of the ECBL In-Day Adjustment Period, except when the fourth hour before first hour of the scheduled Demand Reduction period occurs on the previous day.

b) The third hour before the first hour of the scheduled Demand Reduction period shall be the second hour of the ECBL In-Day Adjustment Period, except when the third hour before the first hour of the scheduled Demand Reduction period occurs on the previous day.

c) When the third and/or fourth hour of the ECBL In-Day Adjustment Period occurs on the previous day, the ISO shall use as a substitute the hour beginning midnight on the day of the scheduled Demand Reduction. Both hours of the ECBL In-Day Adjustment Period may equal the hour beginning midnight on the day of the scheduled Demand Reduction.

ECBL Weekday Window: The ECBL Weekday Window is the time period reviewed in determining the ECBL for any hour of scheduled Demand Reduction that takes place on a weekday. It shall consist of the hours from the previous ten weekdays that correspond to each hourly-interval of the scheduled Demand Reduction period. Treatment of NERC holidays that occur on weekdays shall be equivalent to all hours scheduled on the NERC holiday.

ECBL Weekend Window: The ECBL Weekend Window is the time period reviewed in determining the ECBL for any hour of scheduled Demand Reduction that takes place on a weekend. It shall consist of the hours from the previous three weekend days of the same type (Saturday or Sunday) that correspond to each hourly-interval of the scheduled Demand Reduction period. Treatment of NERC holidays that occur on weekend days shall be equivalent to all hours scheduled on the NERC holiday.

Weekday Proxy: The Weekday Proxy is a value that is substituted for the metered load for any hour in any ECBL Weekday Window in which a Demand Reduction was scheduled. It shall be determined by (1) establishing a new ECBL Weekday Window for that hour consisting of the corresponding hours in the ten weekdays preceding the day the Demand Reduction occurred, and (2) repeating the steps described at section 24.2.1.2 b, c, d, and e.

Weekend Proxy: The Weekend Proxy is a value that is substituted for the metered load for any hour in any ECBL Weekend Window in which a Demand Reduction was scheduled. It shall be determined by (1) establishing a new ECBL Weekend Window for that hour consisting of the corresponding hours in the three weekends preceding the day the Demand Reduction occurred, and (2) repeating the steps described at section 24.2.1.2 b, c, d, and e.

24.2.1.2 Methodology for the Calculating the Economic Customer Baseline Load for Demand Reductions Scheduled on a Weekday

To determine the ECBL for an hour of scheduled Demand Reduction (a "Target Hour") that occurs on a weekday:

a) Select the hours that comprise the ECBL Weekday Window for that Target Hour.

b) Select the metered load value for each hour in the ECBL Weekday Window where no scheduled Demand Reduction occurred pursuant to this Program.

c) For each hour of the ECBL Weekday Window where a scheduled Demand Reduction occurred, select the Weekday Proxy for that hour and day in place of the actual metered load for that hour.

d) Rank in descending order the metered load and Weekday Proxy values determined in steps b and c.

e) Calculate the average of the fifth and sixth ranked values. The value as so calculated shall be the ECBL for the Target Hour.

f) Apply the ECBL In-Day Adjustment Factor to the ECBL to determine the Adjusted Weekday ECBL for the Target Hour.

24.2.1.3 Methodology for the Calculating the Economic Customer Baseline Load for a Resource's Demand Reduction Scheduled Under the Program on a Weekend

To determine the ECBL for a Target Hour that occurs on a weekend:

a) Select the hours that comprise the ECBL Weekend Window for the Target Hour.

b) Select the metered load value for each hour in the ECBL Weekend Window where no scheduled Demand Reduction occurred pursuant to this Program.

c) For each hour of the ECBL Weekend Window where a Scheduled Demand Reduction occurred, select the ECBL Weekend Proxy for that hour and day in place of the actual metered load for the hour.

d) Rank in descending order the metered load and ECBL Weekend Proxy values determined in steps b and c.

e) Calculate the average of the metered load and ECBL Proxy values. The value so calculated is the ECBL for the Target Hour.

f) Apply the ECBL In-Day Adjustment Factor to the ECBL to calculate the Adjusted Weekend ECBL for the Target Hour.

24.3 Verification of Actual Demand Reduction Scheduled in the Program

Demand Reduction calculated using the Economic Customer Baseline Load methodology is subject to verification by the ISO. Demand Reduction Providers shall report the data at the time and in the format required by the ISO pursuant to Section 24.4. If a Demand Reduction Provider fails to report the required data to the ISO in accordance with Section 24.4, the Demand Reduction Provider will be subject to penalties associated with a failure to supply the scheduled Demand Reductions and may lose its eligibility to participate in the Program. All Demand Reduction data are subject to audit by the ISO. If the ISO determines that it has made an erroneous payment to a Demand Reduction Provider, it shall have the right to recover it either by reducing other payments to that Demand Reduction Provider or by any other lawful means.

24.4 Data Reporting Requirements for Demand Reduction Providers

The Demand Reduction Provider must submit to the ISO the information specified in this Section 24.4 for each Demand Side Resource that it has enrolled either as an individual DADRP resource or with other Demand Side Resources as part of a single, aggregated DADRP resource. The Demand Reduction Provider must submit this information for the purpose of enrolling, registering, making settlements, and verifying the participation of each Demand Side Resource in the ISO’s Energy market. To enroll and participate in the DADRP, a Demand Side Resource must have NYPSC-approved, revenue-quality, hourly-interval meters sufficient to calculate its net Load. If the Demand Side Resource has a Local Generator at its site, it must also have an hourly-interval meter that measures the total output of the Local Generator within a 2% accuracy threshold, regardless of whether at initial enrollment the Local Generator is intended to be used to provide Demand Reduction in the DADRP.

24.4.1 Data Reporting Requirements for Enrollment of Demand Side Resources Participating as DADRP Resources

The Demand Reduction Provider shall provide to the ISO the following information for each Demand Side Resource that is seeking to enroll, either individually or collectively with other Demand Side Resources, as a DADRP resource participating in the ISO's Energy market, which shall include providing information regarding each of the Demand Side Resource's interval meters required under Section 24.4:

a. As-left meter test criteria, as prescribed in the New York Department of Public Service 16 NYCRR Part 92 Operating Procedure;

b. Documentation to validate installation of interval meter equipment;

c. Interval metering installation individual, company, and professional engineering license information;

d. Make and model of installed interval metering device(s);

e. Accuracy of installed interval metering device(s);

f. Interval meter Current Transformer (CT) and Potential Transformer (PT) type designation, if applicable;

g. CT Ratio, if applicable;

h. Use of pulse data recorder as an interval metering device, if applicable;

i. Pulse data recorder multiplier, if applicable;

j. Any other type of meter multiplier used in the translation of data collected by the device for measuring demand, kWh, and/or MWh, if applicable;

k. Its service address;

l. Its Load Serving Entity;

m. Its Transmission Owner;

n. Its meter authority/Meter Data Service Provider;

o. Demand Side Resource's maximum Winter and Summer reduction MW;

p. Business classification of the Demand Side Resource (based on ISO-defined categories or national standards for business classification); and

q. A description of any Local Generator at its site, including the Local Generator's system, its primary fuel type, the year in which it was built, the year of any retrofit, its nameplate capacity, and its horsepower, if applicable.

24.4.2 Data Reporting Requirements for Verification of Energy Reductions of DADRP Resources Scheduled in the ISO's Energy Market

The meter authority or Meter Data Service Provider of the Demand Reduction Provider shall provide the ISO with the following required data from each interval meter required under Section 24.4 for each Demand Side Resource that is registered, either individually or collectively with other Demand Side Resources, as a DADRP resource, to verify the scheduled Load reduction of a DADRP resource in the ISO's Energy market:

a) Totalized net hourly Load reduction data of the DADRP resource (*i.e.*, the net hourly Load reduction data totalized across all Demand Side Resources that are registered, either individually or collectively with other Demand Side Resources, as a DADRP resource) for the period of the scheduled Load reduction of the DADRP resource in the format required for reporting to the ISO's Settlement Data Exchange application;

b) Hourly-interval metered Load data for each of the individual Demand Side Resources that is registered as part of a single DADRP resource, for all hours of the day on the days of the scheduled Load reduction of the DADRP resource; and

c) Hourly-interval metered Load data for each of the individual Demand Side Resources that is registered as part of a single DADRP resource, for all hours of each of the thirty days preceding the day in which the DADRP resource is scheduled.

The meter authority or Meter Data Service Provider of the Demand Reduction Provider shall comply with the following when reporting Demand Reduction metering data to the ISO:

a) Section 7.4.1 of the ISO Services Tariff;

b) Section 13 of the ISO Services Tariff; and

c) The ISO's Meter Data Management Protocols as provided on the ISO's website.

24.4.3 Additional Data Required Upon Request

To verify the participation of each Demand Side Resource that is enrolled, either individually or collectively with other Demand Side Resources, as a DADRP resource in the ISO's Energy market, Demand Reduction Providers and/or their meter authority/Meter Data Service Provider shall provide the ISO upon the ISO's request such additional information that may be required, including, but not limited, to the following:

a) Any data reporting requirements of Attachments H and O to the ISO Services Tariff;

b) Any data reporting requirements of Section 3.4 of the ISO Services Tariff;

c) Historical Load documentation;

d) Load data history for Pre- and Post-Validation, Edit and Estimation (VEE);

e) Up to three months of historical Load data when enrolling a Demand Side Resource to participate in the ISO's Energy market;

f) New and existing metering documentation, including, but not limited to:

1. Calibration records;
2. Time check;
3. Sum check;
4. High/Low check; and
5. Zero value check.

25 Attachment S – Rules To Allocate Responsibility for the Cost of New Interconnection Facilities

25.1 Introduction

25.1.1 Purpose of the Rules

The purpose of these rules is to allocate responsibility among Developers and Transmission Owners and Load Serving Entities ("LSEs"), as described herein, for the cost of the new interconnection facilities that are required for the reliable interconnection of generation projects and merchant transmission projects to the New York State Transmission System and to the Distribution System in compliance with the requirements of the type of interconnection service elected by the project Developer. Section 25.6 of this Attachment S describes the rules to estimate and allocate responsibility for the cost of the interconnection facilities required for Energy Resource Interconnection Service ("ERIS") and interconnection in compliance with the NYISO Minimum Interconnection Standard. Section 25.7 of this Attachment S describes the rules to estimate and allocate responsibility for the cost of interconnection facilities required for Capacity Resource Interconnection service ("CRIS") and interconnection in compliance with the NYISO Deliverability Interconnection Standard. Every Developer is responsible for the cost of the new interconnection facilities required for the reliable interconnection of its generation or merchant transmission project in compliance with the NYISO Minimum Interconnection Standard, as that responsibility is determined by these rules. In addition, every Developer electing CRIS is also responsible for the cost of the interconnection facilities required for the reliable interconnection of its generation or merchant transmission project in compliance with the NYISO Deliverability Interconnection Standard, as that responsibility is determined by these rules.

These rules cover (i) Large Facilities greater than 20 MW subject to the Large Facility Interconnection Procedures set out in Attachment X to the ISO OATT ("LFIP"), (ii) Small

Generating Facilities no larger than 20 MW subject to the Small Generator Interconnection Procedures set out in Attachment Z to the ISO OATT ("SGIP") that are required to enter a Class Year Study pursuant to Section 32.3.5.3.2 of the SGIP, and facilities greater than 2 MW that seek to obtain or increase CRIS beyond the levels permitted by this Attachment S, Section 30.3.2.6 of the LFIP and Section 32.4.10.1 of the SGIP, as applicable.

As described herein, the intent is that each Developer be held responsible for the net impact of the interconnection of its project on the reliability of the New York State Transmission System. A Developer is held responsible for the cost of the interconnection facilities that are required by its project, facilities that would not be required but for its project. However, a Developer is not responsible for the cost of facilities that are, without considering the impact of its project, required to maintain the reliability of the New York State Transmission System. Transmission Owners are, in accordance with the ISO OATT and FERC precedent, responsible for the cost of the facilities that are, without considering the impact of the Developer's project, required to maintain the reliability of the New York State Transmission System.

25.1.2 Definitions

Unless defined here in Section 25.1.2 of this Attachment S, the definition of each defined term used in this Attachment S shall be the same as the definition for that term set forth in Section 1 of the ISO Open Access Transmission Tariff ("OATT"), Section 30.1 of Attachment X to the ISO OATT, Attachment Z to the ISO OATT, or Section 2 of the ISO Services Tariff.

Acceptance Notice: The notice by which a Developer communicates to the ISO its decision to accept a Project Cost Allocation or Revised Project Cost Allocation.

Affected System: An electric system other than the transmission system owned, controlled or operated by the Connecting Transmission Owner that may be affected by the proposed interconnection.

Affected System Operator: The entity that operates an Affected System.

Affected Transmission Owner: The New York public utility or authority (or its designated agent) other than the Connecting Transmission Owner that (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, and (ii) owns, leases or otherwise possesses an interest in a portion of the New York State Transmission System where System Deliverability Upgrades, System Upgrade Facilities, or Network Upgrade Facilities are or will be installed pursuant to Attachment P, Attachment X, Attachment S.or Attachment Z to the OATT.

Annual Transmission Baseline Assessment ("ATBA"): An assessment conducted by the ISO staff in cooperation with Market Participants, to identify the System Upgrade Facilities that Transmission Owners are expected to need during the time period covered by the Assessment to comply with Applicable Reliability Requirements, and reliably meet the load growth and changes in load pattern projected for the New York Control Area.

Annual Transmission Reliability Assessment ("ATRA"): An assessment, conducted by the ISO staff in cooperation with Market Participants, to determine the System Upgrade Facilities required for each generation and merchant transmission project included in this Assessment to interconnect to the New York State Transmission System in compliance with Applicable Reliability Requirements and the NYISO Minimum Interconnection Standard.

Applicable Reliability Requirements: The NYSRC Reliability Rules and other criteria, standards and procedures, as described in Section 25.6.1.1.1.1 of this Attachment S, applied when conducting the Annual Transmission Baseline Assessment and the Annual Transmission Reliability Assessment to determine the System Upgrade Facilities needed to maintain the reliability of the New York State Transmission System. The Applicable Reliability Requirements applied are those in effect when the particular assessment is commenced.

Article VII Certificate: The certificate of environmental compatibility and public need required under Article VII of the New York State Public Service Law for the siting and construction of any new transmission facility of a size and type specified in the statute.

Article10 Certificate: The certificate of environmental compatibility and public need required under Article 10 of the New York State Public Service Law for the siting and construction of electric generating facilities with greater than 25 megawatts of capacity.

Attachment Facilities: The Connecting Transmission Owner's Attachment Facilities and the Developer's Attachment Facilities. Collectively, Attachment Facilities include all facilities and equipment between the Large Generating Facility or Merchant Transmission Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Large Facility to the New York State Transmission System. Attachment Facilities are sole use facilities and shall not include Stand Alone System Upgrade Facilities, Distribution Upgrades, System Upgrade Facilities or System Deliverability Upgrades.

Byway: All transmission facilities comprising the New York State Transmission System that are neither Highways nor Other Interfaces. All transmission facilities in Zone J and Zone K are Byways.

Capacity Region: One of four subsets of the Installed Capacity statewide markets comprised of: (1) Rest of State (*i.e.*, Load Zones A through F); (2) Lower Hudson Valley (*i.e.*, Load Zones G, H and I); (3) New York City (*i.e.,* Load Zone J); and (4) Long Island (*i.e.,* Zone K), except for Class Year Interconnection Facility Studies conducted prior to Class Year 2012, for which "Capacity Region" shall be defined as set forth in Section 25.7.3 of this Attachment S.

Capacity Resource Interconnection Service ("CRIS"): The service provided by the ISO to Developers that satisfy the NYISO Deliverability Interconnection Standard or that are otherwise eligible to receive CRIS in accordance with this Attachment S; such service being one of the eligibility requirements for participation as an ISO Installed Capacity Supplier.

Class Year: The group of generation and merchant transmission projects included in any particular Class Year Interconnection Facilities Study (Annual Transmission Reliability Assessment and/or Class Year Deliverability Study), in accordance with the criteria specified in this Attachment S and in Attachment Z for including such projects.

Class Year CRIS Project: A Class Year Project with an executed Class Year Interconnection Facilities Study Agreement entering a Class Year Study for a CRIS evaluation, that thereby becomes one of the group of Class Year Projects included in the Class Year Deliverability Study. A Class Year CRIS Project may be a "CRIS-only" project that is entering a Class Year Study only for a CRIS evaluation, or it may be a project seeking both ERIS and CRIS.

Class Year Deliverability Study: An assessment, conducted by the ISO staff in cooperation with Market Participants, to determine whether System Deliverability Upgrades are required for Class Year CRIS Projects under the NYISO Deliverability Interconnection Standard.

Class Year Interconnection Facilities Study shall mean a study conducted by the ISO or a third party consultant for the Developer to determine a list of facilities (including Connecting Transmission Owner's Attachment Facilities, Distribution Upgrades, System Upgrade Facilities and System Deliverability Upgrades as identified in the Interconnection System Reliability Impact Study), the cost of those facilities, and the time required to interconnect the Large Generating Facility or Merchant Transmission Facility with the New York State Transmission System or with the Distribution System. The scope of the study is defined in Section 30.8 of the Large Facility Interconnection Procedures in Attachment X to the ISO OATT.

Class Year Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 2 of the Large Facility Interconnection Procedures in Attachment X to the ISO OATT for conducting the Class Year Interconnection Facilities Study.

Class Year Project: An Eligible Class Year Project with an executed Class Year Interconnection Facilities Study Agreement that thereby becomes one of the group of generation and Merchant Transmission Facilities included in any particular Class Year Interconnection Facilities Study (Annual Transmission Reliability Assessment and/or Class Year Deliverability

Study), in accordance with the criteria specified in this Attachment S and in Attachment Z for including such projects.

Class Year Start Date: The deadline for Eligible Class Year Projects to enter a Class Year Interconnection Facilities Study, determined in accordance with Section 25.5.9 of this Attachment S.

Connecting Transmission Owner: The New York public utility or authority (or its designated agent) that (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, (ii) owns, leases or otherwise possesses an interest in the portion of the New York State Transmission System or Distribution System at the Point of Interconnection, and (iii) is a Party to the Standard Large Generator Interconnection Agreement.

Contribution Percentage: The ratio of an interconnection project's measured impact or pro rata contribution to a System Upgrade Facility identified in the Annual Transmission Reliability Assessment, to the sum of the measured impacts or pro rata contributions of all the projects that have at least a *de minimus* impact or contribution to the System Upgrade Facility.

Developer: For purposes of this Attachment S, references to Developer(s) include (i) Developer(s) of Large Facilities, (ii) Interconnection Customers of Small Generating Facilities subject to the Rules in this Attachment S pursuant to Section 32.1.1.7 and/or Section 32.3.5.3.2 of Attachment Z to the OATT; and (iii) owners of facilities seeking to obtain or increase CRIS as permitted by this Attachment S.

Distribution System: The Transmission Owner's facilities and equipment used to distribute electricity that are subject to FERC jurisdiction, and are subject to the ISO's Large Facility Interconnection Procedures in Attachment X to the ISO OATT or Small Generator Interconnection Procedures in Attachment Z to the ISO OATT under FERC Order Nos. 2003 and/or 2006. The term Distribution System shall not include LIPA's distribution facilities.

Distribution Upgrades: The modifications or additions to the existing Distribution System at or beyond the Point of Interconnection that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Minimum Interconnection Standard. Distribution Upgrades do not include Interconnection Facilities, System Upgrade Facilities, or System Deliverability Upgrades.

Eligible Class Year Project: Any Developer or Interconnection Customer that (i) satisfies the criteria for inclusion in the next Class Year Interconnection Facilities Study, as those criteria are specified in Sections 25.5.9 and 25.6.2.3.1 of this Attachment S, Section 32.1.1.7 of Attachment Z to the OATT and/or Section 32.3.5.3.2 of Attachment Z to the OATT; or (ii) that seeks evaluation in a Class Year Study to obtain or increase CRIS as permitted by this Attachment S and satisfies the criteria for inclusion in the next Class Year Interconnection Facilities Study specified in Section 25.5.9 of this Attachment S.

Energy Resource Interconnection Service "(ERIS"): The service provided by the ISO to interconnect the Developer's Large Generating Facility, Merchant Transmission Facility or Small Generating Facility required to participate in a Class Year Interconnection Facilities Study under Section 32.3.5.3 of Attachment Z to the New York State Transmission System or to the Distribution System, in accordance with the NYISO Minimum Interconnection Standard, to enable the New York State Transmission System to receive Energy and Ancillary Services from the Large Generating Facility, Merchant Transmission Facility or Small Generating Facility required to participate in a Class Year Interconnection Facilities Study under Section 32.3.5.3 of Attachment Z, pursuant to the terms of the ISO OATT.

Existing System Representation: The representation of the New York State Power System developed as specified in Section 25.5.5 of this Attachment S.

External CRIS Rights: A determination of deliverability within the Rest of State Capacity Region (*i.e.*, Load Zones A – F), awarded by the ISO for a term of five (5) years or longer, to a specified number of Megawatts of External Installed Capacity that satisfy the requirements set forth in Section 25.7.11 of this Attachment S to the ISO OATT, and that can be certified in a Bilateral Transaction used for the NYCA and not a Locality, or sold into the NYCA for an Installed Capacity auction and not in an Installed Capacity auction for a Locality.

Final Decision Round: The round of ISO-communicated cost estimates and Developer responses for a Class Year Interconnection Facilities Study, in which all remaining eligible Developers issue an Acceptance Notice and post Security.

Financial Settlement: The Settlement Agreement approved by FERC in Docket Nos. EL02-125-000 and EL02-125-001 addressing the financial issues raised in those proceedings.

Headroom: The functional or electrical capacity of the System Upgrade Facility or the electrical capacity of the System Deliverability Upgrade that is in excess of the functional or electrical capacity actually used by the Developer's generation or merchant transmission project.

Highway: 115 kV and higher transmission facilities that comprise the following NYCA interfaces: Dysinger East, West Central, Volney East, Moses South, Central East/Total East, and UPNY-ConEd, and their immediately connected, in series, Bulk Power System facilities in New York State. Each interface shall be evaluated to determine additional "in series" facilities, defined as any transmission facility higher than 115 kV that (a) is located in an upstream or downstream zone adjacent to the interface and (b) has a power transfer distribution factor (DFAX) equal to or greater than five percent when the aggregate of generation in zones or systems adjacent to the upstream zone or zones which define the interface is shifted to the aggregate of generation in zones or systems adjacent to the downstream zone or zones which define the interface. In determining "in series" facilities for Dysinger East and West Central interfaces, the 115 kV and 230 kV tie lines between NYCA and PJM located in LBMP Zones A and B shall not participate in the transfer. Highway transmission facilities are listed in ISO Procedures.

Initial Decision Period: The 30 calendar day period within which a Developer must provide an Acceptance Notice or Non-Acceptance Notice to the ISO in response to the first Project Cost Allocation issued by the ISO to the Developer.

Interconnection System Reliability Impact Study ("SRIS"): An engineering study that evaluates the impact of the proposed Large Generation Facility or Merchant Transmission

Facility on the safety and reliability of the New York State Transmission System and, if applicable, an Affected System, to determine what Attachment Facilities, Distribution Upgrades and System Upgrade Facilities are needed for the proposed Large Generation Facility or Merchant Transmission Facility of the Developer to connect reliably to the New York State Transmission System or to the Distribution System in a manner that meets the NYISO Minimum Interconnection Standard for ERIS. The scope of the SRIS is defined in Section 7.3 of the Large Facility Interconnection Procedures in Attachment X to the ISO OATT.

NERC Planning Standards: The transmission system planning standards of the North American Electric Reliability Council.

Non-Acceptance Notice: The notice by which a Developer communicates to the ISO its decision not to accept a Project Cost Allocation or Revised Project Cost Allocation.

Non-Financial Settlement: The Settlement Agreement approved by FERC in Docket Nos. EL02-125-000 and EL01-125-001 addressing non-financial issues for future cost allocations.

NPCC Basic Design and Operating Criteria: The transmission system design and operating criteria of the Northeast Power Coordinating Council.

NYISO Deliverability Interconnection Standard: The standard that must be met, unless otherwise provided for by this Attachment S, by (i) any generation facility larger than 2 MW in order for that facility to obtain CRIS (ii) any Merchant Transmission Facility proposing to interconnect to the New York State Transmission System or to the Distribution System and receive Unforced Capacity Deliverability Rights; (iii) any entity requesting External CRIS Rights, and (iv) any entity requesting a CRIS transfer pursuant to Section 25.9.5 of this Attachment S. To meet the NYISO Deliverability Interconnection Standard, the Developer must, in accordance with these rules, fund or commit to fund any System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

NYISO Load and Capacity Data Report: The annual ISO survey of power demand and supply in New York State, published pursuant to Section 6-106 of the Energy Law of New York State.

NYISO Minimum Interconnection Standard: The reliability standard described in Section 25.2 of this Attachment S that must be met by any generation project or Merchant Transmission Facility that is subject to ISO’s Large Facility Interconnection Procedures in Attachment X to the ISO OATT or the ISO’s Small Generator Interconnection Procedures in Attachment Z to the ISO OATT, that is proposing to connect to the New York State Transmission System or to the Distribution System to obtain ERIS. The Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System or to the Distribution System, as applicable. The Standard does not impose any deliverability test or deliverability requirement on the proposed project.

NYSRC Reliability Rules: The reliability rules of the New York State Reliability Council.

Open Class Year: Class Year open for new members pursuant to the Class Year Start Date deadline specified in Section 25.5.9 of this Attachment S.

Other Interfaces: The following Interfaces into Capacity Regions: Lower Hudson Valley [*i.e.*, Rest of State (Load Zones A-F) to Lower Hudson Valley (Load Zones G, H and I)]; New York City [*i.e.*, Lower Hudson Valley (Load Zones G, H and I) to New York City (Load Zone J)]; and Long Island [*i.e.*, Lower Hudson Valley (Load Zones G, H and I) to Long Island (Load Zone K)], and the following Interfaces between the NYCA and adjacent Control Areas: PJM to NYISO, ISO-NE to NYISO, Hydro-Quebec to NYISO, and Norwalk Harbor (Connecticut) to Northport (Long Island) Cable.

Overage Cost: The dollar amount by which the total cost of System Upgrade Facilities identified in the Annual Transmission Reliability Assessment exceeds the total cost of System Upgrade Facilities considered in the Annual Transmission Baseline Assessment for the same Class Year.

Overage Cost Percentage: The ratio of the Overage Cost to the total cost of System Upgrade Facilities identified in the Annual Transmission Reliability Assessment.

Project Cost Allocation: The dollar figure estimate for a Developer's share of the cost of the System Upgrade Facilities required for the reliable interconnection of its project to the New York State Transmission System or to the Distribution System and/or the share of the cost of the System Deliverability Upgrades required for the Developer's project to meet the NYISO Deliverability Interconnection Standard.

Revised Project Cost Allocation: The revised dollar figure cost estimate and related information provided by the ISO to a Developer following receipt by the ISO of a Non-Acceptance Notice, or upon the occurrence of a Security Posting Default by another member of the respective Class Year.

Security: Under the interconnection facilities cost allocation rules set out in Attachment S, a Developer must signify its willingness to pay the Connecting Transmission Owner and Affected Transmission Owner(s) for the Developer's share of the required System Upgrade Facilities and System Deliverability Upgrades by posting Security for the full amount of the Developer's share within a specified time frame. The Security can be a bond, irrevocable letter of credit, parent company guarantee or other form of security from an entity with an investment grade rating, executed for the benefit of the Connecting Transmission Owner and Affected Transmission Owner(s), meeting the requirements of Attachment S, and meeting the commercially reasonable requirements of the Connecting Transmission Owner and Affected Transmission Owner(s).

Security Posting Default: A failure by one or more Developers to post Security as required by this Attachment S.

Subsequent Decision Period: A seven calendar day period within which a Developer must provide an Acceptance Notice or Non-Acceptance Notice to the ISO in response to the Revised Project Cost Allocation issued by the ISO to the Developer.

System Deliverability Upgrades: The least costly configuration of commercially available components of electrical equipment that can be used, consistent with Good Utility Practice and Applicable Reliability Requirements, to make the modifications or additions to Byways and Highways and Other Interfaces on the existing New York State Transmission System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Deliverability Interconnection Standard at the requested level of Capacity Resource Interconnection Service.

System Upgrade Facilities: The least costly configuration of commercially available components of electrical equipment that can be used, consistent with Good Utility Practice and Applicable Reliability Requirements, to make the modifications to the existing transmission system that are required to maintain system reliability due to: (i) changes in the system, including such changes as load growth, and changes in load pattern, to be addressed in accordance with Section 25.4.1 of this Attachment S; and (ii) proposed interconnections. In the case of proposed interconnection projects, System Upgrade Facilities are the modifications or additions to the existing New York State Transmission System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Minimum Interconnection Standard.

25.2 Minimum Interconnection Standard

25.2.1 Scope and Purpose of Standard.

Each Large Facility, or Small Generating Facility subject to Attachment S, regardless of whether the Developer elects CRIS, must, to obtain ERIS, meet the NYISO Minimum Interconnection Standard. A Transmission Owner that has constructed a reliability-based transmission or distribution system upgrade, or an upgrade pursuant to an order issued by a regulatory body requiring such construction, will not be deemed to be a Developer under these rules because of the construction of that upgrade.

25.2.1.1 The NYISO Minimum Interconnection Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System and to the Distribution System. The NYISO Minimum Interconnection Standard does not impose any deliverability test or deliverability requirement on the proposed project. Application of these rules, including the Annual Transmission Baseline Assessment and the Annual Transmission Reliability Assessment, to allocate responsibility for the cost of new transmission facilities to permit interconnection is not intended to affect the NYISO Minimum Interconnection Standard.

25.2.1.1.1 Consequently, the Minimum Interconnection Standard is not intended to address in any way the allocation of responsibility for the cost of upgrades and other new facilities associated with transmission service and the delivery of power across the Transmission System, the reduction of Congestion, economic transmission system upgrades, or the mitigation of Transmission System overloads associated with the delivery of power.

25.2.1.1.2 It is not anticipated that the installation of any interconnection facilities covered by the Minimum Interconnection Standard will improve the deliverability of power, reduce Congestion, or mitigate overloads associated with the delivery of power. If the installation of any facilities by a Developer does improve deliverability, reduce Congestion and create Incremental Transmission Congestion Contracts, or mitigate overloads, then that situation will be handled in accordance with the relevant provisions of the NYISO Open Access Transmission Tariff, including Sections 3.7 and 4.5, and applicable FERC precedent.

25.3 Deliverability Interconnection Standard

25.3.1 Scope and Purpose of Standard

Each Large Facility or Small Generating Facility larger than 2 MW that is proposed by a Developer must meet the NYISO Deliverability Interconnection Standard before it can receive CRIS or Unforced Capacity Deliverability Rights, unless otherwise provided for in this Attachment S. Pursuant to Section 32.1.1.7 of Attachment Z to the OATT, a Small Generating Facility 2 MW or smaller may obtain CRIS without being evaluated for deliverability under the NYISO Deliverability Interconnection Standard. The requirement that a facility not subject to the ISO's Large Facility Interconnection Procedures or Small Generator Interconnection Procedures must meet the NYISO Deliverability Interconnection Standard to become a qualified Installed Capacity Supplier first applies on May 19, 2016, subject to the transition rule specified in Section 25.9.3.4.1 of this Attachment S.

25.3.1.1 The NYISO Deliverability Interconnection Standard is designed to ensure that the project is deliverable throughout the New York Capacity Region where the project will interconnect or is interconnected. The NYISO Deliverability Interconnection Standard is also designed to ensure that the Developer of the project restores the transfer capability of any Other Interfaces degraded by its interconnection.

25.3.1.2. Each generation or merchant transmission project electing Capacity Resource Interconnection Service will be allowed to become an Installed Capacity Supplier, or will be allowed to receive Unforced Capacity Deliverability Rights, in accordance with the rules of the New York capacity market, up to the amount of its deliverable capacity, as that amount is determined in accordance with the rules in this Attachment S, once the Developer of the project has funded or committed to fund any required System Deliverability Upgrades in accordance with the rules in this Attachment S.

25.3.1.3. The requirement that each Large Facility or Small Generating Facility larger than 2 MW that is proposed by a Developer must meet the NYISO Deliverability Interconnection Standard before it can become a qualified Installed Capacity Supplier or receive Unforced Capacity Deliverability Rights first applies to the projects comprising Class Year 2007. The interconnection agreements for these projects will explicitly condition participation in the Installed Capacity market on satisfaction of the NYISO Deliverability Interconnection Standard and, to the extent a project is found not to be deliverable, on funding, or committing to fund, any required System Deliverability Upgrades. Implementation of the NYISO Deliverability Interconnection Standard for the projects comprising Class Year 2007 will be accomplished by conducting, only for Class Year 2007, the Project Cost Allocation decision process contained in Section 25.8 of Attachment S in two separate steps. First, the ISO will administer the decision process for the System Upgrade Facilities required for the projects in the Class Year. Then, upon the effectiveness of the NYISO Deliverability Interconnection Standard, the ISO will separately administer a decision process for the System Deliverability Upgrades and Deliverable MW for the projects in Class Year 2007 that have previously provided an Acceptance Notice and posted Security for the cost of their System Upgrade Facilities. A member of Class Year 2007 cannot modify, as part of the decision process for System Deliverability Upgrades, the decision reflected in its Acceptance or Non-Acceptance Notice regarding its Project Cost Allocation for System Upgrade Facilities. Members of Class Year 2007 that provide a Non-Acceptance Notice or that commit a Security Posting Default relating to their System Upgrade Facilities will be removed from Class Year 2007 and processed further in accordance with Section 25.8.2.3 of Attachment S. The Project Cost Allocation decision process for Class Years subsequent to Class Year 2007 will be conducted as described in Section 25.8 of Attachment S.

25.4 Interconnection Facilities Covered by Attachment S

25.4.1 Interconnection Standards

The interconnection facilities covered by these cost allocation rules are (i) those required for the proposed project to reliably interconnect to the New York State Transmission System or to the Distribution System in a manner that meets the NYISO Minimum Interconnection Standard for ERIS, and (ii) those required for the project to meet the NYISO Deliverability Interconnection Standard for CRIS.

25.4.2 Interconnection Facilities

The interconnection facilities covered by these cost allocation rules are comprised of the following types of facilities: Attachment Facilities, Distribution Upgrades, System Upgrade Facilities and System Deliverability Upgrades.

25.5 Cost Responsibility Rules for Both ERIS and CRIS

25.5.1 Side Agreements

These cost allocation rules will not preclude or supersede any binding cost allocation agreements that are executed between or among Developers, Connecting Transmission Owners and/or Affected Transmission Owners; provided, however, that no such agreements will increase the cost responsibility or cause a material adverse change in the circumstances as determined by these rules of any Developer or Transmission Owner who is not a party to such agreement.

25.5.2 Costs Covered By Attachment S

The interconnection facility cost allocated by these rules is comprised of all costs and overheads associated with the design, procurement and installation of the new interconnection facilities. These rules do not address in any way the allocation of responsibility for the cost of operating and maintaining the new interconnection facilities once they are installed. Nor do these rules address in any way the ownership of the new interconnection facilities.

25.5.3 Dispatch Costs

Developers, Connecting Transmission Owners and Affected Transmission Owners will not be charged directly for any redispatch cost that may be caused by the temporary removal of transmission facilities from service to install new interconnection facilities, as such cost is reflected in Locational Based Marginal Prices. Nor will existing generators be paid for any lost opportunity cost that may be incurred when their units are dispatched down or off in connection with the installation of new interconnection facilities.

25.5.4 Transmission Owners' Cost Recovery

Any Connecting or Affected Transmission Owner implementation and construction of (i) System Upgrade Facilities as identified in the Annual Transmission Baseline Assessment or Annual Transmission Reliability Assessment, or (ii) System Deliverability Upgrades as identified in the Class Year Deliverability Study, shall be in accordance with the ISO OATT, Commission-approved ISO Related Agreements, the Federal Power Act and Commission precedent, and therefore shall be subject to the Connecting or Affected Transmission Owner's right to recover, pursuant to appropriate financial arrangements contained in agreements or Commission-approved tariffs, all reasonably incurred costs, plus a reasonable return on investment.

25.5.5 Existing System Representation

The ISO shall include in the Existing System Representation for purposes of the ATBA and ATRA for a given Class Year:

25.5.5.1 For Class Year 2017: (i) All generation and transmission facilities identified in the ISO's NYISO Load and Capacity Data Report, excluding those facilities that are subject to Class Year cost allocation but for which Class Year cost allocations have not been accepted; (ii) all planned generation and merchant transmission projects that have accepted their cost allocation in a prior Class Year cost allocation process and System Upgrade Facilities and System Deliverability Upgrades associated with those projects except that System Deliverability Upgrades where construction has been deferred pursuant to Section 25.7.12.2 and 25.7.12.3 of Attachment S will only be included if construction of the System Deliverability Upgrades has been triggered under Section 25.7.12.3 of Attachment

S; (iii) all generation and transmission retirements and derates identified in the NYISO Load and Capacity Data Report as scheduled to occur during the five-year cost allocation study planning period; and (iv) all other changes to existing facilities, other than changes that are subject to Class Year cost allocation but that have not accepted their Class Year cost allocation, that are identified in the NYISO Load and Capacity Data Report or reported by Market Participants to the ISO as scheduled to occur during the five year cost allocation study planning period. Facilities in a Mothball Outage, an ICAP Ineligible Forced Outage, or Inactive Reserves will be modeled as in, and not removed from, the Existing System Representation. The point of interconnection of a Retired generator with a terminated interconnection agreement is available to proposed facilities on a non-discriminatory basis pursuant to the ISO's applicable interconnection and transmission expansion processes and procedures. A Retired generator with an interconnection agreement that remains in effect after it is Retired will retain its right to the specific point of interconnection as provided for in the interconnection agreement and access to this point will not available for new facilities.

25.5.5.2 For Class Years subsequent to Class Year 2017: (i) the following facilities included in the ISO's most recent NYISO Load and Capacity Data Report: all generation identified as existing and all transmission facilities identified as existing and/or firm, excluding those facilities that are subject to Class Year cost allocation but for which Class Year cost allocations have not been accepted; (ii) all proposed generation and merchant transmission projects, together with their associated System Upgrade Facilities and System Deliverability Upgrades, that have accepted their cost allocation in a prior Class Year cost allocation process; provided however, that System Deliverability Upgrades where construction has been deferred pursuant to Sections 25.7.12.2 and 25.7.12.3 of Attachment S will only be included if construction of the System Deliverability Upgrades has been triggered under Section 25.7.12.3 of Attachment S; (iii) all generation and transmission retirements and derates identified in the Load and Capacity Data Report as scheduled to occur during the five-year cost allocation study planning period; and (iv) Transmission Projects that are proposed under Attachment Y of the ISO OATT and have met the following milestones prior to the Class Year Start Date: (1) have been triggered under the reliability planning process, selected under the Public Policy Transmission Planning Process, or approved by beneficiaries under the CARIS process); and (2) have a completed System Impact Study; (3) have a determination pursuant to Article VII that the Article VII application filed for the facility is in compliance with Public Service Law §122 (*i.e.*, “deemed complete”) (if applicable); and (4) are making reasonable progress under the applicable OATT Attachment Y planning process ; (v) Transmission Projects that are not proposed under Attachment Y to the ISO OATT that have completed a Facilities Study and posted Security for Network Upgrade Facilities as required in Section 22.9.10 of Attachment P to the ISO OATT and have a determination pursuant to Article VII that the Article VII application filed for the facility is in compliance with Public Service Law §122 (*i.e.*, “deemed complete”) (if applicable); (vi) transmission projects not subject to the Transmission Interconnection Procedures or the Attachment X and S interconnection procedures (*i.e.*, new transmission facilities or upgrades proposed by a Transmission Owner in its Local Transmission Owner Plan or NYPA transmission plan) identified as "firm" by the Connecting Transmission Owner and either (1) have commenced a Facilities Study (if applicable) and have an Article VII application deemed complete (if applicable); or (2) are under construction and scheduled to be in-service within 12 months after the Class Year Start Date and (vii) all other changes to existing facilities, other than changes that are subject to Class Year cost allocation but that have not accepted their Class Year cost allocation, that are identified in the Load and Capacity Data Report or reported by Market Participants to the ISO as scheduled to occur during the five year cost allocation study planning period. Facilities in a Mothball Outage, an ICAP Ineligible Forced Outage, or Inactive Reserves will be modeled as in, and not removed from, the Existing System Representation. If the ISO has triggered multiple Transmission Projects under its reliability planning process, the ISO will include in the base case the selected Transmission Project until or unless that project is halted or its Development Agreement is terminated, in which case the ISO will include in the base case the regulated backstop solution. The point of interconnection of a Retired generator with a terminated interconnection agreement is available to proposed facilities on a non-discriminatory basis pursuant to the ISO's applicable interconnection and transmission expansion processes and procedures. A Retired generator with an interconnection agreement that remains in effect after it is Retired will retain its right to the specific point of interconnection as provided for in the interconnection agreement and access to this point will not available for new facilities.

25.5.5.3 The System Upgrade Facilities listed on Exhibit A to the Financial Settlement shall be included in the Existing System Representation. Such System Upgrade Facilities shall be shown as in service in the first year of the five-year cost allocation study planning period and in each subsequent year, unless such System Upgrade Facilities are cancelled or otherwise not in service by January 1, 2010; provided that if such facilities are expected to be in service after January 1, 2010, starting with the Class Year 2010, the ISO shall independently determine such later date when the System Upgrade Facilities are expected to be in service and represent them according to the ISO's determination.

25.5.5.4 System Upgrade Facilities not listed on Exhibit A to the Financial Settlement, but for which cost allocations have been accepted in a prior Class Year cost allocation process, shall be represented in the Existing System Representation for subsequent cost allocation studies in the year of their anticipated in-service date.

25.5.6 Attachment Facilities.

Each Developer is responsible for 100% of the cost of the Attachment Facilities.

25.5.7 Distribution Upgrades

Each Developer is responsible for 100% of the cost of the Distribution Upgrades.

25.5.8 No Prioritization of Class Year Projects

There will be no prioritization of the projects grouped and studied together in a Class Year. Each such project will share in the then currently available functional or electrical capability of the transmission system, and share in the cost of the System Upgrade Facilities required to interconnect its respective project and, for Developers seeking CRIS, System Deliverability Upgrades required under the NYISO Deliverability Interconnection Standard, in accordance with the rules set forth herein.

25.5.9 Class Year Start Date and Schedule

Starting with the Class Year subsequent to Class Year 2017, the Annual Transmission Reliability Assessment (*i.e.,* Class Year Study) will begin on the Class Year Start Date, which will be the first Business Day after thirty (30) Calendar Days following the completion of the prior Class Year Interconnection Facilities Study as to all Class Year members (*i.e.*, date upon which all remaining Class Year Developers in Class Year X-2 in a Bifurcated Class Year, or alternatively, all remaining Class Year Developer in a Class Year that is not bifurcated, have accepted their Project Cost Allocations and have posted Security for same). In order to become a Class Year Project in a Class Year subsequent to Class Year 2012, an Eligible Class Year Project must (1) satisfy the criteria for inclusion in the next Class Year, as those criteria are specified in Section 25.6.2.3.1 of this Attachment S, Section 25.8.2.3 of this Attachment S and Sections 32.1.1.7 of Attachment Z to the OATT and/or Section 32.3.5.3.2 of Attachment Z to the OATT, as applicable and (2) must elect to enter the applicable Class Year by providing notice to the ISO by five (5) Business Days after the Class Year Start Date. This Section 25.5.9 does not limit membership or eligibility for membership in Class Year 2011 or Class Year 2012.

Starting with the Class Year subsequent to Class Year 2012, all parties engaged in performing study work as part of the Annual Transmission Reliability Assessment and Class Year Deliverability Study (collectively, the Class Year Interconnection Facilities Study) are required to use Reasonable Efforts to complete the basic required evaluations and cost estimates for Connecting Transmission Owner's Attachment Facilities, Distribution Upgrades, System Upgrade Facilities, and System Deliverability Upgrades in order that the Class Year Interconnection Facilities Study can be presented to the Operating Committee for approval within twelve (12) months from the Class Year Start Date. Starting with the Class Year subsequent to Class Year 2012, if a new System Deliverability Upgrade is identified (i.e., a System Deliverability Upgrade not previously identified and cost allocated in a Class Year Interconnection Facilities Study and not substantially similar to a System Deliverability Upgrade previously identified and cost allocated in a Class Year Interconnection Facilities Study), an additional six (6) months will be provided within which to perform additional System Deliverability Upgrade studies, subject to Reasonable Efforts, for the study of and development of cost estimates for such a System Deliverability Upgrade.

Through the Interconnection Projects Facilities Study Working Group distribution list, the ISO will provide the anticipated Class Year Schedule, including the status of and anticipated completion date of the Annual Transmission Baseline Assessment study cases.

25.5.10 Preliminary SDU Decision Period and Class Year Bifurcation

25.5.10.1 Notice of SDUs Requiring Additional Studies

Starting with Class Year 2017, if the ISO determines that any Class Year Project requires System Deliverability Upgrades for which additional System Deliverability Upgrade studies are required pursuant to Section 25.5.9 of this Attachment S, the ISO will notify all members of the

ISO's Interconnection Projects Facilities Study Working Group that the ISO has made such a determination, such notice to be provided as soon as practicable after the ISO presents the results of the full preliminary Class Year Study results (*i.e.*, the results of the System Upgrade Facilities Study and preliminary Deliverability Study) to stakeholders and the ISO Operating Committee approves such results. This notice will be referred to as the "Notice of SDUs Requiring Additional Study."

25.5.10.2 Preliminary SDU Decision Period

At the same time the ISO issues the Notice of SDUs Requiring Additional Study, the ISO will issue a notice to only those Class Year Project Developers for which the ISO has identified System Deliverability Upgrades requiring additional studies. This notice will trigger the "Preliminary SDU Decision Period." Each Developer to which such notice is issued shall respond to the ISO within 10 Business Days to indicate if it elects to proceed or not proceed with additional studies for the identified System Deliverability Upgrades. If the ISO does not receive the Developer's election by the deadline, the Developer will be deemed to have notified the ISO that it elects to not proceed with the additional studies for the identified System Deliverability Upgrades.

If no Class Year Project Developer to which the notice of Preliminary SDU Decision Period is issued elects to proceed with such additional studies, the Class Year Study will proceed to the decision and settlement phase set forth in Section 25.8.2 of this Attachment S. Alternatively, if any Class Year Project Developer to which the notice of Preliminary SDU Decision Period is issued elects to proceed with such additional studies, the Class Year Study will be bifurcated pursuant to Section 25.5.10.3 of this Attachment S.

If, as a result of election(s) made in the Preliminary SDU Decision Period, the ISO determines that the Class Year Study will be bifurcated, the ISO will issue a notice to members of the ISO's Interconnection Projects Facilities Study Working Group ("Bifurcation Notice") that will serve to bifurcate the Class Year Study into Class Year X-1 and Class Year X-2 (with "X" being the year of the Class Year Start Date) and will provide Class Year X-1 Project Cost Allocations for System Upgrade Facilities and System Deliverability Upgrades, excluding Project Cost Allocations for System Deliverability Upgrades requiring additional studies.

The elections made by a Class Year Project Developer in the Preliminary SDU Decision Period shall be binding on the Class Year Project Developer with respect to System Deliverability Upgrades requiring additional studies – *i.e.*, a Class Year Project Developer may not elect to proceed with additional studies for System Deliverability Upgrades in the Preliminary SDU Decision Period and then, in the subsequent Bifurcated Decision Period elect to complete the decision and settlement phase as part of Class Year X-1. A Class Year Project Developer that elects to proceed with additional studies for System Deliverability Upgrades in the Preliminary SDU Decision Period will be required to proceed to Class Year X-2.

25.5.10.3 Bifurcated Decision Period

On or before the first Business Day after thirty (30) Calendar Days from a Bifurcation Notice (such 30 day period, the "Bifurcated Decision Period"), each Class Year Project, other than a Class Year Project Developer that elected in the Preliminary SDU Decision Period to proceed with additional SDU studies, must make one of the following elections:

(1) complete the decision and settlement phase as part of Class Year X-1 by accepting Project Cost Allocations and posting Security for any of the following, as applicable:

(a) System Upgrade Facilities (*i.e.*, ERIS only);

(b) System Upgrade Facilities and Deliverable MW for CRIS, if any (*i.e.*, ERIS and CRIS that is deliverable without a System Deliverability Upgrade);

(c) System Upgrade Facilities and System Deliverability Upgrades not requiring additional studies, if any (*i.e.*, ERIS and CRIS that is deliverable with a System Deliverability Upgrade previously identified and cost allocated in a previous Class Year Study or substantially similar to a System Deliverability Upgrade previously identified and cost allocated in a previous Class Year Study);

(d) for CRIS-only Class Year Projects that are fully or partially deliverable, the project's Deliverable MW for CRIS; or

(e) for CRIS-only Class Year Projects that are not fully deliverable, System Deliverability Upgrades not requiring additional studies, if any (*i.e.*, ERIS and CRIS that is deliverable with a System Deliverability Upgrade previously identified and cost allocated in a previous Class Year Study or substantially similar to a System Deliverability Upgrade previously identified and cost allocated in a previous Class Year Study);

(2) proceed as a member of Class Year X-2, with no changes to ERIS or CRIS requests;

(3) proceed as a member of Class Year X-2 as ERIS only (*i.e.*, withdrawing its CRIS request);

(4) proceed as a member of Class Year X-2 with ERIS and/or CRIS requests, but electing to have no System Deliverability Upgrades identified to make the project deliverable at its level of requested CRIS (*i.e.*, proceed as a member of Class Year

X-2 with the option of accepting or not accepting all of its requested ERIS MW and only its Deliverable MW for CRIS); or

(5) withdraw from the Class Year entirely.

A Class Year Project Developer that fails to respond to this notice requirement with one of the above elections by the required deadline will proceed as a member Class Year X-2, with no changes to ERIS or CRIS requests.

Class Year X-1 Project Cost Allocations for shared upgrade facilities will be the Class Year X-1 project's highest possible Project Cost Allocation, assuming all, none or any combination of other Class Year projects drop out or accept their Project Cost Allocations. In other words, if a project that elects to settle in Class Year X-1 shares a cost allocation for System Upgrade Facilities, System Deliverability Upgrades or Headroom with a project that elects to proceed as a member of Class Year X-2, the project electing to settle in Class Year X-1 will be required to post Security equal to the highest amount it might possibly be required to post under any Class Year decision and settlement scenario.

If a Class Year Project Developer elects to withdraw its project entirely from the Class Year at this juncture, the Class Year from which the project drops out will constitute one of the two Class Years a project may enter under Section 25.6.2.3.4 of Attachment S. If a Class Year Project Developer elects to withdraw entirely from the Class Year at this juncture, the deposits paid in lieu of satisfaction of the regulatory milestone pursuant to Section 25.6.2.3.1 of Attachment S will be fully refunded.

If a Class Year Project Developer eligible to complete the decision and settlement phase as part of Class Year X-1 elects to do so, the Developer shall, within the Bifurcated Decision Period, complete the following requirements:

(1) The Developer must provide notice to the ISO, in accordance with the instructions set forth by the ISO in the notice, whether it accepts (an "Acceptance Notice") or does not accept (a "Non-Acceptance Notice") the Project Cost Allocation(s) and Deliverable MW, if any, reported to it by the ISO; and

(2) The Developer must, if providing an Acceptance Notice:

(a) include a confirmed In-Service Date and Commercial Operation Date, subject to the limitations set forth in Section 30.4.4.5 of Attachment X; and

(b) signify its willingness to pay the Connecting Transmission Owner and Affected Transmission Owner(s) for its share of the required System Upgrade Facilities and System Deliverability Upgrades by (i) satisfying Headroom payment/security posting obligations, if any, as specified in Section 25.8.7.6 and (ii) paying cash or posting Security (as defined in Section 25.8.2.1 of this Attachment S) in accordance with these rules, for the full amount of its respective Project Cost Allocation.

Developers that respond with a Non-Acceptance Notice or fail to post the required Security will be removed from the Class Year and not proceed as a member of Class Year X-2. Upon receipt of all required Acceptance and Non-Acceptance Notices, and any required Security associated with such notices, Class Year X-1 will be deemed complete.

The Class Year X-1 decision period will not be iterative (*i.e.*, the ISO will not provide for subsequent decision rounds for projects that reject their Class Year X-1 Project Cost Allocation decisions). As soon as practicable following receipt of either an Acceptance Notice or Non-Acceptance Notice from each Class Year Developer participating in the Class Year X-1 decision period, the ISO shall report to all Class Year Developers, in writing via electronic mail, all of the

Acceptance Notices and Non-Acceptance Notices that were received from all of the Developers in the then-current Class Year X-1. In such notice, the ISO will provide final calculations for the Project Cost Allocations for each project that settled in Class Year X-1, potentially requiring the Connecting Transmission Owner to refund excess funds or Security resulting from this recalculation. After the Final Decision Round for Class Year X-2 (the settlement and decision process for which shall proceed pursuant to Section 25.8 of this Attachment S), ISO will similarly provide final calculations or the Project Cost Allocations for each project that settled in Class Year X-1 and Class Year X-2, potentially requiring the Connecting Transmission Owner or Affected Transmission Owner(s) to refund excess funds or Security resulting from this recalculation. To the extent a refund is due to the Class Year Developer pursuant to such final Project Cost Allocation determinations, the Connecting Transmission Owner or Affected Transmission Owner(s) holding funds or Security must return excess funds or Security to the Class Year Developer within fifteen (15) Business Days of the ISO's notice requiring such refund.

For purposes of determining the Class Year Start Date for the next Class Year Study, a bifurcated Class Year Study is complete on the date upon which all remaining Class Year X-2 Developers have accepted their Project Cost Allocations and have posted Security for same..

25.6 Cost Allocation Methodology For ERIS

25.6.1 Cost Allocation Between Developers and Connecting Transmission Owners (ATBA).

The cost of System Upgrade Facilities is first allocated between Developers and Connecting Transmission Owners, in accordance with the rules that are discussed below in this Section 25.6.1.

25.6.1.1 The cost of System Upgrade Facilities is allocated between Developers and Connecting Transmission Owners based upon the results of an Annual Transmission Baseline Assessment of the five-year need for System Upgrade Facilities. The Annual Transmission Baseline Assessment, as described in these rules, will be conducted by the ISO staff in cooperation with Market Participants. No Market Participant will have decisional control over any determinative aspect of the Annual Transmission Baseline Assessment. The ISO and its staff will have decisional control over the entire Annual Transmission Baseline Assessment. If, at any time, the ISO staff decides that it needs specific expert services from entities such as Market Participants, consultants or engineering firms for it to conduct the Annual Transmission Baseline Assessment, then the ISO will enter into appropriate contracts with such entities for such input. As it conducts each Annual Transmission Baseline Assessment, the ISO staff will provide regularly scheduled status reports and working drafts, with supporting data, to the Operating Committee to ensure that all affected Market Participants have an opportunity to contribute whatever information and input they believe might be helpful to the process. Each completed Annual Transmission Baseline Assessment will be reviewed and approved by the Operating Committee. Each

Annual Transmission Baseline Assessment is reviewable by the ISO Board of Directors in accordance with provisions of the Commission-approved ISO Agreement.

25.6.1.1.1 The purpose of the Annual Transmission Baseline Assessment is to identify the System Upgrade Facilities that Transmission Owners are expected to need during the five-year period covered by the Assessment to reliably meet the load growth and changes in the load pattern projected for the New York Control Area, with cost estimates for the System Upgrade Facilities.

25.6.1.1.1.1 Procedure for Annual Transmission Baseline Assessment.

The procedure used to identify the System Upgrade Facilities that will ensure that New York State Transmission System facilities are sufficient to reliably serve existing load and meet load growth and changes in load patterns in compliance with NYSRC Reliability Rules, NPCC Basic Design and Operating Criteria, NERC Planning Standards, ISO rules, practices and procedures, and the Connecting Transmission Owner criteria included in FERC Form No. 715 (collectively "Applicable Reliability Requirements"). In order for the ISO to recognize any revisions to Connecting Transmission Owner criteria as Applicable Reliability Requirements under this Attachment S or Applicable Reliability Standards under Attachments X and Z, the Connecting Transmission Owner shall present proposed revisions to such criteria to the Operating Committee or one of its subcommittees. To the extent such revised criteria are not inconsistent with Order No. 2003 or the ISO's interconnection procedures set forth in Attachments S, X and Z to the OATT, the ISO will accept such revised criteria. The procedure will use the Applicable Reliability Requirements in effect when the Annual Transmission Baseline Assessment is commenced. The procedure will be:

25.6.1.1.1.1.1 The ISO staff will first develop the Existing System Representation.

25.6.1.1.1.1.2 The ISO staff will then utilize the Existing System Representation to develop existing system improvement plans with each Transmission Owner. These improvement plans will use ISO data from the annual NYISO Load and Capacity Data Report to project system load growth and changes in load patterns, including those that reflect demand side management, and will identify the System Upgrade Facilities needed year-by-year for the existing system to reliably serve projected load in the Transmission Owner's Transmission District for a five-year period. The ISO staff will integrate these existing system improvement plans into the Annual Transmission Baseline Assessment to ensure that the System Upgrade Facilities needed for a five-year period are identified on a New York State Transmission System-wide basis. The Annual Transmission Baseline Assessment will identify each anticipated System Upgrade Facility project, its estimated cost, its anticipated in-service date, and the status of the project (in construction, budget approval received, budget approval pending).

25.6.1.1.1.1.3 The ISO will identify in the Annual Transmission Baseline Assessment the System Upgrade Facilities needed to reliably meet projected load growth and changes in load pattern without the interconnection of any proposed Developer projects, except for those proposed projects included in the Existing System Representation pursuant to Section 25.5.5.

25.6.1.1.1.1.4 ISO staff will perform thermal, voltage, and stability analyses, as appropriate, to determine the normal and emergency transfer capabilities of the statewide existing system.

25.6.1.1.1.1.5 ISO staff will perform resource reliability analysis of the existing system to verify that the existing system meets Applicable Reliability Requirements. The results of this analysis will be reported for the entire state and for each of the New York zones.

25.6.1.1.1.1.6 If the transmission and generation facilities included in the Existing System Representation, combined with previously approved and accepted System Upgrade Facilities, are insufficient to meet Applicable Reliability Requirements on a year by year basis, then the ISO staff will develop feasible generic solutions that satisfy the Applicable Reliability Requirements, in accordance with Section 25.6.1.2, below.

25.6.1.1.1.1.7 If the existing system meets Applicable Reliability Requirements, the ISO staff will perform short circuit analysis to determine whether there is sufficient interrupting capability in the existing system. If there are any breaker overloads, the ISO staff will determine the System Upgrade Facilities needed to mitigate the short circuit overloads.

25.6.1.1.1.1.8 A reassessment of Sections 25.6.1.1.1.1.4 through 25.6.1.1.1.1.6 shall be reassessed and, to the extent required by Good Utility Practice, repeated if the improvement plan impacts the transmission transfer capability of the system. The results of the short circuit analysis will be treated in the same manner as the results of thermal, voltage and stability analyses for all purposes under these cost allocation rules.

25.6.1.1.1.1.9 Each Annual Transmission Baseline Assessment conducted by ISO staff will be reviewed and approved by the Operating Committee, and its effectiveness will be subject to the approval of the Operating Committee. In its report to the Operating Committee, the ISO shall explain its reasons for all of its recommendations.

25.6.1.1.1.1.10 Each most recently completed Annual Transmission Baseline Assessment will be reviewed the following year by the ISO staff and updated, as necessary, following the criteria and procedures described herein.

25.6.1.2 In developing solutions as required by Section 25.6.1.2.6, the ISO will, as it develops its own generic solutions, also utilize the following procedures.

25.6.1.2.1 The ISO will first select as generic solutions proposed Class Year Developer projects sufficient to meet Applicable Reliability Requirements on a year by year basis. If a proposed Class Year Developer project is larger than necessary, the ISO shall select that portion or segment of the project that is sufficient to meet but not exceed Applicable Reliability Requirements. If the proposed Developer project is not capable of being segmented or if the Developer project cannot meet Applicable Reliability Requirements on a year by year basis, the ISO shall not select it.

25.6.1.2.2 If the generation and transmission facilities included in the Existing System Representation, together with any proposed Developer projects that qualify as solutions pursuant to Section 25.6.1.2.1, above, are not sufficient to meet Applicable Reliability Requirements, the ISO shall complete the development of its own generic solutions, taking into account any generic solutions proposed pursuant to Section 25.6.1.2.3, below, for inclusion in the ATBA.

25.6.1.2.3 Market Participants may also propose generic solutions for inclusion in the ATBA. The Market Participant proposing such solutions shall provide the ISO with all data necessary for the ISO to determine the feasibility of such proposed generic solutions.

25.6.1.2.4 The ISO shall develop and consider alternative sets of proposed generic solutions that fairly represent the range of feasible solutions to Applicable Reliability Requirements.

25.6.1.2.5 The ISO shall determine the feasibility of additional generic solutions developed pursuant to Sections 25.6.1.2.2, 25.6.1.2.3 and 25.6.1.2.3, according to the following criteria:

25.6.1.2.5.1 The ISO shall select only solutions that are based on proven technologies that have actually been licensed and financed, are under construction or have already been built in similar locations.

25.6.1.2.5.2 The ISO shall select as additional generic solutions only units and facilities that can reasonably be placed in service in time to meet Applicable Reliability Requirements on a year by year basis. In making this determination, the ISO shall consider the size and type of facility, access to fuel, access to transmission facilities, transmission upgrade requirements, construction time, and Good Utility Practice.

25.6.1.2.6 The ISO will submit its proposed generic solutions and the alternatives that it considered to Market Participants and to an independent expert for review and will make the results of the expert's review available to Market Participants. The independent expert shall review the feasibility of the proposed generic solutions developed pursuant to Sections 25.6.1.2.2, 25.6.1.2.3 and 25.6.1.2.3, and of generic solutions based on the segmentation of any Class Year developer projects under Section 25.6.1.2.1, according to the criteria set forth in Section 25.6.1.2.5.

25.6.1.2.6.1 If the independent expert concludes that one or more generic is not feasible, the ISO shall eliminate that solution from further review.

25.6.1.2.6.2 If the ISO does not adopt the expert's recommendations, it will state in its report to the Operating Committee its reasons for not adopting those recommendations.

25.6.1.2.7 Subject to Section 25.6.1.2.7, below, in the event that more than one generic solution or set of solutions satisfies the feasibility requirement of Section 25.6.1.2.7, the ISO shall compare the System Upgrade Facilities that would be necessary to interconnect each such generic solution and shall adopt the solution that is most consistent with Good Utility Practice. For these purposes, in comparing alternative solutions, a generic solution that satisfies sub-load pocket deficiencies shall normally be selected first.

25.6.1.2.7.1 The ISO shall be responsible for determining whether any generic solution or proposed Developer Project meets Applicable Reliability Requirements.

25.6.1.3 With the exception of those upgrades that were previously allocated to, and accepted by Developer projects as a part of the Annual Transmission Reliability Assessment in the Final Decision Round of previous Class Years, Developers are not responsible for the cost of any System Upgrade Facilities that are identified in the Annual Transmission Baseline Assessment, or any System Upgrade Facilities that resolve in whole or in part a deficiency in the system identified in the Annual Transmission Baseline Assessment.

25.6.1.4 Developers are responsible for 100% of the cost of the System Upgrade Facilities, not already identified in the Annual Transmission Baseline Assessment that are needed as a result of their projects, and required for their projects to reliably interconnect to the transmission system in a manner that meets the NYISO Minimum Interconnection Standard. The System Upgrade Facilities necessary to accommodate Developer projects will be determined by the Interconnection Facilities Studies and the Annual Transmission Reliability Assessment. The criteria and procedures that will be followed to conduct the Annual Transmission Reliability Assessment are discussed below.

25.6.1.4.1 If a Connecting Transmission Owner or Developer elects to construct System Upgrade Facilities that are larger or more extensive than the minimum facilities required to reliably interconnect the proposed project, and are reasonably related to the interconnection of the proposed project, then the Connecting Transmission Owner or Developer is responsible for the cost of those System Upgrade Facilities in excess of the minimum System Upgrade Facilities required by the Developer projects. If there is Headroom associated with these larger

System Upgrade Facilities and a Developer of any subsequent project interconnects and uses the Headroom within ten years of its creation, such subsequent Developer shall pay the Connecting Transmission Owner or the Developer for this Headroom in accordance with these rules, including Section 25.8.7, below.

25.6.1.5 The System Upgrade Facilities cost for which a Developer is responsible will be determined on a "net" basis; that is, the Developer's System Upgrade Facilities cost will be determined net of the benefits, or System Upgrade Facility cost reductions, that result from the construction and operation of its project and the related upgrades. The net cost responsibility of a Developer will not be less than zero. Also, the cost responsibility of the Connecting Transmission Owner for System Upgrade Facilities will be no greater than it would have been without the Developer's project. Specifically, the Connecting Transmission Owner shall not be required to pay (in total) more than 100% of the cost of installing a specific piece of equipment.

25.6.1.5.1 The purpose of this approach is to allocate to the Developer the responsibility for the cost of the net impact of its project on the needs of the transmission system for System Upgrade Facilities. Thus, a Developer is responsible for the cost of the System Upgrade Facilities that are required by, or caused by, its project. A Developer is not responsible for the cost of System Upgrade Facilities that would be required anyway, without the construction of its project. If a Developer's project reduces the cost of System Upgrade Facilities that would be required anyway, that beneficial cost reducing impact will be recognized.

25.6.1.5.2 The net System Upgrade Facilities cost and cost reduction benefits of a Developer's project are determined by ISO staff comparing and netting the results of an Annual Transmission Baseline Assessment with the corresponding Annual Transmission Reliability Assessment in accordance with these rules.

25.6.1.5.3 The net System Upgrade Facilities cost and cost reduction benefits of a Developer's project are comprised of those costs and cost reduction benefits caused by (1) the construction of System Upgrade Facilities not contained in the Annual Transmission Baseline Assessment, and (2) eliminating or reducing the need for the construction of System Upgrade Facilities contained in the Annual Transmission Baseline Assessment, due to the construction of System Upgrade Facilities associated with the proposed project.

25.6.1.5.4 The Developer's net cost responsibility will be determined using constant dollars. That is, when netting the cost of System Upgrade Facilities required for its project, as identified in the Annual Transmission Reliability Assessment, with those identified in the Annual Transmission Baseline Assessment, the cost of System Upgrade Facilities in the out-years of the Annual Transmission Baseline Assessment and the out-years of the Annual Transmission Reliability Assessment will be discounted to a current year value for netting. The cost of out-year System Upgrade Facilities will be discounted to a current value using the weighted average cost of capital of the Connecting Transmission Owner.

25.6.2 Cost Allocation Among Developers (ATRA).

The Developers' share of the cost of System Upgrade Facilities is allocated among Developers based upon the ISO Annual Transmission Reliability Assessment. The Annual Transmission Reliability Assessment will be conducted by ISO staff to ensure New York State Transmission System compliance with Applicable Reliability Requirements. The ISO staff will conduct the Annual Transmission Reliability Assessment, as described in these rules, in cooperation with Market Participants. No Market Participant will have decisional control over any determinative aspect of the Annual Transmission Reliability Assessment. The ISO and its staff will have decisional control over the entire Annual Transmission Reliability Assessment. If, at any time, the ISO staff decides that it needs specific expert services from entities such as Market Participants, consultants or engineering firms for it to conduct the Annual Transmission Reliability Assessment, then the ISO will enter into appropriate contracts with such entities for such input. As it conducts each Annual Transmission Reliability Assessment, the ISO staff will provide regularly scheduled status reports and working drafts, with supporting data, to the Operating Committee to ensure that all affected Market Participants have an opportunity to contribute whatever information and input they believe might be helpful to the process. Each completed Annual Transmission Reliability Assessment will be reviewed and approved by the Operating Committee. Each Annual Transmission Reliability Assessment is reviewable by the ISO Board of Directors in accordance with the provisions of the Commission-approved ISO Agreement.

25.6.2.1 The Annual Transmission Reliability Assessment for each Class Year will identify the System Upgrade Facilities required for all Class Year Projects, with cost estimates for the System Upgrade Facilities. The System Upgrade Facilities identified through the Annual Transmission Reliability Assessment will only be those System Upgrade Facilities that are not already included in an Annual Transmission Baseline Assessment.

25.6.2.2 For each Annual Transmission Reliability Assessment, the ISO will utilize the Existing System Representation used for the corresponding Annual Transmission Baseline Assessment.

25.6.2.3 Each Annual Transmission Reliability Assessment will update the results of Interconnection System Reliability Impact Studies that have previously been performed for certain proposed interconnection projects.

25.6.2.3.1 Subject to the additional requirements in Sections 25.6.2.3.2 - 25.6.2.3.4, below, a Large Facility is eligible to have its Interconnection System Reliavility Impact Study updated, and its project included in a given ATRA (*i.e.*, become a Class Year Project), if on or before the Class Year Start Date (i) the Operating Committee has approved the Interconnection System Reliability Impact Study for the project, and (ii) either (1) the regulatory milestone has been satisfied in accordance with Sections 25.6.2.3.1.1, 25.6.2.3.1.2, or 25.6.2.3.1.3; or (2) the Developer, in lieu of satisfying the regulatory milestone requirement, submits a two-part deposit consisting of (1) \$100,000; and (2) \$3,000/MW for the nameplate capability of the Large Facility. The \$100,000 portion of the deposit submitted pursuant to subsection (ii)(2) of this Section 25.6.2.3.1 will be fully refundable if, within twelve months after the Class Year Start Date or the Operating Committee's approval of the Class Year Study, whichever occurs first, the Developer satisfies an applicable regulatory milestone and provides the ISO with adequate documentation that the Large Facility has satisfied an applicable regulatory milestone. The $3,000/MW deposit will be fully refundable upon the earlier of the Large Facility's satisfaction of an applicable regulatory milestone or the Large Facility's withdrawal from the ISO's interconnection queue.

25.6.2.3.1.1 The Developer must obtain or achieve at least one of the regulatory determinations or actions for the Large Facility described in this Section 25.6.2.3.1.1. To satisfy the regulatory milestone, an applicable regulatory body (*e.g.*, local, state, or federal) must determine that the permitting application submitted to site and construct the Large Facility is complete, as described below:

25.6.2.3.1.1.1 In connection with the Large Facility's air or water permit application, either (i) a notice of determination of completeness mailed to the applicant by the New York State Department of Environmental Conservation ("DEC") pursuant to 6 NYCRR § 621.6(c), as may be amended from time to time, or public notice of a complete application in the Environmental Notice Bulletin, or (ii) in the absence of such notices, a demonstration that the permit application is deemed to be complete pursuant to 6 NYCRR § 621.6(h), as may be amended from time to time.

25.6.2.3.1.1.2 A negative declaration issued for the Large Facility by the lead agency pursuant to the New York State Environmental Quality Review Act ("SEQRA").

25.6.2.3.1.1.3 Under SEQRA, either (i) a determination by the lead agency, documented in minutes or other official records, that the Draft Environmental Impact Statement for the Large Facility is adequate for public review, (ii) a notice of completion of a Draft Environmental Impact Statement for the project issued by the lead agency pursuant to SEQRA, or (iii) public notice of completion in the Environmental Notice Bulletin.

25.6.2.3.1.1.4 For a Large Facility that is a Merchant Transmission Facility, a determination pursuant to Article VII that the Article VII application filed for the Merchant Transmission Facility is in compliance with Public Service Law §122.

25.6.2.3.1.1.5 A Notice of Availability of a Draft Environmental Impact Statement for the Large Facility filed with the U.S. Environmental Protection Agency pursuant to the National Environmental Policy Act of 1969 ("NEPA") and its implementing regulations.

25.6.2.3.1.1.6 A final Finding of No Significant Impact for the project issued by the lead agency pursuant to NEPA and its implementing regulations.

25.6.2.3.1.1.7 For a Large Generator that is larger than 25 MW, a determination pursuant to Article 10 of the Public Service Law that the Article 10 application filed for the Large Generator is in compliance with Public Service Law § 164.

25.6.2.3.1.2 A Large Facility located outside New York State will satisfy the regulatory milestone by achieving Section 25.6.2.3.1.1.5 or 25.6.2.3.1.1.6, above, or by satisfying a milestone comparable to that specified in Section 25.6.2.3.1.1.1 through 25.6.2.3.1.1.4, above, under applicable permitting laws.

25.6.2.3.1.3 In the event that none of the permitting processes referred to in Section 25.6.2.3.1.1 and 25.6.2.3.1.2 apply to the Large Facility, the Large Facility will be considered to have satisfied the regulatory milestone and will qualify for Class Year entry as of the date the Operating Committee approved the Large Facility's Interconnection System Reliability Impact Study.

25.6.2.3.1.4 After a Large Facility's Interconnection System Reliability Impact Study is approved by the Operating Committee and until the ISO confirms that the Large Facility has satisfied the regulatory milestone, the Developer must inform the ISO upon request, whether or not the Large Facility has satisfied the regulatory milestone described above. A project Developer must inform the ISO within ten (10) Business Days of the ISO's request for such information.

25.6.2.3.2 A project must satisfy the applicable regulatory milestone in Section 25.6.2.3.1, above, within six (6) months after the date the ISO tenders to the project Developer the Standard Large Generator Interconnection Agreement for the project pursuant to Section 30.11.1 of Attachment X to the ISO OATT.

25.6.2.3.3 If a project fails to satisfy the regulatory milestone within this time period, the Interconnection Request of the project will be deemed to be withdrawn in accordance with Section 30.3.6 of the Large Facility Interconnection Procedures contained in Attachment X.

25.6.2.3.4 Once a project has an Operating Committee-approved SRIS or the ISO has determined the project is required to enter a Class Year Study pursuant to Attachment Z, then the project may enter up to two, but no more than two, of the next three consecutive Class Year Studies. The first Class Year with a Class Year Start Date after the date the Operating Committee approves a project's Interconnection System Reliability Impact Study will count as the first of the three consecutive Class Year Studies. For purposes of this Section 25.6.2.3.4, a Class Year that a project enters and from which it later withdraws for ERIS evaluation pursuant to Section 25.7.7.1 or 25.6.2.3.3 of this Attachment S or

Section 30.8.1.2 of Attachment X, counts as one of the two Class Years a project may enter.

25.6.2.3.4.1 Except as provided in Section 25.6.2.3.4.3, the project must accept its System Upgrade Facilities cost allocation and post required security for Energy Resource Interconnection Service from a Class Year ATRA that is no later than the first to occur of either (i) the second Class Year ATRA the project enters, or (ii) the third consecutive Class Year that starts after the project satisfies the eligibility criteria for inclusion in the Class Year ATRA. If the project fails to accept its System Upgrade Facilities cost allocation and post security by this deadline, the Interconnection Request of the project will be deemed to be withdrawn in accordance with Section 30.3.6 of the Large Facility Interconnection Procedures contained in Attachment X.

25.6.2.3.4.2 Except as provided in Section 25.6.2.3.4.3, below, if a project has not accepted its System Upgrade Facilities cost allocation and posted required security for Energy Resource Interconnection Service from either the first or second Class Year that starts after the project satisfies the eligibility criteria for inclusion in the Class Year ATRA and has not entered both the first and second such Class Year ATRA, then the project must enter the third Class Year ATRA (by executing the Class Year Interconnection Facilities Study Agreement and providing the required data and deposit). If the developer fails to do so within the timeframes specified in Attachments X or Z, as applicable, the Interconnection Request of the project will be deemed to be withdrawn in accordance with Section

30.3.6 of the Large Facilities Interconnection Procedures contained in Attachment X.

25.6.2.3.4.3 A project that was a member of a completed Class Year but did not accept its System Upgrade Facilities cost allocation and post any required security as of January 17, 2010 will be able to enter any one of the three consecutive Class Year ATRAs starting after that date. If the project enters one of these Class Year ATRAs and fails to accept its System Upgrade Facilities cost allocation and post required security, the Interconnection Request of the project will be deemed to be withdrawn in accordance with Section 30.3.6 of the Large Facility Interconnection Procedures. If the project has not entered either the first or second such Class Year, then the project must enter the third Class Year ATRA (by executing the Class Year Interconnection Facilities Study Agreement and providing the required data and deposit). If the Developer fails to do so within the timeframes specified in Attachments X or Z, as applicable, the Interconnection Request of the project will deemed to be withdrawn in accordance with Section 30.3.6 of the Large Facilities Interconnection Procedures.

25.6.2.4 The Annual Transmission Reliability Assessment will update Interconnection System Reliability Impact Study results in accordance with the Class Year Interconnection Facilities Study procedures in Section 30.8 of the Large Facility Interconnection Procedures in Attachment X to the ISO OATT.

25.6.2.5 For interconnection projects included in each Annual Transmission Reliability Assessment, the Interconnection System Reliability Impact Study updated results will specify the impact of each project in the Class Year on the reliability of the transmission system, that is, the pro rata contribution of each project in the Class Year to each individual System Upgrade Facilities identified in the updates.

25.6.2.5.1 In the case of a new System Upgrade Facility that has a functional capacity not readily measured in amperes or other discrete electrical units, such as a System Upgrade Facility dedicated to system protection, the pro rata impact of each project in the Class Year on the reliability of the transmission system will be based upon the number of projects in the Class Year contributing to the need for the new System Upgrade Facility. The pro rata impact of each project in the Class Year needing such a new System Upgrade Facility will be equal. Accordingly, the pro rata contribution of each of the projects to the need for the new System Upgrade Facility will be equal to (1/a), where "a" is the total number of projects in the Class Year needing the new System Upgrade Facility.

25.6.2.5.2 In the case of a new System Upgrade Facility that has a capacity readily measured in amperes or other discrete electrical units, the impact of each project in the Class Year will be stated in terms of its pro rata contribution to the total electrical impact on each individual System Upgrade Facility in the Class Year of all projects that have at least a *de minimus* impact, as described in Section 25.6.2.6.1 of these rules. The contribution to electrical impact will be measured in various ways depending on the nature of the transmission problem primarily causing the need for the individual System Upgrade Facility.

25.6.2.5.2.1 Contribution to short circuit current for interrupting duty beyond the rating of equipment.

25.6.2.5.2.2 Contribution to MW loading on the critical element for thermal overloads under the test conditions that cause the need for a System Upgrade Facility. MW contribution will be calculated by multiplying the associated distribution factor by the declared maximum MW of the project. The distribution factor is calculated by pro rata displacement of New York System load by the added generation.

25.6.2.5.2.3 Contribution to voltage drop on the most critical bus for voltage problems. A critical bus will be defined as representative for voltage conditions during a specific contingency. The pro rata impact of each project is measured as the ratio of the voltage drop at the critical bus caused by the project when none of the other projects are represented, to the voltage drop at the critical bus when all of the projects in the Class Year are represented.

25.6.2.5.2.4 Contribution to transient stability problems as measured by the fault current calculated for the most critical stability test that is causing the need for the System Upgrade Facility.

25.6.2.6 For each individual electrical impact standard listed in subsections 6.(a)(1) through 6.(a)(4) below, a Developer will not be responsible for the cost associated with a corresponding System Upgrade Facility if its project's contribution is less than the *de minimus* impacts defined below. The costs of projects that would otherwise have been allocated to certain Developer's projects but for the sub-*de minimus* impact exemption, shall be allocated 100 percent to the other Developers in the Class Year according to their pro rata contribution.

25.6.2.6.1 *De minimus* impact is defined in terms of any one of the factors listed below in this subsection. Examples of computations used to determine *de minimus* impact are shown in ISO Procedures.

25.6.2.6.1.1 **Short Circuit Contribution**: Equal to or greater than 100 amperes of the existing rating of the equipment that needs to be replaced.

25.6.2.6.1.2 **Thermal Loadings**: Equal to or greater than 10 MW on the most limiting monitored element under the most critical contingency that is causing the need for transmission improvements.

25.6.2.6.1.3 **Voltage Effects**: Equal to or greater than 2% of the voltage drop occurring with all Class Year Projects at the most critical bus.

25.6.2.6.1.4 **Stability Effects**: Equal to or greater than 100 amperes of the fault current for the most critical stability test that is causing the need for the System Upgrade Facility.

25.6.2.7 The pro rata contribution of each project in the Class Year to each of the System Upgrade Facilities identified in the Annual Transmission Reliability Assessment.

25.6.2.7.1 First, in accordance with Section 25.6.1.5 of these rules, the total cost of System Upgrade Facilities identified in the Annual Transmission Reliability Assessment is compared and netted with the total cost of System Upgrade Facilities identified in the Annual Transmission Baseline Assessment. If the total cost of System Upgrade Facilities identified in the Annual Transmission Reliability Assessment does not exceed the total cost of System Upgrade

Facilities identified in the Annual Transmission Baseline Assessment, then there is no cost to be allocated among Class Year Developers.

25.6.2.7.2 If the total cost of System Upgrade Facilities identified in the Annual Transmission Reliability Assessment does exceed the total cost of System Upgrade Facilities identified in the Annual Transmission Baseline Assessment by some amount, then this amount ("Overage Cost") is a cost to be allocated among Class Year Developers. Appendix One to this Attachment S sets out an example of an allocation of Overage Cost among Class Year Developers.

25.6.2.7.3 The Overage Cost represents a percentage of the total cost of System Upgrade Facilities identified in the Annual Transmission Reliability Assessment ("Overage Cost Percentage").

25.6.2.7.4 Each System Upgrade Facility identified in the Annual Transmission Reliability Assessment has a cost specified for it in the Annual Transmission Reliability Assessment.

25.6.2.7.5 The pro rata contribution of each project in the Class Year to a System Upgrade Facility identified in the Annual Transmission Reliability Assessment represents a percentage contribution to the need for that System Upgrade Facility ("Contribution Percentage").

25.6.2.7.6 An individual Developer's pro rata responsibility for the cost of each System Upgrade Facility identified in the Annual Transmission Reliability Assessment is the product of (a) the Overage Cost Percentage; (b) the Developer's Contribution Percentage for the particular System Upgrade Facility; and (c) the cost of the particular System Upgrade Facility as specified in the Annual Transmission Reliability Assessment.

25.6.2.7.7 If the least cost solution identified is to install one System Upgrade Facility (*e.g.*, a series reactor) rather than replacing a number of System Upgrade Facilities (*e.g.*, breakers), the ISO staff will determine each Developer's Contribution Percentage by calculating what each Developer's pro rata contribution would have been on the System Upgrade Facilities not replaced (*e.g.*, breakers) and applying that percentage to the System Upgrade Facility that is installed (*e.g.*, series reactor)..

25.7 Cost Allocation Methodology for CRIS.

25.7.1 Cost Allocation Among Developers in a Class Year.

Each project in a Class Year Deliverability Study ("Class Year CRIS Project") will share in the then currently available deliverability capability of the New York State Transmission System, and will also share in the cost of any System Deliverability Upgrades required for its project to qualify for CRIS at the requested level. The total cost of the System Deliverability Upgrades required for all the projects in the Class Year will be allocated among the projects in the Class Year based on the pro rata impact of each Class Year CRIS Project on the deliverability of the New York State Transmission System, that is, the pro rata contribution of each project in the Class Year Deliverability Study to the total cost of each of the System Deliverability Upgrades identified in the Class Year Deliverability Study. In addition to this allocation of cost responsibility for System Deliverability Upgrades among the projects in a Class Year, the cost of certain Highway System Deliverability Upgrades will be shared with Load Serving Entities and subsequent Developers, as described below in Section 25.7.12 of these rules.

25.7.2 Categories of transmission facilities.

For purposes of applying the NYISO Deliverability Interconnection Standard, transmission facilities comprising the New York State Transmission System will be categorized as either Byways or Highways or Other Interfaces.

25.7.2.1 Byways. The Developer of a Class Year CRIS Project will pay its pro rata share of one hundred percent (100%) of the cost of the System Deliverability Upgrades to any Byway needed to make the Class Year CRIS Project deliverable in accordance with these rules. The System Deliverability Upgrades on the

Byway or Byways will be identified by the ISO, with input from the Connecting Transmission Owner and from the Affected Transmission Owner(s), in the Class Year Deliverability Study.

The Transmission Owner(s) responsible for constructing a System Deliverability Upgrade on a Byway shall request Incremental TCCs with respect to the System Deliverability Upgrade in accordance with the requirements of Section 19.2.4 of Attachment M of the ISO OATT. A Developer paying to upgrade a Byway will receive the right to accept any Incremental TCCs awarded by the ISO in proportion to its contribution to the total cost of the System Deliverability Upgrade. The ISO shall round any non-whole MW quantities to a whole number of Incremental TCCs in a manner that ensures that the sum of all individual allocations to eligible entities is equal to the total number of Incremental TCCs awarded to the System Deliverability Upgrade; provided, however, that a Developer will not be entitled to receive any Incremental TCCs if the whole number value determined by the ISO for the Developer's proportionate share is zero. If a Developer elects to accept its proportionate share of any Incremental TCCs resulting from the System Deliverability Upgrade, the Developer shall be the Primary Holder of such Incremental TCCs. If a Developer declines an award of its proportionate share of any Incremental TCCs resulting from the System Deliverability Upgrade, or subsequently terminates the Incremental TCCs it elected to receive in accordance with Section 19.2.4.9 of Attachment M of the ISO OATT, the declined or terminated Incremental TCCs will be deemed reserved to the extent necessary to facilitate the potential for transfers to subsequent Developers that pay for the use of Headroom pursuant to this Attachment S on a System Deliverability Upgrade that has been awarded Incremental TCCs. Incremental TCCs that are declined or terminated by a Developer and not otherwise deemed reserved will be deemed permanently terminated. Incremental TCCs related to a System Deliverability Upgrade that were previously deemed reserved as a result of prior declination or termination will be deemed permanently terminated when the Headroom on the System Deliverability Upgrade ceases to exist or is otherwise reduced to zero in accordance with Section 25.8.7.4 of this Attachment S.

A Developer paying to upgrade a Byway will be eligible to receive Headroom payments in accordance with these rules. A subsequent Developer paying for use of Headroom on a System Deliverability Upgrade on a Byway will be entitled to receive Incremental TCCs, to the extent Incremental TCCs have been awarded by the ISO for the System Deliverability Upgrade, in proportion to its contribution to the total cost of the System Deliverability Upgrade, as determined based on its required Headroom payments. The ISO shall round any non-whole MW quantities to a whole number of Incremental TCCs in a manner that ensures that the sum of all individual allocations to eligible entities is equal to the total number of Incremental TCCs awarded to the System Deliverability Upgrade; provided, however, that a subsequent Developer will not be entitled to receive any Incremental TCCs if the whole number value determined by the ISO for the subsequent Developer’s proportionate share is zero. If a Developer that initially paid for a System Deliverability Upgrade on a Byway elected to receive its proportionate share of any Incremental TCCs related to the System Deliverability Upgrade and continues to hold such Incremental TCCs, any Incremental TCCs that a subsequent Developer is eligible to receive will be made available by reducing the Incremental TCCs related to the System Deliverability Upgrade held by the Developer that initially paid for the System Deliverability Upgrade in proportion to the Headroom payments received by such Developer from the subsequent Developer making such Headroom payments. If a Developer that initially paid for a System Deliverability Upgrade on a Byway declined to receive its proportionate share of any Incremental TCCs related to the System Deliverability Upgrade or subsequently terminated the Incremental TCCs it elected to receive, any Incremental TCCs that a subsequent Developer is eligible to receive will be made available from the Incremental TCCs related to the System Deliverability Upgrade that were previously deemed reserved as a result of prior declination or termination in proportion to the Headroom payments received by the Developer that initially paid for the System Deliverability Upgrade from the subsequent Developer making such Headroom payments. If a subsequent Developer elects to accept its proportionate share of any Incremental TCCs, the subsequent Developer shall be the Primary Holder of such Incremental TCCs; provided, however, that Incremental TCCs that were previously deemed reserved and are transferred to a subsequent Developer will become effective on the first day of the Capability Period that commences following the next Centralized TCC Auction conducted after the subsequent Developer makes the necessary Headroom payment and elects to receive its proportionate share of

Incremental TCCs. If a subsequent Developer declines an award of its proportionate share of any Incremental TCCs resulting from its Headroom payments, or subsequently terminates the Incremental TCCs it elected to receive in accordance with Section 19.2.4.9 of Attachment M of the ISO OATT, the declined or terminated Incremental TCCs will be deemed permanently terminated.

Any Incremental TCCs resulting from a System Deliverability Upgrade on a Byway, regardless of the Primary Holder thereof, may not be sold or transferred through a Centralized TCC Auction, Reconfiguration Auction or the Secondary Market.

25.7.2.2 **Highways.** The Developer of a Class Year CRIS Project will pay an allocated share of the cost of the System Deliverability Upgrades to any Highway needed to make the Class Year Project deliverable in accordance with these rules. The System Deliverability Upgrades on the Highway or Highways, and the Developer’s allocated share of the cost of those System Deliverability Upgrades, will be identified by the ISO, with input from the Connecting Transmission Owner and from the Affected Transmission Owner(s), in the Class Year Deliverability Study.

The Transmission Owner(s) responsible for constructing a Highway System Deliverability Upgrade shall request Incremental TCCs with respect to the Highway System Deliverability Upgrade in accordance with the requirements of Section 19.2.4 of Attachment M of the ISO OATT. A Developer paying for Highway System Deliverability Upgrades will receive the right to accept any Incremental TCCs awarded by the ISO, in proportion to its contribution to the to the total cost of the Highway System Deliverability Upgrade. The ISO shall round any non-whole MW quantities to a whole number of Incremental TCCs in a manner that ensures that the sum of all individual allocations to eligible entities is equal to the total number of Incremental TCCs awarded to the Highway System Deliverability Upgrade; provided, however, that a Developer will not be entitled to receive any Incremental TCCs if the whole number value determined by the ISO for the subsequent Developer's proportionate share is zero. If a Developer elects to accept its proportionate share of any Incremental TCCs resulting from the Highway System Deliverability Upgrade, the Developer shall be the Primary Holder of such Incremental TCCs. If a Developer declines an award of its proportionate share of any Incremental TCCs resulting from the Highway System Deliverability Upgrade, or subsequently terminates the Incremental TCCs it elected to receive in accordance with Section 19.2.4.9 of Attachment M of the ISO OATT, the declined or terminated Incremental TCCs will be deemed reserved to the extent necessary to facilitate the potential for transfers to subsequent Developers that pay for the use of Headroom pursuant to this Attachment S on a Highway System Deliverability Upgrade that has been awarded Incremental TCCs. Incremental TCCs that are declined or terminated by a Developer and not otherwise deemed reserved will be deemed permanently terminated. Incremental TCCs related to a Highway System Deliverability Upgrade that were previously deemed reserved as a result of prior declination or termination will be deemed permanently terminated when the Headroom on the

Highway System Deliverability Upgrade ceases to exist or is otherwise reduced to zero in accordance with Section 25.8.7.4 of this Attachment S.

The Transmission Owner(s) responsible for constructing a Highway System Deliverability Upgrade shall also be awarded, and be the Primary Holder of, any Incremental TCCs related to the portion of a Highway System Deliverability Upgrade funded by Load Serving Entities pursuant to Section 25.7.12 of this Attachment S, in proportion to the contribution of the Load Serving Entities to the to the total cost of the Highway System Deliverability Upgrade. The ISO shall round any non-whole MW quantities to a whole number of Incremental TCCs in a manner that ensures that the sum of all individual allocations to eligible entities is equal to the total number of Incremental TCCs awarded to the Highway System Deliverability Upgrade; provided, however, that no Incremental TCCs will be awarded to the Transmission Owner(s) responsible for constructing a Highway System Deliverability Upgrade for the portion of a Highway System Deliverability Upgrade funded by Load Serving Entities if the whole number value determined by the ISO for the Load Serving Entities' proportionate share is zero.

A Developer paying for a Highway System Deliverability Upgrade will be eligible to receive Headroom payments in accordance with these rules to the extent that it pays for System Deliverability Upgrade capacity in excess of that required to provide the requested level of CRIS and Load Serving Entities have not funded a portion of the costs of the Highway System Deliverability Upgrade pursuant to Section 25.7.12 of this Attachment S. If Load Serving Entities have funded a portion of a Highway System Deliverability Upgrade pursuant to Section 25.7.12 of this Attachment S, the Transmission Owner(s) responsible for constructing the Highway System Deliverability Upgrade will be eligible to receive any and all Headroom payments related to the System Deliverability Upgrade in accordance with these rules on behalf, and for the benefit, of the Load Serving Entities that funded a portion of the System Deliverability Upgrade.

A subsequent Developer paying for use of Headroom on System Deliverability Upgrades will be entitled to receive Incremental TCCs, to the extent Incremental TCCs have been awarded by the ISO for the System Deliverability Upgrade, in proportion to its contribution to the total cost of the Highway System Deliverability Upgrade, as determined based on its required Headroom payments. The ISO shall round any non-whole MW quantities to a whole number of Incremental TCCs in a manner that ensures that the sum of all individual allocations to eligible entities is equal to the total number of Incremental TCCs awarded to the Highway System Deliverability Upgrade; provided, however, that a subsequent Developer will not be entitled to receive any Incremental TCCs if the whole number value determined by the ISO for the Developer’s proportionate share is zero. If: (i) a Developer that initially paid for a Highway System Deliverability Upgrade paid for capacity in excess of that required to provide its requested level of CRIS; (ii) Load Serving Entities have not funded a portion of the costs of the Highway System Deliverability Upgrade pursuant to Section 25.7.12 of this Attachment S; and (iii) the Developer elected to receive its proportionate share of any Incremental TCCs related to the System

Deliverability Upgrade and continues to hold such Incremental TCCs, any Incremental TCCs that a subsequent Developer is eligible to receive will be made available by reducing the Incremental TCCs related to the System Deliverability Upgrade held by the Developer that initially funded the System Deliverability Upgrade in proportion to the Headroom payments received by such Developer from the subsequent Developer making such Headroom payments. If: (i) a Developer that initially paid for a Highway System Deliverability Upgrade paid for capacity in excess of that required to provide its requested level of CRIS; (ii) Load Serving Entities have not funded a portion of the costs of the Highway System Deliverability Upgrade pursuant to Section 25.7.12 of this Attachment S; and (iii) the Developer declined to receive its proportionate share of any Incremental TCCs related to the System Deliverability Upgrade or subsequently terminated the Incremental TCCs it elected to receive, any Incremental TCCs that a subsequent Developer is eligible to receive will be made available from the Incremental TCCs related to the System Deliverability Upgrade that were previously deemed reserved as a result of prior declination or termination in proportion to the Headroom payments received by the Developer that initially paid for the System Deliverability Upgrade from the subsequent Developer making such Headroom payments. If Load Serving Entities have funded a portion of a Highway System Deliverability Upgrade pursuant to Section 25.7.12 of this Attachment S, any Incremental TCCs that a subsequent Developer is eligible to receive will be made available by reducing the Incremental TCCs related to the System Deliverability Upgrade held by the Transmission Owner(s) responsible for constructing the System Deliverability Upgrade. If a subsequent Developer elects to accept its proportionate share of any Incremental TCCs, the subsequent Developer shall be the Primary Holder of such Incremental TCCs; provided, however, that Incremental TCCs that were previously deemed reserved and are transferred to a subsequent Developer will become effective on the first day of the Capability Period that commences following the next Centralized TCC Auction conducted after the subsequent Developer makes the necessary Headroom payment and elects to receive its proportionate share of Incremental TCCs. If a subsequent Developer declines an award of its proportionate share of any Incremental TCCs resulting from its Headroom payments, or subsequently terminates the Incremental TCCs it elected to receive in accordance with Section 19.2.4.9 of Attachment M of the ISO OATT, the declined or terminated Incremental TCCs will be deemed permanently terminated.

Any Incremental TCCs resulting from a Highway System Deliverability Upgrade, regardless of the Primary Holder thereof, may not be sold or transferred through a Centralized TCC Auction, Reconfiguration Auction or the Secondary Market.

25.7.2.3 **Other Interfaces.** If the Class Year CRIS Project degrades the transfer capability of any one of the Other Interfaces below the transfer capability identified in the current ATBA, then the Developer will pay its pro rata share of one hundred percent (100%) of the cost of the System Deliverability Upgrades needed to restore the transfer capability of the Other Interfaces degraded by its proposed project to what the transfer capability of those Other Interfaces would have been without its project, as that transfer capability was measured in the current ATBA. Where two or more projects would cause degradation of an Other Interface's transfer capability, the cost of the necessary System Deliverability Upgrades to restore the original transfer capability of the interface shall be shared on a pro rata basis, based on the MW of degradation that each project would cause.

25.7.3 Capacity Regions.

For Class Years prior to Class Year 2012, the deliverability test will be applied within each of the three (3) Capacity Regions: (1) Rest of State (*i.e.*, Load Zones A through I); (2) New York City (*i.e.*, Load Zone J); and (3) Long Island (*i.e.*, Load Zone K). To be declared deliverable, a generator or merchant transmission project must be deliverable throughout the Capacity Region in which the project is interconnected. For example, a proposed generator or merchant transmission project interconnecting in the Rest of State Capacity Region (*i.e.,* Load Zones A-I) will be required to demonstrate deliverability throughout the Rest of State Capacity Region (*i.e.*, Load Zones A-I), but will not be required to demonstrate deliverability to or within either of the following Capacity Regions: New York City (*i.e.*, Load Zone J); or Long Island (*i.e.*, Load Zone K).

Starting with Class Year 2012, the deliverability test will be applied within each of the four (4) Capacity Regions: (1) Rest of State (*i.e.,* Load Zones A through F); (2) Lower Hudson Valley (*i.e.,* Load Zones G, H and I); (3) New York City (*i.e.*, Load Zone J); and (4) Long Island (*i.e.,* Load Zone K). To be declared deliverable a generator or merchant transmission project must only be deliverable throughout the Capacity Region in which the project is interconnected or is interconnecting. For example, starting with Class Year 2012, a proposed generator or merchant transmission project interconnecting in the Rest of State Capacity Region (*i.e.,* Load Zones A-F) will be required to demonstrate deliverability throughout the Rest of State Capacity Region (*i.e.,* Load Zones A-F), but will not be required to demonstrate deliverability to or within any of the following Capacity Regions: Lower Hudson Valley (*i.e.*, Load Zones G, H and I); New York City (*i.e.,* Load Zone J); or Long Island (*i.e.,* Load Zone K).

25.7.4 Participation in Capacity Markets.

A Developer, in order to be eligible to become an Installed Capacity Supplier or receive Unforced Capacity Deliverability Rights, must obtain CRIS pursuant to the procedures set forth in this Attachment S. A Developer must enter a Class Year Deliverability Study in order to obtain CRIS, unless otherwise provided for in this Attachment S. The MW amount of CRIS requested by a Developer, stated in MW of Installed Capacity ("ICAP"), cannot exceed the nameplate capacity of its generation or merchant transmission project; provided however, if the Class Year CRIS Project is a BTM:NG Resource, the requested CRIS cannot exceed its Net-ICAP. All requests for CRIS must be in tenths of a MW. The ISO will perform the Class Year Deliverability Study in accordance with these rules and with input of Market Participants, to determine the deliverability of each of the Class Year CRIS Projects. The Class Year Deliverability Study will identify and allocate the cost of the System Deliverability Upgrades needed to make deliverable each Class Year CRIS Project. In order to be eligible to become an Installed Capacity Supplier or receive Unforced Capacity Deliverability Rights, a Developer must fund or commit to fund, in accordance with these rules, the System Deliverability Upgrades needed for its project to be deliverable at the requested level of CRIS.

25.7.5 The Pre-Existing System.

Where the Existing System Representation demonstrates deliverability issues, a Developer electing CRIS need only address the incremental deliverability of its inter-connecting, or interconnected, generator or merchant transmission project, not the deliverability of the pre-existing system depicted in the Existing System Representation. Likewise, Transmission Owners will not be responsible for curing any pre-existing issues related to the deliverability of generators.

25.7.6 CRIS Values.

A Developer may elect no CRIS, partial CRIS, or full CRIS for its facility by satisfying the applicable sections of this Attachment S. All facilities qualifying for CRIS will have two CRIS values: one for the Summer Capability Period and one for the Winter Capability Period. The CRIS value for the Summer Capability Period will be set using the deliverability test methodology and procedures described below. Through the Winter Capability Period 2017/2018, the CRIS value for the Winter Capability Period will be set at a value that will maintain the same proportion of CRIS to ERIS as the facility has for the Summer Capability Period. For Winter Capability Periods beyond 2017/2018, the CRIS value for the Winter Capability Period will be determined by the applicable process below:

25.7.6.1 Winter CRIS will be calculated as follows:

Winter CRIS MW = (Summer CRIS MW x Maximum Net Output at 10 degrees Fahrenheit)/Maximum Net Output at 90 degrees Fahrenheit

Where:

Maximum Net Output at 10 degrees Fahrenheit = the facility's maximum net output at 10 degrees Fahrenheit determined pursuant to the facility's ISO-approved temperature curve; and

Maximum Net Output at 90 degrees Fahrenheit = the facility's maximum net output at 90 degrees Fahrenheit determined pursuant to the facility's ISO-approved temperature curve.

25.7.6.1.1 For facilities with Summer CRIS as of December 16, 2017, the following additional provision applies: For such facilities for which there is an ISO-accepted temperature curve used for determining the facility's DMNC, Winter CRIS will be calculated using such temperature curve, provided the capability represented by the curve does not exceed the facility's ERIS. For facilities for which there is not an ISO-accepted temperature curve used for determining the facility's DMNC, Winter CRIS will be set equal to the facility's Summer CRIS unless the facility provides a temperature curve to the ISO by December 16, 2017, that the ISO subsequently determines is acceptable.

25.7.6.1.2 For facilities first obtaining Summer CRIS on or after December 16, 2017, the Winter CRIS will be determined using the most recent temperature curve provided to and accepted by the ISO, either during the interconnection process or at the time the Summer CRIS is first obtained.

25.7.6.2 Upon an increase to a facility's Summer CRIS pursuant to a permissible increase in Summer CRIS under Section 25.9.4 of this Attachment S, Attachment X, Section 30.3.2.6 or Attachment Z, Section 32.4.11.1 (increases in CRIS not requiring a Class Year Study) or pursuant to an increase in Summer CRIS evaluated in a Class Year Study for which a facility owner accepts its Project Cost Allocation for System Deliverability Upgrades and posts Security therefore (if applicable) or accepts its Deliverable MWs, the Winter CRIS will be determined using the formula set forth in Section 25.7.6 (i), wherein the Summer CRIS MW will be the increased Summer CRIS MW.

25.7.7 Class Year Deliverability Study Procedures.

The ISO staff will conduct the Class Year Deliverability Study, as described in these rules, in cooperation with Market Participants. No Market Participant will have decisional control over any determinative aspect of the Class Year Deliverability Study. The ISO and its staff will have decisional control over the entire Class Year Deliverability Study. If, at any time, the ISO staff decides that it needs specific expert services from entities such as Market Participants, consultants or engineering firms for it to conduct the Class Year Deliverability Study, then the ISO will enter into appropriate contracts with such entities for such input. As it conducts each Class Year Deliverability Study, the ISO staff will provide regularly scheduled status reports and working drafts, with supporting data, to the Operating Committee to ensure that all affected Market Participants have an opportunity to contribute whatever information and input they believe might be helpful to the process. Each completed Class Year Deliverability Study will be reviewed and approved by the Operating Committee, when the Operating Committee approves the ATRA for the same Class Year. Each Class Year Deliverability Study is reviewable by the ISO Board of Directors in accordance with the provisions of the Commission-approved ISO Agreement.

25.7.7.1 Starting with Class Year 2012, if the ISO determines that additional System Deliverability Upgrade studies are required pursuant to Section 25.5.9 of this Attachment S, ISO will notify all Class Year Projects that such additional System Deliverability Upgrade studies will be conducted, such notice to be provided as soon as practicable after the ISO presents the results of the Class Year Deliverability Study to stakeholders. Options to Class Year Developers upon such notice are set forth in Section 25.5.10 of this Attachment S.

25.7.8 Deliverability Test Methodology for Highways and Byways.

25.7.8.1 Definition of NYCA Deliverability. The NYCA transmission system shall be able to deliver the aggregate of NYCA capacity resources to the aggregate of the NYCA load under summer peak load conditions. This is accomplished through ensuring the deliverability of each Class Year CRIS Project, in the Capacity Region where the facility interconnects.

25.7.8.2 NYCA Deliverability Testing Methodology. The current Class Year ATBA, developed in accordance with ISO Procedures, will serve as the starting point for the deliverability baseline for testing under summer peak system conditions, subject to ISO Procedures and the following:

25.7.8.2.1 All Class Year CRIS Projects will be evaluated on an aggregate Class Year basis. Deliverability will be determined through a shift from generation to generation within the Capacity Regions in New York State. Each Capacity Region will be tested on an individual basis.

25.7.8.2.2 Each entity requesting External CRIS Rights will request a certain number of MW to be evaluated for deliverability pursuant to Section 25.7.11 of this Attachment S. The MW of an entity requesting External CRIS Rights will not be derated for the deliverability analysis.

25.7.8.2.3 Each Developer requesting CRIS will request that a certain number of MW, not to exceed the name plate rating of its facility, be evaluated for deliverability; provided however, if the Class Year CRIS Project is a BTM:NG Resource, the requested CRIS cannot exceed its Net-ICAP. The MW requested by a Developer will represent Installed Capacity, and will be derated for the deliverability analysis. At the conclusion of the analysis, the ISO will reconvert only the deliverable MW and report them in terms of MW of Installed Capacity using the same derating factor utilized at the beginning of the deliverability analysis.

A derated generator capacity incorporating availability is used. This derated generator capacity is based on the unforced capacity or "UCAP" or Net UCAP, as applicable, of each resource and can be referred to as the UCAP Deration Factor ("UCDF"). The UCDF used is the average from historic ICAP to UCAP translations on a Capacity Region basis, as determined in accordance with ISO Procedures. This is the average EFORd, which will be used for all non intermittent ICAP providers. The UCDF for intermittent resources will be calculated based on their resource type in accordance with ISO Procedures. The UCDF factor for proposed projects will be applied to the requested CRIS level. For facilities modeled in the ATBA, the UCDF will be applied to their CRIS level.

The CRIS for each facility, regardless of outage state, will be modeled in Deliverability Studies for the Class Year unless that CRIS will expire prior to the scheduled completion of the applicable Class Year study or the CRIS is associated with a Retired facility that cannot transfer such rights prior to CRIS expiration.

25.7.8.2.4 Load uncertainties will be addressed in accordance with ISO Procedures by taking the impact of Load Forecast Uncertainty ("LFU") from the most recent base case IRM and applying it to load.

25.7.8.2.5 Deliverability base case conditioning steps will be consistent with those used for the Comprehensive Reliability Planning Process and Area Transmission Review transfer limit calculation methodology.

25.7.8.2.6 In deliverability testing, Emergency transfer criteria and contingency testing will be in conformance with NYSRC rules and correspond to that used in the NYISO Comprehensive Reliability Planning Process studies.

25.7.8.2.7 The NYISO will monitor all transmission facilities that are part of the New York State Transmission System.

25.7.8.2.8 When either the voltage or stability transfer limit of an interface calculated in the ATBA is more binding than the calculated thermal transfer limit, then the lower of the ATBA voltage or stability transfer limit will be included in the deliverability testing as a proxy limit.

25.7.8.2.9 External system imports will be adjusted as necessary to eliminate or minimize overloads, other than the following external system imports: (i) the grandfathered import contract rights listed in Attachment E to the Installed Capacity Manual, (ii) the operating protocols set forth in Schedule C of Attachment CC to the OATT, (iii) the appropriate rules for reflecting PJM service to RECo load, (iv) beginning with Class Year 2008 and in subsequent Class Years, the Existing Transmission Capacity for Native Load listed for the New York State Electric & Gas Corporation in Table 3 of Attachment L of the OATT, (v) in Class Year 2008 and 2009, 1090 MW of imports made over the Quebec (via Chateauguay) interface, and (vi) beginning with Class Year 2010 and in subsequent Class Years, any External CRIS Rights awarded pursuant to Section

25.7.11 of this Attachment S, either as a result of the conversion of grandfathered rights over the Quebec (via Chateauguay) Interface or as a result of a Class Year Deliverability Study, until, as of the Class Year Start Date, the time available to renew the External CRIS Rights has expired, as described in Section 25.9.3.2.2 of this Attachment S.

25.7.8.2.10 Flows associated with generators physically located in the NYCA but selling capacity out of the market will be modeled as such in the deliverability base cases.

25.7.8.2.11 Resources and demand are brought into balance in the baseline. If resources are greater than demand in the Capacity Region, existing generators within the Capacity Region are prorated down. If resources are lower than demand in the Capacity Region, additional external resources are included in the model.

25.7.8.2.12 PARs within the applicable Capacity Region will be adjusted as necessary, in either direction and within their angle capability, to eliminate or minimize overloads without creating new ones. PARs controlling external ties and ties between the Capacity Regions will be modeled, within their angle capability, to hold the individual tie flows to their respective deliverability baseline schedules, which shall be set recognizing firm commitments and operating protocol set forth in Schedule C of Attachment CC to the OATT.

25.7.8.2.13 Deliverability testing will proceed as follows - The generation/load mix is split into two groups of generation and load, one upstream and one downstream for each zone or sub-zone tested within the Capacity Region. All elements that are part of the New York State Transmission System within the Capacity Region will be monitored. If there is excess generation upstream (that is, more upstream generation than is necessary to serve the upstream load plus LFU) then the generation excess, taking into account generator derate factors described in Section 25.7.8.2.2 above, is assumed to displace downstream generation. If the dispatch of the upstream excess generation causes an overload, this overload is flagged as a potential deliverability problem and will be used to determine the amount of capacity that is assigned CRIS status and the overload mitigation.

25.7.8.2.14 For Highway interfaces, the generator or merchant transmission projects in a Class Year, whether or not they are otherwise deliverable, will not be considered deliverable if their aggregate impact degrades the transfer capability of the interface more than the lesser of 25 MW or 2 percent of the transfer capability identified in the ATBA and results in an increase to the NYCA LOLE determined for the ATBA of .01 or more. The Class Year projects causing the degradation will be responsible, on a pro rata basis, for restoring transfer capability only to the extent their aggregate degradation of transfer capability, compared to that in the ATBA, would not occur but for the Class Year projects.

25.7.9 Deliverability Test Methodology for Other Interfaces.

The generator or merchant transmission projects in a Class Year, whether or not they are otherwise deliverable across Highways and Byways, will not be considered deliverable if their aggregate impact degrades the transfer capability of any Other Interface more than the lesser of 25 MW or 2 percent of the transfer capability of the Other Interface identified in the ATBA. Each Developer will be responsible for its pro rata Class Year share of one hundred percent

(100%) of the cost of System Deliverability Upgrades needed to restore transfer capability on the Other Interfaces impacted by the Class Year Projects but only to the extent that the degradation of transfer capability on the Other Interfaces, compared to that measured in the current Class Year ATBA, would not occur but for the aggregate impact of the Class Year Projects. Where two or more projects contribute to the degradation of the transfer capability of an Other Interface, each project Developer shall pay for a share of the required System Deliverability Upgrades based on its contribution to the degradation of the transfer capability.

25.7.10 Deliverability of External Installed Capacity.

External Installed Capacity not associated with UDRs or External CRIS Rights will be subject to the deliverability test in Section 25.7.8 and 25.7.9 of this Attachment S, but not as a part of the Class Year Deliverability Study. As described in detail in Section 5.12.2 of the Services Tariff, the deliverability of External Installed Capacity not associated with UDRs or External CRIS Rights will be evaluated separately as a part of the annual process under the Services Tariff that sets import rights for the upcoming Capability Year, to determine the amount of External Installed Capacity that can be imported to the New York Control Area.

25.7.11 CRIS Rights For External Installed Capacity

An entity, by following the procedures and satisfying the requirements described in this Section 25.7.11, may obtain External CRIS Rights. While the External CRIS Rights are in effect, External Installed Capacity associated with External CRIS Rights is not subject to (1) the deliverability determination described above in Section 25.7.10 of this Attachment S, (2) the annual deliverability determination applied in the import limit setting process described in Section 5.12.2.2 of the Services Tariff, or (3) to the allocation of import rights described in ISO Procedures.

25.7.11.1 Required Commitment of External Installed Capacity.

An entity requesting External CRIS Rights for a specified number of MW of External Installed Capacity must commit to supply that number of MW of External Installed Capacity for a period of at least five (5) years ("Award Period"). The entity's commitment to supply the specified number of MW for the Award Period may be based upon either an executed bilateral contract to supply ("Contract Commitment"), or based upon another kind of long-term commitment ("Non-Contract Commitment"), both as described herein.

25.7.11.1.1 Contract Commitment. An entity making a Contract Commitment of External Installed Capacity must have one or more executed bilateral contract(s) to supply a specified number of MW of External Installed Capacity ("Contract CRIS MW") to a Load Serving Entity or Installed Capacity Supplier for an Award Period of at least five (5) years. The entity must have ownership or contract control of External Installed Capacity to fulfill its bilateral supply contract throughout the Award Period, and that otherwise satisfies NYISO requirements.

25.7.11.1.1.1 The bilateral supply contract(s) individually or in the aggregate, must be for all months of the Summer Capability Periods over the term of the bilateral supply contract(s), but need not include any of the months of the Winter Capability Periods over that term. The entity seeking External CRIS Rights must specify which, if any, months of the Winter Capability Period it will supply External Installed Capacity under the bilateral supply contract(s) ("Specified Winter Months").

25.7.11.1.1.2 The bilateral supply contract(s) must be for the same number of MW for all months of the Summer Capability Periods ("Summer Contract CRIS MW") and the same number of MW for all Specified Winter Months ("Winter Contract

CRIS MW"). The Winter Contract CRIS MW level must be less than or equal to the Summer Contract CRIS MW level.

25.7.11.1.1.3 An entity holding External CRIS Rights under a Contract Commitment must certify the bilateral supply contract for every month of the Summer Capability Periods and all Specified Winter Months for the applicable Contract CRIS MW. The Summer Contract CRIS MW must be certified for every month of the Summer Capability Period, and the Winter Contract CRIS MW must be certified for every Specified Winter Month (if any).

25.7.11.1.2 Non-Contract Commitment. An entity holding External CRIS Rights under a Non-Contract Commitment must offer the committed number of MW of External Installed Capacity for every month of the commitment, as described below, in the NYISO Installed Capacity auctions for an Award Period of at least five (5) years. The entity must have ownership or contract control of External Installed Capacity to fulfill its Non-Contract Commitment throughout the Award Period.

25.7.11.1.2.1 The Non-Contract Commitment must be made for all months of the Summer Capability Periods over the term of the Award Period, but need not include any months in the Winter Capability Periods. The entity must identify the Specified Winter Months, if any, of the Winter Capability Periods for which it will make the commitment.

25.7.11.1.2.2 The commitment must be for the same number of MW for each month of the Summer Capability Period ("Summer Non-Contract CRIS MW"), and the same number of MW for all Specified Winter Months ("Winter Non-Contract

CRIS MW"). The Winter Non-Contract CRIS MW level must be less than or equal to the Summer Contract CRIS MW level.

25.7.11.1.2.3 An entity holding External CRIS Rights under a Non-Contract Commitment must offer the committed capacity (a) in at least one of the following NYCA auctions: the Capability Period Auction, the Monthly Auction or the ICAP Spot Market Auction, or (b) through a certified and scheduled Bilateral Transaction (as such terms not defined in this Attachment S are defined in the Services Tariff). The Summer Non-Contract CRIS MW must be offered for every month of the Summer Capability Period, and the Winter Non-Contract CRIS MW must be offered for every Specified Winter Month (if any).

25.7.11.1.2.4 Notwithstanding other capacity mitigation measures that may apply, the offers to sell Installed Capacity into an auction submitted pursuant to this Non-Contract Commitment will be subject to an offer cap for each month of the Summer Capability Periods and each Specified Winter Month. This offer cap will be determined in accordance with the provisions contained in Section 5.12.2.4 of the Services Tariff.

25.7.11.1.3 Failure to Meet Commitment. If an entity fails to certify or offer the full number of Contract CRIS MW or Non-Contract CRIS MW in accordance with the terms stated above, in Sections 25.7.11.1.1 and 25.7.11.1.2, the entity shall pay the NYISO an amount equal to 1.5 times the Installed Capacity Spot Auction Market Clearing Price for the month in which either the capacity under Non-Contract Commitment was not offered or the Contract Commitment to supply

ICAP was not certified ("Supply Failure"), times the number of MW committed under the Non-Contract or Contract Commitment but not offered.

25.7.11.1.3.1 Within a given Award Period and each subsequent renewal of an Award Period pursuant to Section 25.9.3.2.2 herein, for the first three instances of a Supply Failure, no additional actions will be taken. Upon the fourth instance within the Award Period or the fourth instance within a subsequent renewal period of a Supply Failure, the associated External CRIS Rights will be terminated in their entirety with no ability to renew. Entities that had External CRIS Rights terminated may reapply for External CRIS in accordance with Section 25.7.11.1.4.2 below. Nothing in this Section 25.7.11.1.3 shall be construed to limit or diminish any provision in the Market Power Mitigation Measures or the Market Monitoring Plan.

25.7.11.1.4 Obtaining External CRIS Rights. An entity making a Contract Commitment or Non-Contract Commitment of External Installed Capacity may obtain External CRIS Rights for a specified number of MW of External Installed Capacity in one of two different ways, either (i) by converting MW of grandfathered deliverability rights over the External Interface with Quebec (via Chateauguay), or (ii) by having its specified MW of External Installed Capacity evaluated in a Class Year Deliverability Study, both as described herein.

25.7.11.1.4.1 One-Time Conversion of Grandfathered Rights. An entity can request to convert a specified number of MW pursuant to the conversion process established in Section 5.12.2.3 of the Services Tariff.

25.7.11.1.4.2 Class Year Deliverability Study. An entity may seek to obtain External CRIS Rights for its External Installed Capacity by requesting that its External Installed Capacity be evaluated for deliverability in the Open Class Year. To make such a request an entity must provide to the NYISO a completed External CRIS Rights Request stating whether it is making a Contract Commitment or Non-Contract Commitment, the number of MW of External Installed Capacity to be evaluated, and the specific External Interface(s). The first Class Year Deliverability Study to evaluate requests for External CRIS Rights will be that for Class Year 2010. After the NYISO receives a completed External CRIS Rights Request, an entity making a Contract Commitment or Non-Contract Commitment that satisfies the requirements of Section 25.7.11.1 of this Attachment S will be eligible to proceed, as follows:

25.7.11.1.4.2.1 The entity is made a Class Year Project when the NYISO receives the entity's executed Class Year Interconnection Facilities Study Agreement for External Installed Capacity and all required data and the full deposit.

25.7.11.1.4.2.2 The entity's MW of External Installed Capacity covered by its bilateral contract(s) or, in the case of a Non-Contract Commitment the number of MW committed by the entity, are evaluated for deliverability within the Rest of State Capacity Region. The entity's External Installed Capacity is not subject to the NYISO Minimum Interconnection Standard. The NYISO will determine whether the requests for External CRIS Rights within a given Class Year exceed the import limit, established pursuant to ISO procedures, for the applicable External Interface that is in effect on the Class Year Start Date when combined, to the extent not already reflected in the import limit, with the following: (1) awarded External CRIS Rights at the same External Interface, (2) Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual at the same External Interface, and (3) the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT (applies to the PJM interface only) ("Combined Total MW"). In addition to the other requirements stated herein, External CRIS Rights will only be awarded to the extent that the Combined Total MW does not exceed the import limit, as described above.

25.7.11.1.4.2.3 The Class Year Deliverability Study report will include an SDU Project Cost Allocation and a Deliverable MW number for the entity's External Installed Capacity.

25.7.11.1.4.2.4 The entity will have the same decision alternatives as other Class Year Projects participating in the Deliverability Study only. That is, the entity may either (a) accept its SDU Project Cost Allocation, (b) decline its SDU Project Cost Allocation and accept its Deliverability MW figure, or (c) decline both its SDU Project Cost Allocation and its Deliverable MW. If the entity does decline both its SDU Project Cost Allocation and its Deliverable MW, the entity's External Installed Capacity will be removed from the Class Year Deliverability Study. Once removed from the then current Class Year Deliverability Study, the entity can request for its External Installed Capacity to be evaluated again for deliverability in a subsequent Class Year Deliverability Study that is open at the time of its request.

25.7.11.1.4.2.5 If the entity accepts its SDU Project Cost Allocation, it must fund, or commit to fund the SDU upgrades, like any other Class Year Project.

25.7.11.1.4.2.6 If the entity accepts its SDU Project Cost Allocation and funds or commits to fund the SDU upgrades as required by Attachment S, the entity must also execute and fulfill agreement(s) with the NYISO and the Connecting Transmission Owner and any Affected Transmission Owner to cover the engineering, procurement and construction of the SDUs.

25.7.11.1.4.2.7 By the end of the Initial Decisional Period (*i.e.*, 30 days from Operating Committee approval of the Class Year Deliverability Study), an entity making a Contract Commitment and accepting either its SDU Project Cost Allocation or Deliverable MW quantity, must provide specific contract and resource information to the NYISO. Unless entities are supplying External Installed Capacity as Control Area System Resources, requests for External Installed Capacity shall be resource-specific. Entities are permitted to substitute resources located in the same External Control Area. Such substitutions shall be subject to review and approval by NYISO consistent with ISO Procedures and deadlines specified therein.

25.7.11.1.4.2.8 If the entity satisfies the requirements described in this Section 25.7.11.1.4, the entity will obtain External CRIS Rights for the number of MW determined to be deliverable, made deliverable through an SDU (with an accepted SDU Project Cost Allocation), or deemed deliverable through a commitment to pay for an SDU.

25.7.12 Cost Allocation for Highway System Deliverability Upgrades

25.7.12.1 If the portion of the Highway System Deliverability Upgrades (measured in MW) required to make one or more CRIS projects in a Class Year deliverable is ninety percent (90%) or more of the total size (measured in MW) of the System Deliverability Upgrades, each Developer(s) of a Class Year CRIS Project(s) will be responsible for its pro rata Class Year share of one hundred percent (100%) of the cost of the System Deliverability Upgrades.

25.7.12.2 If the portion of the System Deliverability Upgrades required to make one or more CRIS projects in a Class Year deliverable is less than 90% of the total size (measured in MW) of the Highway System Deliverability Upgrade, the Developer(s) will be required to pay or commit to pay for a percentage share of the total cost of the Highway System Deliverability Upgrades equal to the estimated percentage megawatt usage by the Class Year CRIS Project of the total megawatts provided by the System Deliverability Upgrades. Other generators or merchant transmission projects in the current Class Year Deliverability Study may share in the cost of these System Deliverability Upgrades, on the same basis. Projects in the current Class Year Deliverability Study will not be allocated all of the cost of these System Deliverability Upgrades. The rest of the cost of these System Deliverability Upgrades will be allocated to Load Serving Entities and subsequent Developers, as described in this Section 25.7.12. The Developer may either (1) make a cash payment of its proportionate share of the upgrade, which will be held by the Connecting Transmission Owner and Affected Transmission Owner(s) in interest-bearing account(s); or (2) post Security (as defined in this Attachment S) meeting the commercially reasonable requirements of the

Connecting Transmission Owner and Affected Transmission Owner(s) for the Developer's proportionate share of the cost of the upgrade. The amount(s) of cash or Security that a Developer must provide to its Connecting Transmission Owner and any Affected Transmission Owners will be included in the Class Year Deliverability Study report. If the Developer chooses to provide Security, its allocated cost will be increased by an annual construction-focused inflation index. The Developer will update its Security on an annual basis to reflect this increase. Except for this adjustment for inflation, the cost allocated to the Developers will not be increased if the estimated cost of the Highway System Deliverability Upgrade increases. However, the costs allocated to subsequent Developers will be based on a current cost estimate of the Highway System Deliverability Upgrade project.

25.7.12.3 The generator or merchant transmission facility will be considered deliverable, and eligible to become a qualified Installed Capacity Supplier or to receive Unforced Capacity Deliverability Rights, when it is in service, provided it has paid its share of the total cost of System Deliverability Upgrades necessary to support the requested CRIS level, or made a satisfactory commitment to do so. Highway System Deliverability Upgrades--where the System Deliverability Upgrades are below the 90% threshold discussed in Section 25.7.12.2 above--will be constructed and funded either (i) according to Sections 25.7.12.3.1 and 25.7.12.3.2 below, or (ii) according to Section 25.7.12.3.3 below.

25.7.12.3.1 When a threshold of 60% of the most current cost estimate of the System Deliverability Upgrade has been paid or posted as Security by Developers, the

Highway System Deliverability Upgrade will be built by the Transmission Owner that owns the facility to be upgraded. If the facility to be constructed will be entirely new, construction should be completed by the Transmission Owner that owns or controls the necessary site or right of way. If no Transmission Owner(s) has such control, construction should be completed by the Transmission Owner in whose Transmission District the facility would be constructed. If the upgrade crosses multiple Transmission Districts, each Transmission Owner will be responsible for the portion of the upgrade in its Transmission District; and

25.7.12.3.2 The actual cost of the Highway System Deliverability Upgrade project above that paid for by Developers will be funded by Load Serving Entities, using the rate mechanism contained in Schedule 12 of the NYISO OATT. Load Serving Entity funding responsibility for the Highway System Deliverability Upgrade will be allocated among Load Serving Entities based on their proportionate share of the ICAP requirement in the statewide capacity market, adjusted to subtract their locational capacity requirements. Provided, however, Load Serving Entities will not be responsible for actual costs in excess of their share of the final Class Year estimated cost of the Highway System Deliverability Upgrade if the excess results from causes, as described in Section 25.8.6.4 of this Attachment S, within the control of a Transmission Owner(s) responsible for constructing the Highway System Deliverability Upgrade; or

25.7.12.3.3 If the NYISO Comprehensive System Planning Process ("CSPP") triggers a Reliability Need, selects a transmission upgrade under the Public Policy Transmission Planning Process or results in a transmission project being approved under the Congestion Assessment and Resource Integration Study ("CARIS") (collectively "CSPP transmission upgrade") and the CSPP transmission upgrade requires construction of a transmission facility that provides the same or greater transfer limit capability as the Highway facility identified as a Highway System Deliverability Upgrade to be constructed earlier than would be the case pursuant to Section 25.7.12.3.1, the CSPP transmission upgrade will be constructed as determined in the CSPP. Funds collected from Developers (pursuant to Section 25.7.12.2, above) will be used to cover a portion of the regulated solution costs to the extent that the funds collected from Developers were collected for System Deliverability Upgrades that are actually constructed by the regulated solution. To the extent this is true, these funds originally collected (or posted as Security) for System Deliverability Upgrades will be used as an offset to the total CSPP transmission upgrade cost, with the remainder of the upgrade cost to be allocated per the requirements of the CSPP, as set forth in Sections 31.4.1, 31.4.2 and 31.4.4 of Attachment Y to the NYISO OATT.

To the extent funds collected from Developers for System Deliverability Upgrades are insufficient to cover the entire cost of the CSPP transmission upgrades, the Developers' contribution to the System Deliverability Upgrades allocated to the CSPP transmission upgrades will not exceed the Developers' respective Project Cost Allocations for the System Deliverability Upgrade. To the extent funds collected from Developers for System Deliverability Upgrades exceed the cost of the CSPP transmission upgrades, the funds collected for the System Deliverability Upgrades will be allocated to the CSPP transmission upgrade *pro rata* with the Developers' contribution to the System Deliverability Upgrades, and excess funds or Security for System Deliverability Upgrades above the cost of the CSPP transmission upgrade will be returned to the Developers.

25.7.12.4 If a Developer has accepted its Project Cost Allocation, before construction of an identified System Deliverability Upgrade for a Highway is commenced, if a Developer elects to be retested for deliverability it may request to be placed in the then Open Class Year. The Developer's cost responsibility for System Deliverability Upgrades shall not increase as a result of such retesting. It may decrease or be eliminated. If the Developer's facility is found to be deliverable without the System Deliverability Upgrades previously identified, the Developer's Security posting will be terminated, or the Developer's cash payment will be returned with the interest earned.

25.7.12.5 When the Highway System Deliverability Upgrades are placed in to Commercial Operation and any resulting Incremental TCCs related to the Highway System Deliverability Upgrade become effective in accordance with Section 19.2.4 of Attachment M of the ISO OATT, a Developer electing to receive its proportionate share of such Incremental TCCs, as further described in Section 25.7.2.2 of this Attachment S, will receive its proportionate share of such Incremental TCCs.

25.7.12.5.1 Load Serving Entities required by this Section 25.7.12 to fund a portion of the costs of a Highway System Deliverability Upgrade will receive the corresponding financial value of any Incremental TCCs related to the System Deliverability Upgrade held by the Transmission Owner(s) responsible for constructing the Highway System Deliverability Upgrade, as further described in Section 25.7.2.2 of this Attachment S. The corresponding financial value of any such Incremental TCCs will be accounted for in determining the applicable Highway Facilities Charge in accordance with Schedule 12 of the ISO OATT. The eligibility of the Load Serving Entities to the financial value of any Incremental TCCs related to the System Deliverability Upgrade held by the Transmission Owner(s) responsible for constructing the Highway System Deliverability Upgrade shall commence as of the date such Incremental TCCs become effective in accordance with Section 19.2.4 of Attachment M of the OATT and continue until the earlier of: (i) the expiration of any such Incremental TCCs; or (ii) the termination of the obligation of the Load Serving Entities to fund a portion of the costs of the Highway System Deliverability Upgrade.

25.7.12.6 As new generators and merchant transmission facilities come on line and use the Headroom on System Deliverability Upgrades created by a prior Highway System Deliverability Upgrade, the Developers of those new facilities will reimburse the prior Developers or will compensate the Load Serving Entities who funded the System Deliverability Upgrades for use of the Headroom created by the prior Developers and Load Saving Entities in accordance with Sections 25.8.7 and 25.8.8 of these rules.

25.7.12.6.1 In accordance with Section 25.7.2.2 of this Attachment S, as subsequent Developers make Headroom payments to prior Developers and if a subsequent Developer elects to receive its proportionate share of any Incremental TCCs related to the Highway System Deliverability Upgrade, such Incremental TCCs will be transferred to the subsequent Developers; provided, however, that Incremental TCCs that were previously deemed reserved and are transferred to a subsequent Developer will become effective on the first day of the Capability Period that commences following the next Centralized TCC Auction conducted after the subsequent Developer makes the necessary Headroom payment and elects to receive its proportionate share of Incremental TCCs.

25.7.12.6.2 In accordance with Section 25.7.2.2 of this Attachment S, as subsequent Developers compensate Load Serving Entities for use of their Headroom by providing any such Headroom payments to the Transmission Owner(s) responsible for constructing a Highway System Deliverability Upgrade and if a subsequent Developer elects to receive its proportionate share of any Incremental TCCs related to the Highway System Deliverability Upgrade, such Incremental TCCs will be transferred to the subsequent Developer.

25.7.12.7 The Transmission Owner responsible for constructing a System Deliverability Upgrade or a Developer contributing toward the cost of a System Deliverability Upgrade can elect to construct upgrades that are larger and/or more expensive than the System Deliverability Upgrades identified to support the requested level of CRIS for the Class Year CRIS Project in the Class Year Deliverability Study, provided that those upgrades are reasonably related to the Class Year Project. The party electing to construct the larger upgrade will pay for the incremental cost of the upgrade; *i.e.*, the difference in cost between the cost of the System Deliverability Upgrades as determined by these rules, and the cost of the larger and/or more expensive upgrade.

25.8 Project Cost Allocation Decisions

25.8.1 Project Cost Allocation Figures

Starting with the Class Year subsequent to Class Year 2012, each Developer in the Open Class Year whose project is not yet In-Service will specify an Interconnection Service evaluation election and provide an updated In-Service Date and Commercial Operation Date (subject to the limitations set forth in Sections 30.3.3.1 and 30.4.4.5 of Attachment X) when it executes a Class Year Interconnection Facilities Study Agreement. If the Class Year Project is covered by a new Interconnection Request, the Developer will either elect to be evaluated for ERIS alone, or elect to be evaluated for both ERIS and for some MW level of CRIS, not to exceed the nameplate capacity of its facility; provided however, if the Class Year Project is a BTM:NG Resource, it can elect to be evaluated for ERIS alone, or both ERIS and some MW level of CRIS, not to exceed its Net ICAP. If the Class Year Project is existing and/or already interconnected taking ERIS, the Class Year Project will be evaluated for a MW level of CRIS specified by the Developer, not to exceed the nameplate capacity of its facility, or for a BTM:NG Resource, not to exceed the Net ICAP.

Based on these Interconnection Service evaluation elections, on the Annual Transmission Reliability Assessment update of Interconnection System Reliability Impact Study results, and on the results of the Class Year Deliverability Study, NYISO staff shall, in accordance with these rules, provide the Developer of each interconnection project included in the then current Class Year with a dollar figure for its share of the cost of the System Upgrade Facilities required for reliable interconnection of the project to the New York State Transmission System ("SUF Project Cost Allocation"). The NYISO shall also provide each Class Year Developer requesting CRIS with (i) a dollar figure for its share of the cost of the System Deliverability Upgrades required for the megawatt level of CRIS requested for the Class Year Project ("SDU Project Cost Allocation"), and (ii) the number of megawatts of Installed Capacity, if any, that are deliverable from the Class Year Project with no new System Deliverability Upgrades ("Deliverable MW"). The NYISO shall also provide a dollar figure for the total cost of the System Upgrade Facilities and System Deliverability Upgrades required for interconnection of the Class Year Project, as well as a description of the required System Upgrade Facilities and System Deliverability Upgrades, their expected in-service date, and a plan for their installation that is sufficient to verify these dollar figures. The NYISO shall also provide a dollar figure for the total cost of all System Upgrade Facilities required by projects in the Class Year and a dollar figure for the total cost of the System Deliverability Upgrades necessary to support the level of CRIS requested by each Class Year Developer. Each Class Year Developer will be given the Project Cost Allocation(s) and, Deliverable MW, if any associated with its Interconnection Service evaluation election, as soon as practicable prior to the submittal of the Annual Transmission Reliability Assessment and Class Year Deliverability Study to the Operating Committee.

25.8.2 Decision Periods for Class Years X-2 and Class Years Not Bifurcated Pursuant to Section 25.5.10

Within 30 calendar days following the later of (1) approval of the final Annual Transmission Reliability Assessment and Class Year Deliverability Study by the Operating Committee; or (2) the end of the Preliminary SDU Decision Period set forth in Section 25.5.10.2, if applicable, (such 30 calendar day period to be referred to as the "Initial Decision Period"), or within 7 calendar days following the NYISO's issuance of a revised Annual Transmission Reliability Assessment, Class Year Deliverability Study and accompanying Revised Project Cost Allocation and revised Deliverable MW report, as defined in and pursuant to Section 25.8.3 (a "Subsequent Decision Period"), if applicable, each Developer shall provide notice to the NYISO, in writing and via electronic mail, stating whether it shall accept (an "Acceptance Notice") or not accept (a "Non-Acceptance Notice") the Project Cost Allocation(s) and Deliverable MW, if any, reported to it by the NYISO. Failure to notify the NYISO by the prescribed deadline as to whether a Developer accepts or rejects its Project Cost Allocation and Deliverable MW, if any, will be deemed a Non-Acceptance Notice. Each Developer may respond with either an Acceptance Notice or a Non-Acceptance Notice to each Project Cost Allocation and Deliverable MW reported to it by the NYISO. Starting with Class Year 2012, an Acceptance Notice for projects not yet In-Service must also include a confirmed In-Service Date and Commercial Operation Date, subject to the limitations set forth in Section 30.4.4.5 of Attachment X. A Developer in its first Class Year Interconnection Facilities Study and requesting to be evaluated for CRIS may accept both its SDU Project Cost Allocation and its SUF Project Cost Allocation. Alternatively, that Developer may provide a Non-Acceptance Notice for its SDU Project Cost Allocation and at the same time accept, or not accept its Deliverable MW. Or, as another alternative, that same Developer may elect to interconnect taking ERIS by providing an Acceptance Notice only for its SUF Project Cost Allocation. Starting with Class Year 2012, a Developer that accepts an SUF and/or SDU Project Cost Allocation will not be provided with the option to accept a Revised Project Cost Allocation following a Subsequent Decision Period unless the Revised Project Cost Allocation provides for (1) an increase in the SUF or the SDU Project Cost Allocation; or (2) a decrease in the Class Year Project's Deliverable MW.

As soon as practicable following receipt of either an Acceptance Notice or Non-Acceptance Notice from each Class Year Developer, but not later than two (2) business days following receipt, the NYISO shall report to all Class Year Developers, in writing and via electronic mail, all of the acceptance Notices and Non-Acceptance Notices that were received from all of the Developers in the then-current Class Year. Starting with Class Year 2012, consistent with Section 30.4.4.5 of Attachment X, for any project that fails to provide a confirmed In-Service Date and Commercial Operation Date in its Acceptance Notice or that provides a proposed In-Service Date or Commercial Operation Date with its Acceptance Notice that is beyond the time period permissible by Section 30.4.4.5 of Attachment X, the NYISO's Interconnection queue will reflect the latest possible permissible date, even if that requires the NYISO to reject and modify the proposed In-Service Date or Commercial Operation Date provided in the Class Project's Acceptance Notice. Subsequent modifications to a project's In-Service Date or Commercial Operation Date are governed by Section 30.4.4.5.2 of Attachment X.

25.8.2.1 If, following the Initial Decision Period or any Subsequent Decision Period, each and every Developer that remains eligible at that time provides Acceptance Notice(s), each Developer must signify its willingness to pay the Connecting Transmission Owner and Affected Transmission Owner(s) for its share of the required System Upgrade Facilities and System Deliverability Upgrades by (i) satisfying Headroom payment/security posting obligations, if any, as specified in Section 25.8.7.6 and (ii) paying cash or posting Security (as hereinafter defined) in accordance with these rules, for the full amount of its respective Project Cost Allocation within 5 business days after the end of the Initial Decision Period or Subsequent Decision Period, as applicable. "Security" means a bond, irrevocable letter of credit, parent company guarantee or other form of security from an entity with an investment grade rating, executed for the benefit of the Connecting Transmission Owner and Affected Transmission

Owner(s), meeting the requirements of these cost allocation rules, and meeting the respective commercially reasonable requirements of the Connecting Transmission Owner and Affected Transmission Owner(s). Security shall be posted to cover the period ending on the date on which full payment is made to the Connecting Transmission Owner for the System Upgrade Facilities, and the date(s) on which full payment is made to the Connecting Transmission Owner or Affected Transmission Owner(s) for the System Deliverability Upgrades; provided, however, that Security may be posted with a term as short as one year, so long as such Security is replaced no later than 15 business days before its stated expiration. In the event Security is not replaced as required in the preceding sentence, the Connecting Transmission Owner, or an Affected Transmission Owner in the case of Security for System Deliverability Upgrades, shall be entitled to draw upon the Security and convert it to cash, which cash shall be held by the Connecting Transmission Owner or Affected Transmission Owner for the account of the Developer. The round in which no remaining eligible Developers issue a Non-Acceptance Notice or commits a Security Posting Default shall be the final round for that Class Year (the "Final Decision Round").

25.8.2.2 At the end of the Initial Decision Period or any Subsequent Decision Period, if one or more of the Developers in the Class Year provides Non-Acceptance Notice (such event a "Non-Acceptance Event"), then every Developer in the Class Year shall be relieved of its obligation to pay cash or post Security in connection with that version of its Project Cost Allocation for both System Upgrade Facilities and System Deliverability Upgrades. In addition, following the Initial Decision Period or any Subsequent Decision Period, if all Developers in the Class Year provide Acceptance Notice under the Class Year Deliverability Study, the ATRA or both, but one or more of the Developers fails to pay cash or post the Security required hereunder (such event a "Security Posting Default"), then the beneficiaries of the payments and Security posted by the Developers that did pay or post Security (*e.g.*, the Connecting Transmission Owners and Affected Transmission Owners) shall surrender the cash and posted Security to the respective Developers immediately. The Connecting Transmission Owners or Affected Transmission Owner(s) shall not make any draws or encumbrances on any cash or posted Security unless and until cash has been paid and Security has been posted by all Developers that issued Acceptance Notices in the Final Decision Round.

25.8.2.3 Following the Initial Decision Period, or any Subsequent Decision Period, if a Non-Acceptance Event or a Security Posting Default shall have occurred with respect to the ATRA, the Developer that provided the Non-Acceptance Notice or committed the Security Posting Default with respect to its SUF Project Cost Allocation will be removed by the NYISO from the then current Class Year Interconnection Facilities Study. If a Developer provides an Acceptance Notice and posts the required Security for ifs SUF Project Cost Allocation, or has done so in a prior Class Year, but provides a Non-Acceptance Notice with respect to its SDU Project Cost Allocation, it may issue an Acceptance Notice for its Deliverable MW and interconnect taking CRIS at that level. If the Developer either (i) provides a Non-Acceptance Notice with respect to both its SDU Project

Cost Allocation and its Deliverable MW, or (ii) commits a Security Posting Default with respect to its SDU Project Cost Allocation, then that Developer shall be removed from the Class Year Deliverability Study, but it may continue to participate in the ATRA and interconnect taking ERIS if it provides an Acceptance Notice and posts the required Security for its SUF Project Cost Allocation. The Developer electing to interconnect taking ERIS may later request, any number of times, to be placed in the then Open Class Year and be evaluated for CRIS. The Developer will not be re-evaluated for ERIS. Once evaluated for CRIS in the later Class Year, the Developer may elect to accept either its SDU Project Cost Allocation or its Deliverable MW, or the Developer may provide a Non-Acceptance Notice for both its SDU Project Cost Allocation and its Deliverable MW and continue its interconnection taking ERIS. If the Developer does provide a Non-Acceptance Notice for both its SDU Project Cost Allocation and Deliverable MW and continues taking ERIS, the Developer may later request to be placed in the then Open Class Year and be evaluated again for CRIS. If, however, a Developer provides a Non-Acceptance Notice or commits a Security Posting Default for its SUF Project Cost Allocation, that Class Year Project shall be removed from both the ATRA and, if applicable, the Class Year Deliverability Study, and that Developer's Interconnection Request will be processed further in accordance with Section 25.6.2.3 above.

25.8.2.4 Whenever projects are removed from an Annual Transmission Reliability Assessment and/or Class Year Deliverability Study, NYISO staff will notify the

Developers of the remaining Class Year Projects still included in the Annual Transmission Reliability Assessment and/or Class Year Deliverability Study.

25.8.3 Revised Study Results and Project Cost Allocations for Class Years X-2 and Class Years Not Bifurcated Pursuant to Section 25.5.10

Immediately following receipt of Non-Acceptance Notices for any SDU Project Cost Allocations or SUF Project Cost Allocations or Deliverable MW, or upon the occurrence of a Security Posting Default, the NYISO shall update the Class Year Interconnection Facilities Study results for those remaining Class year Projects that continue to be included in the then-current Annual Transmission Reliability Assessment and Class Year Deliverability Study to reflect the impact of Non acceptance Notices and any Security posting Default. The updated Class Year Interconnection Facilities Study shall include updated SUF Project Cost Allocations and updated SDU Project Cost Allocations (each a “Revised Project Cost Allocation”) together with a revised Deliverable MW report. The updated Class Year Interconnection Facilities Study shall be issued as soon as practicable, but in no event later than 14 calendar days following the occurrence of the Non-Acceptance Event or the Security Posting Default that necessitated development of the Revised Project Cost Allocations and revised Deliverable MW report. The NYISO shall also provide the additional dollar figures relating to total cost and Class Year projects, and the related information, described in Section 25.8.1, above. Following the issuance of the revised Annual Transmission Reliability Assessment and Class Year Deliverability Study, and the issuance of Revised Project Cost Allocations and the revised Deliverable MW report, each remaining Developer shall provide notice to the NYISO within 7 calendar days whether it will accept its respective Revised Project Cost Allocation and revised Deliverable MW.

25.8.4 Completion of Decision Process for Class Years X-2 and Class Years Not Bifurcated Pursuant to Section 25.5.10

The process set forth in Sections 25.8.2 through 25.8.3 shall be repeated until either (a) none of the remaining eligible Developers in the Class Year provides a Non-Acceptance Notice or commits a Security Posting Default, or (b) all Developers have dropped out of the Class Year.

25.8.5 Forfeiture of Security

With the exception of the requirement that cash and Security shall be surrendered back to the issuing Developer in connection with another Developer's Security Posting Default, once a Developer has accepted the Project Cost Allocation(s) or Revised Project Cost Allocation(s) appropriate for its Interconnection Service election, as the case may be, and paid cash and posted Security or posted Security for that amount, such cash payment and Security shall be irrevocable and shall be subject to forfeiture as provided herein in the event that the Developer that paid cash and posted Security or posted the Security subsequently terminates or abandons development of its project. Any cash and Security previously posted on a terminated interconnection project will be subject to forfeiture to the extent necessary to defray the cost of the System Upgrade Facilities and System Deliverability Upgrades required for the projects still included in the Annual Transmission Reliability Assessment and Class Year Deliverability Study, but only as described below. Security for System Upgrade Facilities constructed by the Developer (i.e., for which the Developer elects the option to build), shall be reduced after discrete portions of the System Upgrade Facilities have been completed, such reductions to be based on cost estimates from the Class Year Interconnection Facilities Study, subject to review by the Connecting Transmission Owner or Affected Transmission Owner with which Security is posted, and subject to transfer of ownership to the Connecting Transmission Owner or Affected Transmission Owner, as applicable of all subject property, free and clear of any liens, as well as transfer of title and any transferable equipment warranties reasonably acceptable to the Connecting Transmission Owner or Affected Transmission Owner with which Security is posted. For System Upgrade Facilities constructed by the Connecting Transmission Owner or Affected Transmission Owner, Security shall be reduced after discrete portions of the System Upgrade Facilities have been completed by the Transmission Owner and paid for by the Developer, on a dollar-for-dollar basis for payments made to the Connecting Transmission Owner or Affected Transmission Owner pursuant to an E&P Agreement or Interconnection Agreement, subject to the Connecting Transmission Owner's or Affected Transmission Owner's review and approval.

25.8.6 Developer's Future Cost Responsibility

Once a Developer has accepted a Project Cost Allocation or Revised Project Cost Allocation, as the case may be, in the Final Decision Round and paid cash and posted Security or posted Security for that amount, then the accepted figure caps the Developer's maximum potential responsibility for the cost of System Upgrade Facilities and System Deliverability Upgrades required for its project, except as discussed below.

25.8.6.1 If the portion of the Highway System Deliverability Upgrades required to make the Developer's generator or merchant transmission facility deliverable is less than 90% of the total size of the Highway System Deliverability Upgrade identified for the Developer's project, and the Developer elects to commit to pay for its proportionate share of the Highway System Deliverability Upgrade by posting Security instead of paying cash, then the Developer's allocated cost of the Highway System Deliverability Upgrade will be increased during the period of construction deferral by application of a construction inflation adjustment, as discussed in Section 25.7.12.2 of these rules. When deferred construction of the

Highway System Deliverability Upgrade commences, the Developer will be responsible for actual costs in excess of the secured amount only when the excess results from changes to the operating characteristics of the Developer's project. If the portion of the System Deliverability Upgrades for a Highway System Deliverability Upgrade required to make one or more generators or merchant transmission facilities in a Class Year deliverable is ninety percent (90%) or more of the total size (measured in MW) of the System Deliverability Upgrades, construction is not deferred, and those Developers will be responsible for actual costs in excess of the secured amount in accordance with the rules in Sections 25.8.6.2-25.8.6.4 of this Attachment S.

25.8.6.2 If the actual cost of the Developer's share of required System Upgrade Facilities or System Deliverability Upgrades is less than the agreed-to and secured amount, the Developer is responsible only for the actual cost figure.

25.8.6.3 If the actual cost of the Developer's share of required System Upgrade Facilities or System Deliverability Upgrades would be greater than the agreed-to and secured amount because other projects have been expanded, accelerated, otherwise modified or terminated, then the Developer is responsible only for the agreed-to and secured amount for its project. The additional cost is covered by the Developers of the modified projects, in accordance with these cost allocation rules, or by the drawing on the cash that has been paid and the Security that has been posted for terminated projects, depending on the factors that caused the additional cost. Forfeitable cash and Security will be drawn on only as needed for this purpose, and only to the extent that the terminated project associated with that Security has caused additional cost.

25.8.6.4 If the actual cost of the Developer's share of required System Upgrade Facilities or System Deliverability Upgrades is greater than the agreed-to and secured amount because of circumstances that are not within the control of the Connecting Transmission Owner or Affected Transmission Owner(s) (such as, for example: (i) changes to the design or operating characteristics of the Class Year Project that impact the scope or cost of related System Upgrade Facilities or System Deliverability Upgrades; (ii) any costs that were not within the scope of the Class Year Interconnection Facilities Study that subsequently become known as part of the final construction design, including costs related to detailed design studies such as electro-magnetic transient analyses and subsynchronous resonance analyses; or (iii) cost escalation of materials or labor, or changes in the commercial availability of physical components required for construction), the cost cap shall be adjusted by any such amount and the Developer or the Load Serving Entity will pay the additional costs to the Connecting Transmission Owner or Affected Transmission Owner(s) as such costs are incurred by each of them. However, to the extent that some or all of the excess cost is due to factors within the control of the Connecting Transmission Owner or the Affected Transmission Owner(s) (such as, for example, additional construction man-hours due to Connecting Transmission Owner or the Affected Transmission Owner(s) management, or correcting equipment scope deficiencies due to Connecting Transmission Owner or the Affected Transmission Owner(s) oversights), then that portion of the excess cost will be borne by the Connecting Transmission Owner or the Affected Transmission Owner(s). Disputes between the Developer and the Connecting Transmission Owner concerning costs in excess of the agreed-to and secured amount will be resolved by the parties in accordance with the terms and conditions of their interconnection agreement. Disputes between the Developer and an Affected Transmission Owner will be resolved in accordance with Section 30.13.5 of the LFIP, or Section 32.4.2 of Attachment Z, as applicable.

25.8.7 Headroom Accounting

If, pursuant to these rules, a Developer, Connecting Transmission Owner, Affected Transmission Owner or Load Serving Entity (each an "Entity") pays for any System Upgrade Facilities or System Deliverability Upgrades, or for any Attachment Facilities or Distribution Upgrades that are later determined to be System Upgrade Facilities or System Deliverability Upgrades, that create "Headroom", and pays for the Headroom that is created, then that Entity will be paid the depreciated cost of that Headroom by the Developer of any subsequent project that interconnects and uses the Headroom within the applicable period of time following the creation of the Headroom, as specified in Section 25.8.7.4.3 herein. The NYISO will depreciate Headroom cost in accordance with Section 25.8.7.3 herein.

25.8.7.1 Developers of terminated projects who have paid for Headroom with forfeited cash or Security instruments, as well as Developers of completed projects who have paid for Headroom, will be repaid in accordance with these rules.

25.8.7.2 The Developer of the subsequent project shall pay the prior Entity as soon as the cost responsibilities of the subsequent Developer are determined in accordance with these rules. In the case of Headroom created by Load Serving Entity funding Highway System Deliverability Upgrades pursuant to Schedule 12 of the NYISO OATT, the Developer of the subsequent project shall pay the Connecting Transmission Owner, and any Affected Transmission Owner(s), that are receiving or will receive Load Serving Entity funding for the Highway System Deliverability Upgrades pursuant to Schedule 12 of the NYISO OATT. Upon receipt of the Developer Headroom payment, the Connecting Transmission Owner and any Affected Transmission Owner(s), will make the rate adjustment(s) called for by Section 6.12.4.1.3 of Schedule 12 of the NYISO OATT.

25.8.7.3 The NYISO will determine the depreciated cost of the System Upgrade Facilities and/or System Deliverability Upgrades associated with the Entity - created Headroom using one of the following two methods:

25.8.7.3.1 In all cases except the case of Highway System Deliverability Upgrades funded by Load Serving Entities pursuant to Schedule 12 of the NYISO OATT, the NYISO will use the FERC-approved depreciation schedule applied to comparable facilities by the Connecting Transmission Owner or the applicable Affected Transmission Owner. The NYISO will depreciate the Headroom cost annually, starting with the year when the Headroom account is first established.

25.8.7.3.2 In the case of Highway System Deliverability Upgrades funded by Load Serving Entities pursuant to Schedule 12 of the NYISO OATT, the NYISO will use the FERC-approved depreciation schedule applied to the particular Highway System Deliverability Upgrades by the Connecting Transmission Owner or the applicable Affected Transmission Owner pursuant to Schedule 12 of the NYISO

OATT. The NYISO will depreciate the Headroom cost annually, starting with the year the Highway System Deliverability Upgrade is placed in service. If a Class Year Deliverability Study determines that a Class Year project uses Headroom on such a Highway System Deliverability Upgrade before the Highway System Deliverability Upgrade has been placed in service, the NYISO will calculate the Headroom use payment obligation of the Class Year project using the undepreciated cost of the Headroom.

25.8.7.4 Entity-created Headroom will be measured by the NYISO in accordance with these rules. The use that a subsequent project makes of Entity -created Headroom will also be measured by the NYISO in accordance with these rules.

25.8.7.4.1 In the case of Headroom on System Upgrade Facilities that have an excess functional capacity not readily measured in amperes or other discrete electrical units, the use that each subsequent project makes of the Entity-created Headroom will be measured solely by using the total number of projects in the current and prior Class Years needing or using the System Upgrade Facility.

25.8.7.4.1.1 The use that each project in a subsequent Class Year makes of Headroom on such a System Upgrade Facility will be measured as an amount equal to (1/b), where “b” is the total number of projects in all prior and current Class Years using the System Upgrade Facility.

25.8.7.4.1.2 Each Developer in a subsequent Class Year that uses Headroom on such a System Upgrade Facility will make a Headroom payment to all prior Developers that have previously made payments for that System Upgrade Facility, both the prior Developers that have previously made Headroom payments and the

Developers in the first Class Year that paid for the original installation of the System Upgrade Facility. The amount of the Headroom payment to each prior Developer that each Developer in a subsequent Class Year must make for its use of Headroom on such a System Upgrade Facility will be an amount equal to c/(b)x(d), where "c" is the depreciated cost of the System Upgrade Facility at the time of the subsequent Class Year Interconnection Facilities Study, "b" is the total number of projects in all prior and current Class Years using the System Upgrade Facility, and "d" is the total number of projects in all the prior Class Years that have previously made payments for the System Upgrade Facility, both Headroom payments and payments for original installation.

25.8.7.4.2 In the case of System Upgrade Facilities or System Deliverability Upgrades that have an excess capacity readily measured in amperes or other discrete electrical units, the use the subsequent project makes of the Entity-created Headroom will be measured in terms of the electrical impact of the subsequent project, as that electrical impact is determined by the NYISO in accordance with these rules.

25.8.7.4.3 The NYISO will publish accounts showing the Headroom for each Class Year of Developers and other Entities, and will update those accounts to reflect the impact of subsequent projects. With the exception of Headroom on Highway System Deliverability Upgrades funded by Load Serving Entities pursuant to Schedule 12 of the NYISO OATT, the NYISO will close the Headroom account of an Entity when the electrical values in the account are reduced to zero or when ten years have passed since the establishment of the account, whichever occurs first.

25.8.7.4.3.1 In the case of Headroom on Highway System Deliverability Upgrades funded by Load Serving Entities pursuant to Schedule 12 of the NYISO OATT, the NYISO will close the Headroom account of the Load Serving Entity when the MW value in the account is reduced to zero, or at the end of the useful financial life of the Highway System Deliverability Upgrades, whichever occurs first.

25.8.7.4.4 If a subsequent Developer uses up all the Headroom of an earlier Entity, and also triggers the need for a new System Upgrade Facility or System Deliverability Upgrade, then the subsequent Developer will pay the Connecting Transmission Owner or Affected Transmission Owner for the new System Upgrade Facility or System Deliverability Upgrade, but will not pay the earlier Entity for the Headroom used up or the account extinguished. However, the earlier Entity will get a new Headroom account and a *pro rata* share of the Headroom in the new System Upgrade Facility or System Deliverability Upgrade purchased by the subsequent Developer. The economic value of this *pro rata* share will be equal to the economic value of the earlier Entity's Headroom account that was extinguished by the subsequent Developer.

25.8.7.5 For Class Years 2001 and 2002, the NYISO shall account for Headroom as provided by the Non-Financial Settlement. Developers in Class Year 2002 shall reimburse Class Year 2001 Developers in accordance with the terms of the Non-Financial Settlement.

25.8.7.6 The Developer of the subsequent project shall pay the prior Entity within the five (5) business day period specified in Section 25.8.2.1 of this Attachment S. Headroom obligations related to a System Upgrade Facility that has been fully constructed must be satisfied by cash payment. Starting with Class Year 2012, all remaining Headroom obligations may be satisfied by a form of "Headroom Security" – a bond, irrevocable letter of credit, parent company guarantee or other form of security from an entity with an investment grade rating, executed for the benefit of the prior Entity, meeting the requirements of these cost allocation rules, and meeting the respective commercially reasonable requirements of the prior Entity. Headroom Security shall be posted to cover the period ending on the date on which full payment is made to the prior Entity for the Headroom obligation; provided, however, that Headroom Security may be posted with a term as short as one year, so long as such Headroom Security is replaced no later than fifteen (15) business days before its stated expiration. In the event Headroom Security is not replaced as required in the preceding sentence, the prior Entity shall be entitled to draw upon the Headroom Security and convert it to cash, which cash shall be held by the prior Entity for the account of the Developer.

25.8.8 Headroom Account Adjustments in the ATBA

In addition to the adjustments made by the NYISO in Headroom accounts to reflect the impact of subsequent projects, the NYISO will make other adjustments to Headroom accounts when preparing for each Annual Transmission Baseline Assessment. The NYISO will make these adjustments to reflect the impact of changes in the Existing System Representation modeled for the Annual Transmission Baseline Assessment that result from the installation, expansion or retirement of generation and transmission facilities for load growth and changes in load patterns. Such changes in the Existing System Representation can also result from changes in these rules or the criteria, methods or, software used to apply these rules.

25.8.8.1 No compensation will be paid as a result of these changes to the Existing System Representation. However, the NYISO will adjust the ratios of dollars to electrical values in each Entity's account to maintain the economic value of the Entity's account that existed before the changes were made in the Existing System Representation.

25.8.8.2 The NYISO will make no adjustments to Headroom accounts for the impact of subsequent generic solutions, except in those cases where the generic solution is a Class Year project and the adjustment is made to reflect the impact of the Class Year project.

25.8.9 Rate Base Facilities

With the exception of Developer use of Headroom created by Load Serving Entity funding of Highway System Deliverability Upgrades pursuant to Schedule 12 of the NYISO OATT, Developers are not charged for their use of any rate base facilities, except to the degree applicable as customers taking service in accordance with the rates, if any, that apply to those facilities..

25.9 Going Forward

25.9.1 ERIS Election and future Evaluation for CRIS

Whenever a Developer elects to interconnect taking ERIS only, that Developer may, at any later date, ask the ISO to evaluate the Developer's Large Facility or Small Generating Facility for CRIS by including the Developer's Large Facility or Small Generating Facility in the Open Class Year and the Deliverability Study to be conducted for that Class Year.

25.9.2 No Developer Responsibility for Future Upgrades

Once a Developer has posted Security for its share of the System Upgrade Facilities required for its project, and paid cash or posted Security for its share of the System Deliverability Upgrades required for its project, then, except as provided in Section 25.8.6 of these rules, that Developer has no further responsibility for the cost of additional Attachment Facilities, Distribution Upgrades System Upgrade Facilities and System Deliverability Upgrades that may be required in the future.

25.9.2.1 The Project interconnection agreement executed between a Developer and its Connecting Transmission Owner will reflect the Developer's responsibility for the cost of new Attachment Facilities, Distribution Upgrades and System Upgrade Facilities and System Deliverability Upgrades, as that responsibility has been determined in accordance with these rules.

25.9.2.2 The cost of those additional Attachment Facilities, Distribution Upgrades, System Upgrade Facilities and System Deliverability Upgrades needed for future interconnection projects will be shared between future Developers and Transmission Owners, and allocated among future Developers, in accordance with the rules.

25.9.3 CRIS Rights

25.9.3.1 Retaining CRIS Status

Large Facilities and Small Generating Facilities qualifying for CRIS will retain their CRIS Status at the capacity level found deliverable in the Class Year Deliverability Study or at the final CRIS level determined pursuant Section 25.9.3.3, Section 25.9.3.4.1, or Section 25.9.3.5, as applicable, regardless of subsequent changes to the transmission system or the transfer of facility ownership, provided the facility remains capable of operating at the capacity level studied and is not CRIS-inactive for more than three (3) continuous years. For the purpose of the rules in this Section 25.9.3, and in Sections 25.9.4 and 25.9.5 of Attachment S, a facility becomes CRIS-inactive on the last day of the month during which (i) it ceases to offer capacity into ISO capacity auctions, or (ii) it ceases to be registered as a Capacity Resource for a Load Serving Entity through a bilateral transaction(s) or self-supply arrangement. In the case of a CRIS-inactive facility, the facility's CRIS status at the capacity level eligible for CRIS terminates three years after the facility becomes CRIS-inactive, except as provided in Sections 5.18.2.3.2, 5.18.3.3.2, and 5.18.5 of the Services Tariff, unless the CRIS-inactive facility takes one of the following actions before the end of the three-year period: (1) returns to service and participation in ISO capacity auctions or bilateral transactions; (2) transfers capacity deliverability rights to another Large Facility or Small Generating Facility at the same or a different electrical location that becomes operational within three years from the deactivation of the original facility.

25.9.3.2 Term of External CRIS Rights

25.9.3.2.1 The initial term of External CRIS Rights, whether based on a Contract or Non-Contract Commitment, will be for an Award Period of no less than five (5) years.

25.9.3.2.2 An entity holding External CRIS Rights may renew those rights for one or more subsequent terms, as described below:

25.9.3.2.2.1 An entity holding External CRIS Rights based on a Contract Commitment may renew its External CRIS Rights, provided that the ISO receives from the entity a request to renew on or before the date specified in Section 25.9.3.2.2.3 indicating that the entity has renewed its bilateral contract to supply External Installed Capacity for an additional term of no less than five (5) years. If the entity does so, then that entity's External CRIS Rights will be renewed for the same additional term, without any further evaluation of the deliverability of the External Installed Capacity covered by the renewed bilateral contract.

25.9.3.2.2.2 An entity holding External CRIS Rights based on a Non-Contract Commitment may renew its External CRIS Rights, provided that the ISO receives from the entity a request to renew on or before the date specified in Section 25.9.3.2.2.3. Any Non-Contract Commitment renewal must be for an additional term of no less than five (5) years. If the entity does so, then that entity's External CRIS Rights will be renewed for the same additional term, without any further evaluation of the deliverability of the External Installed Capacity associated with the Non-Contract Commitment.

25.9.3.2.2.3 Requests for renewal of External CRIS Rights must be received by the ISO on or before a date defined by the earlier of: (i) six months prior to the expiration date of the Contract or Non-Contract Commitment, or (ii) one month prior to the Study Start Date of the ATRA that is prior to the start of the last Summer Capability Period within the current Award Period or renewal of an Award Period.

25.9.3.2.3 External CRIS Rights will terminate at the end of the effective Award Period or renewal of an Award Period if those rights have not been renewed for an additional term, pursuant to the process described above.

25.9.3.3 CRIS for Facilities Pre-Dating Class Year 2007

For Large Facilities and Small Generating Facilities pre-dating Class Year 2007, *i.e.*, facilities interconnected or completely studied for interconnection before the projects in Class Year 2007, the facility shall qualify for CRIS service so long as (i) it is not retired (*e.g.*, identified as retired in a NYISO Load and Capacity Data Report prior to October 5, 2008, (ii) its interconnection agreement is not terminated, and (iii) the facility begins commercial operations within three years of the commercial operation date or comparable commencement date specified in its initial interconnection agreement filing. A generator or merchant transmission facility pre-dating Class Year 2007 without an interconnection agreement on October 5, 2008, or one with an initial interconnection agreement filing that does not specify a commercial operation date or any comparable commencement date, shall qualify for CRIS so long as it is not retired (*e.g.*, identified as retired in a NYISO Load and Capacity Data Report) prior to October 5, 2008 and it begins commercial operations within three years of its in-service date specified in the 2008 NYISO Load and Capacity Data Report. For generators pre-dating Class Year 2007, the CRIS capacity level will be set at the maximum DMNC level achieved during the five most recent

Summer Capability Periods prior to October 5, 2008, even if that DMNC value exceeds nameplate MW.

For a generator pre-dating Class Year 2007 and not having DMNC levels recorded for five Summer Capability Periods prior to October 5, 2008, its CRIS capacity level will be set, and reset if necessary, at the maximum DMNC level achieved during successive Summer Capability Periods until it has DMNC levels recorded for five Summer Capability Periods. Prior to the establishment of the generator's first DMNC value for a Summer Capability Period, the generator's CRIS level will be set at nameplate MW. The CRIS capacity level for intermittent resources pre-dating Class Year 2007 will be set at nameplate MW, and the CRIS capacity level for controllable lines pre-dating Class Year 2007 will be set at the MW of Unforced Capacity Deliverability Rights awarded to them. Existing generators that are eligible for CRIS under this Section 25.9.3.3.3 that wish to obtain CRIS pursuant to this provision must request CRIS within 60 days of May 19, 2016; CRIS cannot be obtained under this Section 25.9.3.3.3 if not requested by such date.

25.9.3.4 CRIS for Facilities Not Subject to ISO Interconnection Procedures

Starting May 19, 2016, all facilities that wish to become eligible to participate as Installed Capacity Suppliers pursuant to the requirements of Section 5.12 of the ISO Services Tariff, must have CRIS, even if the facility is not or was not, when interconnected, subject to the ISO's interconnection procedures set forth in Attachments X or Z to the OATT.

Facilities not subject to the ISO's interconnection procedures set forth in Attachments X and Z to the OATT may obtain CRIS rights by (i) entering a Class Year Deliverability Study and satisfying the NYISO Deliverability Interconnection Standard or (ii) satisfying the requirements set forth in Section 25.9.3.4.1.

25.9.3.4.1 A facility not subject to the ISO's interconnection procedures set forth in Attachments X and Z to the OATT may obtain CRIS without being evaluated in a Class Year Deliverability Study if it meets the following requirements (i) if the facility has not commenced Commercial Operation, it must have completed all required interconnection studies and have an effective interconnection agreement by May 19, 2016, (ii) if the facility has commenced Commercial Operation by May 19, 2016, it must have an effective interconnection agreement and must not have been out-of-service for more than three (3) consecutive years; (iii) it is not or was not, when first interconnected, subject to the ISO's interconnection procedures set forth in Attachments X and Z to the OATT, and (iv) the facility owner must request CRIS within 60 days of May 19, 2016. The CRIS level for a facility that qualifies for CRIS under this Section 25.9.3.4.1 will be set in accordance with Section 25.9.3.4.1.1 and 25.9.3.4.1.2.

25.9.3.4.1.1 BTM:NG Resource

A BTM:NG Resource's initial CRIS level will be set at its Net-ICAP level. The CRIS level will be set, and reset if necessary, at the maximum Net-ICAP level achieved during successive Summer Capability Periods until the facility has Net-ICAP levels recorded for five Summer Capability Periods. The five-year CRIS set and reset period begins with the first Summer Capability Period, following receipt of an initial CRIS value, for which the BTM:NG Resource's Net-ICAP calculation incorporates a demonstrated Average Coincident Host Load. The final CRIS level will be the highest Net-ICAP recorded for the Summer Capability Period during the five-year set and reset period, excluding the initial CRIS level.

The five-year CRIS set and reset period will terminate early, before five Net-ICAP values have been recorded if any of the following conditions occurs: (i) the BTM:NG Resource ceases to qualify as a BTM:NG Resource pursuant to Section 5.12.1 of the Services Tariff; (ii) the BTM:NG Resource elects to participate as another type of Installed Capacity Supplier, other than as a BTM:NG Resource; or (iii) the BTM:NG Resource's Net ICAP is equal to or less than zero for a Capability Period. Upon an early termination of the five-year CRIS set and reset period, the final CRIS value will be determined based on the available data from the CRIS set and reset period up to the point of early termination – *i.e.*, the highest Net-ICAP value recorded during the CRIS set and reset period prior to the point of early termination.

25.9.3.4.1.2. Facilities Other than BTM:NG Resources.

Prior to the establishment of the generator's first DMNC value for a Summer Capability Period, the generator's CRIS level will be set at nameplate MW. The CRIS level will be set, and reset if necessary, at the maximum DMNC level achieved during successive Summer Capability Periods until the facility has DMNC levels recorded for five Summer Capability Periods.

25.9.3.5 CRIS for BTM:NG Resources Evaluated in a Class Year Deliverability Study

If meter data is available for both the Load and the generator, the initial CRIS that can be requested is limited to the demonstrated Net-ICAP. If meter data is not available for either the Load or the generator of the BTM:NG Resource, the initial CRIS that can be requested is limited to the Net-ICAP calculation set forth in Section 5.12.1 of the ISO Services Tariff. The initial CRIS level will set at the CRIS MW level evaluated in the Class Year Deliverability Study and either found to be deliverable or for which the Developer accepted its Project Cost Allocation and posted Security for any required System Deliverability Upgrades.

The CRIS level will be set, and reset if necessary, at the maximum DMNC level achieved during successive Summer Capability Periods, not to exceed the initial CRIS level, until the facility has DMNC levels recorded for five Summer Capability Periods – *i.e.*, the initial CRIS level will act as a cap through the set and reset period and for the final CRIS level. The final CRIS level will be the highest Net-ICAP recorded for the Summer Capability Period during the five-year set and reset period, excluding the initial CRIS level.

The five-year CRIS set and reset period will terminate early, before five Net-ICAP values have been recorded if any of the following conditions occurs: (i) the BTM:NG Resource ceases to qualify as a BTM:NG Resource pursuant to Section 5.12.1 of the Services Tariff; (ii) the BTM:NG Resource elects to participate as another type of Installed Capacity Supplier, other than as a BTM:NG Resource; or (iii) the BTM:NG Resource's Net ICAP is equal to or less than zero for a Capability Period. Upon an early termination of the five-year CRIS set and reset period, the final CRIS value will be determined based on the available data from the CRIS set and reset period up to the point of early termination – *i.e.*, the highest Net ICAP value recorded during the CRIS set and reset period prior to the point of early termination.

25.9.4 Transfer of Deliverability Rights - Same Location

If a facility deactivates an existing unit within the NYCA and commissions a new one at the same electrical location, the CRIS status of the deactivated facility and its deliverable capacity level may be transferred to that same electrical location, provided that the new facility becomes operational within three years from the deactivation of the original facility. The new facility will only acquire the assigned capacity deliverability rights once the new facility becomes operational. Capacity rights will be stated in MW of Installed Capacity. In the case of transfers between the same or different resource types, those MW of Installed Capacity will be adjusted by the derate factor applicable to the existing facility (based on the asset-class derate factors used in the most recent Class Year Deliverability Study) before the transfer and, following the transfer, will be readjusted to MW of Installed Capacity in accordance with the derate factor applicable to the new facility (based on the asset-class derate factors used in the most recent Class Year Deliverability Study).

25.9.5 Transfer of Deliverability Rights - Different Locations

Rights may also be transferred on a bilateral basis between an existing facility within the NYCA and a new facility at a different location within the NYCA to the extent that the new facility is found to be deliverable after the existing facility assumes ERIS status or deactivates. The new facility may contract with an existing facility (with assigned capacity rights) to transfer some or all of the existing facility's assigned capacity rights. The new facility will be allowed to acquire these rights if it meets the deliverability test executed in the following manner:

25.9.5.1 Prior to the Class Year Deliverability Study, the new and existing facilities involved in the transfer transaction must tell the ISO the MW level of capacity rights proposed to be transferred. Capacity rights will be stated in MW of Installed Capacity. In the case of transfers between different resource types, those MW of Installed Capacity will be adjusted by the derate factor applicable to the existing facility before the transfer and, following the transfer, will be readjusted to MW of Installed Capacity in accordance with the derate factor applicable to the new project. All derate factors will be based on the asset-class derate factors in the current Class Year Deliverability Study.

25.9.5.1.1 The ISO will evaluate the deliverability of the Class Year projects together, with no transfers, to determine the extent to which new facilities in the

Class Year that are parties to proposed transactions are deliverable without the proposed transfers.

25.9.5.1.2 The ISO will then reduce the output of all established facilities that are parties to proposed transactions to see if the new facility counterparties benefit, *i.e.*, their undeliverable capacity is made deliverable, from the proposed transfers; provided, however, the established facilities will be reduced only to the extent that their reduction does not adversely impact the deliverability of Class Year projects that are not parties to the proposed transactions.

25.9.5.1.3 If the deliverability test conducted by the ISO shows that the new Class Year projects that are parties to the proposed transactions are fully or partially deliverable with these reductions of the established facility counterparties, then the new projects will be given five business days to notify the ISO as to whether their particular transaction is final or not. If any proposed transactions are not finalized, then Sections 25.9.5.1.1 and 25.9.5.1.2 will be repeated until all proposed transactions have been terminated or finalized.

25.9.5.2 For each finalized transaction, the existing facility that is a party to the transaction will be modeled in Class Year Interconnection Facilities Study at its reduced output level (current level less CRIS finally transferred adjusted by the applicable derate factors). The Deliverability of Class Year Projects not parties to finalized transactions may benefit, but will not be adversely affected, by those transactions.

25.9.5.3 The existing facility will be restricted in future capacity sales up to levels consistent with the CRIS rights that were transferred to the new project counterparty.

25.9.5.4 The new project will only acquire the assigned capacity rights once the new project becomes operational at the levels necessary to utilize those rights.

25.9.6 Transfer of External CRIS Rights

A holder of External CRIS Rights may transfer some or all of the Contract or Non-Contract CRIS MW that it holds to another entity, provided that the following requirements are met:

25.9.6.1 The entity to receive the External CRIS Rights must, prior to the transfer, make either (i) a Contract Commitment of External Installed Capacity satisfying the requirements of Section 25.7.11.1.1 of this Attachment S, or (ii) a Non-Contract Commitment of External Installed Capacity satisfying the requirements of Section 25.7.11.1.2 of this Attachment S; and

25.9.6.2 The External Installed Capacity of the entity to receive the External CRIS Rights must use the same External Interface(s) used by the External Installed Capacity of the entity currently holding the External CRIS Rights; and

25.9.6.3 The transfer must be for the remaining duration of the Award Period or renewal of an Award Period currently effective for the External CRIS Rights to be transferred; and

25.9.6.4 If the holder of External CRIS Rights transfers some, but not all of its CRIS MW, the number of CRIS MW transferred must be such that, following the transfer, both the holder and the entity receiving External CRIS Rights satisfy the applicable requirements of Section 25.7.11.1.1 and 25.7.11.1.2 of this Attachment S; and

25.9.6.5 The transfer must take place on or before the earlier of:

25.9.6.5.1 Six months prior to the expiration date of the Contract or Non-Contract Commitment of the entity currently holding the External CRIS Rights to be transferred; or

25.9.6.5.2 One month prior to the Study Start Date of the ATRA that is prior to the start of the last Summer Capability Period within the current Award Period or renewal of an Award Period.

25.10 Miscellaneous Provisions

25.10.1 Non-financial Settlement of 2004

Notwithstanding any foregoing provisions to the contrary, the following provisions apply to the resumption of the cost allocation process after the approval by FERC of the Non-Financial Settlement.

25.10.1.1 Upon the study start date specified in the Non-Financial Settlement ("Study Start Date"), the ISO shall resume the cost allocation process set forth herein.

25.10.1.2 Except as provided below, the initial cost allocation shall determine the System Upgrade Facilities required for the reliable interconnection of all Developer projects that have met the milestones identified in Section IV.G.6.c.1, above, on or before the Study Start Date. The ISO shall prepare an ATRA with respect to these Developer projects as a single class (the "Catch Up Class Year"). The Catch Up Class Year shall not include (1) Class Year 2001 Developer projects that have accepted their Project Cost Allocation prior to the Study Start Date, or (2) Class Year 2002 Developer Projects that have accepted their Project Cost Allocation pursuant to the terms of the Non-Financial Settlement.

25.10.1.3 The ISO shall use the 2004 Load and Capacity Data Report for the Catch Up Class Year cost allocation studies, unless the Study Start Date is later than January 1, 2005 in which event the ISO shall use the 2005 Load and Capacity Data Report. The Catch Up Class Year cost allocation studies shall identify system needs for the five-year period beginning January 1, 2005. In the event the Study Start Date is later than January 1, 2005 the Catch Up Class Year cost allocation studies shall identify system needs for the five-year period beginning January 1, 2006. The ISO shall present the results of the Catch Up Class Year cost allocation studies to the Operating Committee for approval as provided in Section IV.F.8 of these rules.

25.10.1.4 The ISO shall represent the NYPA Poletti project in the ATBA and ATRA for the Catch Up Class Year as connected to the Astoria West Substation.

25.10.1.5 Once all Developers in the Catch Up Class Year have either (i) accepted their Project Cost Allocation, or (ii) dropped out of the class, the ISO shall resume annual cost allocations with respect to individual Class Years in accordance with the time frames set out in these rules.

25.10.1.6 All Developer projects in the Catch Up Class Year who do not accept their Project Cost Allocation shall be included in the ATRA in the next Class Year cost allocation process.

25.10.1.7 The ISO shall finalize the results of the Class Year 2002 cost allocation (including headroom issues) in accordance with the provisions of the Non-Financial Settlement.

25.10.2 Combined Study of Class Years 2009 and 2010

Notwithstanding any foregoing provisions to the contrary, the following special provisions apply to the Interconnection Facilities Studies for Class Year 2009 and Class Year 2010. These provisions provide that Class Year 2009 and Class Year 2010 will be performed on a combined basis. However, cost allocation for these two Class Years will be calculated separately, as described herein. All provisions of this Attachment S that are not inconsistent with the special provisions of this Section 25.10.2 shall apply as they normally do to projects in Class

Year 2009 and Class Year 2010.

25.10.2.1 A single ATBA under the Minimum Interconnection Standard for the Class Year 2009 and Class Year 2010 will be developed using the 2010 NYISO Load and Capacity Data Report and will be the same ATBA as would otherwise be developed for the 2010 Class Year Interconnection Facilities Study absent the combination of Class Year 2010 with Class Year 2009. This ATBA will be the starting point for a single deliverability baseline used under the Deliverability Interconnection Standard for Class Year 2009 and Class Year 2010. For purposes of this Section 25.10.2, "ATBA-Deliverability" refers to the deliverability baseline developed for Class Year 2009 and Class Year 2010 pursuant to this Section, and "ATRA-Deliverability" refers to the ATBA-Deliverability with the relevant Class Year projects added, as described below.

25.10.2.2 There will be two ATRAs and two ATRAs-Deliverability in the combined Class Year study: an ATRA and ATRA-Deliverability for Class Year 2009, as well as an ATRA and ATRA-Deliverability for Class Year 2010.

25.10.2.2.1 The ATRA and ATRA-Deliverability for Class Year 2009 will be the ATBA and ATBA-Deliverability, respectively, developed pursuant to Section 25.10.2.1 above, plus the projects that qualified for Class Year 2009 on or before March 1, 2009 and entered Class Year 2009.

25.10.2.2.2 The ATRA and ATRA-Deliverability for Class Year 2010 will be the ATRA and ATRA-Deliverability for Class Year 2009, plus the projects that qualified for Class Year 2010 on or before March 1, 2010 and entered Class Year 2010.

25.10.2.3 Cost Allocation for the Two Class Years

25.10.2.3.1 The cost allocation for Class Year 2009 System Upgrade Facilities and System Deliverability Upgrades will be calculated based on the incremental impact of the Class Year 2009 projects (i.e., the 2009 ATRA and ATRA-Deliverability) over the ATBA and ATBA-Deliverability, respectively, developed pursuant to Section 25.10.2.1 above.

25.10.2.3.2 The cost allocation for Class Year 2010 System Upgrade Facilities and System Deliverability Upgrades will be calculated based on the incremental impact of the Class Year 2010 projects (i.e., the 2010 ATRA and ATRA-Deliverability) over the Class Year 2009 ATRA and ATRA-Deliverability, respectively, as described fully below.

25.10.2.3.3 If Class Year 2010 projects use Headroom on System Upgrade Facilities or System Deliverability Upgrades identified for Class Year 2009 projects, the Class Year Interconnection Facilities Study for Class Year 2010 will identify the Headroom use payments that must be made by Class Year 2010 projects to Class Year 2009 projects.

25.10.2.3.4 In the event that a System Upgrade Facility or System Deliverability Upgrade identified for Class Year 2009 is replaced in the Class Year Interconnection Facilities Study for Class Year 2010 by a more capable System Upgrade Facility or System Deliverability Upgrade required for projects in Class Year 2010, the cost allocation for Class Year 2009 will be based on the System Upgrade Facility or System Deliverability Upgrade identified for Class Year 2009, and the cost allocation to Class Year 2010 will be based on the more capable replacement System Upgrade Facility or System Deliverability Upgrade.

25.10.2.4 Operating Committee Approval, Project Cost Allocation Decision Process and Class Year Settlement.

25.10.2.4.1 The initial Project Cost Allocation contained in the ATRA and Class Year Deliverability Study for Class Year 2009 will be based upon all projects in Class Year 2009. The initial Project Cost Allocation contained in the ATRA and Class Year Deliverability Study for Class Year 2010 will be based upon all projects in Class Year 2009 and Class Year 2010, except as described below in Section 25.10.2.4.4.3.

25.10.2.4.2 The ISO will undertake to complete the Class Year Interconnection Facilities Study Report for Class Year 2009 and the Class Year Interconnection Facilities Study Report for Class Year 2010 in parallel so that both study reports are ready to be presented at the same Operating Committee meeting. However, if at any time, the ISO determines that the Class Year Interconnection Facilities Study Report for Class Year 2009 is ready for presentation to the Operating Committee (following applicable working group and subcommittee review), the ISO will present that study report to the Operating Committee regardless of the status of the Class Year Interconnection Facilities Study Report for Class Year 2010. The Operating Committee will separately vote to approve the study report for Class Year 2009 and the study report for Class Year 2010, even if both study reports are presented at the same Operating Committee meeting.

25.10.2.4.3 If the Class Year Interconnection Facilities Study Reports for Class Year 2009 and Class Year 2010 are both approved at the same Operating Committee meeting, the Project Cost Allocation decision process will commence at that time and be conducted in parallel for the projects in both Class Years, as described in Section 25.10.2.4.5 below.

25.10.2.4.4 If the Class Year Interconnection Facilities Study Report for Class Year 2009 is approved at an Operating Committee meeting where either (1) the study report for Class Year 2010 is not presented for approval, or (2) the study report for Class Year 2010 is presented for approval but not approved, the following process will be followed:

25.10.2.4.4.1 The Project Cost Allocation decision process for Class Year 2009 will not commence until the following Operating Committee meeting ("Second Operating Committee Meeting"), held not more than forty-five (45) days after the Operating Committee meeting where the study report for Class Year 2009 was approved.

25.10.2.4.4.2 If the Class Year Interconnection Facilities Study Report for Class Year 2010 is approved at the Second Operating Committee Meeting, the Project Cost Allocation decision process for the projects in both Class Year 2009 and Class Year 2010 will commence at that time and be conducted in parallel for the projects in both Class Years as described in Section 25.10.2.4.5 below.

25.10.2.4.4.3 If the Class Year Interconnection Facilities Study Report for Class Year 2010 is not approved at the Second Operating Committee Meeting, the Project Cost Allocation decision process for the projects in Class Year 2009 will commence immediately upon the Second Operating Committee Meeting and will follow the existing Project Cost Allocation decision process described in Sections 25.8.1-25.8.4 of Attachment S, with initial Acceptance Notices and/or Non-

Acceptance Notices due 30 days after the Second Operating Committee Meeting. When the Project Cost Allocation decision process for the projects in Class Year 2009 is completed, and the Class Year Interconnection Facilities Study Report for Class Year 2010 has been revised to reflect the final settlement of Class Year 2009 and is otherwise complete, the Class Year Interconnection Facilities Study Report for Class Year 2010 will be presented to the Operating Committee meeting for approval. Upon Operating Committee approval of the Class Year Interconnection Facilities Study Report for Class Year 2010, the Project Cost Allocation decision process for the projects in Class Year 2010 will begin.

25.10.2.4.4.4 Only in the event that the Class Year Interconnection Facilities Study Report for Class Year 2010 is not approved at the Second Operating Committee Meeting, as described immediately above in Section 25.10.2.4.4.3, a Developer or Interconnection Customer in Class Year 2009 providing a Non-Acceptance Notice for its System Upgrade Facility Project Cost Allocation may, by the due date for providing such notice, elect to enter Class Year 2010, and its project will be placed in Class Year 2010, provided that (a) the project is otherwise eligible under the Class Year re-entry rules, (b) it submits to the ISO an executed Interconnection Facilities Study Agreement, together with the required deposit and data, within ten (10) days of its receipt of the Interconnection Facilities Study Agreement, and (c) cures any deficiency in its submittal within five (5) Business Days after receiving notice from the ISO about such deficiency. A project in Class Year 2009 committing a Security Posting Default may not enter Class Year 2010. Other than as described in this Section 25.10.2.4.4.4, projects in Class Year

2009 may not enter Class Year 2010.

25.10.2.4.5 If both Class Year Interconnection Facilities Study Reports are approved by the Operating Committee, either at the same meeting or by the Second Operating Committee Meeting, as described above in Sections 25.10.2.4.2-25.10.2.4.4, the Developers and Interconnection Customers in both Class Year 2009 and Class Year 2010 will have thirty (30) days from the date of Operating Committee approval of the Interconnection Facilities Study Report for Class Year 2010 to provide an Acceptance Notice(s) or Non-Acceptance Notice(s) in accordance with Sections 25.8.1-25.8.4 of Attachment S. If any Developer or Interconnection Customer in either Class Year 2009 or Class Year 2010 provides a Non-Acceptance Notice or commits a Security Posting Default, the ISO will prepare a revised Class Year Interconnection Facilities Report by the following process:

25.10.2.4.5.1 If any Developer or Interconnection Customer in Class Year 2009 provides a Non-Acceptance Notice(s) and/or commits a Security Posting Default, the ISO will notify all Developers and Interconnection Customers in both Class Years as required by Section 25.8.2 of Attachment S, and will prepare (1) a revised ATRA and/or Class Year Deliverability Study for Class Year 2009 to reflect impact of the Non-Acceptance Notice(s) and/or Security Posting Default(s) from Class Year 2009 projects, and (2) a revised ATRA and/or Class Year Deliverability Study for Class Year 2010 to reflect the impact of the Non-Acceptance Notice(s) and/or Security Posting Default(s) from Class Year 2009 project and Class Year 2010 projects. The ISO will prepare and publish the required ATRAs and/or Class Year Deliverability Study(ies) for both Class Years within four (4) weeks of its receipt of the last Non-Acceptance Notice or its receipt of notice of the last Security Posting Default, whichever is later.

25.10.2.4.5.2 If any Developer or Interconnection Customer in Class Year 2010 provides a Non-Acceptance Notice(s) and/or commits a Security Posting Default, but no Developer or Interconnection Customer in Class Year 2009 does so, the ISO will notify all Developers and Interconnection Customers in both Class Years as required by Section 25.8.2 of Attachment S, and will prepare and publish a revised ATRA and/or Class Year Deliverability Study for Class Year 2010 within two (2) weeks of its receipt of the last Non-Acceptance Notice or its receipt of notice of the last Security Posting Default, whichever is later. The ISO will not revise the ATRA or the Class Year Deliverability Study for Class Year 2009 as a result of a Non-Acceptance Notice from or a Security Posting Default by a Developer or Interconnection Customer in Class Year 2010.

25.10.2.4.5.3 The process described in the foregoing Sections 25.10.2.4.5.1 and/or 25.10.2.4.5.2 will be repeated until either (1) none of the remaining eligible Class Year Developers or Interconnection Customers provides a Non-Acceptance Notice or commits a Security Posting Default, or (2) all Developers or Interconnection Customers have dropped out of their respective Class Years.

25.10.2.5 Except for projects in Class Year 2009 that elect to enter Class Year 2010 pursuant to the procedures described above in Section 25.10.2.4.4.4, Class Year 2009 and Class Year 2010 will be considered as a single Class Year for purposes of calculating the number of Class Years a project may enter pursuant to Section

25.8.2.3 of Attachment S. A project that was in Class Year 2009 but elects to enter Class Year 2010 under section 25.10.2.4.4.4 that subsequently provides a Non-Acceptance Notice or commits a Security Posting Default related to its System Upgrade Facilities for Class Year 2010 will be deemed to have withdrawn its Interconnection Request in accordance with Section 30.3.6 of the Large Facility Interconnection Procedures in Attachment X of the OATT, or in accordance with Attachment Z of the OATT, as applicable.

25.10.3 ISO Data Requirements

Developers and Transmission Owners shall provide the ISO with all data necessary to make the determinations contemplated by these rules.

25.10.4 Rights Under the Federal Power Act

Nothing in these rules restricts the rights of any person under the OATT, or the right of any person to file a complaint with the Federal Energy Regulatory Commission under the relevant provisions of the Federal Power Act.

25.10.5 Transmission Service Customer Rights

Nothing in these rules precludes any transmission service customer from receiving transmission service charge credits to the extent the customer is entitled to such credits under FERC policy and precedent.

ATTACHMENT S - APPENDIX ONE – Allocation of Overage Cost

An Example of the Allocation of Overage Cost Among Class Year Developers, in Accordance with Section 25.6.2 of Attachment S:

- There are five Developer projects in Class Year 200X.
- The Annual Transmission Reliability Assessment ("ATRA") determines that 10 System Upgrade Facilities ("SUFs") are needed to reliably interconnect the Class Year 200X projects, at a total cost of $30 million.
- The Annual Transmission Baseline Assessment ("ATBA") determines that 7 SUFs would be needed to meet reliability standards without the Class Year 200X projects, at a total cost of $20 million. (Note: The ATBA may have included some generic "projects" identical to or similar to some of the Class Year 200X projects, but not necessarily. Also, some of the SUFs identified by the ATBA may be the same as those identified in the ATRA, but not necessarily.)

(1) The total cost of ATRA SUFs allocated to the Transmission Owners ("TOs") is equal to the total cost of the ATBA SUFs ($20 million).

(2) The total cost of ATRA SUFs allocated to the Developers, the Overage Cost, is the net of the total cost of the ATRA vs. ATBA SUFs ($30 million - $20 million = $10 million).

(3) The ratio of the Overage Cost to the total cost of ATRA SUFs, the Overage Cost Percentage, is used to compute the Developers' cost allocations for each ATRA SUF. In this example, the Overage Cost Percentage, the ratio, = $10 million/$30 million = 1/3 (The Developers pay 1/3 the cost of each ATRA SUF). Assume the cost of one of the ATRA SUFs (SUF#1) is $3 million. The Developers' share of the cost of that SUF = 1/3 x $3 million = $1 million.

(4) The Developers' share of the cost of each ATRA SUF is allocated among all the Developers that have at least a *de minimus* impact causing the need for that SUF. In this example, the ATRA determines that 3 of the 5 Class Year 200X projects

have at least a *de minimus* impact causing the need for SUF#1.

(5) The Developers' cost of an ATRA SUF is allocated to each Developer that has at least a *de minimus* impact in accordance with the Contribution Percentage, or ratio of that Developer's measured impact, its electrical contribution, to the sum of the measured impact of all the Developers that have at least a *de minimus* impact.

In this example, the measured impacts of the three projects are 200, 300, and 500 amps, respectively. Thus the pro rata shares of the projects' cost of SUF#1 are $200K, $300K, and $500K, respectively.

26 Attachment T – Cost Allocation Methodology for Schedule 1 Bid Production Guarantees for Additional Generating Units Committed to Meet Forecast Load

The Day-Ahead commitment of generating units includes sufficient Resources to provide for the safe and reliable operation of the NYS Power System. In cases in which the sum of all Day-Ahead Bilateral Schedules, and all Day-Ahead purchases of energy to serve Load within the NYCA is less than the ISO's Day-Ahead forecast of Load, the ISO may commit Resources in addition to the reserves it normally maintains ("Additional Resources"). Payments for Bid Production Cost guarantees ("BPCG") made to such Additional Resources are to be allocated pursuant to the methodology set forth below and recovered under Rate Schedule 1 of the OATT. Any BPCG payments made to Additional Resources that are not allocated pursuant to this methodology shall be allocated to Transmission Customers according to the provisions of Section 6.1.7.2, of Rate Schedule 1 of the OATT

For purposes of this Attachment T, "Eligible Transmission Customers" are Transmission Customers that are scheduled to sell Energy at a Load bus specified for Virtual Transactions in the Day-Ahead Market and Transmission Customers purchasing Energy to serve load in the real-time market at a Load bus that is not a Load bus specified for Virtual Transactions and not a Proxy Generator Bus. Load Zones and composite Load Zones used in the allocation of Bid Production Cost guarantee payments made to Additional Resources are initially set as: (i) Load Zones A-E, (ii) Load Zones F-I, (iii) Load Zone J, and (iv) Load Zone K and may be adjusted by the ISO to reflect the most frequently constrained transmission interfaces in the NYCA.

BPCG payments made to Additional Resources shall be allocated to each Eligible Transmission Customer as follows:

$$BPCG_c = BPCG_{NYCA} * \sum_{L \in NYCA} \left(K_L^{fe} * K_L^{loc} * K_{c,l}^{customer} \right)$$

Where:

$BPCG_c$	=	Obligation of Transmission Customer "c" for the Bid Production Cost guarantees for Additional Resources for the day.
$BPCG_{NYCA}$	=	Total Bid Production Cost guarantees paid to Additional Resources in the NYCA for the day.
c	=	An Eligible Transmission Customer.
J	=	Index for Load Zones or Composite Load Zones in the set NYCA
D	=	Index for eligible transmission customers in the NYCA
E	=	Set of all eligible transmission customers
L	=	Load Zone or Composite Load Zone
K_L^{fe}	=	A scale factor calculated for each Load Zone or Composite Load Zone that determines the portion of BPCG to Additional Resources that will be allocated through the procedures described in this attachment.
K_L^{loc}	=	A scale factor calculated for each Load Zone or Composite Load Zone "L" that determines the share of BPCG to Additional Resources that shall be allocated to that Load Zone or Composite Load Zone. The scale factor is based on the ratio of Energy purchases in the real-time market by Eligible Transmission Customers in load zone or composite load zone "L" in each hour, summed over the hours of the day in which these purchases are positive, to all Energy purchases in the real-time market by Eligible Transmission Customers in each Load Zone or Composite Load Zone in each hour, summed over the hours of the day in which these purchases in a given Load Zone or Composite Load Zone are positive, and summed over all Load Zones or Composite Load Zones.
$K_{c,L}^{customer}$	=	A scale factor calculated for Eligible Transmission Customer "c" in Load Zone or Composite Load Zone "L" which determines the portion of the BPCG to Additional Resources allocated to that Load Zone or Composite Load Zone that shall be allocated to that Eligible Transmission Customer "c."
RTP_L^{act}	=	Net Energy purchases from the Real-Time market in Load Zone or Composite Load Zone "L" by all Eligible Transmission Customers in each hour, summed over the hours of the day in which these purchases are positive.
$RTP_{c,L}^{act}$	=	Energy purchases from the Real-Time market in Load Zone or Composite Load Zone "L" by an Eligible Transmission Customer "c" in each hour summed over hours of the day in which these purchases are positive.
RTP_L^{fcst}	=	The sum of (1) Day-Ahead sales for each hour of the day in the Day-Ahead market at the Load bus specified for Virtual Transactions in Load Zone or

Composite Load Zone "L" by Eligible Transmission Customers; and (2) the ISO's Day-Ahead forecast Load requirement for Load Zone or Composite Load Zone "L" for that hour of the day less the sum of Energy purchases from the Day-Ahead market at Load buses including Load buses specified for Virtual Transactions but not Proxy Generator Buses and Bilateral Transactions with POWs that are Load Buses other than those specified for Virtual Transactions and other than Proxy Generator Buses for that hour; summed over the hours of the day in which the sum of (1) and (2) is positive.

K_L^{fe} shall be calculated as shown below except that the value one shall be used if the expression yields a number greater than one.

$$K_L^{fe} = \frac{RTP_L^{act}}{RTP_L^{fcst}}$$

K_L^{loc} shall be calculated as shown below.

$$K_L^{loc} = \frac{RTP_L^{act}}{\sum_{j \in NYCA} RTP_j^{act}}$$

$K_{c,L}^{customer}$ shall be calculated as shown below.

$$K_{c,L}^{customer} = \frac{RTP_{c,L}^{act}}{\sum_{d \in E} RTP_{d,L}^{act}}$$

The residual BPCG payments not allocated to such Additional Resources according to the methodology described above shall be allocated to all Transmission Customers using the methods described in Section 6.1.7.2., of Rate Schedule 1 of the OATT. The residual is determined according to:

$$BPCG_{NYCA} - \sum_{c \in E} BPCG_c$$

27 Attachment U – Declaration and Recovery of Bad Debt Losses

The ISO shall recover bad debt losses resulting from non-payment of money owed under this ISO OATT or the ISO Services Tariff by Transmission Customers or Customers (hereinafter, collectively referred to as "Transmission Customers" for purposes of this Attachment U) in accordance with this Attachment U.

27.1 Declaration Of A Bad Debt Loss

At such time that the ISO's Chief Financial Officer concludes that the ISO does not reasonably expect payment in full from a defaulting Transmission Customer within an acceptable time period, then the ISO's Chief Financial Officer shall declare that the net unpaid obligation is a bad debt loss that requires recovery by the ISO in accordance with this Attachment U through a Schedule 1 charge, and the ISO shall pursue available remedies for customer defaults under the ISO Tariffs.

27.2 Notice To Market Participants

The ISO shall notify Market Participants of the declaration of a bad debt loss under Section 27.1 of this Attachment U by a posting to the ISO website and to the Market Participant subscriber e-mail lists. Such notification shall identify the defaulting Transmission Customer, the dollar amount of the unpaid balance, the applicable Billing Period(s) for which settlement invoice obligations remain unpaid and are still owing to the ISO, and the future Billing Period(s) in which the ISO will recover the bad debt loss in accordance with this Attachment U through a Schedule 1 charge.

27.3 Recovery of Payment Defaults and Bad Debt Losses

Whenever all or any portions of any settlement invoices remain unpaid to the ISO after the invoice due date, the ISO, at its discretion, may use the Working Capital Fund to maintain the liquidity of the New York wholesale energy markets and pay all Transmission Customers who are owed monies in their settlement invoices under the ISO Tariffs . The ISO shall not use the Working Capital Fund to satisfy WTSC non-payments. In the case of WTSC non-payments, the ISO may draw upon collateral for the benefit of the affected Transmission Owners in accordance with Section 26.11 of the ISO Services Tariff.

The ISO will ordinarily first seek to recover the amount of a payment default by drawing upon the entire amount of collateral provided by the defaulting Transmission Customer. If the ISO were unable to promptly recover the full amount of the debt in this way, the ISO would ordinarily seek to recover the amount of the payment default by drawing upon the defaulting Transmission Customer’s contributions to the Working Capital Fund that is described in Attachment V to this ISO OATT. If the ISO were unable to promptly recover the full amount of the debt through this measure, it would then ordinarily make claims against any available loss protection insurance in accordance with the insurance’s terms. The ISO may deviate from the sequence of steps above, or pursue alternative cost-recovery measures, if it determines that doing so would be more likely to minimize the size of, or avoid, a bad debt loss. After the ISO’s Chief Financial Officer has declared a bad debt loss , and notified Market Participants in accordance with this Attachment U, the amount of the bad debt loss shall be allocated *pro rata* to all Transmission Customers pursuant to the following formula:

$$\text{Percentage of Loss to Be Paid by Transmission Customer} = \frac{\text{CAR} + \text{CAP}}{\text{NYAR} + \text{NYAP}}$$

Where:

CAR =	Transmission Customer's gross accounts receivable, including WTSC in the Billing Period in which the payment obligation that resulted in the loss occurred.
CAP =	Absolute value of Transmission Customer's gross accounts payable, including WTSC, in the Billing Period in which the payment obligation that resulted in the loss occurred.
NYAR =	ISO's gross accounts receivable plus the Transmission Owners' accounts receivable from WTSC, in the Billing Period in which the payment obligation that resulted in the loss occurred.
NYAP =	Absolute value of ISO's gross accounts payable plus the absolute value of the Transmission Owners' accounts payable from WTSC, in the Billing Period in which the payment obligation that resulted in the loss occurred.

Notwithstanding any recovery of unpaid WTSC in accordance with this Attachment U through a Schedule 1 charge, a Transmission Owner shall be required to pursue reasonable debt collection efforts and remit to the ISO any such WTSC ultimately collected.

The ISO shall recover the bad debt loss through a Schedule 1 charge in a subsequent Billing Period after the Billing Period in which the bad debt loss is declared; provided, however, that the ISO may recover bad debt losses over several Billing Periods if, in its discretion, the ISO determines such method of recovery to be a prudent course of action.

Transmission Customers that are subject to a Schedule 1 charge for a bad debt loss will be assessed the outstanding balance owing to the ISO, as originally reflected in the defaulting Transmission Customer's invoice, including any accrued interest through the date of such invoice, but exclusive of any additional interest on the unpaid balance that accrued subsequent to the original due date. The ISO shall have the option to adjust Transmission Customers' shares of bad debt loss recovery costs, on a ratable basis, if necessary to fully recover a loss. The ISO shall not be required to determine the outcome of any insurance claim before allocating bad debt loss recovery costs to Transmission Customers. Any bad debt losses that are later recovered through insurance proceeds or from a defaulting Transmission Customer, or otherwise, shall be allocated to all Transmission Customers previously charged for the loss according to the same allocation method originally used to collect the loss.

27.4 Re-Entry of Defaulting Transmission Customer

In addition to the provisions for curing a Transmission Customer default contained elsewhere in the ISO Tariffs, a Transmission Customer whose previous default resulted in a Schedule 1 bad debt loss charge to other Transmission Customers must (i) cure such default by payment to the ISO of all outstanding and unpaid obligations and (ii) meet all ISO minimum participation criteria, registration requirements, and creditworthiness requirements, including posting of required collateral, prior to being re-admitted by the ISO to participate in the New York wholesale energy markets.

28 Attachment V – ISO Working Capital Fund

The ISO's Working Capital Fund shall be maintained according to the provisions of this Attachment V to the ISO OATT.

28.1 Purpose of the ISO Working Capital Fund

The ISO has accumulated and will maintain a Working Capital Fund through charges, as the ISO deems necessary, under Rate Schedule 1, Section 6.1.4 of the ISO OATT. The Working Capital Fund will be used, among other items, to offset temporary imbalances in ISO cash flow and to ensure the liquidity and stability of the markets administered by the ISO under the ISO Services Tariff. Pursuant to its authority under the ISO Agreement, the ISO Board will determine the ISO's working capital requirements. The ISO shall repay any draws from the Working Capital Fund as soon as reasonably practicable.

28.2 Monitoring and Reporting of Working Capital Fund

The ISO will monitor the activity of the Working Capital Fund, both in the aggregate and according to each Customer's pro rata share of the Working Capital Fund. With respect to each Customer's pro rata share of the Working Capital Fund, the ISO will make available to each Customer electronically, each month, a summary of the Customer's (i) opening balance, (ii) current month contributions, (iii) current month accrued interest, (iv) any other adjustments, and (v) ending balance. When practicable, the ISO will also provide a separate detailed working capital transaction history page for each Customer, in a format that can be downloaded for the Customer's use. The detailed working capital transaction history page will provide a complete history of all transactions relating to the Customer's contributions to the Working Capital Fund.

28.3 Customer Contributions to Increases of the Working Capital Fund

The ISO shall determine each Customer's pro rata share of any increase of the amount of the Working Capital Fund using the following formula:

$$\textbf{Customer's Percentage of Total Collection} = \frac{\mathbf{CAR + CAP}}{\mathbf{NYAR + NYAP}}$$

Where:

CAR = Customer's accounts receivable, including WTSC, for the service month prior to the month in which the billing invoice is issued.

CAP = Absolute value of Customer's accounts payable, including WTSC, for the service month prior to the month in which the billing invoice is issued.

NYAR = ISO's gross accounts receivable plus the Transmission Owners' accounts receivable from WTSC for the service month prior to the month in which the billing invoice is issued.

NYAP = Absolute value of ISO's gross accounts payable plus the absolute value of the Transmission Owners' accounts payable from WTSC for the service month prior to the month in which the billing invoice is issued.

28.4 Decrease in the Amount of the Working Capital Fund

At the sole discretion of the ISO Board, the ISO periodically may decrease the amount of the Working Capital Fund and distribute to each Customer, on a pro rata basis, a portion of its cumulative principal contribution to the Working Capital Fund. Any such distribution will be made through adjustments to Customer billing invoices.

28.5 Interest Accrued on Working Capital Fund

Interest earned on the Working Capital Fund shall, on a monthly basis, be attributed to, and recorded for, each Customer based on the Customer's percentage share of the balance in the Working Capital Fund.

At the sole discretion of the ISO Board, the ISO periodically may distribute to Customers all or a portion of their pro rata shares of the accrued interest earned on the Working Capital Fund. Any such distribution of interest will be made through adjustments to Customer billing invoices and, if required by applicable federal tax law, the ISO shall issue to those Customers the appropriate federal tax form (e.g., an Internal Revenue Service Form 1099-INT) for the amount of interest distributed.

28.6 Other Adjustments to the Working Capital Fund

Other adjustments to the Working Capital Fund include, but are not limited to, the adjustments described in this Section.

28.6.1 Distributions to Customers Exiting the ISO Markets

The ISO will refund to a Customer terminating its ISO Service Agreements and exiting the ISO markets its cumulative principal contribution to the Working Capital Fund, along with any earned interest that has been accrued but not previously distributed, through the annual contribution adjustment process in Section 28.7 of this Attachment V; *provided, however,* that the ISO shall retain these amounts as security for any unsatisfied financial obligations to the ISO. Customers shall be responsible for providing the ISO with the wire transfer information necessary for the ISO to complete any refund of the Customer’s Working Capital Fund contribution.

28.6.2 Customer Nonpayment and Default

In the event that part or all of a payment owed by a Customer remains unpaid after the payment is due, the ISO may use the Working Capital Fund as necessary to meet its cash flow requirements. If the ISO draws from the Working Capital Fund to meet its cash flow requirements in the event of a Customer nonpayment and then later declares the nonpayment to be a bad debt loss, the ISO shall recover the bad debt loss through the provisions of Rate Schedule 1 in accordance with Attachment U to the ISO OATT and shall replenish the Working Capital Fund through Rate Schedule 1.

The ISO shall pursue available remedies for Customer defaults under the ISO tariffs. After applying a nonpaying Customer’s available collateral, if any, the ISO shall apply the

Customer's share of the Working Capital Fund to satisfy remaining amounts owed to the ISO, including amounts owed as a result of settlement corrections. Upon termination of service to the Customer and reconciliation by the ISO of final settlement corrections affecting the Customer, the ISO shall return the Customer's remaining share of the Working Capital Fund, if any, in accordance with the provisions of Section 28.5.1 of this Attachment V.

28.6.3 Differences between ISO Actual and Forecasted Loads

The ISO funds its operating costs by charging Customers according to Section 6.1.3.1 of Rate Schedule 1. In the event that differences between actual and forecasted ISO loads result in an insufficient recovery of its operating costs, the ISO may offset any shortfall in operating costs by (i) temporarily drawing from the Working Capital Fund or (ii) increasing the Rate Schedule 1 charge. Whenever practicable, the ISO shall provide notice to Market Participants of the potential need to offset a shortfall in operating costs in accordance with this Section 28.6.3.

28.7 Contributions to Working Capital Fund from New Customers

Customers that execute ISO Service Agreements and become approved ISO Customers after the effective date of this Attachment V will not be required to make an initial contribution to the Working Capital Fund, but will be required to (i) contribute, through a Rate Schedule 1 charge, their pro rata share of any subsequent increases of the Working Capital Fund as described in Section 28.3 of this Attachment V and (ii) make a contribution~~s~~ to the Working Capital Fund in connection with the next annual adjustment as described in Section 28.7 of this Attachment V.

28.8 Annual Adjustment of Working Capital Fund Contributions

During the month of January of each calendar year, the ISO shall determine and adjust, if necessary, the contributions to the Working Capital Fund required from each Customer during that year using the following formula, except as provided in Section 28.5.1 of this Attachment V.

$$\textbf{Customer's Annual Adjusted Percentage of Total Collection} = \frac{\textbf{CAR + CAP}}{\textbf{NYAR + NYAP}}$$

Where:

CAR = Customer's accounts receivable, including WTSC, during the prior calendar year.

CAP = Absolute value of Customer's accounts payable, including WTSC, during the prior calendar year.

NYAR = ISO's gross accounts receivable plus the Transmission Owners' accounts receivable from WTSC during the prior calendar year.

NYAP = Absolute value of ISO's gross accounts payable plus the absolute value of the Transmission Owners' accounts payable from WTSC during the prior calendar year.

In February of each calendar year, the ISO shall either refund or charge, as applicable, each Customer for the difference between the Customer's principal share of the Working Capital Fund at the conclusion of the prior calendar year and the Customer's adjusted principal share of the Working Capital Fund as calculated in accordance with this Section 28.8. The ISO shall have the discretion to amortize such refunds or charges over one or more months beyond February, based upon the magnitude of the annual adjustments.

28.9 Working Capital Fund Contributions Not Considered As Collateral

A Customer's contributions to, and its pro rata share of, the Working Capital Fund shall not be considered as, or counted towards, any collateral that may be required from the Customer.

29 Attachment W – Creditworthiness Requirements for Transmission Customers

All Transmission Customers and all applicants seeking to become Transmission Customers are subject to the creditworthiness requirements contained in Attachment K to the ISO Services Tariff. “Customer,” as used in Attachment K to the ISO Services Tariff, shall also mean “Transmission Customer” and an applicant seeking to become a Transmission Customer.

30 Attachment X – Standard Large Facility Interconnection Procedures (Applicable to Generating Facilities that exceed 20 MWs and to Merchant Transmission Facilities)

30.1 Definitions

Whenever used in these Large Facility Interconnection Procedures with initial capitalization, the following terms shall have the meanings specified in this Section 30.1. Terms used in these procedures with initial capitalization that are not defined in this Section 30.1 shall have the meanings specified in Section 1 of the ISO OATT, Section 25.1.2 of Attachment S of the ISO OATT, or in Article 2 of the ISO Services Tariff.

Affected System shall mean an electric system other than the transmission system owned, controlled or operated by the Connecting Transmission Owner that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affected Transmission Owner shall mean the New York public utility or authority (or its designated agent) other than the Connecting Transmission Owner that (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, and (ii) owns, leases or otherwise possesses an interest in a portion of the New York State Transmission System where System Deliverability Upgrades or System Upgrade Facilities are installed pursuant to Attachment X and Attachment S of the Tariff.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority, including but not limited to Environmental Law.

Applicable Reliability Councils shall mean the NERC, the NPCC and the NYSRC.

Applicable Reliability Standards shall mean the requirements and guidelines of the Applicable Reliability Councils, and the Transmission District, to which the Developer's Large Facility is directly interconnected, as those requirements and guidelines are amended and modified and in effect from time to time; provided that no Party shall waive its right to challenge the applicability or validity of any requirement or guideline as applied to it in the context of the Large Facility Interconnection Procedures.

Attachment Facilities shall mean the Connecting Transmission Owner's Attachment Facilities and the Developer's Attachment Facilities. Collectively, Attachment Facilities include all facilities and equipment between the Large Generating Facility or Merchant Transmission Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Large Facility to the New York State Transmission System. Attachment Facilities are sole use facilities and shall not include Stand Alone System Upgrade Facilities, Distribution Upgrades, System Upgrade Facilities or System Deliverability Upgrades.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the ISO, Connecting Transmission Owner or Developer; described in Section 30.2.3 of the Large Facility Interconnection Procedures.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding federal holidays.

Byway shall mean all transmission facilities comprising the New York State Transmission System that are neither Highways nor Other Interfaces. All transmission facilities in Zone J and Zone K are Byways.

Calendar Day shall mean any day including Saturday, Sunday or a federal holiday.

Capacity Region shall mean one of four subsets of the Installed Capacity statewide markets comprised of: (1) Rest of State (*i.e.*, Load Zones A through F); (2) Lower Hudson Valley (*i.e.*, Load Zones G, H and I); (3) New York City (*i.e.*, Load Zone J); and (4) Long Island (*i.e.*, Load Zone K), except for Class Year Interconnection Facilities Studies conducted prior to Class Year 2012, for which "Capacity Region" shall be defined as set forth in Section 25.7.3 of Attachment S to the ISO OATT.

Capacity Resource Interconnection Service ("CRIS") shall mean the service provided by the ISO to Developers that satisfy the NYISO Deliverability Interconnection Standard or that are otherwise eligible to receive CRIS in accordance with Attachment S to the ISO OATT; such service being one of the eligibility requirements for participation as an ISO Installed Capacity Supplier.

Class Year shall mean the group of generation and merchant transmission projects included in any particular Class Year Interconnection Facilities Study (Annual Transmission Reliability Assessment and/or Class Year Deliverability Study), in accordance with the criteria specified in Attachment S and in Attachment Z for including such projects.

Class Year CRIS Project: A Class Year Project with an executed Class Year Interconnection Facilities Study Agreement entering a Class Year Study for a CRIS evaluation, that thereby becomes one of the group of Class Year Projects included in the Class Year Deliverability Study. A Class Year CRIS Project may be a "CRIS-only" project that is entering a Class Year Study only for a CRIS evaluation, or it may be a project seeking both ERIS and CRIS.

Class Year Deliverability Study shall mean an assessment, conducted by the ISO staff in cooperation with Market Participants, to determine whether System Deliverability Upgrades are required for Class Year CRIS Projects under the NYISO Deliverability Interconnection Standard.

Class Year Interconnection Facilities Study shall mean a study conducted by the ISO or a third party consultant for the Developer to determine a list of facilities (including Connecting

Transmission Owner's Attachment Facilities, Distribution Upgrades, System Upgrade Facilities and System Deliverability Upgrades as identified in the Interconnection System Reliability Impact Study), the cost of those facilities, and the time required to interconnect the Large Generating Facility or Merchant Transmission Facility with the New York State Transmission System or with the Distribution System. The scope of the study is defined in Section 30.8 of the Standard Large Facility Interconnection Procedures in this Attachment X.

Class Year Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 2 of the Large Facility Interconnection Procedures in this Attachment X for conducting the Class Year Interconnection Facilities Study.

Class Year Project shall mean an Eligible Class Year Project with an executed Class Year Interconnection Facilities Study Agreement that thereby becomes one of the group of generation and Merchant Transmission Facilities included in any particular Class Year Interconnection Facilities Study (Annual Transmission Reliability Assessment and/or Class Year Deliverability Study), in accordance with the criteria specified in this Attachment S and in Attachment Z for including such projects.

Class Year Start Date shall mean the deadline for Eligible Class Year Projects to enter a Class Year Interconnection Facilities Study, determined in accordance with Section 25.5.9 of Attachment S.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Reliability Impact Study.

Commercial Operation shall mean the status of a Large Facility that has commenced generating or transmitting electricity for sale, excluding electricity generated or transmitted during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Large Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any information that is defined as confidential by Section 30.13.1 of the Large Facility Interconnection Procedures.

Connecting Transmission Owner shall mean the New York public utility or authority (or its designated agent) that (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, (ii) owns, leases or otherwise possesses an interest in the portion of the New York State Transmission System or Distribution System at the Point of Interconnection, and (iii) is a Party to the Standard Large Interconnection Agreement.

Connecting Transmission Owner's Attachment Facilities shall mean all facilities and equipment owned, controlled or operated by the Connecting Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Connecting Transmission Owner's Attachment Facilities are sole use facilities and shall not include Stand Alone System Upgrade Facilities or System Upgrade Facilities.

Default shall mean the failure of a Party in Breach of the Standard Large Generator Interconnection Agreement to cure such Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Developer's Attachment Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Large Generating Facility or Merchant Transmission Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Large Generating Facility or Merchant Transmission Facility to the New York State Transmission System. Developer's Attachment Facilities are sole use facilities.

Dispute Resolution shall mean the procedure described in Section 30.13.5 of the Large Facility Interconnection Procedures for resolution of a dispute between the Parties.

Distribution System shall mean the Transmission Owner's facilities and equipment used to distribute electricity that are subject to FERC jurisdiction, and are subject to the ISO's Large Facility Interconnection Procedures in this Attachment X or Small Generator Interconnection Procedures in Attachment Z to the ISO OATT under FERC Order Nos. 2003 and/or 2006. The term Distribution System shall not include LIPA's distribution facilities.

Distribution Upgrades shall mean the modifications or additions to the existing Distribution System at or beyond the Point of Interconnection that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Minimum Interconnection Standard.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties, subject to acceptance by the Commission, or if filed unexecuted, upon the date specified by the Commission.

Eligible Class Year Project: Any Developer or Interconnection Customer that (1) satisfies the criteria for inclusion in the next Class Year Interconnection Facilities Study, as those criteria are specified in Sections 25.5.9 and 25.6.2.3.1 of Attachment S to the OATT, Section 32.1.1.7 of Attachment Z to the OATT and/or Section 32.3.5.3.2 of Attachment Z to the OATT; or (2) that seeks evaluation in a Class Year Study to obtain or increase CRISs as permitted by Attachment S to the ISO OATT and satisfies the criteria for inclusion in the next Class Year Interconnection Facilities Study specified in Section 25.5.9 of Attachment S to the OATT.

Energy Resource Interconnection Service ("ERIS") shall mean the service provided by the ISO to interconnect the Developer's Large Generating Facility or Merchant Transmission Facility to the New York State Transmission System or to the Distribution System, in accordance with the NYISO Minimum Interconnection Standard, to enable the New York State Transmission System to receive Energy and Ancillary Services from the Large Generating Facility or Merchant Transmission Facility, pursuant to the terms of the ISO OATT.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes Connecting Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

External CRIS Rights: A determination of deliverability within the Rest of State Capacity Region (*i.e.,* Load Zones A-F), awarded by the ISO for a term of five (5) years or longer, to a specified number of Megawatts of External Installed Capacity that satisfy the requirements set forth in Section 25.7.11 of Attachment S to the ISO OATT, and that can be certified in a Bilateral Transaction used for the NYCA and not a Locality, or sold into the NYCA for an Installed Capacity auction and not in an Installed Capacity auction for a Locality.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Developer's device for the production of electricity identified in the Interconnection Request, but shall not include the Developer's Attachment Facilities or Distribution Upgrades.

Generating Facility Capacity shall mean the net seasonal capacity of the Generating Facility and the aggregate net seasonal capacity of the Generating Facility where it includes multiple energy production devices.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over any of the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Developer, the ISO, Affected Transmission Owner, Connecting Transmission Owner, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Highway shall mean 115 kV and higher transmission facilities that comprise the following NYCA interfaces: Dysinger East, West Central, Volney East, Moses South, Central East/Total

East, and UPNY-ConEd, and their immediately connected, in series, Bulk Power System facilities in New York State. Each interface shall be evaluated to determine additional "in series" facilities, defined as any transmission facility higher than 115 kV that (a) is located in an upstream or downstream zone adjacent to the interface and (b) has a power transfer distribution factor (DFAX) equal to or greater than five percent when the aggregate of generation in zones or systems adjacent to the upstream zone or zones which define the interface is shifted to the aggregate of generation in zones or systems adjacent to the downstream zone or zones which define the interface. In determining "in series" facilities for Dysinger East and West Central interfaces, the 115 kV and 230 kV tie lines between NYCA and PJM located in LBMP Zones A and B shall not participate in the transfer. Highway transmission facilities are listed in ISO Procedures.

Initial Synchronization Date shall mean the date upon which the Large Generating Facility or Merchant Transmission Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Developer reasonably expects it will be ready to begin use of the Connecting Transmission Owner's Attachment Facilities to obtain back feed power.

Interconnection Request shall mean Developer's request, in the form of Appendix 1 to the Standard Large Facility Interconnection Procedures, in accordance with the Tariff, to interconnect a new Large Generating Facility or Merchant Transmission Facility to the New York State Transmission System or to the Distribution System, or to materially increase the capacity of, or make a material modification to the operating characteristics of, an existing Large Generating Facility or Merchant Transmission Facility that is interconnected with the New York State Transmission System or with the Distribution System.

Interconnection Study shall mean any of the following studies: the Optional Interconnection Feasibility Study, the Interconnection System Reliability Impact Study, and the Class Year Interconnection Facilities Study described in the Standard Large Facility Interconnection Procedures.

Interconnection System Reliability Impact Study ("SRIS") shall mean an engineering study that evaluates the impact of the proposed Large Generation Facility or Merchant Transmission Facility on the safety and reliability of the New York State Transmission System and, if applicable, an Affected System, to determine what Attachment Facilities, Distribution Upgrades and System Upgrade Facilities are needed for the proposed Large Generation Facility or Merchant Transmission Facility of the Developer to connect reliably to the New York State Transmission System or to the Distribution System in a manner that meets the NYISO Minimum Interconnection Standard. The scope of the SRIS is defined in Section 30.7.3 of the Large Facility Interconnection Procedures in this Attachment X.

IRS shall mean the Internal Revenue Service.

Large Facility shall mean either a Large Generating Facility or a Merchant Transmission Facility.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Local System Upgrade Facilities shall mean the System Upgrade Facilities necessary to physically interconnect a proposed project to the Connecting Transmission Owner’s transmission system, consistent with applicable interconnection and system protection design standards. Local System Upgrade Facilities include any electrical facilities required to make the physical connection (*e.g.,* a new ring bus for a line connection or facilities required to create a new bay for a substation connection). Local System Upgrade Facilities also include any system protection or communication facilities that may be required for protection of the Connecting Transmission Owner’s transmission facility (line or substation) involved in the interconnection. Local System Upgrade Facilities do not include System Upgrade Facilities required to mitigate any adverse reliability impact(s) of the project(s) identified through analysis such as power flow, short circuit, or stability (e.g., replacement of a circuit breaker at a nearby substation that becomes overdutied as a result of the project(s)).

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Indemnified Party’s performance or non-performance of its obligations under the Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Merchant Transmission Facility shall mean Developer’s device for the transmission of electricity identified in the Interconnection Request, proposing to interconnect to the New York State Transmission System, but shall not include Attachment Facilities, System Upgrade Facilities or System Deliverability Upgrades. Merchant Transmission Facilities shall be those transmission facilities developed by an entity that is not a Transmission Owner signatory to the ISO-Related Agreements. Merchant Transmission Facilities shall not include upgrades or additions to the New York State Transmission System made by a Transmission Owner signatory to the ISO-Related Agreements.

Metering Equipment shall mean all metering equipment installed or to be installed at the Large Generating or Merchant Transmission Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Facility Interconnection Procedures, or the Standard Large Generator Interconnection Agreement or its performance.

NPCC shall mean the Northeast Power Coordinating Council or its successor organization.

NYISO shall mean the New York Independent System Operator, Inc.

NYISO Deliverability Interconnection Standard – The standard that must be met, unless otherwise provided for by Attachment S to the ISO OATT, by (i) any generation facility larger than 2MW in order for that facility to obtain CRIS; (ii) any Merchant Transmission Facility proposing to interconnect to the New York State Transmission System and receive Unforced Capacity Delivery Rights; (iii) any entity requesting External CRIS Rights, and (iv) any entity requesting a CRIS transfer pursuant to Section 25.9.5 of Attachment S to the ISO OATT. To meet the NYISO Deliverability Interconnection Standard, the Interconnection Customer must, in accordance with the rules in Attachment S to the ISO OATT, fund or commit to fund any System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

NYISO Minimum Interconnection Standard – The reliability standard that must be met by any generation facility or Merchant Transmission Facility that is subject to ISO's Large Facility Interconnection Procedures in Attachment X to the ISO OATT or the ISO's Small Generator Interconnection Procedures in this Attachment Z, that is proposing to connect to the New York State Transmission System or Distribution System, to obtain ERIS. The Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System or to the Distribution System. The Standard does not impose any deliverability test or deliverability requirement on the proposed interconnection.

Open Class Year shall mean the Class Year open for new members pursuant to the Class Start Date deadline specified in Section 25.5.9 of Attachment S.

Optional Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Large Generating Facility or Merchant Transmission Facility to the New York State Transmission System or to the Distribution System, the scope of which is described in Section 30.6 of the Standard Large Facility Interconnection Procedures.

Optional Interconnection System Reliability Impact Study shall mean a sensitivity analysis based on assumptions specified by the Developer in the Optional Interconnection System Reliability Impact Study scope.

Other Interfaces shall mean the following interfaces into Capacity Regions: Lower Hudson Valley [*i.e.*, Rest of State (Load Zones A-F) to Lower Hudson Valley (Load Zones G, H and I)]; New York City [*i.e.*, Lower Hudson Valley (Load Zones G, H and I) to New York City (Load Zone J)]; and Long Island [*i.e.*, Lower Hudson Valley (Load Zones G, H and I) to Long Island (Load Zone K)], and the following Interfaces between the NYCA and adjacent Control Areas: PJM to NYISO, ISO-NE to NYISO, Hydro-Quebec to NYISO, and Norwalk Harbor (Connecticut) to Northport (Long Island) Cable.

Party or Parties shall mean NYISO, Connecting Transmission Owner, or Developer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Developer's Attachment Facilities connect to the Connecting Transmission Owner's Attachment Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Attachment Facilities connect to the New York State Transmission System or to the Distribution System.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid request by the ISO.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Facility Interconnection Procedures or Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Developer, the ISO and Connecting Transmission Owner conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Services Tariff shall mean the NYISO Market Administration and Control Area Tariff, as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff thereto.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Large Generating Facility or Merchant Transmission Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Developer and the entity having the right to sell, lease or grant Developer the right to possess or occupy a site for such purpose.

Stand Alone System Upgrade Facilities shall mean System Upgrade Facilities that a Developer may construct without affecting day-to-day operations of the New York State Transmission System during their construction. The ISO, the Connecting Transmission Owner and the Developer must agree as to what constitutes Stand Alone System Upgrade Facilities and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Facility Interconnection Procedures ("Large Facility Interconnection Procedures" or "LFIP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility or Merchant Transmission Facility that are included in Attachment X of the ISO OATT.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in Attachment X of the ISO OATT.

System Deliverability Upgrades shall mean the least costly configuration of commercially available components of electrical equipment that can be used, consistent with Good Utility Practice and Applicable Reliability Requirements, to make the modifications or additions to

Byways and Highways and Other Interfaces on the existing New York State Transmission System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Deliverability Interconnection Standard for Capacity Resource Interconnection Service.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to (1) protect the New York State Transmission System from faults or other electrical disturbances occurring at the Large Generating Facility or Merchant Transmission Facility and (2) protect the Large Generating Facility or Merchant Transmission Facility from faults or other electrical system disturbances occurring on the New York State Transmission System or on other delivery systems or other generating systems to which the New York State Transmission System is directly connected.

System Upgrade Facilities shall mean the least costly configuration of commercially available components of electrical equipment that can be used, consistent with good utility practice and Applicable Reliability Requirements, to make the modifications to the existing transmission system that are required to maintain system reliability due to: (i) changes in the system including such changes as load growth and changes in load pattern, to be addressed in the form of generic generation or transmission projects; land (ii) proposed interconnections. In the case of proposed interconnection projects, System Upgrade Facilities are the modifications or additions to the existing New York State Transmission System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Minimum Interconnection Standard.

Tariff shall mean the NYISO Open Access Transmission Tariff ("OATT"), as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff.

Trial Operation shall mean the period during which Developer is engaged in on-site test operations and commissioning of the Large Generating Facility or Merchant Transmission Facility prior to Commercial Operation..

30.2 Scope and Application

30.2.1 Application of Standard Large Facility Interconnection Procedures

Sections 30.2 through 30.13 apply to processing an Interconnection Request pertaining to (i) a Large Generating Facility or Merchant Transmission Facility proposing to interconnect to the New York State Transmission System or to the Distribution System or (ii) an existing Large Generating Facility or Merchant Transmission Facility proposing a material increase or modification requiring a new Interconnection Request pursuant to these Procedures.

30.2.2 Comparability

The ISO shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in the Large Facility Interconnection Procedures. As described herein, the ISO will process and analyze all Interconnection Requests with independence and impartiality, in cooperation with and with input from the Developers, Connecting Transmission Owners and other Market Participants. The ISO will perform, oversee or review the Interconnection Studies to ensure compliance with the Large Facility Interconnection Procedures. The ISO will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Developers, whether or not the Large Generating Facilities or Merchant Transmission are owned by a Connecting Transmission Owner, its subsidiaries or Affiliates, or others.

30.2.3 Base Case Data

The ISO or Connecting Transmission Owner, depending upon which of those Parties possesses the data requested, shall provide base power flow, short circuit and stability databases, including all underlying assumptions and contingency lists, to the Developer upon request. All Parties shall treat Confidential Information in accordance with Section 30.13.1 of these Large Facility Interconnection Procedures. The ISO and Connecting Transmission Owner are permitted to require that the Developer sign a non-disclosure agreement before the release of Confidential Information or Critical Energy Infrastructure Information in the Base Case Data. The power flow, short circuit and stability data bases, hereinafter referred to as Base Cases, provided shall be those that the ISO is using in the Annual Transmission Baseline Assessment then in progress, or if such data bases are not available, the data bases from the last completed Annual Transmission Reliability Assessment conducted pursuant to Attachment S of the ISO OATT prior to the request. In the case of a request from a Developer considering Capacity Resource Interconnection Service, the power flow data bases provided shall include the Annual Transmission Reliability Assessment case from the most recently completed Class Year Deliverability Study.

30.2.4 No Applicability to Transmission Service or Other Services

Nothing in these Large Facility Interconnection Procedures shall constitute a request for Transmission Service or confer upon a Developer any right to receive Transmission Service. Nothing in these Large Facility Interconnection Procedures shall constitute a request for, nor agreement to provide, any energy, Ancillary Services or Installed Capacity under the ISO Services Tariff, except to the extent that a Developer’s election of Capacity Resource Interconnection Service and satisfaction of the NYISO Deliverability Interconnection Standard are prerequisites for the Large Generating Facility to become a qualified Installed Capacity Supplier and for the Merchant Transmission Facility to receive Unforced Capacity Deliverability Rights.

30.2.5 Inclusion of Black Start Capability at Large Generating Facility

A Developer proposing, pursuant to this Attachment X, to interconnect a new Large Generating Facility to Zone J or to modify – i.e., materially increase (as defined in Section 30.3.1

of this Attachment X) the capacity of or make a material modification to the operating characteristics of – an existing Large Generating Facility already interconnected to Zone J that will commence Commercial Operation after November 1, 2012, shall include black start capability at the Large Generating Facility; provided, however, the Large Generating Facility shall not be required to include black start capability if:

(A) the ISO determines that: (i) the inclusion of black start capability at the Large Generating Facility would not provide a material benefit to system restoration in Zone J, or (ii) the Developer has shown good cause for not including black start capability at the Large Generating Facility, or

(B) as of November 1, 2012, the Large Generating Facility has: (i) received one or more draft or final air permits from the appropriate regulatory agency, or (ii) has completed a draft environmental impact statement and submitted it to the appropriate governmental agency for issuance for public comment.

The inclusion of black start capability at a given Large Generating Facility would provide a material benefit to system restoration in Zone J if, among other things, such action would improve the speed, adequacy, or flexibility of Consolidated Edison Company of New York, Inc.'s ("Consolidated Edison's") black start and system restoration plan for restoring electric service in Zone J in a safe, orderly, and prompt manner following a major system disturbance that would require Consolidated Edison to undertake system restoration efforts.

To facilitate the ISO's determination regarding material benefit, Consolidated Edison shall at its expense perform contemporaneously with the Interconnection System Reliability Impact Study a separate study to examine whether a new or modified Large Generating Facility would provide a material benefit to system restoration as a black start resource. If requested by the Developer, Consolidated Edison shall perform this separate study contemporaneously with the earlier Optional Interconnection Feasibility Study. If changes to the project made subsequent to this study are deemed by the ISO to be significant, Consolidated Edison shall perform a new study at the Developer's expense. The study will indicate the black start performance measures under Consolidated Edison's black start and system restoration plan and the impact on relevant factors of the Large Generating Facility having black start capability. Consolidated Edison will provide its study to the ISO and to the Developer(s) of the Generating Facility(ies) that were considered in the study, subject to appropriate confidentiality protections. Consolidated Edison may provide the study to other parties that have a direct interest in this matter as well, subject to appropriate confidentiality protections.

If a Developer asserts that good cause exists for not including black start capability at a new or modified Large Generating Facility, it shall provide documentation demonstrating the technical, financial, spatial, and/or other reasons that justify its assertion. Factors that may constitute reasonable justification include, but are not limited to: (i) physical site limitations would unreasonably impair the planned use of the site or prevent the inclusion of black start equipment in addition to the equipment required to properly operate and maintain the proposed Large Generating Facility; (ii) the cost of adding black start capability would increase the overall cost of the project to a level that would impair the ability of the Developer to secure financing at commercially competitive terms; or (iii) the inclusion of black start capability would prevent the Developer from obtaining the permits and approvals needed for the project, or result in the imposition of significantly more burdensome permit conditions than would be imposed absent the installation of black start capability. The Developer will provide a study to the ISO and Consolidated Edison that supports its claim under this section, subject to appropriate confidentiality protections. The Developer may provide the study to other parties that have a direct interest in this matter as well, subject to appropriate confidentiality protections.

Any decision by the ISO regarding a new or modified Large Generating Facility's installation of black start capability pursuant to these provisions shall not be considered precedential or binding on the New York State Board on Electric Generation Siting and the Environment. In the event the New York State Board on Electric Generation Siting and the Environment makes a determination regarding the installation of black start equipment in the course of its siting process under Public Service Law Article 10, the ISO will accept that determination and not make a separate determination hereunder.

30.3 Interconnection Requests

30.3.1 General

A Developer proposing to interconnect a new Large Facility to the New York State Transmission System or to the Distribution System, or proposing to materially increase the capacity of, or make a material modification to the operating characteristics of, an existing Large Facility that is interconnected to the New York State Transmission System or to the Distribution System shall submit to the ISO a Interconnection Request in the form of Appendix 1 to these Large Facility Interconnection Procedures. An increase in the capacity of an existing Large Facility is a material increase for purposes of this Section 30.3.1 unless the increase (a) is not associated with any equipment changes or is associated with equipment changes determined by the ISO to be non-material; and (b) is an increase in the Large Facility's baseline ERIS level that is equal to or less than ten (10) megawatts or five (5) percent, whichever is greater. For purposes of this Section 30.3.1, the baseline ERIS level of an existing Large Facility is (a) the greater of (i) the existing Large Facility's CRIS level determined as a facility pre-dating Class Year 2007 pursuant to Section 25.9.3.1 of Attachment S of the ISO OATT, if applicable; or (ii) the final maximum summer megawatt electrical output studied for ERIS in the ISO's interconnection process for the existing Large Facility; or (b) if neither (a)(i) nor (a)(ii) are applicable, the baseline ERIS level is the value reflected in the Large Facility's interconnection agreement or other applicable documentation governing the Large Facility's interconnection; however, if the Large Facility has requested a modification to its facility to decrease its size, and such modification has been deemed nonmaterial by the ISO, the decreased MW level will be a cap on its baseline ERIS. If the existing Large Facility is a BTM:NG Resource, the increase in existing capacity will be measured based on the increase from the existing gross capability of the generator to the proposed gross capability of the generator, as modified. Notwithstanding the above, if the existing Large Facility is a temperature sensitive unit, the maximum capacity of which varies based on ambient temperature, the increase in existing capacity will be measured based on the largest increase from the existing capacity to the proposed capacity at the same temperature, *i.e.*, at the same temperature along the maximum megawatt electrical output versus temperature curves.

The Interconnection Request in the form of Appendix 1 to these Large Facility Interconnection Procedures must be accompanied by a non-refundable application fee of $10,000. The application fee shall be divided equally between the ISO and Connecting Transmission Owner(s). The Developer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. The Developer must submit an application fee and study deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests unless the Large Generating Facility, as it proposes to interconnect, includes either (1) a 3-winding transformer with the potential to connect to two different voltage level lines simultaneously; or (2) a combined cycle with a generator turbine and steam turbine connected at two different voltage levels.

At Developer's option, the ISO, Connecting Transmission Owner and Developer will provide input regarding alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. During the Optional Interconnection Feasibility Study, System Reliability Impact Study, or Class Year Interconnection Facilities Study, as applicable, the Connecting Transmission Owner and Affected Transmission Owner(s), identified pursuant to Section 30.3.5 of this Attachment X, shall provide input regarding proposed Point(s) of Interconnection and configurations. Developer will select the definitive Point of Interconnection to be studied no later than the commencement of the Interconnection System Reliability Impact Study.

A Developer seeking to return a Large Generating Facility to Commercial Operations after it is Retired must submit a new Interconnection Request as a new facility. A Developer returning a Large Generating Facility to service prior to the expiration or termination of its Mothball Outage or ICAP Ineligible Forced Outage need not submit a new Interconnection Request unless the Large Generating Facility is making modifications or is increasing its capacity such as would otherwise trigger a new Interconnection Request for an existing Large Generating Facility.

30.3.2 Types of Interconnection Service

30.3.2.1 Two Types of Service

The ISO offers Energy Resource Interconnection Service under the Large Facility Interconnection Procedures for interconnection in compliance with the NYISO Minimum Interconnection Standard. The ISO also offers Capacity Resource Interconnection Service under the Large Facility Interconnection Procedures for interconnection in compliance with the NYISO Deliverability Interconnection Standard.

30.3.2.2 Service Elections, Generally

All Large Facilities must interconnect in compliance with the NYISO Minimum Interconnection Standard. In addition, Large Facilities must also comply with the NYISO Deliverability Interconnection Standard before Large Generating Facilities can become qualified

Installed Capacity Suppliers and before Merchant Transmission Facilities can receive Unforced Capacity Deliverability Rights. A Developer initially states its election to be evaluated in its Interconnection Studies for ERIS alone, or for both ERIS and CRIS, as a part of its Interconnection Request. An existing Large Generating Facility requesting only CRIS must request CRIS in an Open Class Year Study unless it is requesting CRIS pursuant to Section 30.3.2.6 of this Attachment X. The ISO evaluates an Interconnection Request for compliance with the Minimum Interconnection Standard throughout the Interconnection Study process. The ISO evaluates an Interconnection Request for compliance with the Deliverability Interconnection Standard formally during the Class Year Deliverability Study. At other times during the Interconnection Study process, during the Optional Interconnection Feasibility Study and the Interconnection System Reliability Study, the ISO will assist any Developer considering Capacity Resource Interconnection Service to assess potential system deliverability issues by providing the Developer, upon its request, with the Annual Transmission Reliability Assessment case from the most recently completed Class Year Deliverability Study. The Developer may modify its interconnection service evaluation election when it executes the Class Year Interconnection Facilities Study Agreement for its project in accordance with Section 30.8.1 of these Large Facility Interconnection Procedures. At that time, the Developer may reduce the number of MW it initially requested to be evaluated for CRIS, and such a reduction shall not constitute a Material Modification. Any increase in the MW initially requested to be evaluated for CRIS shall constitute a Material Modification.

30.3.2.3 ERIS Elections

A Large Facility that elects ERIS, and not CRIS, will not be able to become an eligible Installed Capacity Supplier or to receive Unforced Capacity Deliverability Rights. Such a Large

Facility will be eligible to participate only in the energy and applicable ancillary service markets. When a Developer elects ERIS its project will be evaluated in the Interconnection Studies at full output. When a Developer elects ERIS and interconnects under ERIS, the Developer may at a later date ask the ISO to reevaluate the Large Facility for CRIS by including the Large Facility in the Open Class Year to identify the System Deliverability Upgrades, if any, needed for the Large Facility to be declared deliverable.

30.3.2.4 CRIS Elections

The amount of CRIS requested by a Developer shall be stated in MW of Installed Capacity ("ICAP"), and cannot exceed the nameplate capacity of the Developer's Large Facility; provided however, if the Large Facility is a BTM:NG Resource, its requested CRIS cannot exceed its Net ICAP. When a Developer elects CRIS, the ISO will evaluate the deliverability of the Large Facility by applying the test methodology described in Section 25.7 of Attachment S to the ISO OATT. The ISO will apply this test methodology to identify the System Deliverability Upgrades, if any, needed to make the Large Facility deliverable and will also identify the MW of Installed Capacity, if any, that are deliverable from the Large Facility with no System Deliverability Upgrades. A Large Facility electing CRIS will be able to become a qualified Installed Capacity Supplier or receive Unforced Capacity Deliverability Rights to the extent of its deliverable capacity, once it has funded or committed to fund any required System Deliverability Upgrades in accordance with the relevant provisions of Attachment S to the ISO OATT. A Developer qualifying for CRIS will have two CRIS values: one for the summer capability period and one for the winter capability period. The CRIS value, in MW of Installed Capacity, for the summer capability period will be set using the deliverability test methodology and procedures described in Section 25.7 of Attachment S to the ISO OATT. The CRIS value for the winter capability period, also in MW of Installed Capacity, will be set in accordance with Section 25.7.6 of Attachment S to the ISO OATT.

30.3.2.5 Partial CRIS Service

A Developer may elect partial CRIS, measured in whole MW of Installed Capacity, for its Large Facility.

30.3.2.6 Increases In Established CRIS Values

Any facility with an established CRIS value may at a later date, without submitting a new Interconnection Request, ask the ISO to reevaluate the Large Facility for a higher level of MW of Installed Capacity, not to exceed the nameplate rating of the Large Facility, by including the Large Facility in the Open Class Year to identify the System Deliverability Upgrades, if any, needed for the Large Facility to be declared deliverable at the higher level of MW. Any facility with an established CRIS value may, without such evaluation and without submitting a new Interconnection Request, increase that CRIS value by a total of no more than 2 MW of Installed Capacity during the operating life of the facility. For purposes of this Section 30.3.2.6, an "established CRIS value" for facilities subject to a CRIS set and reset period pursuant to Section 25.9.3.3, Section 25.9.3.1.4.1, Section 25.9.3.1.4.2, or Section 25.9.3.5 of Attachment S to the ISO OATT is the final CRIS value established after the termination of the CRIS set and reset period.

30.3.2.7 The Interconnection Studies

The Interconnection Studies conducted under the Large Facility Interconnection Procedures consist of short circuit/fault duty, steady state (thermal and voltage) and stability analyses designed to identify the Attachment Facilities, Distribution Upgrades and System

Upgrade Facilities required for the reliable interconnection of Large Facilities to the New York State Transmission System or to the Distribution System in compliance with the NYISO Minimum Interconnection Standard, as well as the deliverability analysis described in Attachment S of the OATT designed to identify the System Deliverability Upgrades required for reliable interconnection in compliance with the NYISO Deliverability Interconnection Standard, where applicable.

30.3.3 Valid Interconnection Request

30.3.3.1 Initiating an Interconnection Request

To initiate an Interconnection Request, Developer must submit all of the following: (i) a $10,000 non-refundable application fee; (ii) a completed application in the form of Appendix 1; and (iii) demonstration of Site Control or a posting of an additional deposit of $10,000. Deposits, excluding the application fee, shall be applied toward any Interconnection Studies pursuant to the Interconnection Request. If Developer demonstrates Site Control within the cure period specified in Section 30.3.3.3 after submitting its Interconnection Request, the additional deposit shall be refundable; otherwise, all such deposit(s), additional and initial, become non-refundable.

The expected Commercial Operation Date of the new Large Facility or proposed increase in capacity of the existing Large Facility provided at the time of the submission of the Interconnection Request shall be no more than ten (10) years from the date the Interconnection Request is received by the ISO. Extensions of Commercial Operation Dates are governed by Section 30.4.4.5.

30.3.3.2 Acknowledgment and Notification of Interconnection Request

The ISO shall acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement it returns to the Developer. At the same time, the ISO shall forward a copy of the Interconnection Request and its acknowledgement to the Connecting Transmission Owner with whom the Developer is proposing to connect.

30.3.3.3 Deficiencies in Interconnection Request

An Interconnection Request will not be considered to be a valid request until all items in Section 30.3.3.1 have been received by the ISO. If an Interconnection Request fails to meet the requirements set forth in Section 30.3.3.1, the ISO shall notify the Developer and Connecting Transmission Owner within ten (10) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Developer shall provide the ISO the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. The ISO shall promptly forward such information to the Connecting Transmission Owner. Failure by Developer to comply with this Section 30.3.3.3 shall be treated in accordance with Section 30.3.6.

30.3.3.4 Scoping Meeting

Within ten (10) Business Days after receipt of a valid Interconnection Request, the ISO shall establish a date agreeable to Developer and Connecting Transmission Owner for the Scoping Meeting, and such date shall be no later than thirty (30) Calendar Days from receipt of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be to reinforce the roles and responsibilities of all parties in the interconnection process, discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection, and to determine if Developer wishes to proceed with an Optional Interconnection Feasibility Study. The ISO, Connecting Transmission Owner and Developer will bring to the meeting such technical data, including, but not limited to: (i) general facility loadings, (ii) general stability issues, (iii) general short circuit issues, (iv) general voltage issues, (v) general reliability issues, and (vi) general system protection issues, and (vii) general deliverability issues as may be reasonably required to accomplish the purpose of the meeting. The Connecting Transmission Owner and Affected Transmission Owner(s), identified pursuant to Section 30.3.5 of this Attachment X, shall provide input regarding proposed Point(s) of Interconnection and configurations. The ISO, Connecting Transmission Owner, Affected Transmission Owner(s), and Developer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Developer shall designate its Point of Interconnection, pursuant to Section 30.6.1, and one or more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose. Within five (5) Business Days after the Scoping Meeting, Developer shall advise the ISO whether it elects to proceed with an Optional Interconnection Feasibility Study.

30.3.4 OASIS Posting

The ISO will maintain on its OASIS a list of all valid Interconnection Requests. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date, Initial Synchronization Date and Commercial Operation Date; (v) the status of the Interconnection Request, including Queue Position; (vi) the identity of the Developer; and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Large Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. Before holding a Scoping Meeting with an Affiliate of a Connecting Transmission Owner and that Connecting Transmission Owner, the ISO shall post on its OASIS an advance notice of its intent to do so. The ISO shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection System Reliability Impact Study reports shall be posted to the ISO password-protected website subsequent to the meeting between the Developer, The ISO and Connecting Transmission Owner to discuss the applicable study results. The ISO shall also post any known deviations in date proposed by the Large Facility in Section 30.3.4(iv), above.

30.3.5 Coordination with Affected Systems

The ISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators, as soon as they are identified – either by their own accord, by the Connecting Transmission Owner, by the ISO or by members of the ISO’s Operating Committee or Transmission Planning Advisory Subcommittee of the ISO’s Operating Committee. The ISO will include those results on Affected Transmission Owner systems in its applicable Interconnection Study within the time frame specified in these Large Facility Interconnection Procedures. The ISO will also include results, if available, on other Affected Systems. The ISO will invite such Affected System Operators to all meetings held with the Developer as required by these Large Facility Interconnection Procedures. The Developer will cooperate with the ISO in all matters related to the conduct of studies and the determination of modifications to Affected Systems. An Affected System Operator shall cooperate with the ISO and Connecting Transmission Owner with whom interconnection has been requested in all matters related to the type and/or conduct of studies and the determination of modifications to Affected Systems. The ISO shall include in the appropriate interconnection study proposed studies requested by an identified Affected Transmission Owner to the extent such studies are reasonably justified in accordance with Good Utility Practice.

For identified Affected Transmission Owner(s) of facilities electrically adjacent to the Point of Interconnection and that have design criteria, operational criteria or other local planning criteria applicable to either (1) the substation to which the Developer proposes to interconnect; or (2) the substation that will be required to be built to accommodate the interconnection, the ISO shall provide such Affected Transmission Owner(s) with the opportunity to review and provide comments on all study scopes, study reports and drafts thereof for the project, and will be included on communications regarding the project and meetings discussing the project or any of its studies, where such communications or meetings involve the ISO, Developer and Connecting Transmission Owner. The ISO shall include in the appropriate interconnection study proposed studies requested by such an identified Affected Transmission Owner to the extent such studies are reasonably justified in accordance with Good Utility Practice.

30.3.6 Withdrawal

The Developer may withdraw its Interconnection Request at any time by written notice of such withdrawal to the ISO. In addition, if the Developer fails to adhere to all requirements of these Large Facility Interconnection Procedures, except as provided in Section 30.13.5 (Disputes), the ISO shall deem the Interconnection Request to be withdrawn and shall provide written notice to the Developer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, the Developer shall have a cure period of fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify the ISO of its intent to pursue Dispute Resolution; except that such cure period does not extend specific deadlines set forth in Sections 25.6.2.3.2 and 25.8.2 of Attachment S and the deadlines for study agreement execution and submittal of all required deposits set forth in Section 30.8.1 of this Attachment X (*i.e.*, Developer cannot obtain an additional fifteen (15) business days by virtue of the cure period to comply with the requirements of the above-referenced tariff provisions, but could use the cure period to provide evidence that Developer did in fact provide the required information by the tariff-required date).

Withdrawal shall result in the loss of the Developer's Queue Position. If a Developer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, the Developer's Interconnection Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. A Developer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to the ISO and Connecting Transmission Owner all costs that the ISO and Connecting Transmission Owner prudently incur with respect to that Interconnection Request prior to the receipt of notice described above. The Developer must pay all monies due to the ISO and Connecting Transmission Owner before it is allowed to obtain any Interconnection Study data or results.

The ISO shall (i) update the OASIS Queue Position posting and (ii) after all outstanding invoices for study work for the project have been received by the ISO, refund to the Developer any portion of the Developer's deposit or study payments that exceeds the costs that the ISO has incurred, including interest calculated in accordance with section 35.19a(a)(2) of FERC's regulations. In the event of such withdrawal, the ISO and Connecting Transmission Owner, subject to the confidentiality provisions of Section 30.13.1, shall provide, at Developer's request, all information that the ISO and Connecting Transmission Owner developed for any completed study conducted up to the date of withdrawal of the Interconnection Request..

30.4 Queue Position

30.4.1 General

The ISO shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and the Developer provides such information in accordance with Section 30.3.3.3, then the ISO shall assign the Developer a Queue Position based on the date the application form was originally filed. The Queue Position of each Interconnection Request will be used to determine the order of performing the Interconnection Studies. A higher queued Interconnection Request is one that has been placed "earlier" in the queue in relation to another Interconnection Request that is lower queued.

30.4.2 Clustering

At the ISO's option, Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Reliability Impact Study.

Clustering shall be implemented on the basis of Queue Position. If the ISO elects to study Interconnection Requests using Clustering, all Interconnection Requests received within a period not to exceed one hundred and eighty (180) Calendar Days, hereinafter referred to as the "Queue Cluster Window" shall be studied together. Deadlines for completing all Interconnection System Reliability Impact Studies for all Interconnection Requests assigned to the same Queue Cluster Window shall be in accordance with Section 30.7.4. The ISO may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Facility.

Clustering Interconnection System Reliability Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the New York State Transmission System capabilities at the time of each study.

The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on the ISO's OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the end date of the first Queue Cluster Window that is to be modified.

30.4.3 Transferability of Queue Position

A Developer may transfer its Queue Position to another entity only if such entity acquires the specific Large Facility identified in the Interconnection Request and the Point of Interconnection does not change. As a result of such a transfer, the acquiring entity shall become the Developer of the specific Large Facility identified in the Interconnection Request.

30.4.4 Modifications

The Developer shall submit to the ISO, in writing, modifications to any information provided in the Interconnection Request. The Developer shall retain its Queue Position if the modifications are permitted in accordance with Sections 30.4.4.1, 30.4.4.2, 30.4.4.5 or 30.4.4.6, or are determined not to be Material Modifications pursuant to Section 30.4.4.3.

Notwithstanding the above, during the course of the Interconnection Studies, either the Developer or the ISO or Connecting Transmission Owner may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the New York State Transmission System to accommodate the Interconnection Request. To the extent the identified changes are acceptable to the ISO, Connecting Transmission Owner and Developer, such acceptance not to be unreasonably withheld, the ISO shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 30.6.4, Section 30.7.6 and Section 30.8.5 as applicable and Developer shall retain its Queue Position.

30.4.4.1 Prior to the commencement of the Interconnection System Reliability Impact Study Agreement as posted on the ISO's interconnection queue , modifications permitted under this section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project; (b) modifying the technical parameters associated with the Large Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of study analysis.

30.4.4.2 Prior to the return of the executed Interconnection Facility Study Agreement to the ISO, the modifications permitted under this section shall include specifically: (a) additional 15 percent decrease of electrical output (MW), (b) Large Facility technical parameters associated with modifications to Large Facility technology and transformer impedances; and (c) a reduction in the number of MW the Developer requests to be evaluated for CRIS; provided, however, the incremental Interconnection Study costs associated with those modifications are the responsibility of the requesting Developer.

30.4.4.3 Prior to making any modification other than those specifically permitted by Sections 30.4.4.1, 30.4.4.2, 30.4.4.5 and 30.4.4.6, Developer may first request that the ISO evaluate whether such modification is a Material Modification. In response to Developer's request, the ISO shall evaluate the proposed modifications prior to making them and inform the Developer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection except those deemed acceptable under Section 30.4.4.1, 30.6.1, 30.7.2 or so allowed elsewhere shall constitute a Material Modification. The Developer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

30.4.4.4 Upon receipt of Developer's request for modification permitted under this Section 30.4.4, the ISO shall commence and perform any necessary additional studies as soon as practicable, but in no event shall the ISO commence such studies later than thirty (30) Calendar Days after receiving notice of Developer's request. Any additional studies resulting from such modification shall be done at Developer's cost.

30.4.4.5 Extensions of the proposed Commercial Operation Date will not be Material Modifications if:

30.4.4.5.1 The proposed Commercial Operation Date is within four (4) years from the following date:

30.4.4.5.1.1 For all Large Facilities and for Small Generating Facilities subject to Attachment S, the date the Developer and all other Developers remaining in the Class Year post security as part of a Class Year Interconnection Facilities Study (*i.e.,* completion of the Class Year).

30.4.4.5.1.2 For Small Generating Facilities not subject to Attachment S, the date the ISO tenders the SGIA to the Interconnection Customer.

30.4.4.5.2 Developer may request an extension of its Commercial Operation Date beyond the limit specified in Section 30.4.4.5.1. Such request will not be a Material Modification only if the following conditions have been met:

30.4.4.5.2.1 Developer must have an executed Interconnection Agreement for the project or have an unexecuted Interconnection Agreement jointly filed at FERC by the ISO and Connecting Transmission Owner; and

30.4.4.5.2.2 Developer must demonstrate (via an Officer certification) that it has made reasonable progress against milestones set forth in the Interconnection Agreement (*e.g.*, completion of engineering design, major equipment orders, commencement and continuation of construction of the Large Facility and associated System Upgrade Facilities, as applicable). If Developer has requested an unexecuted Interconnection Agreement be filed with FERC, Developer must meet this requirement within sixty (60) days of a FERC Order on the unexecuted Interconnection Agreement.

30.4.4.5.3 For projects in the ISO interconnection queue that as of February 18, 2013 have accepted Project Cost Allocations and posted Security for System Upgrade Facilities from the final round of a Class Year Interconnection Facilities Study, the following criteria must be satisfied with respect to the proposed Commercial Operation Date:

30.4.4.5.3.1 The project's proposed Commercial Operation Date posted on the ISO interconnection queue as of February 18, 2013 must be within the limit specified in Section 30.4.4.5.1; or

30.4.4.5.3.2 The project's proposed Commercial Operation Date posted on the ISO interconnection queue as of February 18, 2013 must have been reviewed by the ISO and determined not to be a Material Modification prior to February 18, 2013; or

30.4.4.5.3.3 If the project's proposed Commercial Operation Date posted on the ISO interconnection queue as of February 18, 2013 is beyond the limit specified in Section 30.4.4.5.1 and the project has not satisfied Section 30.4.4.5.3.2, the following conditions must be satisfied or the project will be withdrawn from the ISO interconnection queue:

30.4.4.5.3.3.1 Within sixty (60) days of February 18, 2013, Developer must either (1) have an executed Interconnection Agreement for the project; or (2) have an unexecuted Interconnection Agreement jointly filed at FERC by the ISO and Connecting Transmission Owner; and

30.4.4.5.3.3.2 Within sixty (60) days of execution of an Interconnection Agreement or a FERC Order on an unexecuted Interconnection Agreement, as applicable, Developer must demonstrate (via an Officer certification) that it has made reasonable progress against milestones set forth in the Interconnection Agreement (*e.g.*, completion of engineering design, major equipment orders, commencement and continuation of construction of the Large Facility and associated System Upgrade Facilities, as applicable).

30.4.4.5.3.4 For a project that is subject to Section 30.4.4.5.3, subsequent requests for an extension of the project's Commercial Operation Date (*i.e.*, requests submitted to the ISO after February 18, 2013) will not be a Material Modification only if Developer satisfies the requirements set forth in Section 30.4.4.5.2.

30.4.4.5.4 Prior to the expiration of the proposed In-Service Date posted on the ISO interconnection queue, as applicable, Developer is obligated to provide the ISO with notice of any proposed extensions of proposed In-Service Date, proposed Initial Synchronization Date or proposed Commercial Operation Date, as applicable, as soon as it becomes apparent to Developer that the most recent proposed In-Service Date posted on the ISO's interconnection queue is infeasible.

30.4.4.6 Any increase by the Developer, when it executes the Class Year Interconnection Facilities Study Agreement, in the number of MW of Installed Capacity that it previously requested to be evaluated for CRIS shall constitute a Material Modification. Any decrease in the number of MWs the Developer requests, pursuant to Section 25.7.7.1 of Attachment S to the ISO OATT, to be evaluated for CRIS after it executes the Class Year Interconnection Facilities Study Agreement, shall not constitute a Material Modification.

30.5 Procedures for Interconnection Requests Submitted Prior to Effective Date of Standard Large Facility Interconnection Procedures

30.5.1 Queue Position for Pending Requests

30.5.1.1 Any Developer assigned a Queue Position prior to the effective date of these Large Facility Interconnection Procedures shall retain that Queue Position.

30.5.1.1.1 If an Interconnection Study Agreement has not been executed as of the effective date of these Large Facility Interconnection Procedures, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with these Large Facility Interconnection Procedures.

30.5.1.1.2 If an Interconnection Study Agreement has been executed prior to the effective date of this these Large Facility Interconnection Procedures, such Interconnection Study shall be completed in accordance with the terms of such agreement. With respect to any remaining studies for which a Developer has not signed an Interconnection Study Agreement prior to the effective date of these Large Facility Interconnection Procedures, the ISO must offer the Developer the option of either continuing under the ISO's existing interconnection study process or going forward with the completion of the necessary Interconnection Studies (for which it does not have a signed Interconnection Studies Agreement) in accordance with these Large Facility Interconnection Procedures.

30.5.1.1.3 If a Standard Large Generator Interconnection Agreement has been submitted to the Commission for approval before the effective date of these Standard Large Facility Interconnection Procedures, then the Standard Large Generator Interconnection Agreement would be grandfathered.

30.5.1.2 Transition Period

To the extent necessary, the ISO and Developers with an outstanding request (i.e., an Interconnection Request for which an interconnection agreement has not been submitted to the Commission for approval as of the effective date of these Large Facility Interconnection Procedures) shall transition to these procedures within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term "outstanding request" herein shall mean any Interconnection Request, on the effective date of these Large Facility Interconnection Procedures: (i) that has been submitted but not yet accepted by the ISO; (ii) where the related interconnection agreement has not yet been submitted to the Commission for approval in executed or unexecuted form, (iii) where the relevant Interconnection Study Agreements have not yet been executed, or (iv) where any of the relevant Interconnection Studies are in process but not yet completed. Any Developer with an outstanding request as of the effective date of these Large Facility Interconnection Procedures may request a reasonable extension of any deadline, otherwise applicable, if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension shall be granted by the ISO to the extent consistent with the intent and process provided for under these Large Facility Interconnection Procedures. This paragraph shall not apply to a Large Facility's obligation to obtain CRIS in order to quality as an Installed Capacity Supplier or obtain Unforced Capacity Delivery Rights under the ISO Services Tariff.

30.5.2 New Transmission Provider

If the ISO transfers its control of the New York State Transmission System to a successor transmission provider during the period when an Interconnection Request is pending, the ISO shall transfer to the successor transmission provider any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by these Large Facility Interconnection Procedures shall be paid by or refunded to the Developer, as appropriate. The ISO shall coordinate with the successor transmission provider to complete any Interconnection Request (including Interconnection Studies), as appropriate, that the ISO has begun but has not completed. If the ISO has tendered a draft Standard Large Generator Interconnection Agreement to the Developer but the Developer has not either executed that interconnection agreement or requested the filing of an unexecuted Standard Large Generator Interconnection Agreement with FERC, unless otherwise provided, the Developer must complete negotiations with the successor transmission provider.

30.6 Optional Interconnection Feasibility Study

30.6.1 Commencing an Optional Interconnection Feasibility Study

If, within five (5) Business Days after the Scoping Meeting, Developer advises the ISO that it elects to proceed with an Optional Interconnection Feasibility Study, the ISO shall provide to Developer and Connecting Transmission Owner a good faith estimate of the cost and timeframe for completing the Optional Interconnection Feasibility Study. The Developer is responsible for the actual cost of the Optional Interconnection Feasibility Study. Developer shall specify the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection. The Developer must provide a $10,000 or $60,000 study deposit, depending on the scope of analyses requested pursuant to Section 30.6.2 of this Attachment X The Developer shall deliver to the ISO the required deposit of $10,000 or $60,000, depending upon the scope of the study work elected pursuant to Section 30.6.2 of this Attachment X and the technical data requested by the ISO no later than fifteen (15) Business Days after Developer's receipt of the ISO's good faith estimate of the study costs. If the Developer does not provide the required study deposit within fifteen (15) Business Days after the ISO's notice to Developer and the Connecting Transmission Owner of the good faith estimate of the cost and timeframe for completing the SRIS, the Interconnection Request will be subject to withdrawal. If the Developer does not provide all required technical data, the ISO shall notify the Developer of the deficiency and the Developer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such ability to cure technical deficiencies does not apply to failure to submit the required deposit. The ISO shall notify the Developer and the Connecting Transmission Owner that the Optional Interconnection Feasibility Study has commenced following receipt of the required deposit and once the ISO deems the required technical data sufficient.

If the Optional Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by either Developer or Connecting Transmission Owner and the ISO, and acceptable to the other Parties, such acceptance not to be unreasonably withheld, may be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and re-studies shall be completed pursuant to Section 30.6.4 as applicable. For the purpose of this Section 30.6.1, if the ISO, Connecting Transmission Owner and Developer cannot agree on the substituted Point of Interconnection, then Developer may direct that an alternative, as specified pursuant to Section 30.3.3.4, shall be the substitute.

If the Developer opts to forego the Optional Interconnection Feasibility Study, the ISO will initiate an Interconnection System Reliability Impact Study under Section 30.7 of these Large Facility Interconnection Procedures.

30.6.2 Scope of Optional Interconnection Feasibility Study

The Optional Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the New York State Transmission System in accordance with the scope that the Developer elects pursuant to this Section 30.6.2. The scope of the Optional Interconnection Feasibility Study will be provided to the Developer and Connecting Transmission Owner for review and comment. After the Optional Feasibility Study scope is finalized, the ISO will provide the final scope to the Developer and Connecting Transmission Owner. The Connecting Transmission Owner shall indicate its agreement to the Optional

Feasibility Study scope by signing it and promptly returning it to the ISO, such agreement not to be unreasonably withheld.

The Optional Interconnection Feasibility Study shall be conducted in accordance with Applicable Reliability Standards.

The Optional Interconnection Feasibility Study will consider the Base Case and, if not already included in the Base Case, all generating and merchant transmission facilities (and with respect to (iii), any identified System Upgrade Facilities and, if security or cash has been posted in accordance with Attachment S, System Deliverability Upgrades, except for Highway facility upgrades that have not yet been triggered under Section 25.7.12.3.1 of Attachment S) that, on the date the Optional Interconnection Feasibility Study commences: (i) are directly interconnected to the New York State Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have accepted their cost allocation for System Upgrade Facilities and posted security for such System Upgrade Facilities in accordance with Attachment S; and (iv) have no Queue Position but have executed a Standard Large Generator Interconnection Agreement or requested that an unexecuted Standard Large Generator Interconnection Agreement be filed with FERC.

The Optional Interconnection Feasibility Study may consist of the any of the following levels of analysis, at Developer's election:

For a $10,000 Optional Interconnection Feasibility Study Deposit, Developer may request the following limited analyses:

(1) Development of conceptual breaker-level one-line diagram of existing NYS Transmission System or Distribution System where the Large Facility proposes to

interconnect (i.e., how to integrate the Large Facility into the existing system); and/or

(2) Review of feasibility/constructability of a conceptual breaker-level one-line diagram of the proposed interconnection (e.g., space for additional breaker bay in existing substation or identification of cable routing concerns inside existing substation).

For a $60,000 Optional Interconnection Feasibility Study Deposit, Developer may request the following detailed analyses:

(1) Development of conceptual breaker-level one-line diagram of existing NYS Transmission System or Distribution System where the Large Facility proposes to interconnect (i.e., how to integrate the Large Facility into the existing system);

(2) Review of feasibility/constructability of a conceptual breaker-level one-line diagram of the proposed interconnection (e.g., space for additional breaker bay in existing substation or identification of cable routing concerns inside existing substation);

(3) Preliminary review of local protection, communication, and grounding issues associated with the proposed interconnection;

(4) Power flow, short circuit, and/or bus flow analyses; and/or

(5) Identification of Connecting Transmission Owner Attachment Facilities and Local System Upgrade Facilities with a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

30.6.3 Optional Interconnection Feasibility Study Procedures

ISO may request additional information from Developer and Connecting Transmission Owner as may reasonably become necessary consistent with Good Utility Practice during the course of the Optional Interconnection Feasibility Study. Upon request from the ISO for additional information required for or related to the Optional Interconnection Feasibility Study, Developer and Connecting Transmission Owner shall provide such additional information in a prompt manner.

The ISO shall utilize existing studies to the extent practicable when it performs the study. If Developer elects the more limited study scope described in Section 30.6.2, the ISO shall use Reasonable Efforts to complete the Optional Interconnection Feasibility Study no later than forty-five (45) Calendar Days after the ISO confirms receipt of the required the required study deposit and required technical data. If Developer elects the more detailed study scope described in Section 30.6.2, the ISO shall use Reasonable Efforts to complete the Optional Interconnection Feasibility Study no later than ninety (90) Calendar Days after the ISO confirms receipt of the required study deposit and required technical data. At the request of the Developer or at any time the ISO determines that it will not meet the required time frame for completing the Optional Interconnection Feasibility Study, ISO shall notify the Developer as to the schedule status of the Optional Interconnection Feasibility Study. If the ISO is unable to complete the Optional Interconnection Feasibility Study within that time period, it shall notify the Developer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, the ISO shall provide the Developer supporting documentation, workpapers and relevant power flow, and short circuit databases for the Optional Interconnection Feasibility Study, subject to confidentiality arrangements consistent with Section 30.13.1.

30.6.3.1 Study Report Meeting

Connecting Transmission Owner and any Affecting Transmission Owners, together with Developer, will be provided with drafts of the Optional Interconnection Feasibility Study report for review. Review and comments shall be provided to the ISO within fifteen (15) Business Days of receipt. Within ten (10) Business Days of providing a final draft of the Optional Interconnection Feasibility Study report to Developer, the ISO and Connecting Transmission Owner shall meet with Developer to discuss the results of the Optional Interconnection Feasibility Study.

30.6.4 Re-Study

If the ISO determines that re-study of the Optional Interconnection Feasibility Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to Section 30.4.4, or re-designation of the Point of Interconnection pursuant to Section 30.6.1 the ISO shall notify Developer in writing. Such re-study shall take not longer than forty-five (45) Calendar Days from the date of the notice. Any cost of re-study shall be borne by the Developer being re-studied.

30.7 Interconnection System Reliability Impact Study

30.7.1 Commencing an Interconnection System Reliability Impact Study

Developer shall advise the ISO that it elects to proceed with an Interconnection System Reliability Impact Study within five (5) Business Days after either the delivery of the final Optional Interconnection Feasibility Study report to the Developer, or, the Scoping Meeting, if the Developer opts to forego the Optional Interconnection Feasibility Study. As soon as practicable after receipt of such election from the Developer, the ISO shall provide to the Developer and Connecting Transmission Owner a good faith estimate of the cost and timeframe for completing the Interconnection System Reliability Impact Study ("SRIS"). The Developer shall compensate the ISO and Connecting Transmission Owner for the actual cost of the SRIS.

30.7.2 Study Deposit and Site Control Requirements for an Interconnection System Reliability Impact Study

The Developer shall submit to the ISO no later than fifteen (15) Business Days after the ISO's notice to Developer and the Connecting Transmission Owner of the good faith estimate of the cost and timeframe for completing the SRIS the following: (1) demonstration of Site Control (if Site Control was not provided with the Interconnection Request); (2) the required SRIS deposit pursuant to Section 30.7.2.1 of this Attachment X; and (3) the technical data requested by the ISO. The ISO shall notify the Developer and the Connecting Transmission Owner that the Interconnection System Reliability Impact Study has commenced following receipt of the required SRIS deposit and once the ISO deems the required technical data and site control sufficient.

30.7.2.1 Applicable Study Deposit

If the ISO is responsible for performing the entire study, the required deposit is $120,000 ($150,000 if the Developer elects to include a preliminary, non-binding evaluation of the Large Facility's deliverability under the NYISO Deliverability Interconnection Standard). If the Developer is hiring a third-party consultant to perform the analytical portion of the study, the required deposit is $40,000 ($70,000 if the Developer elects to include a preliminary, non-binding evaluation of the Large Facility's deliverability under the NYISO Deliverability Interconnection Standard). If the Developer does not provide the required study deposit within fifteen (15) Business Days after the ISO's notice to the Developer and the Connecting Transmission Owner of the good faith estimate of the cost and timeframe for completing the SRIS, the Interconnection Request will be subject to withdrawal.

30.7.2.2 Required Technical Data for the SRIS

If the Developer does not provide all required technical data , the ISO shall notify the Developer of the deficiency and the Developer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such ability to cure technical deficiencies does not apply to failure to demonstrate site control or submit the required deposit in lieu of demonstrating site control.

30.7.2.3 Substitute Point of Interconnection

If the SRIS uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Optional Interconnection Feasibility Study, a substitute Point of Interconnection identified by either Developer or Connecting Transmission Owner and the ISO, and acceptable to the other Parties, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and restudies shall be completed pursuant to Section 30.7.6 as applicable. For the purpose of this Section 30.7.2.3, if the ISO, Connecting Transmission Owner and Developer cannot agree on the substituted Point of Interconnection, then Developer may direct that one of the alternatives as specified in the Optional Interconnection Feasibility Study Agreement, as specified pursuant to Section 30.3.3.4, shall be the substitute.

30.7.3 Scope of Interconnection System Reliability Impact Study

The SRIS shall evaluate the impact of the proposed interconnection on the reliability of the New York State Transmission System. If an Optional Interconnection Feasibility Study is not performed for the project, the SRIS will also evaluate the feasibility of the proposed interconnection. The SRIS shall be conducted in accordance with Applicable Reliability Standards. The SRIS will consider the Base Case, and if not already included in the Base Case, all generating and merchant transmission facilities (and with respect to (iii) below, any identified System Upgrade Facilities associated with such higher queued interconnection and, if security or cash has been posted in accordance with Attachment S, System Deliverability Upgrades, except for Highway facility upgrades that have not yet been triggered under Section 25.7.12.3.1 of Attachment S) that, on the date the SRIS scope is approved by the Operating Committee: (i) are directly interconnected to the New York State Transmission System or to the Distribution System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have accepted their cost allocation for System Upgrade Facilities and posted security for such System Upgrade Facilities in accordance with Attachment S; and (iv) have no Queue Position but have executed a Standard Large Generator Interconnection Agreement or requested that an unexecuted Standard Large Generator Interconnection Agreement be filed with FERC.

The ISO may request additional information from Developer and Connecting Transmission Owner as may reasonably become necessary consistent with Good Utility Practice during the course of the SRIS. Upon request from the ISO for additional information required for or related to the SRIS, the Developer and Connecting Transmission Owner shall provide such additional information in a prompt manner.

The SRIS will consist of a short circuit analysis, a stability analysis, and a power flow analysis; however, for a Developer proposing an incremental increase in output to an existing Large Facility, the SRIS scope may be narrowed upon mutual agreement among the ISO, Connecting Transmission Owner and the Developer. The SRIS will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing Energy Resource Interconnection Service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The SRIS will provide a list of facilities that are required as a result of the Interconnection Request and a nonbinding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct. The scope of the SRIS will be provided to the Developer and Connecting Transmission Owner for review and comment. After the SRIS scope is finalized, the ISO will provide the final scope to the Connecting Transmission Owner. The Connecting Transmission Owner shall indicate its agreement to the scope of the SRIS by signing it and promptly returning it to the ISO, such agreement not to be unreasonably withheld.

The ISO Operating Committee shall approve the specific study scope proposed for each SRIS.

At Developer's option, and subject to an additional $30,000 SRIS deposit, the SRIS may include a preliminary evaluation of the Large Facility under the Deliverability Interconnection Standard if the Large Facility elected both Energy Resource Interconnection Service and Capacity Resource Interconnection Service in its Interconnection Request. Such preliminary deliverability evaluation will state the assumptions upon which it is based; state the results of the preliminary analyses; identify potential System Deliverability Upgrades at a high level; and provide preliminary System Deliverability Upgrade cost estimates which may be based on generic information. To the extent the project subsequently elects to proceed to a Class Year Interconnection Facilities Study, the portion of the Class Year Interconnection Facilities Study costs attributable to the Class Year Deliverability Study would not be offset by any expenses paid by the Developer for a preliminary deliverability evaluation in its SRIS.

30.7.4 Interconnection System Reliability Impact Study Procedures

The ISO shall coordinate the SRIS with any Affected System that is affected by the Interconnection Request pursuant to Section 30.3.5 above. The ISO shall utilize existing studies to the extent practicable when it performs the study. The ISO shall use Reasonable Efforts to complete the SRIS within ninety (90) Calendar Days after the ISO confirms receipt of the required study deposit, required technical data, and Site Control (if Site Control was not provided with the Interconnection Request), . If ISO uses Clustering, the ISO shall use Reasonable Efforts to deliver a completed SRIS within ninety (90) Calendar Days after the close of the Queue Cluster Window. The ISO Operating Committee shall approve each final SRIS.

At the request of the Developer or at any time the ISO determines that it will not meet the required timeframe for completing the SRIS, the ISO shall notify the Developer as to the schedule status of the SRIS. If the ISO is unable to complete the SRIS within the time period, it shall notify the Developer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, the ISO shall provide the Developer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the SRIS, subject to confidentiality arrangements consistent with Section 30.13.1.

30.7.5 Study Report Meeting

Connecting Transmission Owner and any Affecting Transmission Owners, together with Developer, will be provided with drafts of the SRIS report for review. Review and comments shall be provided to the ISO within fifteen (15) Business Days of receipt. Within ten (10) Business Days of providing a final draft SRIS report to Developer, the ISO and Connecting Transmission Owner shall meet with Developer to discuss the results of the SRIS.

Upon the ISO's issuance of a final draft SRIS report, the Developer must proceed with its study report to the Transmission Planning Advisory Subcommittee ("TPAS") of the ISO Operating Committee within three (3) months and to the next ISO Operating Committee meeting following the TPAS review; provided, however, if the TPAS recommends revisions or supplements to the study report, the revised report must proceed to the next TPAS meeting following completion of such revisions, and to the next ISO Operating Committee following the TPAS review of the revised study report. Failure to proceed with its study report to the TPAS and ISO Operating Committee within these timeframes will result in withdrawal of the Interconnection Request.

The ISO Operating Committee shall approve each final SRIS report after review of the final SRIS report by the TPAS.

30.7.6 Re-Study

If the ISO determines that re-study of the SRIS is required due to a higher queued project dropping out of the queue, a modification of a higher queued project subject to Section 30.4.4, or re-designation of the Point of Interconnection pursuant to Section 30.7.2, the ISO shall notify Developer in writing. Such re-study shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of re-study shall be borne by the Developer being re-studied.

30.8 Class Year Interconnection Facilities Study

30.8.1 Class Year Interconnection Facilities Study Agreement

As soon as practicable after a Study Start Date is established pursuant to Section 25.5.9 of Attachment S to the OATT, the ISO shall provide a Class Year Interconnection Facilities Study Agreement for the next Class Year in the form of Appendix 4 to these Large Facility Interconnection Procedures to each Developer and Interconnection Customer who has not previously received an agreement for the next Class Year, upon request, contingent upon confirmation by the ISO that the Developer is an Eligible Class Year Project. The ISO shall tender a Class Year Interconnection Facilities Study Agreement at an earlier point to any Developer or Interconnection Customer that so requests and that the ISO confirmed to be an Eligible Class Year Project. When the ISO provides a Class Year Interconnection Facilities Study Agreement to an Eligible Class Year Project, the ISO shall, at the same time, also provide one to that Eligible Class Year Project's Connecting Transmission Owner. The Class Year Interconnection Facilities Study Agreement shall provide that the Class Year Project shall compensate the ISO and Connecting Transmission Owner for the actual cost of the Class Year Interconnection Facilities Study. When the ISO provides the Class Year Interconnection Facilities Study Agreement to the Eligible Class Year Project, the ISO shall provide to the Eligible Class Year Project a non-binding good faith estimate of the cost and timeframe for completing the Class Year Interconnection Facilities Study. The Eligible Class Year Project shall execute the Class Year Interconnection Facilities Study Agreement and deliver the executed Class Year Interconnection Facilities Study Agreement to the ISO within thirty (30) Calendar Days after the Developer's receipt of the Class Year Interconnection Facilities Study Agreement. Starting with the Class Year subsequent to Class Year 2012, with the executed Class Year

Interconnection Facilities Study Agreement, the Class Year Project shall deliver to the ISO (1) the required technical data; (2) the Class Year Project's interconnection service evaluation election; (3) for Large Facilities not yet In-Service, an updated proposed In-Service Date, an updated proposed Initial Synchronization Date and an updated proposed Commercial Operation Date (subject to the ten (10) year limitation set forth in Section 30.3.1); (4) a study deposit of $100,000 (if the Class Year Project seeks evaluation for ERIS or ERIS and CRIS), or $50,000 (if the Class Year Project seeks only CRIS); and (5) if the Developer has not satisfied the applicable regulatory milestone described in Section 25.6.2.3.1.1 of Attachment S to the ISO OATT, a two-part deposit consisting of $100,000 plus $3,000/MW deposit as required by Section 25.6.2.3.1(ii)(2). At the same time the Class Year Project provides the above items to the ISO, the Class Year Project shall deliver the executed Class Year Interconnection Facilities Study Agreement, together with the required technical data (as applicable), to the Connecting Transmission Owner. The ISO and Connecting Transmission Owner shall execute the Class Year Interconnection Facilities Study Agreement no later than ten (10) Business Days after the ISO confirms receipt of the executed Class Year Interconnection Facilities Study Agreement, the required technical data and required deposits from the Developer. The ISO shall provide a copy of the fully executed Class Year Interconnection Facilities Study Agreement to the Developer and Connecting Transmission Owner.

30.8.1.1 The ISO shall invoice the Class Year Project on a monthly basis for the work to be conducted on the Class Year Interconnection Facilities Study each month. Any Class Year Project having elected only ERIS shall not be invoiced for any part of the cost of the Class Year Deliverability Study. Any Class Year Project that elects to reduce the MW of CRIS it requests to be evaluated in the

Class Year Deliverability Study and thereby opts out of any additional detailed studies, if required, for System Deliverability Upgrades, shall not be invoiced for any additional detailed studies required for System Deliverability Upgrades. The Class Year Project shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. The ISO shall continue to hold the amounts on deposit until settlement of the final invoice.

30.8.1.2 Starting with the Class Year Study subsequent to Class Year 2017, a Class Year project may withdraw from the Class Year Study pursuant to Section 25.5.9 of Attachment S prior to completion of the Annual Transmission Baseline Assessment study cases. Upon such withdrawal, the deposits paid in lieu of satisfaction of the regulatory milestone pursuant to Section 25.6.2.3.1 of Attachment S will be fully refunded.

30.8.2 Scope of Class Year Interconnection Facilities Study

The Class Year Interconnection Facilities Study shall be performed concurrently as a combined Class Year Interconnection Facilities Study for a Class Year, as determined in accordance with Attachment S of the ISO OATT, to fulfill the requirements of this Section 30.8, and the requirements of the Annual Transmission Reliability Assessment and Class Year Deliverability Study called for by Attachment S.

The combined Class Year Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering and design work, permitting, site acquisition, procurement and construction work and commissioning needed for the Class Year in accordance with Good Utility Practice and, for each of these cost categories, shall specify and estimate the cost of the work to be done at each substation and/or on each feeder to physically and electrically connect each facility in the Class Year to the Transmission System. The combined Class Year Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Connecting Transmission Owners' Attachment Facilities, any Distribution Upgrades, any System Upgrade Facilities and, for Class Year Projects seeking CRIS, any System Deliverability Upgrades necessary to accomplish the interconnection of each Class Year Project; and shall include a schedule showing the estimated time required to complete the engineering and design, permitting, site acquisition, procurement, construction, installation and commissioning phases of the Class Year Projects. The schedule shall contain major milestones to facilitate the tracking of the progress of each Class Year Project.

30.8.2.1 Following execution of the Class Year Interconnection Facilities Study Agreement, Developer shall submit to the ISO an updated proposed In-Service Date, an updated proposed Initial Synchronization Date and an updated proposed Commercial Operation Date every ninety (90) Calendar Days.

30.8.2.2 Following commencement of the activities described in Section 30.8.2 of this Attachment X, for each Class Year Project not yet In-Service, the Class Year Project, that Class Year Project's Connecting Transmission Owner and each Affected Transmission Owner(s) shall report every other month on the progress of their respective activities to the ISO and to each other. Such reports shall be in a format consistent with, and include the content required by, applicable ISO Procedures. In these bimonthly reports, each Class Year Project and Connecting Transmission Owner and Affected Transmission Owner(s) shall report any material variance from earlier schedule estimates for their respective activities, and the reasons for such variance. In addition, the Connecting Transmission Owner and Affected Transmission Owner(s) shall report any material variance from earlier cost estimates for its activities, and the reasons for such variance.

30.8.3 Class Year Interconnection Facilities Study Procedures

The ISO shall coordinate the Class Year Interconnection Facilities Study with the Connecting Transmission Owner and Affected Transmission Owners, and with any other Affected System pursuant to Section 30.3.5 above. The ISO shall utilize existing studies to the extent practicable in performing the Class Year Interconnection Facilities Study.

The ISO may request additional information from the Developer and Connecting Transmission Owner as may reasonably become necessary consistent with Good Utility Practice during the course of the Class Year Interconnection Facilities Study. Upon request from the ISO for additional information required for or related to the Class Year Interconnection Facilities Study, the Developer and Connecting Transmission Owner shall provide such additional information in a prompt manner.

The ISO shall follow the procedures set forth in Attachment S of the ISO OATT and shall use Reasonable Efforts to complete the study and issue a Class Year Interconnection Facilities Study report to the Class Year Projects within the timeframe called for in Attachment S.

At the request of any Class Year Project, or at any time the ISO determines that it will not meet the required time frame for completing the Class Year Interconnection Facilities Study, the ISO shall notify the Class Year Projects as to the schedule status of the Class Year Interconnection Facilities Study. If the ISO is unable to complete the Class Year Interconnection Facilities Study and issue a cost allocation report within the time required, it shall notify the

Class Year Projects and provide an estimated completion date and an explanation of the reasons why additional time is required.

Upon request, the ISO shall provide each Class Year Project supporting documentation, workpapers, and databases or data developed in the preparation of the Class Year Interconnection Facilities Study, subject to non-disclosure arrangements consistent with Section 30.13.1.

30.8.4 Study Report Meeting

Within ten (10) Business Days of providing a draft Class Year Interconnection Facilities Study report to Class Year Projects, the ISO and Connecting Transmission Owner and Affected Transmission Owners shall meet with the Developers (and Interconnection Customers, as applicable) for Class Year Projects to discuss the results of the Class Year Interconnection Facilities Study.

30.8.5 Re-Study

If re-study of the Class Year Interconnection Facilities Study and cost allocation report is required pursuant to Section 25.8.2 and Section 25.8.3 of Attachment S, the ISO shall so notify Class Year Projects and conduct such re-study in accordance with the requirements of Attachment S. Any cost of re-study shall be borne by the Class Year Projects being re-studied.

30.9 Engineering & Procurement ("E&P") Agreement

Prior to executing a Standard Large Generator Interconnection Agreement, a Developer may, in order to advance the implementation of its interconnection, request and Connecting Transmission Owner shall offer the Developer, an E&P Agreement that authorizes the Connecting Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, the Connecting Transmission Owner shall not be obligated to offer an E&P Agreement if the Developer is in Dispute Resolution as a result of an allegation that the Developer has failed to meet any milestones or comply with any prerequisites specified in other parts of these Large Facility Interconnection Procedures. The E&P Agreement is an optional procedure and it will not alter the Developer's Queue Position or In-Service Date. The E&P Agreement shall provide for the Developer to pay the cost of all activities authorized by the Developer and to make advance payments or provide other satisfactory security for such costs. The Developer shall, in accordance with Attachment S to the ISO OATT, pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If the Developer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, the Developer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Connecting Transmission Owner may elect: (i) to take title to the equipment, in which event Connecting Transmission Owner shall refund the Developer any amounts paid by the Developer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to Developer, in which event the

Developer shall pay any unpaid balance and cost of delivery of such equipment.

30.10 Optional Interconnection System Reliability Impact Study

30.10.1 Commencing an Optional Interconnection System Reliability Impact

Upon the initiation of a Developer's SRIS, the Developer may request, and the ISO shall perform concurrently with that SRIS a reasonable number of Optional Interconnection System Reliability Impact Studies. The request shall describe the assumptions that the Developer wishes the ISO to study within the scope described in Section 30.10.2. Within five (5) Business Days after receipt of a request for an Optional Interconnection System Reliability Impact Study, the ISO shall provide to the Developer a good faith estimate of the cost and timeframe for completing such study.

The Optional Interconnection System Reliability Impact Study scope shall: (i) specify the technical data that the Developer must provide for each phase of the Optional Interconnection System Reliability Impact Study, (ii) specify Developer's assumptions as to which Interconnection Requests with earlier queue priority dates will be excluded from the Optional Interconnection System Reliability Impact Study case, and (iii) the ISO's estimate of the cost of the Optional Interconnection System Reliability Impact Study. To the extent known by the ISO, such estimate shall include any costs expected to be incurred by any Affected System whose participation is necessary to complete the Optional Interconnection System Reliability Impact Study. Notwithstanding the above, the ISO shall not be required as a result of an Optional Interconnection System Reliability Impact Study request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

The Developer shall submit the requested technical data and a $10,000 deposit to the ISO within fifteen (15) Business Days after the ISO's notice to the Developer and Connecting

Transmission Owner of the good faith estimate of the cost and timeframe for completing such study.

30.10.2 Scope of Optional Interconnection System Reliability Impact Study

The Optional Interconnection System Reliability Impact Study will consist of a sensitivity analysis based on the assumptions specified by the Developer in the Optional Interconnection System Reliability Impact Study scope. The Optional Interconnection System Reliability Impact Study will also identify the Connecting Transmission Owner's Attachment Facilities and the System Upgrade Facilities, and the estimated cost thereof, that may be required to provide Energy Resource Interconnection Service based upon the results of the Optional Interconnection System Reliability Impact Study. The scope of the Optional Interconnection System Reliability Impact Study will be provided to the Developer and Connecting Transmission Owner for review and comment. After the Optional Interconnection System Reliability Impact Study scope is finalized, the ISO will provide the final scope to the Connecting Transmission Owner and the Developer. The Connecting Transmission Owner shall indicate its agreement to the Optional Interconnection System Reliability Impact Study scope by signing it and promptly returning it to the ISO, such agreement not to be unreasonably withheld. The Optional Interconnection System Reliability Impact Study shall be performed solely for informational purposes. The ISO shall use Reasonable Efforts to coordinate the study with any Affected System that may be affected by the types of options that are being studied. The ISO shall utilize existing studies to the extent practicable in conducting the Optional Interconnection System Reliability Impact Study.

30.10.3 Optional Interconnection System Reliability Impact Study Procedures

The required study deposit and technical data called for in the Optional Interconnection

System Reliability Impact Scope must be provided to the ISO within fifteen (15) Business Days of Developer receipt of the good faith estimate of the cost and time frame for completing the Optional Interconnection System Reliability Impact Study from the ISO. The ISO shall notify the Developer and the Connecting Transmission Owner that the Optional Interconnection System Reliability Impact Study has commenced following receipt of the required study deposit and once the ISO deems the required technical data sufficient. The ISO shall use Reasonable Efforts to complete the Optional Interconnection System Reliability Impact Study within a mutually agreed upon time period specified within the Optional Interconnection System Reliability Impact Study scope. If the ISO is unable to complete the Optional Interconnection System Reliability Impact Study within such time period, it shall notify the Developer and provide an estimated completion date and an explanation of the reasons why additional time is required. Any difference between the study payment and the actual cost of the study shall be paid to the ISO or refunded to the Developer, as appropriate. Upon request, the ISO shall provide the Developer supporting documentation and workpapers and databases or data developed in the preparation of the Optional Interconnection System Reliability Impact Study, subject to confidentiality arrangements consistent with Section 30.13.1.

30.11 Standard Large Generator Interconnection Agreement (LGIA)

30.11.1 Tender

As soon as practicable upon completion of the Developer decision process and satisfaction of Security posting requirements described in Section 25.8 of Attachment S, acceptance by the Developer of its Attachment S cost allocation, the ISO shall tender to the Developer and Connecting Transmission Owner a draft LGIA together with draft appendices completed to the extent practicable. The draft LGIA shall be in the form of the ISO's Commission-approved LGIA, which is in Appendix 3 to this Attachment X. Within six (6) months after the date the ISO tenders the draft LGIA, the Developer must have satisfied the applicable regulatory milestone described in Section 25.6.2.3.1 of Attachment S. If the Developer has not done so, the ISO will withdraw the Interconnection Request pursuant to Sections 25.6.2.3 of Attachment S to the OATT and pursuant to Section 30.3.6 of this Attachment X.

30.11.2 Negotiation

Notwithstanding Section 30.11.1, at the request of the Developer the ISO and Connecting Transmission Owner shall begin negotiations with the Developer concerning the LGIA and its appendices at any time after the Developer executes the Class Year Interconnection Facilities Study Agreement. The ISO, Connecting Transmission Owner and the Developer shall finalize the appendices and negotiate concerning any disputed provisions of the draft LGIA and its appendices subject to the six (6) month time limitation specified below in this Section 30.11.2. If the Developer determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft LGIA pursuant to Section 30.11.1 and request submission of the unexecuted LGIA to FERC or initiate Dispute Resolution procedures pursuant to Section 30.13.5. If the Developer requests termination of the negotiations, but within sixty (60) Calendar Days thereafter fails to request either the filing of the unexecuted LGIA or initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if the Developer has not executed the LGIA, requested filing of an unexecuted LGIA, or initiated Dispute Resolution procedures pursuant to Section 30.13.5 within six (6) months of tender of draft LGIA, it shall be deemed to have withdrawn its Interconnection Request.

30.11.3 Execution and Filing

Within fifteen (15) Business Days after receipt of the executed LGIA, the Developer shall provide the ISO and Connecting Transmission Owner (A) reasonable evidence of continued Site Control or (B) posting of $250,000, non-refundable additional security with the Connecting Transmission Owner, which shall be applied toward future construction costs. At the same time, the Developer also shall provide the ISO and Connecting Transmission Owner reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at the Developer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit.

The Developer shall either: (i) execute three (3) originals of the tendered LGIA and return them to the ISO and Connecting Transmission Owner; or (ii) request in writing that the ISO and Connecting Transmission Owner file with FERC an LGIA in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the two executed originals of the tendered LGIA (if it does not conform with a Commission-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, the ISO and Connecting Transmission Owner shall file the LGIA with FERC. The ISO will draft the portions of the LGIA and appendices that are in dispute and assume the burden of justifying any departure from the pro forma LGIA and appendices. The ISO will provide its explanation of any matters as to which the Parties disagree and support for the costs that the Connecting Transmission Owner proposes to charge to the Developer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by the ISO for the Interconnection Request. The Connecting Transmission Owner will provide in the filing any comments it has on the unexecuted agreement, including any alternative positions, it may have with respect to the disputed provisions. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending Commission action.

30.11.4 Interconnection Agreement Pre-Dating Completion of the Large Facility's Class Year Study

At the request of the Developer, the ISO and Connecting Transmission Owner shall begin negotiations with the Developer concerning the LGIA and its appendices at any time after the Developer executes the Class Year Interconnection Facilities Study Agreement; however, certain analysis required by the Facilities Study must be completed before the LGIA can be completed – specifically, identification of all required Connecting Transmission Owner Attachment Facilities and Local System Upgrade Facilities. If the LGIA is executed prior to the completion of the Class Year Study, the Developer must agree, in the LGIA, that in the Class Year decision process, it will accept the Project Cost Allocation and post Security for any System Upgrade

Facilities that are identified and cost allocated in the Class Year Study even if such Project Cost Allocations exceed the estimates included in the LGIA and include equipment not identified in the LGIA.

The Developer executing an LGIA prior to the completion of a Class Year Study cannot participate as an Installed Capacity Supplier until after the Class Year Study is completed and (1) the project is deemed deliverable and accepts its deliverable megawatts; or (2) the Developer accepts its Project Cost Allocation and posts Security for any required System Deliverability Upgrades.

To the extent that upgrades or cost estimates in the Class Year Study differ from the amounts or descriptions in the LGIA, the Developer shall work with the ISO and Connecting Transmission Owner to promptly amend the LGIA as needed.

30.11.5 Commencement of Interconnection Activities

If the Developer executes the final LGIA, the ISO, Connecting Transmission Owner and the Developer shall perform their respective obligations in accordance with the terms of the LGIA, subject to modification by FERC. Upon submission of an unexecuted LGIA in accordance with Section 30.11.3, the Parties shall promptly comply with the unexecuted LGIA, subject to modification by FERC.

30.11.6 Termination of the Standard Large Generator Interconnection Agreement

The classification of a Large Generating Facility as Retired will be grounds for the termination of its Standard Large Facility Interconnection Agreement (LGIA). The ISO will file with the Federal Energy Regulatory Commission a notice of termination of the LGIA as soon as practicable after the Large Generating Facility is Retired. The termination of a non-conforming *pro forma* LGIA will be effective only upon acceptance by the Federal Energy Regulatory

Commission of the notice of termination and proposed effective date. Upon the effective date of the termination of the LGIA access to the Point of Interconnection of the Large Generating Facility will be available on a non-discriminatory basis pursuant to the ISO's applicable interconnection and transmission expansion processes and procedures.

30.12 Construction of Connecting Transmission Owner's Attachment Facilities and System Facilities

30.12.1 Schedule

The Connecting Transmission Owner and the Developer shall negotiate in good faith concerning a schedule for the construction of the Connecting Transmission Owner's Attachment Facilities and the System Upgrade Facilities and the System Deliverability Upgrades. If the System Upgrade Facilities or System Deliverability Upgrades involve Affected Transmission Owners, the Developer must execute and fulfill agreement(s) with the ISO and the Connecting Transmission Owner and any Affected Transmission Owner to cover the engineering, procurement and construction of such upgrades.

30.12.2 Construction Sequencing

30.12.2.1 General

In general, the In-Service Dates of the Developers in each Class Year seeking interconnection to the New York State Transmission System will determine the sequence of construction of System Upgrade Facilities and System Deliverability Upgrades.

30.12.2.2 Advance Construction of System Upgrade Facilities and System Deliverability Upgrades that are an Obligation of an Entity other than the Developer

A Developer with a Standard Large Generator Interconnection Agreement, in order to maintain its In-Service Date, may request that the Connecting Transmission Owner advance to the extent necessary the completion of System Upgrade Facilities, and System Deliverability Upgrades that: (i) were assumed in the Interconnection Studies for such Developer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than the Developer that is seeking interconnection to the New York State Transmission System, in time to support such In-Service Date. Upon such request, Connecting Transmission Owner will use Reasonable Efforts to advance the construction of such System Upgrade Facilities and System Deliverability Upgrades to accommodate such request; provided that the Developer commits in writing to pay Connecting Transmission Owner any associated expediting costs.

30.12.2.3 Advancing Construction of System Upgrade Facilities or System Deliverability Upgrades that are Part of an Expansion Plan of the ISO or Connecting Transmission Owner

A Developer with a Standard Large Generator Interconnection Agreement, in order to maintain its In-Service Date, may request that the Connecting Transmission Owner advance to the extent necessary the completion of System Upgrade Facilities and System Deliverability Upgrades that: (i) are necessary to support such In-Service Date and (ii) would otherwise not be completed, pursuant to an expansion plan of the ISO or Connecting Transmission Owner, in time to support such In-Service Date. Upon such request, Connecting Transmission Owner will use Reasonable Efforts to advance the construction of such System Upgrade Facilities and System Deliverability Upgrades to accommodate such request; provided that the Developer commits in writing to pay Connecting Transmission Owner any associated expediting costs.

30.12.2.4 Amended Interconnection System Reliability Impact Study

An Interconnection System Reliability Impact Study will be amended to determine the facilities necessary to support the requested In-Service Date. This amended study will include those transmission and Large Generating Facilities that are expected to be in service on or before the requested In-Service Date.

30.12.3 Limited Operations

The ISO shall, upon the request and at the expense of the Developer, in conjunction with the Connecting Transmission Owner, perform operating studies to determine the extent to which the Developer's Large Generating Facility and the Developer's Attachment Facilities may operate prior to the completion of the Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice. This provision does not permit the Developer to request the evaluation of an alternative configuration of the proposed Large Generating Facility; rather, this provision merely allows the Developer to request an evaluation of the extent to which its Large Generating Facility may operate, if at all, prior to the completion of all required upgrade facilities. This provision does not permit the Developer to operate the Developer's Large Generating Facility and the Developer's Attachment Facilities in accordance with the results of such studies. Such requirements must be documented in the Large Facility's Interconnection Agreement, which must be fully executed or filed unexecuted and accepted by the Commission prior to the Large Facility going into Commercial Operation. Such requirements must also have a defined end date specified in the Interconnection Agreement – the date beyond which Limited Operations is not permitted.

30.13 Miscellaneous

30.13.1 Confidentiality

Certain information exchanged by the Parties during the administration of these Large Facility Interconnection Procedures shall constitute confidential information ("Confidential Information") and shall be subject to this Section 30.13.1.

The following shall constitute Confidential Information: (1) any non-public information that is treated as confidential by the disclosing Party and which the disclosing Party identifies as Confidential Information in writing at the time, or promptly after the time, of disclosure; or (2) information designated as Confidential Information by the ISO Code of Conduct contained in Attachment F to the ISO OATT.

If requested by either Party receiving information, the Party supplying information shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

30.13.1.1 Scope

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential

Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of the Standard Large Generator Interconnection Agreement; or (6) is required, in accordance with Section 30.13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the Standard Large Generator Interconnection Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

30.13.1.2 Release of Confidential Information

No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by FERC Standards of Conduct requirements), employees, consultants, or to parties who may be or considering providing financing to or equity participation with Developer, or to potential purchasers or assignees of Developer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 30.13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 30.13.1.

30.13.1.3 Rights

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to another Party. The disclosure by each Party to the other Parties of Confidential Information shall not be deemed a waiver by any Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

30.13.1.4 No Warranties

By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to the other Parties nor to enter into any further agreements or proceed with any other relationship or joint venture.

30.13.1.5 Standard of Care

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Parties under these procedures or its regulatory requirements, including the ISO OATT and NYISO Services Tariff. The ISO shall, in all cases, treat the information it receives in accordance with the requirements of Attachment F to the ISO OATT.

30.13.1.6 Order of Disclosure

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of the Standard Large Generator Interconnection Agreement. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

30.13.1.7 Remedies

The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Section 30.13.1. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Section 30.13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Section 30.13.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 30.13.1.

30.13.1.8 Disclosure to FERC, its Staff, or a State

Notwithstanding anything in this Section 30.13.1 to the contrary, and pursuant to 18 C.F.R. section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to these Large Facility Interconnection Procedures or the ISO OATT, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties prior to the release of the Confidential Information to the Commission or its staff. The Party shall notify the other Parties to the LGIA when its is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner consistent with applicable state rules or regulations. A Party shall not be liable for any losses, consequential or otherwise, resulting from that Party divulging Confidential Information pursuant to a FERC or state regulatory body request under this paragraph.

30.13.1.9 Subject to the exception in Section 30.13.1.8, no Party shall disclose Confidential Information to any person not employed or retained by the Party possessing the Confidential Information, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the supplying Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under these Large Facility Interconnection Procedures, the ISO OATT or NYISO Services Tariff. Prior to any disclosures of a Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Parties in writing and agrees to assert confidentiality and cooperate with the other Parties in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

30.13.1.10 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

30.13.1.11 The ISO and Connecting Transmission Owner shall, at Developer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

30.13.2 Delegation of Responsibility

The ISO may use the services of subcontractors as it deems appropriate to perform its obligations under these Large Facility Interconnection Procedures. The ISO shall remain primarily liable to the Developer for the performance of such subcontractors and compliance with its obligations under these Large Facility Interconnection Procedures. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

30.13.3 Obligation for Study Costs and Study Deposits

30.13.3.1 The ISO shall charge and Developer shall pay the actual costs of the Interconnection Studies incurred by the ISO and Transmission Owner. If a number of Interconnection Studies are conducted concurrently as a combined study, except for a Class Year Interconnection Facilities Study, each Developer shall pay an equal share of the actual cost of the combined study. However, no Developer electing to be evaluated only for ERIS shall be responsible for any cost of any CRIS evaluation in the combined study and any Class Year Project that

that elects, pursuant to Section 25.7.7.1 of Attachment S, to withdraw from the Class Year Interconnection Facilities Study, withdraw its CRIS request or elect to have no System Deliverability Upgrade identified to make the project deliverable at its level of requested CRIS, shall not be responsible for any additional detailed studies required for System Deliverability Upgrades. Beginning with the Class Year subsequent to Class Year 2012, Class Year Projects shall be responsible for Class Year Interconnection Facilities Study costs in the following manner: (1) each Class Year Project shall pay the actual cost of studying the Attachment Facilities, Interconnection Facilities and Distribution Upgrades for its own facility; (2) each Class Year Project shall pay the actual cost of studying Local System Upgrade Facilities for its own facility; and (3) each Class Year Project in a Class Year shall pay an equal share of all other Class Interconnection Facilities Study costs (*i.e.*, those not related to Attachment Facilities, Interconnection Facilities, Distribution Upgrades or Local System Upgrade Facilities). With respect to the costs of studying the Attachment Facilities, Interconnection Facilities and Distribution Upgrades referenced above, if more than one Class Year Project contributes to the need for particular Attachment Facilities, Interconnection Facilities or Distribution Upgrades, those Class Year Projects shall share equally in the cost to study those Attachment Facilities, Interconnection Facilities or Distribution Upgrades. With respect to the costs of studying the Local System Upgrade Facilities referenced above, if more than one Class Year Project contributes to the need for particular Local System Upgrade Facilities, those Class Year Projects shall share equally in the cost to study those

Local System Upgrade Facilities. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein, to the Class Year Project or offset against the cost of any future Interconnection Studies associated with the applicable Interconnection Request prior to beginning of any such future Interconnection Studies. Any invoices for Interconnection Studies must be submitted to the ISO within sixty (60) days of completion of the subject Interconnection Study and shall include a detailed and itemized accounting of the cost of each Interconnection Study. Developers and Interconnection Customers shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefore. Neither the ISO nor Connecting Transmission Owner shall be obligated to perform or continue to perform any studies unless Developer (or Interconnection Customer, as applicable) has paid all undisputed amounts in compliance herewith.

30.13.4 Third Parties Conducting Studies

If (i) at the time that ISO provides a good faith estimate of the time to complete or at the time of the signing of an Interconnection Facilities Study Agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) the Developer receives notice pursuant to Sections 30.6.3, 30.7.4 or 30.8.3 that the ISO will not complete an Interconnection Study within the applicable timeframe for such Interconnection Study, or (iii) the Developer receives neither the Interconnection Study nor a notice under Sections 30.6.3, 30.7.4 or 30.8.3 within the applicable timeframe for such Interconnection Study, then the Developer may request the ISO to utilize a consultant or other third party reasonably acceptable to the Developer and the

ISO to perform such Interconnection Study under the direction of the ISO. At other times, the ISO may also utilize a Connecting Transmission Owner or other third party to perform such Interconnection Study, either in response to a general request of the Developer, or on its own volition. In all cases, use of a third party shall be in accord with Article 26 of the LGIA (Subcontractors) and limited to situations where the ISO determines that doing so will help maintain or accelerate the study process for the Developer's pending Interconnection Request and not interfere with the ISO's progress on Interconnection Studies for other pending Interconnection Requests. In cases where the Developer requests to use a third party to perform such Interconnection Study, the Developer, the ISO and Connecting Transmission Owner shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the estimated study completion date and study review deadline. The ISO shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as practicable upon the Developer's request subject to the confidentiality provision in Section 30.13.1. In any case, such third-party study contract may be entered into with either the Developer or the ISO at the ISO's discretion. If a Developer enters into a third-party study contract, the Developer shall provide the study to the ISO and the Connecting Transmission Owner for review, and such third-party study contract shall provide for reimbursement by the Developer of the ISO's and Connecting Transmission Owner's actual cost of participating in and reviewing the study. In the case of (iii) above in this Section 30.13.4, the Developer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third-party study. Such third party shall be required to comply with these Large Facility Interconnection Procedures, Article 26 of the LGIA (Subcontractors), and the relevant ISO OATT procedures and protocols as would apply if the ISO were to conduct the

Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. The ISO and Connecting Transmission Owner shall cooperate with such third party and Developer to complete and issue the Interconnection Study in the shortest reasonable time.

30.13.5 Disputes

30.13.5.1 Submission

In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with the LGIA, these Standard Large Facility Interconnection Procedures, or their performance (a "Dispute"), such Party shall provide the other Parties with written notice of the Dispute ("Notice of Dispute"). Such Dispute shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Parties. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Parties' receipt of the Notice of Dispute, such Dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such Dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of the Standard Large Generator Interconnection Agreement.

30.13.5.2 External Arbitration Procedures

Any arbitration initiated under these procedures shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the Dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The arbitrators so chosen shall within twenty (20) Calendar Days select one of them to chair the arbitration panel. In each case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Section 30.13, the terms of this Section 30.13 shall prevail.

30.13.5.3 Arbitration Decisions

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the LGIA and LFIP and shall have no power to modify or change any provision of the LGIA and LFIP in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Attachment Facilities, Distribution Upgrades or System Upgrade Facilities.

30.13.5.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel; or (2) one-third the cost of the single arbitrator jointly chosen by the Parties.

30.13.6 Local Furnishing Bonds and Other Tax-Exempt Financing

30.13.6.1 Connecting Transmission Owners and Affected Transmission Owner(s) that Own Facilities Financed by Local Furnishing Bonds or Other Tax-Exempt Bonds

This provision is applicable only to a Connecting Transmission Owner or Affected Transmission Owner(s) that has financed facilities with tax-exempt bonds including, but not limited to, Local Furnishing Bonds ("Tax-Exempt Bonds"). Notwithstanding any other provision of this LGIA and LFIP, neither the ISO nor Connecting Transmission Owner shall be required to provide interconnection service to Developer, nor shall any Connecting Transmission Owner or Affected Transmission Owner be required to construct System Upgrade Facilities or System Deliverability Upgrades, pursuant to this LGIA and LFIP, if the provision of such interconnection service or such construction would jeopardize the tax-exempt status of any Tax-Exempt Bonds or impair the ability of Connecting Transmission Owner or Affected Transmission Owner(s) to issue future tax-exempt obligations. For purposes of this provision, Tax-Exempt Bonds shall include the obligations of the Long Island Power Authority, NYPA and Consolidated Edison Company of New York, Inc., the interest on which is not included in gross income under the Internal Revenue Code.

30.13.6.2 Alternate Procedures for Requesting Interconnection Service

If a Connecting Transmission Owner or Affected Transmission Owner(s) determines that the provision of interconnection service requested by a Developer would jeopardize the tax-exempt status of any Tax-Exempt Bond(s) used to finance its facilities that would be used in providing such interconnection service, or impair its ability to issue future tax-exempt obligations, Connecting Transmission Owner or Affected Transmission Owner(s) shall advise the Developer and the ISO within thirty (30) Calendar days of receipt of the Interconnection Request.

The Developer thereafter may renew its request for interconnection using the process specified in Section 30.3 of the ISO OATT.

30.14 Appendices

APPENDIX 1 TO LFIP - INTERCONNECTION REQUEST

1. The undersigned Developer submits this request to interconnect its Large Generating Facility or Merchant Transmission Facility with the New York State Transmission System or Distribution System pursuant to the Standard Large Facility Interconnection Procedures in the ISO OATT ("LFIP").

2. This Interconnection Request is for [insert project name]:___________________________

____, which

is (check one of the following):

____ A proposed new Large Generating Facility

____ A proposed new BTM:NG Resource

____ A proposed new Merchant Transmission Facility

____ A material modification to a proposed or existing facility (*e.g.*, an increase in the capacity of an existing facility beyond the permissible *de minimis* increases permitted under Section 30.3.1 of Attachment X to the ISO OATT)

3. Address or location or the proposed new Large Facility site (to the extent known) or, in the case of an existing Generating Facility or Merchant Transmission Facility, the name and specific location of that existing facility:_____________________________________
____
____

4. MW nameplate rating: ________

5. MW of requested ERIS: ________

- Maximum summer net (net MW = gross MW minus auxiliary loads total MW) which can be achieved at 90 degrees F: ________
  Maximum winter net (net MW = gross MW minus auxiliary loads total MW) which can be achieved at 10 degrees F : ______
- MW of requested increase in ERIS of an existing facility, as calculated from the baseline ERIS (as defined in Section 30.3.1 of this Attachment X – for temperature-sensitive machines, provide the summer and winter MW vs. temperature curves for both gross MW and net MW corresponding to the requested net MW values provided above):__________

6. General description of the proposed project (*e.g.*: describe type/size/number/general configuration of the proposed generator units, merchant

transmission, transformers, feeders, lines leading to the proposed point of interconnection(s), breakers, etc): ____
____
____
____

7. Attach a conceptual breaker one-line diagram and a project location geo map.;

8. Proposed In-Service Date (Month/Year): _______________

Proposed Initial Synchronization Date (Month/Year): ___________

Proposed Commercial Operation Date (Month/Year): _____

9.Developer's contact person:

Name (type or print): _____________________________________

Title: ____

Company: ____

Date: ____

Email: ____

10. Approximate location, and, if available, coordinates, of the proposed Point(s) of Interconnection: ____
____
____

11. Project power flow, short circuit, transient stability modeling data and supporting documentation (as set forth in Attachment A) (optional). Modeling data will be required during the scoping and applicable study agreement process, as coordinated by the ISO.

12. $10,000 non-refundable application fee must be submitted with this Interconnection Request form.

13. Evidence of Site Control as specified in the LFIP (check one):

____ Is attached to this Interconnection Request and provides site control for the following number of acres: _________; or

____ Will be provided at a later date in accordance with the LFIP, in which case a non-refundable $10,000 deposit in lieu of site control must be provided with this Interconnection Request form

14. This Interconnection Request shall be submitted to the ISO at the following email address: NewProject@nyiso.com

15. This Interconnection Request is submitted by:

Signature: ____

Name (type or print): ______________________________

Title: ____

Company: ____

Date: ____

LARGE GENERATING FACILITY PRELIMINARY DATA
(Additional data will be required at subsequent stages of the interconnection study process)

UNIT RATINGS

MVA _________ °F ___________ Voltage (kV)__________

Maximum Reactive Power at Rated Power Leading (MVAR):

__________ Lagging (MVAR): ________

Connection (*e.g.* Wye, Delta or Wye-grounded) __________

Reactance data per unit, Subtransient – unsaturated (X"di): _________

Unit manufacturer/make: ____

NOTE: If requested information is not applicable, indicate by marking "N / A."

GENERATOR STEP-UP TRANSFORMER DATA

RATINGS

Capacity Self-cooled/Maximum Nameplate

___________/__________________MVA

Voltage Ratio (Generator Side/System Side/Tertiary)

___________/__________/__________kV

Winding Connections (Generator Side/System Side/Tertiary (Delta or Wye))

___________/_________/_________

Fixed Taps Available ____

Present Tap Setting ____

IMPEDANCE

Positive Z1 (on self-cooled MVA rating) ___________ % _________ X/R

Zero Z0 (on self-cooled MVA rating) ___________ % _________ X/R

ADDITIONAL INFORMATION REQUESTED FOR WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request: ______

Generator Height: __________ ________ Single Phase _______

Three Phase

Inverter manufacturer, model name, number, and version:

____

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied at a later stage of the interconnection study process.

ADDITIONAL INFORMATION REQUESTED FOR SOLAR GENERATORS

Number of solar panels to be interconnected pursuant to this Interconnection Request: ______

Type of solar arrays (*i.e.*, fixed, 1-axis, 2-axis, 2-axis flat panel, 2-axis CPV, CSP, etc.):

____

Inverter manufacturer, model name, number, and version:

____

ADDITIONAL INFORMATION REQUESTED FOR MERCHANT TRANSMISSION FACILITIES

Description of proposed project:

a. General description of the equipment configuration and kV level:

____

____

____

b. Transmission technology and manufacturer (*e.g.*, HVDC VSC): _______________
____

ADDITIONAL INFORMATION REQUESTED FOR BTM:NG RESOURCES

Type of Generator: ____Synchronous ____Induction ____Inverter

Generator Nameplate Rating: _______kW (Typical) Generator Nameplate kVAR:_______

Interconnection Customer or Customer-Site Load:________________kW (if none, so state)

Existing load? Yes ___ No___

If existing load with metered load data, provide coincident Summer peak load: ________

If new load or existing load without metered load data, provide estimated coincident Summer peak load, together with supporting documentation for such estimated value: _________

ADDITIONAL INFORMATION REQUESTED FOR ENERGY STORAGE RESOURCES

Energy storage capability (MWh): ____________________

Duration for full discharge (*i.e.*, injection) (Hours): _______

Duration for full charge (*i.e.*, withdrawal) (Hours): _______

Maximum withdrawal from the system (*i.e.*, when charging) (MW):____________

Inverter manufacturer, model name, number, and version: ________________________________

____

ATTACHMENT A TO APPENDIX 1 – LFIP INTERCONNECTION REQUEST
Terms and Conditions of Interconnection Study(ies)

These terms and conditions for the study of a Large Generating Facility or Merchant Transmission Facility, or a material modification to an existing Large Generating Facility or Merchant Transmission Facility proposed in the Interconnection Request dated _____________ ("the Project") and submitted by ____, a __________________ organized and existing under the laws of the State of _____________ ("Developer") sets forth the respective obligations between Developer and the New York Independent System Operator, Inc., a not-for-profit corporation organized and existing under the laws of the State of New York ("NYISO") (hereinafter the "Terms and Conditions"). By signing below, Developer confirms its understanding and acceptance of the Terms and Conditions.

RECITALS

WHEREAS, Developer is proposing to develop the Project; and

WHEREAS, the Project is already interconnected to the New York State Transmission System (or Distribution System, as applicable) or desires to interconnect the Large Facility with the New York State Transmission System (or Distribution System, as applicable); and

WHEREAS, Developer has requested NYISO to perform one or more of the following studies: Optional Interconnection Feasibility Study, Interconnection System Reliability Impact Study, or Optional Interconnection System Reliability Impact Study to assess the impact of the Project on the New York State Transmission System (or Distribution System, as applicable).and any Affected Systems.

Now, THEREFORE, in consideration of and subject to the terms and conditions contained herein, Developer and NYISO agree as follows:

1.0 When used in these Terms and Conditions, with initial capitalization, the terms specified shall have the meanings indicated in the NYISO's Commission-approved Standard Large Facility Interconnection Procedures ("LFIP").

2.0 Developer shall elect and NYISO shall cause to be performed, in accordance with the NYISO Open Access Transmission Tariff ("OATT"), one or more of the following: an Optional Interconnection Feasibility Study consistent with Section 30.6 of the LFIP, an Interconnection System Reliability Impact Study consistent with Section 30.7 of the LFIP, and an Optional Interconnection System Reliability Impact Study consistent with Section 30.10 of the LFIP, collectively referred to as the "Studies." The terms of Sections 30.6, 30.7, 30.10, 30.13.1, and 30.13.3 of the LFIP, as applicable, are incorporated by reference herein.

3.0 The scopes for the Studies that Developer elects or is required to perform under its Interconnection Request and these Terms and Conditions shall be subject to the assumptions developed by Developer, NYISO, and the Connecting Transmission

Owner(s) at the respective scoping meetings for each Study and approved by NYISO Operating Committee.

4.0 The Studies shall be based on the technical information provided by Developer in the Interconnection Request, as may be modified as the result of the Scoping Meeting and completed study results, if performed and available. NYISO reserves the right to request additional information from Developer as may reasonably become necessary consistent with Good Utility Practice during the course of the Studies (including dynamic modeling data) and as designated in accordance with Section 30.3.3.4 of the LFIP and such additional information shall be provided in a prompt manner. If, after the designation of the Point of Interconnection pursuant to Section 30.3.3.4 of the LFIP, Developer modifies its Interconnection Request pursuant to Section 30.4.4, the time to complete the Studies may be extended.

5.0 Optional Interconnection Feasibility Study. If Developer elects to perform an Optional Interconnection Feasibility Study, the study report shall provide the following:

- If Developer elects to perform an Optional Interconnection Feasibility Study with a limited analysis (*i.e.*, $10,000 study deposit), the study report shall provide, to the extent selected by Developer:
    - development of a conceptual breaker-level one-line diagram of existing NYS Transmission System or Distribution System where the Large Facility proposes to interconnect; and/or
    - a review of the feasibility/constructability of a conceptual breaker-level one-line diagram of the proposed interconnection (*e.g.*, space for additional breaker bay in existing substation or identification of cable routing concerns inside existing substation).
- If Developer elects to perform an Optional Interconnection Feasibility Study with detailed analyses (*i.e.*, $60,000 study deposit), the study report shall provide, to the extent selected by Developer:
    - development of conceptual breaker-level one-line diagram of existing NYS Transmission System or Distribution System where the Large Facility proposes to interconnect (*i.e.*, how to integrate the Large Facility into the existing system);
    - a review of the feasibility/constructability of a conceptual breaker-level one-line diagram of the proposed interconnection (*e.g.*, space for additional breaker bay in existing substation or identification of cable routing concerns inside existing substation);
    - preliminary review of local protection, communication, and grounding issues associated with the proposed interconnection;

- power flow, short circuit, and/or bus flow analyses; and/or

- preliminary identification of Connecting Transmission Owner Attachment Facilities and Local System Upgrade Facilities with a non-binding good faith cost estimate of Developer's cost responsibility and a non-binding good faith estimated time to construct.

6.0 Interconnection System Reliability Impact Study. The Interconnection System Reliability Impact Study report shall provide the following information:

- Identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection;

- description and non-binding, good faith estimated cost of facilities required to interconnect the Large Facility to the New York State Transmission System (or Distribution System, as applicable) and to address the identified short circuit, instability, and power flow issues; and

- if Developer opts to skip the Optional Interconnection Feasibility Study or if Developer elects to include a preliminary non-binding evaluation under the Deliverability Interconnection Standard, NYISO will supplement the information set forth above.

7.0 Optional Interconnection System Reliability Impact Study. If Developer elects to perform an Optional Interconnection System Reliability Impact Study, the study report shall provide a sensitivity analysis based on the assumptions specified by Developer in the scope for the Optional Interconnection System Reliability Impact Study developed in accordance with Section 3.0 of these Terms and Conditions. The Optional Interconnection System Reliability Impact Study will identify the Connecting Transmission Owner's Attachment Facilities, Distribution Upgrades, and System Upgrade Facilities, and the estimated cost thereof, that may be required to provide Energy Resource Interconnection Service based upon the assumptions specified by Developer in the scope for the Optional Interconnection System Reliability Impact Study developed in accordance with Section 3.0 of these Terms and Conditions.

8.0 Developer shall provide a deposit in accordance with the LFIP for the performance of each study that Developer elected to be performed in connection with its Interconnection Request and under these Terms and Conditions. NYISO shall provide a good faith estimate for the time of completion for each of the studies elected or required to be performed in accordance with the LFIP.

8.1 Upon Developer's receipt of the final report for each study performed, NYISO shall charge and Developer shall pay to NYISO the actual costs of each respective study incurred by NYISO, as computed on a time and materials basis in accordance with the rates provided to the Developer at the time that NYISO provides the good faith estimate of the cost for each study elected or required to be performed in connection with the Interconnection Request and under these Terms and Conditions.

8.2 Any difference between the deposit for and the actual cost of any study performed under these Terms and Conditions shall be paid by or refunded to Developer, as appropriate.

9.0 Miscellaneous.

9.1 Accuracy of Information. Except as Developer may otherwise specify in writing when it provides information to NYISO under these Terms and Conditions, Developer represents and warrants that the information it provides to NYISO shall be accurate and complete as of the date the information is provided. Developer shall promptly provide NYISO with any additional information needed to update information previously provided.

9.2 Disclaimer of Warranty. In preparing the Studies, NYISO and any subcontractor consultants hired by it shall have to rely on information provided by Developer, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, neither NYISO nor any subcontractor consultant hired by NYISO makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy, content, or conclusions of the Studies performed under these Terms and Conditions. Developer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

9.3 Limitation of Liability. In no event shall NYISO or its subcontractor consultants be liable for indirect, special, incidental, punitive, or consequential damages of any kind including loss of profits, arising under or in connection with these Terms and Conditions or the Studies performed or any reliance on the Studies by Developer or third parties, even if NYISO or its subcontractor consultants have been advised of the possibility of such damages. Nor shall any NYISO or its subcontractor consultants be liable for any delay in delivery or for the non-performance or delay in performance of its obligations under these Terms and Conditions.

9.4 Third-Party Beneficiaries. Without limitation of Sections 8.2 and 8.3 under these Terms and Conditions, Developer further agrees that subcontractor consultants hired by NYISO to conduct or review, or to assist in the conducting or reviewing, one or more of the Studies requested under the Interconnection Request shall be deemed third-party beneficiaries of these Sections 8.2 and 8.3 under these Terms and Conditions.

9.5 Term and Termination. The obligations to conduct the Studies and under these Terms and Conditions shall be effective from the date hereof and, unless earlier terminated under these Terms and Conditions, shall continue in effect until the Studies are completed (*i.e.*, approved by the NYISO Operating Committee, as applicable). Developer or NYISO may terminate their obligations under these Terms and Conditions upon the withdrawal of Developer's Interconnection Request under Section 30.3.6 of the LFIP.

9.6 Governing Law. These Terms and Conditions and any study performed thereunder shall be governed by and construed in accordance with the laws of the State of New York, without regard to any choice of laws provisions.

9.7 Severability. In the event that any part of these Terms and Conditions are deemed as a matter of law to be unenforceable or null and void, such unenforceable or void part shall be deemed severable from these Terms and Conditions and the obligations under these Terms and Conditions shall continue in full force and effect as if each part was not contained herein.

9.8 Amendment. No amendment, modification, or waiver of any term or condition hereof shall be effective unless set forth in writing and signed by Developer and NYISO hereto.

9.9 Survival. All warranties, limitations of liability, and confidentiality provisions provided herein shall survive the expiration or termination hereof.

9.10 Independent Contractor. Developer agrees that NYISO shall at all times be deemed to be an independent contractor and none of its employees or the employees of its subcontractors shall be considered to be employees of Developer as a result of performing any work under these Terms and Conditions.

9.11 No Implied Waivers. The failure of Developer or NYISO to insist upon or enforce strict performance of any of the provisions of these Terms and Conditions shall not be construed as a waiver or relinquishment to any extent of such party's right to insist or rely on any such provision, rights, and remedies in that or any other instances; rather, the same shall be and remain in full force and effect.

9.12 Successors and Assigns. The obligations under these Terms and Conditions, and each and every term and condition hereof, shall be binding upon and inure to the benefit of Developer and NYISO and their respective successors and assigns.

IN WITNESS THEREOF, Developer has agreed to accept and be bound by the Terms and Conditions by its duly authorized officers or agents execution on the day and year first below written.

____
[Insert name of Developer]

By: ____________________

Title: ____________________

Date: ____________________

APPENDIX 1-A TO LFIP – EXTERNAL CRIS RIGHTS REQUEST

1. The undersigned Entity (the "Requestor") submits this request to obtain External CRIS Rights for the number of Megawatts ("MW") of External ICAP specified below, pursuant to Section 25.7.11 of Attachment S to the ISO OATT and ISO Procedures.

2. The Requestor provides the following information:

2.1 ______ Years - The term of the requested Award Period (minimum five (5) years).

2.2 _______ MW of External CRIS requested for each month of Summer Capability Period. The same number of MW must be supplied for all months of each Summer Capability Period throughout the Award Period.

2.3 _______ MW of External CRIS requested each month of Winter Capability Period (cannot exceed MW committed for Summer Capability Period). None required, but if Requestor does commit MW to any month of Winter Capability Period, Requestor must specify months requested below.

___November ☐
___December ☐
___January ☐
___February ☐
___March ☐
___April ☐

2.4 The External Interface(s) to be used for the External ICAP:

____

3. A Requestor may request external CRIS rights by making either a contract commitment or a non-contract commitment for the award period. A requestor must indicate the type of its commitment, as follows:

3.1 _________ Contract commitment; or

3.2 _________ Non-contract commitment.

4. This External Rights Request shall be submitted to the ISO via the following email address:

NewProject@nyiso.com

5. Representative of the Requestor to contact, including phone number and e-mail address:

Name (type or print): ____________________________________

Title: ____

Company: ____

Date: ____

Email: ____

6. This External CRIS Rights Request is submitted by:

By (signature): _______________________________

Name (type or print): ____________________________

Title: ____

Company: ____

Date: ____

APPENDIX 2 to LFIP - INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this ____ day of ________, 20__ by and among _________, a ___________ organized and existing under the laws of the State of ________ ("Developer"), the New York Independent System Operator, Inc., a not-for-profit corporation organized and existing under the laws of the State of New York ("NYISO"), and _______ a __________________ organized and existing under the laws of the State of New York ("Connecting Transmission Owner"). Developer, NYISO and Connecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Developer is [proposing to develop a Large Generating Facility or Merchant Transmission Facility/proposing a capacity addition to an existing Generating Facility or Merchant Transmission Facility consistent with the Interconnection Request submitted by the Developer dated ___________, including any project modifications reviewed and approved by the NYISO /owns an existing or proposed facility requesting only Capacity Resource Interconnection Service ("CRIS") or requesting an increase in CRIS]; and

WHEREAS, Developer [indicate whether the Developer desires to interconnect the Large Facility with the New York State Transmission System (or Distribution System, as applicable) or is already interconnected];

WHEREAS, the NYISO has confirmed that the Developer has satisfied the eligibility requirements for entering a Class Year Interconnection Facilities Study ("Class Year Study"); and

WHEREAS, Developer has elected to enter an Interconnection Facilities Study in order to obtain [Energy Resource Interconnection Service ("ERIS")/ERIS and CRIS/CRIS only/an increase in CRIS] pursuant to Attachments S, X and Z to the NYISO's Open Access Transmission Tariff ("OATT"), as applicable.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Section 30.1 of Attachment X to the NYISO's OATT or Section 25.1.2 of Attachment S to the NYISO's OATT.

2.0 Developer elects to be evaluated for [ERIS/ERIS and CRIS/CRIS only/an increase in CRIS] and NYISO shall cause to be performed an Interconnection Facilities Study consistent with Attachments S and X to the ISO OATT. The terms of the above-referenced OATT Attachments, as applicable, are hereby incorporated by reference herein.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 For Developers seeking ERIS, the Interconnection Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the facility to the New York State Transmission System (or Distribution System, as applicable) and (ii) shall address the short circuit, instability, and power flow issues identified in the Interconnection System Reliability Impact Study. For Developers seeking CRIS, the Interconnection Facilities Study report (i) shall identify whether System Deliverability Upgrades are required for the facility to be fully deliverable at its requested level of Capacity Resource Interconnection Service; and (ii) shall provide a description and estimated cost of any required System Deliverability Upgrades, to the extent required, based on the Developer's election under Section 25.7.7.1 of Attachment S to the ISO OATT. For Developers seeking both ERIS and CRIS, the Interconnection Facilities Study report shall provide all of the information described in this Section 4.0.

5.0 The Developer shall provide a deposit of [$100,000 if requesting evaluation for ERIS or ERIS and CRIS/$50,000 if requesting only CRIS] for the performance of the Interconnection Facilities Study. The time for completion of the Interconnection Facilities Study is specified in Attachment A.

NYISO shall invoice Developer on a monthly basis for the expenses incurred by NYISO and the Connecting Transmission Owner on the Interconnection Facilities Study each month, as computed on a time and materials basis in accordance with the rates attached hereto. Developer shall pay invoiced amounts to NYISO within thirty (30) Calendar Days of receipt of invoice. NYISO shall continue to hold the amounts on deposit until settlement of the final invoice.

6.0 Miscellaneous.

6.1 Accuracy of Information. Except as Developer or Connecting Transmission Owner may otherwise specify in writing when they provide information to NYISO under this Agreement, Developer and Connecting Transmission Owner each represent and warrant that the information it provides to NYISO shall be accurate and complete as of the date the information is provided. Developer and Connecting Transmission Owner shall each promptly provide NYISO with any additional information needed to update information previously provided.

6.2 Disclaimer of Warranty. In preparing the Interconnection Facilities Study, the Party preparing such study and any subcontractor consultants employed by it shall have to rely on information provided by the other Parties, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, neither the Party preparing the Interconnection Facilities Study nor any subcontractor consultant employed by that Party makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy, content, or conclusions of the Interconnection Facilities Study. Developer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

6.3 Limitation of Liability. In no event shall any Party or its subcontractor consultants be liable for indirect, special, incidental, punitive, or consequential damages of any kind including loss of profits, arising under or in connection with this Agreement or the Interconnection Facilities Study or any reliance on the Interconnection Facilities Study by any Party or third parties, even if one or more of the Parties or its subcontractor consultants have been advised of the possibility of such damages. Nor shall any Party or its subcontractor consultants be liable for any delay in delivery or for the non-performance or delay in performance of its obligations under this Agreement.

6.4 Third-Party Beneficiaries. Without limitation of Sections 6.2 and 6.3 of this Agreement, Developer and Connecting Transmission Owner further agree that subcontractor consultants employed by NYISO to conduct or review, or to assist in the conducting or reviewing, an Interconnection Facilities Study shall be deemed third party beneficiaries of these Sections 6.2 and 6.3.

6.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 30.6.5, shall continue in effect until the Interconnection Facilities Study for Developer's facility is completed and approved by the NYISO Operating Committee. Developer or NYISO may terminate this Agreement upon the withdrawal of the Developer's project from the Interconnection Facilities Study pursuant to Section 25.7.7.1 of Attachment S.

6.6 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of New York, without regard to any choice of laws provisions.

6.7 Severability. In the event that any part of this Agreement is deemed as a matter of law to be unenforceable or null and void, such unenforceable or void part shall be deemed severable from this Agreement and the Agreement shall continue in full force and effect as if each part was not contained herein.

6.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.

6.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing signed by the Parties hereto.

6.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.

6.11 Independent Contractor. NYISO shall at all times be deemed to be an independent contractor and none of its employees or the employees of its subcontractors shall be considered to be employees of Developer or Connecting Transmission Owner as a result of this Agreement.

6.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such party's right to insist or rely on any such provision, rights and remedies in that or any other instances; rather, the same shall be and remain in full force and effect.

6.13 Successors and Assigns. This Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

New York Independent System Operator, Inc.

By: ____________________

Title: ____________________

Date: ____________________

[Insert name of Connecting Transmission Owner]

By: ____________________

Title: ____________________

Date: ____________________

[Insert name of Developer]

By: ____________________

Title: ____________________

Date: ____________________

Attachment A To Appendix 2 - Interconnection Facilities Study Agreement

SCHEDULE FOR CONDUCTING THE INTERCONNECTION FACILITIES STUDY

The NYISO and Connecting Transmission Owner shall use Reasonable Efforts to complete the study and issue an Interconnection Facilities Study report to the Developer within the following number of days after of receipt of an executed copy of this Interconnection Facilities Study Agreement:

- estimated completion date (*i.e.*, Operating Committee approval of the Class Interconnection Facilities Study) for Class Year 20__ Interconnection Facility Study for the Annual Transmission Reliability Assessment required by Attachment S to the ISO OATT: ____/____/________, if no additional System Deliverability Upgrade studies are required.

- Study work (other than data provision and study review) that may be requested of the Transmission Owner by the NYISO is currently not specified, but will be specified in a Study Work Agreement to be developer between the NYISO and Transmission Owner.

- Pursuant to Article 5.0 of this Agreement, the rates for the study work are attached as Exhibit 1.

Attachment B To Appendix 2 - Interconnection Facilities Study Agreement

DATA FORM TO BE PROVIDED BY DEVELOPER

WITH THE INTERCONNECTION FACILITIES STUDY AGREEMENT

1. Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

2. Finalize and specify your Interconnection Service evaluation election for the Class Year Interconnection Facilities Study. Developer should specify either Energy Resource Interconnection Service ("ERIS") alone, both ERIS and some MW level of Capacity Resource Interconnection Service ("CRIS") not to exceed the nameplate capacity of your facility, or CRIS only (*e.g.*, if your facility is already interconnected taking only ERIS, you may elect to be evaluated for CRIS at a MW level you specify, not to exceed the nameplate capacity of your facility or, if your facility is already interconnected taking ERIS and CRIS, you may elect an increase of CRIS, not to exceed the nameplate capacity of your facility). Evaluation election:

   ERIS: ____________

   CRIS: ____________

   Additional Information:

   Nameplate MW: ____________

   Nameplate MVA: ____________

   Auxiliary Load: ____________

   For temperature sensitive units, provide MW vs. temp curves and indicate maximum summer and winter net capability below:

   - Maximum summer net (net MW = gross MW minus auxiliary loads total MW) which can be achieved at 90 degrees F: ________

   - Maximum winter net (net MW = gross MW minus auxiliary loads total MW) which can be achieved at 10 degrees F : ______

3. One set of metering is required for each generation connection to the new ring bus or existing Connecting Transmission Owner station. Number of generation connections: _________

4. On the one-line indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

5. On the one-line indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

6. Will an alternate source of auxiliary power be available during CT/PT maintenance?
   ______ Yes ________ No

7. Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? ______ Yes ______ No

   (If yes, indicate on one-line diagram).

8. What type of control system or PLC will be located at the Developer's facility?

____

9. What protocol does the control system or PLC use?

____

10. Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

____

11. Physical dimensions of the proposed interconnection station:

____

12. Bus length from generation to interconnection station:

____

13. Line length from interconnection station to Connecting Transmission Owner's transmission line.

____

14. Tower number observed in the field. (Painted on tower leg):

____

15. Number of third-party easements required for transmission lines, if known:

____

16. In addition to the above information, as applicable, for BTM:NG Resources, please also provide the following information:

Interconnection Customer or Customer-Site Load:_____________kW (if none, so state)

Existing load? Yes ___ No___

If existing load with metered load data, provide coincident Summer peak load: ________

If new load or existing load without metered load data, provide estimated coincident Summer peak load: __________

Is the facility in the Transmission Owner's service area?

_____ Yes _____No Local provider: __________________________

Please provide proposed schedule dates:

Begin Construction Date: ______________

In-Service Date: ______________

Initial Synchronization Date: ______________

Generation Testing Date: ______________

Commercial Operation Date: ______________

APPENDIX 2-A TO LFIP – FACILITIES STUDY AGREEMENT FOR EXTERNAL CRIS RIGHTS

THIS AGREEMENT is made and entered into this _____ day of ____________, 20__ by and between _________________, a ______________ organized and existing under the laws of the State of ________________ ("Requestor"), the New York Independent System Operator, Inc., a not-for-profit corporation organized and existing under the laws of the State of New York ("NYISO"), and __________ a __________________ organized and existing under the laws of the State of New York ("Connecting Transmission Owner"). Requestor, NYISO and Connecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Requestor has, pursuant to Section 25.7.11 of Attachment S to the ISO OATT, requested External CRIS Rights for a specified number of MW of External CRIS; and

WHEREAS, NYISO has determined that Requestor has submitted a complete External CRIS Rights Request, in accordance with the applicable requirements of the NYISO Tariffs and ISO Procedures; and

WHEREAS, Requestor has requested NYISO and Connecting Transmission Owner to evaluate the specified number of MW of External ICAP in the currently Open Class Year Deliverability Study to specify the Deliverable MW for its External ICAP, and also to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the System Deliverability Upgrades required for External CRIS Rights.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meaning indicated herein, or in Attachment S or Attachment X to the ISO OATT, or in Article Z of the NYISO Services Tariff.

2.0 Requestor requests that NYISO and Connecting Transmission Owner evaluate the deliverability of Requestor's External CRIS Rights in accordance with Section 25.7.11 of Attachment S to the ISO OATT. Requestor's External CRIS Rights are not subject to, and shall not be evaluated by applying, the NYISO Minimum Interconnection Standard.

3.0 Requestor shall provide a deposit of $50,000 for the performance of the Class Year Interconnection Facilities Study for its External CRIS Rights. The time for completion of the Class Year Deliverability Study is specified in Attachment A to this Agreement.

NYISO shall invoice Requestor on a monthly basis for the expenses incurred by NYISO and Connecting Transmission Owner on the Class Year Deliverability Study for Requestor each month, as computed on a time and materials basis in accordance with the rates attached hereto. Requestor shall pay invoiced amount to NYISO within thirty (30) Calendar Days of receipt of invoice. NYISO shall continue to hold Requestor's deposit until settlement of the final invoice.

4.0 Miscellaneous

4.1 Accuracy of Information. Except as Requestor or Connecting Transmission Owner may otherwise specify in writing when they provide information to NYISO under this Agreement, Requestor and Connecting Transmission Owner each represent and warrant that the information it provides to NYISO shall be accurate and complete as of the date the information is provided. Requestor and Connecting Transmission Owner shall each promptly provide NYISO with any additional information needed to update information previously provided.

4.2 Disclaimer of Warranty. In preparing the Class Year Deliverability Study, the Party preparing such study and any subcontractor consultants employed by it shall have to rely on information provided by the other Parties, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, neither the Party preparing such study nor any subcontractor consultant employed by that Party makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy, content, or conclusions of the Class Year Deliverability Study for External ICAP. Requestor acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

4.3 Limitation of Liability. In no event shall any Party or its subcontractor consultants be liable for indirect, special, incidental, punitive, or consequential damages of any kind including loss of profits, arising under or in connection with this Agreement or the Class Year Deliverability Study for External ICAP, or any reliance on the Class Year Deliverability Study by any Party or third parties, even if one or more of the Parties or its subcontractor consultants have been advised of the possibility of such damages. Nor shall any Party or its subcontractor consultants be liable for any delay in delivery or for the non-performance or delay in performance of its obligations under this Agreement.

4.4 Third-Party Beneficiaries. Without limitation of Sections 4.2 and 4.3 of this Agreement, Requestor and Connecting Transmission Owner further agree that subcontractor consultants hired by NYISO to conduct or review, or to assist in the conducting or reviewing, a Class Year Deliverability

Study shall be deemed third party beneficiaries of these Sections 4.2 and 4.3.

4.5 Terms and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 30.4.5, shall continue in effect until the Class Year Deliverability Study for Requestor’s External CRIS Rights is completed and approved by the NYISO Operating Committee. Requestor or NYISO may terminate this Agreement upon the withdrawal of Requestor’s External CRIS Rights Request under Section 25.7.11 of Attachment S to the ISO OATT or upon Developer’s withdrawal from the Class Year Interconnection Facilities Study pursuant to Section 25.7.7.1 of Attachment S.

4.6 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of New York, without regard to any choice of laws provisions.

4.7 Severability. In the event that any part of this Agreement is deemed as a matter of law to be unenforceable or null and void, such unenforceable or void part shall be deemed severable from this Agreement and the Agreement shall continue in full force and effect as if each part was not contained herein.

4.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.

4.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing signed by the Parties hereto.

4.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.

4.11 Independent Contractor. NYISO shall at all times be deemed to be an independent contractor and none of its employees or the employees of its subcontractors shall be considered to be employees of Requestor as a result of this Agreement.

4.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a wavier or relinquishment to any extent of such Party’s right to insist or rely on any such provision, rights and remedies in that or any other instances; rather, the same shall be and remain in full force and effect.

4.13 Successors and Assigns. This Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

New York Independent System Operator, Inc.

By. ______________________________

Title: ______________________________

Date: ______________________________

[Insert name of Connecting Transmission Owner]

By: ______________________________

Title: ______________________________

Date: ______________________________

[Insert name of Requestor]

By: ______________________________

Title: ______________________________

Date: ______________________________

Attachment A To Facilities Study Agreement for External CRIS Rights

SCHEDULE FOR CONDUCTING THE FACILITIES STUDY FOR EXTERNAL CRIS Rights

NYISO and Connecting Transmission Owner shall use Reasonable Efforts to complete the study and issue a Class Year Deliverability Study report to Requestor within the following number of days after or receipt of an executed copy of this Agreement:

> Estimated completion date for Class Year 20__ Deliverability Study required by Section 25.7.11 Attachment S to the ISO OATT: ____/____/________, assuming no additional detailed studies are required to evaluate System Deliverability Upgrades.

DATA FORM TO BE PROVIDED BY REQUESTOR WITH THE FACILITIES STUDY AGREEMENT FOR EXTERNAL ICAP

a. _______MW of External ICAP certified to be supplied for each month of Summer Capability Period. The same number of MW must be supplied for all months of each Summer Capability Period throughout the Award Period

b. _______MW of External ICAP certified to be supplied for each month of Winter Capability Period (cannot exceed MW committed for Summer Capability Period). None required, but if Requestor does commit MW to any month of Winter Capability Period, Requestor must specify months covered by commitment.

c. The External Interface(s) proposed to be used for the External ICAP.

____

OTHER ASSUMPTIONS

____

____

Appendix 3 – STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

(Applicable to Generating Facilities that exceed 20 MW)

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STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (“Agreement”) is made and entered into this ____ day of ________ 20__, by and among _____________, a [corporate description] organized and existing under the laws of the State/Commonwealth of__________ (“Developer” with a Large Generating Facility), the New York Independent System Operator, Inc., a not-for-profit corporation organized and existing under the laws of the State of New York (“NYISO”), and _____________ a [corporate description] organized and existing under the laws of the State of New York (“Connecting Transmission Owner”). Developer, the NYISO, or Connecting Transmission Owner each may be referred to as a “Party” or collectively referred to as the “Parties.”

RECITALS

WHEREAS, NYISO operates the New York State Transmission System and Connecting Transmission Owner owns certain facilities included in the New York State Transmission System;

WHEREAS, Developer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Developer, NYISO, and Connecting Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the New York State Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

ARTICLE 1. DEFINITIONS

Whenever used in this Agreement with initial capitalization, the following terms shall have the meanings specified in this Article 1. Terms used in this Agreement with initial capitalization that are not defined in this Article 1 shall have the meanings specified in Section 1 of the ISO OATT, Section 30.1 of Attachment X of the ISO OATT, Section 25.1.2 of Attachment S of the ISO OATT, the body of the LFIP or the body of this Agreement.

Affected System shall mean an electric system other than the transmission system owned, controlled or operated by the Connecting Transmission Owner that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affected Transmission Owner shall mean the New York public utility or authority (or its designated agent) other than the Connecting Transmission Owner that (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, and (ii) owns, leases or otherwise possesses an interest in a portion of the New York State

Transmission System where System Deliverability Upgrades or System Upgrade Facilities are installed pursuant to Attachment X and Attachment S of the Tariff.

Affiliate shall mean, with respect to a person or entity, any individual, corporation, partnership, firm, joint venture, association, joint-stock company, trust or unincorporated organization, directly or indirectly controlling, controlled by, or under common control with, such person or entity. The term "control" shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Ancillary Services shall mean those services that are necessary to support the transmission of Capacity and Energy from resources to Loads while maintaining reliable operation of the New York State Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority, including but not limited to Environmental Law.

Applicable Reliability Councils shall mean the NERC, the NPCC and the NYSRC.

Applicable Reliability Standards shall mean the requirements and guidelines of the Applicable Reliability Councils, and the Transmission District to which the Developer's Large Generating Facility is directly interconnected, as those requirements and guidelines are amended and modified and in effect from time to time; provided that no Party shall waive its right to challenge the applicability or validity of any requirement or guideline as applied to it in the context of this Agreement.

Attachment Facilities shall mean the Connecting Transmission Owner's Attachment Facilities and the Developer's Attachment Facilities. Collectively, Attachment Facilities include all facilities and equipment between the Large Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Large Generating Facility to the New York State Transmission System. Attachment Facilities are sole use facilities and shall not include Stand Alone System Upgrade Facilities, Distribution Upgrades, System Upgrade Facilities or System Deliverability Upgrades.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by NYISO, Connecting Transmission Owner or Developer; described in Section 30.2.3 of the Standard Large Facility Interconnection Procedures.

Breach shall mean the failure of a Party to perform or observe any material term or condition of this Agreement.

Breaching Party shall mean a Party that is in Breach of this Agreement.

Business Day shall mean Monday through Friday, excluding federal holidays.

Byway shall mean all transmission facilities comprising the New York State Transmission System that are neither Highways nor Other Interfaces. All transmission facilities in Zone J and Zone K are Byways.

Calendar Day shall mean any day including Saturday, Sunday or a federal holiday.

Capacity Region shall mean one of four subsets of the Installed Capacity statewide markets comprised of (1) Rest of State (*i.e.*, Load Zones A through F); (2) Lower Hudson Valley (*i.e.,* Load Zones G, H and I); (3) New York City (*i.e.,* Load Zone J); and (4) Long Island (*i.e.,* Load Zone K) , except for Class Year Interconnection Facility Studies conducted prior to Class Year 2012, for which "Capacity Region" shall be defined as set forth in Section 25.7.3 of Attachment S to the ISO OATT.

Capacity Resource Interconnection Service ("CRIS") shall mean the service provided by NYISO to Developers that satisfy the NYISO Deliverability Interconnection Standard or that are otherwise eligible to receive CRIS in accordance with Attachment S to the ISO OATT; such service being one of the eligibility requirements for participation as a NYISO Installed Capacity Supplier.

Class Year Deliverability Study shall mean an assessment, conducted by the NYISO staff in cooperation with Market Participants, to determine whether System Deliverability Upgrades are required for Class Year CRIS Projects under the NYISO Deliverability Interconnection Standard.

Commercial Operation shall mean the status of a Large Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Large Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to this Agreement.

Confidential Information shall mean any information that is defined as confidential by Article 22 of this Agreement.

Connecting Transmission Owner shall mean the New York public utility or authority (or its designated agent) that (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, (ii) owns, leases or otherwise possesses an interest in the portion of the New York State Transmission System or Distribution System at the Point of Interconnection, and (iii) is a Party to this Agreement.

Connecting Transmission Owner's Attachment Facilities shall mean all facilities and equipment owned, controlled or operated by the Connecting Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Connecting Transmission Owner's Attachment Facilities are sole use facilities and shall not include Stand Alone System Upgrade Facilities, System Upgrade Facilities, or System Deliverability Upgrades.

Control Area shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (1) match, at all times, the power output of the Generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the Load within the electric power system(s); (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain Operating Reserves in accordance with Good Utility Practice. A Control Area must be certified by the NPCC.

Default shall mean the failure of a Party in Breach of this Agreement to cure such Breach in accordance with Article 17 of this Agreement.

Developer shall mean an Eligible Customer developing a Large Generating Facility, proposing to connect to the New York State Transmission System, in compliance with the NYISO Minimum Interconnection Standard.

Developer's Attachment Facilities shall mean all facilities and equipment, as identified in Appendix A of this Agreement, that are located between the Large Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Large Generating Facility to the New York State Transmission System. Developer's Attachment Facilities are sole use facilities.

Distribution System shall mean the Connecting Transmission Owner's facilities and equipment used to distribute electricity that are subject to FERC jurisdiction, and are subject to the NYISO's Large Facility Interconnection Procedures in Attachment X to the ISO OATT or Small Generator Interconnection Procedures in Attachment Z to the ISO OATT under FERC Order Nos. 2003 and/or 2006. The term Distribution System shall not include LIPA's distribution facilities.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Connecting Transmission Owner's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of a Large Facility or Small Generating Facility and render the transmission service necessary to affect the Developer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Attachment Facilities, System Upgrade Facilities, or System Deliverability Upgrades. Distribution Upgrades are sole use facilities and shall not include Stand Alone System Upgrade Facilities, System Upgrade Facilities, or System Deliverability Upgrades.

Effective Date shall mean the date on which this Agreement becomes effective upon execution by the Parties, subject to acceptance by the Commission, or if filed unexecuted, upon the date specified by the Commission.

Emergency State shall mean the condition or state that the New York State Power System is in when an abnormal condition occurs that requires automatic or immediate manual action to prevent or limit loss of the New York State Transmission System or Generators that could adversely affect the reliability of the New York State Power System.

Energy Resource Interconnection Service ("ERIS") shall mean the service provided by NYISO to interconnect the Developer's Large Generating Facility to the New York State Transmission System or to the Distribution System in accordance with the NYISO Minimum Interconnection Standard, to enable the New York State Transmission System to receive Energy and Ancillary Services from the Large Generating Facility, pursuant to the terms of the ISO OATT.

Environmental Law shall mean Applicable Laws and Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a *et seq.* ("FPA").

FERC shall mean the Federal Energy Regulatory Commission ("Commission") or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Developer's device for the production of electricity identified in the Interconnection Request, but shall not include the Developer's Attachment Facilities or Distribution Upgrades.

Generating Facility Capacity shall mean the net seasonal capacity of the Generating Facility and the aggregate net seasonal capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to delineate acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over any of the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Developer, NYISO, Affected Transmission Owner, Connecting Transmission Owner, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Highway shall mean 115 kV and higher transmission facilities that comprise the following NYCA interfaces: Dysinger East, West Central, Volney East, Moses South, Central East/Total East, and UPNY-ConEd, and their immediately connected, in series, bulk power system facilities in New York State. Each interface shall be evaluated to determine additional "in series" facilities, defined as any transmission facility higher than 115 kV that (a) is located in an upstream or downstream zone adjacent to the interface and (b) has a power transfer distribution factor (DFAX) equal to or greater than five percent when the aggregate of generation in zones or systems adjacent to the upstream zone or zones that define the interface is shifted to the aggregate of generation in zones or systems adjacent to the downstream zone or zones that define the interface. In determining "in series" facilities for Dysinger East and West Central interfaces, the 115 kV and 230 kV tie lines between NYCA and PJM located in LBMP Zones A and B shall not participate in the transfer. Highway transmission facilities are listed in ISO Procedures.

Initial Synchronization Date shall mean the date upon which the Large Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Developer reasonably expects it will be ready to begin use of the Connecting Transmission Owner's Attachment Facilities to obtain back feed power.

Interconnection Facilities Study shall mean a study conducted by NYISO or a third party consultant for the Developer to determine a list of facilities (including Connecting Transmission Owner's Attachment Facilities, Distribution Upgrades, System Upgrade Facilities and System Deliverability Upgrades as identified in the Interconnection System Reliability Impact Study), the cost of those facilities, and the time required to interconnect the Large Generating Facility with the New York State Transmission System or with the Distribution System. The scope of the study is defined in Section 30.8 of the Standard Large Facility Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Facility Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Request shall mean a Developer's request, in the form of Appendix 1 to the Standard Large Facility Interconnection Procedures, in accordance with the Tariff, to interconnect a new Large Generating Facility to the New York State Transmission System or to the Distribution System, or to materially increase the capacity of, or make a material modification to the operating characteristics of, an existing Large Generating Facility that is interconnected with the New York State Transmission System or with the Distribution System.

Interconnection Study shall mean any of the following studies: the Optional Interconnection Feasibility Study, the Interconnection System Reliability Impact Study, and the Interconnection Facilities Study described in the Standard Large Facility Interconnection Procedures.

Interconnection System Reliability Impact Study ("SRIS") shall mean an engineering study, conducted in accordance with Section 30.7 of the Standard Large Facility Interconnection Procedures, that evaluates the impact of the proposed Large Generating Facility on the safety and reliability of the New York State Transmission System and, if applicable, an Affected System, to determine what Attachment Facilities, Distribution Upgrades and System Upgrade Facilities are needed for the proposed Large Generating Facility of the Developer to connect reliably to the New York State Transmission System or to the Distribution System in a manner that meets the NYISO Minimum Interconnection Standard in Attachment X to the ISO OATT.

IRS shall mean the Internal Revenue Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Indemnified Party's performance or non-performance of its obligations under this Agreement on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Large Generating Facility pursuant to this Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

New York State Transmission System shall mean the entire New York State electric transmission system, which includes (i) the Transmission Facilities Under ISO Operational Control; (ii) the Transmission Facilities Requiring ISO Notification; and (iii) all remaining transmission facilities within the New York Control Area.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with this Agreement or its performance.

NPCC shall mean the Northeast Power Coordinating Council or its successor organization.

NYISO Deliverability Interconnection Standard – The standard that must be met, unless otherwise provided for by Attachment S to the ISO OATT, by (i) any generation facility larger than 2MW in order for that facility to obtain CRIS; (ii) any Merchant Transmission Facility proposing to interconnect to the New York State Transmission System and receive Unforced Capacity Delivery Rights; (iii) any entity requesting External CRIS Rights, and (iv) any entity requesting a CRIS transfer pursuant to Section 25.9.5 of Attachment S to the ISO OATT. To meet the NYISO Deliverability Interconnection Standard, the Interconnection Customer must, in accordance with the rules in Attachment S to the ISO OATT, fund or commit to fund any System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

NYISO Minimum Interconnection Standard – The reliability standard that must be met by any generation facility or Merchant Transmission Facility that is subject to NYISO's Large Facility Interconnection Procedures in Attachment X to the ISO OATT or the NYISO's Small Generator Interconnection Procedures in Attachment Z, that is proposing to connect to the New York State Transmission System or Distribution System, to obtain ERIS. The Minimum Interconnection Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System or to the Distribution System. The Minimum Interconnection Standard does not impose any deliverability test or deliverability requirement on the proposed interconnection.

NYSRC shall mean the New York State Reliability Council or its successor organization.

Other Interfaces shall mean the following interfaces into Capacity Regions: Lower Hudson Valley [*i.e.*, Rest of State (Load Zones A-F) to Lower Hudson Valley (Load Zones G, H and I)]; New York City [*i.e.*, Lower Hudson Valley (Load Zones G, H and I) to New York City (Load Zone J)]; and Long Island [*i.e.*, Lower Hudson Valley (Load Zones G, H and I) to Long Island (Load Zone K)], and the following Interfaces between the NYCA and adjacent Control Areas: PJM to NYISO, ISO-NE to NYISO, Hydro-Quebec to NYISO, and Norwalk Harbor (Connecticut) to Northport (Long Island) Cable.

Party or Parties shall mean NYISO, Connecting Transmission Owner, or Developer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to this Agreement, where the Developer's Attachment Facilities connect to the Connecting Transmission Owner's Attachment Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to this Agreement, where the Attachment Facilities connect to the New York State Transmission System or to the Distribution System.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under this Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Retired: A Generator that has permanently ceased operating on or after May 1, 2015 either: i) pursuant to applicable notice; or ii) as a result of the expiration of its Mothball Outage or its ICAP Ineligible Forced Outage.

Services Tariff shall mean the NYISO Market Administration and Control Area Tariff, as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff thereto.

Stand Alone System Upgrade Facilities shall mean System Upgrade Facilities that a Developer may construct without affecting day-to-day operations of the New York State Transmission System during their construction. NYISO, the Connecting Transmission Owner and the Developer must agree as to what constitutes Stand Alone System Upgrade Facilities and identify them in Appendix A to this Agreement.

Standard Large Facility Interconnection Procedures ("Large Facility Interconnection Procedures" or "LFIP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in Attachment X of the ISO OATT.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean this Agreement, which is the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in Appendix 6 to Attachment X of the ISO OATT.

System Deliverability Upgrades shall mean the least costly configuration of commercially available components of electrical equipment that can be used, consistent with Good Utility Practice and Applicable Reliability Requirements, to make the modifications or additions to Byways and Highways and Other Interfaces on the existing New York State Transmission System and Distribution System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Deliverability Interconnection Standard at the requested level of Capacity Resource Interconnection Service.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to (1) protect the New York State Transmission System from faults or other electrical disturbances occurring at the Large Generating Facility and (2) protect the Large Generating Facility from faults or other electrical system disturbances occurring on the New York State Transmission System or on other delivery systems or other generating systems to which the New York State Transmission System is directly connected.

System Upgrade Facilities shall mean the least costly configuration of commercially available components of electrical equipment that can be used, consistent with Good Utility Practice and Applicable Reliability Requirements, to make the modifications to the existing transmission system that are required to maintain system reliability due to: (i) changes in the system, including such changes as load growth and changes in load pattern, to be addressed in the form of generic generation or transmission projects; and (ii) proposed interconnections. In the case of proposed interconnection projects, System Upgrade Facilities are the modifications or additions to the existing New York State Transmission System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Minimum Interconnection Standard.

Tariff shall mean the NYISO Open Access Transmission Tariff ("OATT"), as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff.

Trial Operation shall mean the period during which Developer is engaged in on-site test operations and commissioning of the Large Generating Facility prior to Commercial Operation.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

2.1 Effective Date.

This Agreement shall become effective upon execution by the Parties, subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC. The NYISO and Connecting Transmission Owner shall promptly file this Agreement with FERC upon execution in accordance with Article 3.1.

2.2 Term of Agreement.

Subject to the provisions of Article 2.3, this Agreement shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as the Developer may request (*Term to be Specified in Individual Agreements*) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination.

2.3.1 Written Notice.

This Agreement may be terminated by the Developer after giving the NYISO and Connecting Transmission Owner ninety (90) Calendar Days advance written notice, or by the NYISO and Connecting Transmission Owner notifying FERC after the Large Generating Facility is Retired.

2.3.2 Default.

Any Party may terminate this Agreement in accordance with Article 17.

2.3.3 Compliance.

Notwithstanding Articles 2.3.1 and 2.3.2, no termination of this Agreement shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this Agreement, which notice has been accepted for filing by FERC.

2.4 Termination Costs.

If a Party elects to terminate this Agreement pursuant to Article 2.3.1 above, the terminating Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Attachment Facilities and equipment) or charges assessed by the other Parties, as of the date of the other Parties' receipt of such notice of termination, that are the responsibility of the terminating Party under this Agreement. In the event of termination by a Party, all Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this Agreement, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of the Connecting Transmission Owner's Attachment Facilities that have not yet been constructed or installed, the Connecting Transmission Owner shall to the extent possible and with Developer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Developer elects not to authorize such cancellation, Developer shall assume all payment obligations with respect to such materials, equipment, and contracts, and the Connecting Transmission Owner shall deliver such material and equipment, and, if necessary, assign such contracts, to Developer as soon as practicable, at Developer's expense. To the extent that Developer has already paid Connecting Transmission Owner for any or all such costs of materials or equipment not taken by Developer, Connecting Transmission Owner shall promptly refund such amounts to Developer, less any costs, including penalties incurred by the Connecting Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If Developer terminates this Agreement, it shall be responsible for all costs incurred in association with Developer's interconnection, including any cancellation costs relating to orders or contracts for Attachment Facilities and equipment, and other expenses including any System Upgrade Facilities and System Deliverability Upgrades for which the Connecting Transmission Owner has incurred expenses and has not been reimbursed by the Developer.

2.4.2 Connecting Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Developer chooses not to accept delivery of, in which case Connecting Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Attachment Facilities, and any other facilities already installed or constructed pursuant to the terms of this Agreement, Developer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection.

Upon termination of this Agreement, Developer and Connecting Transmission Owner will take all appropriate steps to disconnect the Developer's Large Generating Facility from the New York State Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this Agreement or such non-terminating Party otherwise is responsible for these costs under this Agreement.

2.6 Survival.

This Agreement shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder; including billings and payments pursuant to this Agreement; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect; and to permit Developer and Connecting Transmission Owner each to have access to the lands of the other pursuant to this Agreement or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

ARTICLE 3. REGULATORY FILINGS

NYISO and Connecting Transmission Owner shall file this Agreement (and any amendment hereto) with the appropriate Governmental Authority, if required. Any information related to studies for interconnection asserted by Developer to contain Confidential Information shall be treated in accordance with Article 22 of this Agreement and Attachment F to the ISO OATT. If the Developer has executed this Agreement, or any amendment thereto, the Developer shall reasonably cooperate with NYISO and Connecting Transmission Owner with respect to such filing and to provide any information reasonably requested by NYISO and Connecting Transmission Owner needed to comply with Applicable Laws and Regulations.

ARTICLE 4. SCOPE OF INTERCONNECTION SERVICE

4.1 Provision of Service.

NYISO will provide Developer with interconnection service of the following type for the term of this Agreement.

4.1.1 Product.

NYISO will provide [ ] Interconnection Service to Developer at the Point of Interconnection.

4.1.2 Developer is responsible for ensuring that its actual Large Generating Facility output matches the scheduled delivery from the Large Generating Facility to the New York State Transmission System, consistent with the scheduling requirements of the NYISO's FERC-approved market structure, including ramping into and out of such scheduled delivery, as measured at the Point of Interconnection, consistent with the scheduling requirements of the ISO OATT and any applicable FERC-approved market structure.

4.2 No Transmission Delivery Service.

The execution of this Agreement does not constitute a request for, nor agreement to provide, any Transmission Service under the ISO OATT, and does not convey any right to deliver electricity to any specific customer or Point of Delivery. If Developer wishes to obtain Transmission Service on the New York State Transmission System, then Developer must request such Transmission Service in accordance with the provisions of the ISO OATT.

4.3 No Other Services.

The execution of this Agreement does not constitute a request for, nor agreement to provide Energy, any Ancillary Services or Installed Capacity under the NYISO Market Administration and Control Area Services Tariff ("Services Tariff"). If Developer wishes to supply Energy, Installed Capacity or Ancillary Services, then Developer will make application to do so in accordance with the NYISO Services Tariff.

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.1 Options.

Unless otherwise mutually agreed to by Developer and Connecting Transmission Owner, Developer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either Standard Option or Alternate Option set forth below for completion of the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades as set forth in Appendix A hereto, and such dates and selected option shall be set forth in Appendix B hereto.

5.1.1 Standard Option.

The Connecting Transmission Owner shall design, procure, and construct the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades, using Reasonable Efforts to complete the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades by the dates set forth in Appendix B hereto. The Connecting Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Connecting Transmission Owner reasonably expects that it will not be able to complete the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades by the specified dates, the Connecting Transmission Owner shall promptly provide written notice to the Developer and NYISO, and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option.

If the dates designated by Developer are acceptable to Connecting Transmission Owner, the Connecting Transmission Owner shall so notify Developer and NYISO within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of the Connecting Transmission Owner's Attachment Facilities by the designated dates. If Connecting Transmission Owner subsequently fails to complete Connecting Transmission Owner's Attachment Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete System Upgrade Facilities or System Deliverability Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Developer and Connecting Transmission Owner for such Trial Operation; or fails to complete the System Upgrade Facilities and System Deliverability Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B hereto; Connecting Transmission Owner shall pay Developer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Developer shall be extended day for day for each day that NYISO refuses to grant clearances to install equipment.

5.1.3 Option to Build.

If the dates designated by Developer are not acceptable to Connecting Transmission Owner, the Connecting Transmission Owner shall so notify the Developer and NYISO within thirty (30) Calendar Days, and unless the Developer and Connecting Transmission Owner agree otherwise, Developer shall have the option to assume responsibility for the design, procurement and construction of Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities on the dates specified in Article 5.1.2; provided that if an Attachment Facility or Stand Alone System Upgrade Facility is needed for more than one Developer's project, Developer's option to build such facility shall be contingent on the agreement of all other affected Developers. NYISO, Connecting Transmission Owner and Developer must agree as to what constitutes Stand Alone System Upgrade Facilities and identify such Stand Alone System Upgrade Facilities in Appendix A hereto. Except for Stand Alone System Upgrade Facilities, Developer shall have no right to construct System Upgrade Facilities under this option.

5.1.4 Negotiated Option.

If the Developer elects not to exercise its option under Article 5.1.3, Option to Build, Developer shall so notify Connecting Transmission Owner and NYISO within thirty (30) Calendar Days, and the Developer and Connecting Transmission Owner shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities by Developer) pursuant to which Connecting Transmission Owner is responsible for the design, procurement and construction of the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades. If the two Parties are unable to reach agreement on such terms and conditions, Connecting Transmission Owner shall assume responsibility for the design, procurement and construction of the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades pursuant to 5.1.1, Standard Option.

5.2 General Conditions Applicable to Option to Build.

If Developer assumes responsibility for the design, procurement and construction of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities, the following conditions apply:

5.2.1 Developer shall engineer, procure equipment, and construct the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by the Connecting Transmission Owner;

5.2.2 Developer's engineering, procurement and construction of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities shall comply with all requirements of law to which Connecting Transmission Owner would be subject in the engineering, procurement or construction of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities;

5.2.3 Connecting Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities;

5.2.4 Prior to commencement of construction, Developer shall provide to Connecting Transmission Owner and NYISO a schedule for construction of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities, and shall promptly respond to requests for information from Connecting Transmission Owner or NYISO;

5.2.5 At any time during construction, Connecting Transmission Owner shall have the right to gain unrestricted access to the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities and to conduct inspections of the same;

5.2.6 At any time during construction, should any phase of the engineering, equipment procurement, or construction of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities not meet the standards and specifications provided by Connecting Transmission Owner, the Developer shall be obligated to remedy deficiencies in that portion of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities;

5.2.7 Developer shall indemnify Connecting Transmission Owner and NYISO for claims arising from the Developer's construction of Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities under procedures applicable to Article 18.1 Indemnity;

5.2.8 Developer shall transfer control of Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities to the Connecting Transmission Owner;

5.2.9 Unless the Developer and Connecting Transmission Owner otherwise agree, Developer shall transfer ownership of Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities to Connecting Transmission Owner;

5.2.10 Connecting Transmission Owner shall approve and accept for operation and maintenance the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

5.2.11 Developer shall deliver to NYISO and Connecting Transmission Owner "as built" drawings, information, and any other documents that are reasonably required by NYISO or Connecting Transmission Owner to assure that the Attachment Facilities and Stand Alone System Upgrade Facilities are built to the standards and specifications required by Connecting Transmission Owner.

5.3 Liquidated Damages.

The actual damages to the Developer, in the event the Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades are not completed by the dates designated by the Developer and accepted by the Connecting Transmission Owner pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Developer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by the Connecting Transmission Owner to the Developer in the event that Connecting Transmission Owner does not complete any portion of the Connecting Transmission Owner's Attachment Facilities, System Upgrade Facilities or System Deliverability Upgrades by the applicable dates, shall be an amount equal to 1/2 of 1 percent per day of the actual cost of the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades, in the aggregate, for which Connecting Transmission Owner has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of the Connecting Transmission Owner Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades for which the Connecting Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by the Connecting Transmission Owner to the Developer as just compensation for the damages caused to the Developer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this Agreement. Liquidated damages, when the Developer and Connecting Transmission Owner agree to them, are the exclusive remedy for the Connecting Transmission Owner's failure to meet its schedule.

Further, Connecting Transmission Owner shall not pay liquidated damages to Developer if: (1) Developer is not ready to commence use of the Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades to take the delivery of power for the Developer's Large Generating Facility's Trial Operation or to export power from the Developer's Large Generating Facility on the specified dates, unless the Developer would have been able to commence use of the Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades to take the delivery of power for Developer's Large Generating Facility's Trial Operation or to export power from the Developer's Large Generating Facility, but for Connecting Transmission Owner's delay; (2) the Connecting Transmission Owner's failure to meet the specified dates is the result of the action or inaction of the Developer or any other Developer who has entered into a Standard Large Generator Interconnection Agreement with the Connecting Transmission Owner and NYISO, or action or inaction by any other Party, or any other cause beyond Connecting Transmission Owner's reasonable control or reasonable ability to cure; (3) the

Developer has assumed responsibility for the design, procurement and construction of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities; or (4) the Connecting Transmission Owner and Developer have otherwise agreed. In no event shall NYISO have any liability whatever to Developer for liquidated damages associated with the engineering, procurement or construction of Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades.

5.4 Power System Stabilizers.

The Developer shall procure, install, maintain and operate Power System Stabilizers in accordance with the requirements identified in the Interconnection Studies conducted for Developer's Large Generating Facility. NYISO and Connecting Transmission Owner reserve the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Developer shall immediately notify the Connecting Transmission Owner and NYISO. The requirements of this paragraph shall not apply to wind generators.

5.5 Equipment Procurement.

If responsibility for construction of the Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades is to be borne by the Connecting Transmission Owner, then the Connecting Transmission Owner shall commence design of the Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Developer and Connecting Transmission Owner otherwise agree in writing:

5.5.1 NYISO and Connecting Transmission Owner have completed the Interconnection Facilities Study pursuant to the Interconnection Facilities Study Agreement;

5.5.2 The NYISO has completed the required cost allocation analyses, and Developer has accepted his share of the costs for necessary System Upgrade Facilities and System Deliverability Upgrades in accordance with the provisions of Attachment S of the ISO OATT;

5.5.3 The Connecting Transmission Owner has received written authorization to proceed with design and procurement from the Developer by the date specified in Appendix B hereto; and

5.5.4 The Developer has provided security to the Connecting Transmission Owner in accordance with Article 11.5 by the dates specified in Appendix B hereto.

5.6 Construction Commencement.

The Connecting Transmission Owner shall commence construction of the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System

Deliverability Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades;

5.6.3 The Connecting Transmission Owner has received written authorization to proceed with construction from the Developer by the date specified in Appendix B hereto; and

5.6.4 The Developer has provided security to the Connecting Transmission Owner in accordance with Article 11.5 by the dates specified in Appendix B hereto.

5.7 Work Progress.

The Developer and Connecting Transmission Owner will keep each other, and NYISO, advised periodically as to the progress of their respective design, procurement and construction efforts. Any Party may, at any time, request a progress report from the Developer or Connecting Transmission Owner. If, at any time, the Developer determines that the completion of the Connecting Transmission Owner's Attachment Facilities will not be required until after the specified In-Service Date, the Developer will provide written notice to the Connecting Transmission Owner and NYISO of such later date upon which the completion of the Connecting Transmission Owner's Attachment Facilities will be required.

5.8 Information Exchange.

As soon as reasonably practicable after the Effective Date, the Developer and Connecting Transmission Owner shall exchange information, and provide NYISO the same information, regarding the design and compatibility of their respective Attachment Facilities and compatibility of the Attachment Facilities with the New York State Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation.

If any of the Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Developer's Large Generating Facility, NYISO shall, upon the request and at the expense of Developer, in conjunction with the Connecting Transmission Owner, perform operating studies on a timely basis to determine the extent to which the Developer's Large Generating Facility and the Developer's Attachment Facilities may operate prior to the completion of the Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this Agreement. Connecting Transmission Owner and NYISO shall permit Developer to operate the

Developer's Large Generating Facility and the Developer's Attachment Facilities in accordance with the results of such studies.

5.10 Developer's Attachment Facilities ("DAF").

Developer shall, at its expense, design, procure, construct, own and install the DAF, as set forth in Appendix A hereto.

5.10.1 DAF Specifications.

Developer shall submit initial specifications for the DAF, including System Protection Facilities, to Connecting Transmission Owner and NYISO at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Connecting Transmission Owner and NYISO shall review such specifications to ensure that the DAF are compatible with the technical specifications, operational control, and safety requirements of the Connecting Transmission Owner and NYISO and comment on such specifications within thirty (30) Calendar Days of Developer's submission. All specifications provided hereunder shall be deemed to be Confidential Information.

5.10.2 No Warranty.

The review of Developer's final specifications by Connecting Transmission Owner and NYISO shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the DAF. Developer shall make such changes to the DAF as may reasonably be required by Connecting Transmission Owner or NYISO, in accordance with Good Utility Practice, to ensure that the DAF are compatible with the technical specifications, operational control, and safety requirements of the Connecting Transmission Owner and NYISO.

5.10.3 DAF Construction.

The DAF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Developer and Connecting Transmission Owner agree on another mutually acceptable deadline, the Developer shall deliver to the Connecting Transmission Owner and NYISO "as-built" drawings, information and documents for the DAF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the DAF, plan and elevation drawings showing the layout of the DAF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with the Developer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the DAF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. The Developer shall provide to, and coordinate with, Connecting Transmission Owner and NYISO with respect to proposed specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Connecting Transmission Owner's Attachment Facilities Construction.

The Connecting Transmission Owner's Attachment Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Connecting Transmission Owner and Developer agree on another mutually acceptable deadline, the Connecting Transmission Owner shall deliver to the Developer "as-built" drawings, relay diagrams, information and documents for the Connecting Transmission Owner's Attachment Facilities set forth in Appendix A.

The Connecting Transmission Owner [shall/shall not] transfer operational control of the Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities to the NYISO upon completion of such facilities.

5.12 Access Rights.

Upon reasonable notice and supervision by the Granting Party, and subject to any required or necessary regulatory approvals, either the Connecting Transmission Owner or Developer ("Granting Party") shall furnish to the other of those two Parties ("Access Party") at no cost any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress at the Point of Interconnection to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the New York State Transmission System; (ii) operate and maintain the Large Generating Facility, the Attachment Facilities and the New York State Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this Agreement. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party. The Access Party shall indemnify the Granting Party against all claims of injury or damage from third parties resulting from the exercise of the access rights provided for herein.

5.13 Lands of Other Property Owners.

If any part of the Connecting Transmission Owner's Attachment Facilities and/or System Upgrade Facilities and/or System Deliverability Upgrades is to be installed on property owned by persons other than Developer or Connecting Transmission Owner, the Connecting Transmission Owner shall at Developer's expense use efforts, similar in nature and extent to those that it typically undertakes for its own or affiliated generation, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove the Connecting Transmission Owner's Attachment Facilities and/or System Upgrade Facilities and/or System Deliverability Upgrades upon such property.

5.14 Permits.

NYISO, Connecting Transmission Owner and the Developer shall cooperate with each other in good faith in obtaining all permits, licenses and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Connecting Transmission Owner shall provide permitting assistance to the Developer comparable to that provided to the Connecting Transmission Owner's own, or an Affiliate's generation, if any.

5.15 Early Construction of Base Case Facilities.

Developer may request Connecting Transmission Owner to construct, and Connecting Transmission Owner shall construct, subject to a binding cost allocation agreement reached in accordance with Attachment S to the ISO OATT, including Section 25.8.7 thereof, using Reasonable Efforts to accommodate Developer's In-Service Date, all or any portion of any System Upgrade Facilities or System Deliverability Upgrades required for Developer to be interconnected to the New York State Transmission System which are included in the Base Case of the Class Year Interconnection Facilities Study for the Developer, and which also are required to be constructed for another Developer, but where such construction is not scheduled to be completed in time to achieve Developer's In-Service Date.

5.16 Suspension.

Developer reserves the right, upon written notice to Connecting Transmission Owner and NYISO, to suspend at any time all work by Connecting Transmission Owner associated with the construction and installation of Connecting Transmission Owner's Attachment Facilities and/or System Upgrade Facilities and/or System Deliverability Upgrades required for only that Developer under this Agreement with the condition that the New York State Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and the safety and reliability criteria of Connecting Transmission Owner and NYISO. In such event, Developer shall be responsible for all reasonable and necessary costs and/or obligations in accordance with Attachment S to the ISO OATT including those which Connecting Transmission Owner (i) has incurred pursuant to this Agreement prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the New York State Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Connecting Transmission Owner cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Connecting Transmission Owner shall obtain Developer's authorization to do so.

Connecting Transmission Owner shall invoice Developer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Developer suspends work by Connecting Transmission Owner required under this Agreement pursuant to this Article 5.16, and has not requested Connecting Transmission Owner to recommence the work required under this Agreement on or before the expiration of three (3) years following commencement of such suspension, this Agreement shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Connecting Transmission Owner and NYISO, if no effective date is specified.

5.17 Taxes.

5.17.1 Developer Payments Not Taxable.

The Developer and Connecting Transmission Owner intend that all payments or property transfers made by Developer to Connecting Transmission Owner for the installation of the Connecting Transmission Owner's Attachment Facilities and the System Upgrade Facilities and the System Deliverability Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants.

In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Developer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the New York State Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to the Connecting Transmission Owner for the Connecting Transmission Owner's Attachment Facilities will be capitalized by Developer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of the Connecting Transmission Owner's Attachment Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Connecting Transmission Owner's request, Developer shall provide Connecting Transmission Owner with a report from an independent engineer confirming its representation in clause (iii), above. Connecting Transmission Owner represents and covenants that the cost of the Connecting Transmission Owner's Attachment Facilities paid for by Developer will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Connecting Transmission Owner.

Notwithstanding Article 5.17.1, Developer shall protect, indemnify and hold harmless Connecting Transmission Owner from the cost consequences of any current tax liability imposed against Connecting Transmission Owner as the result of payments or property transfers made by Developer to Connecting Transmission Owner under this Agreement, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Connecting Transmission Owner.

Connecting Transmission Owner shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Developer under this Agreement unless (i) Connecting Transmission Owner has determined, in good faith, that the payments or property transfers made by Developer to Connecting Transmission Owner should be reported as income subject to taxation or (ii) any Governmental Authority directs Connecting Transmission Owner to report payments or property as income subject to taxation; provided, however, that Connecting Transmission Owner may require Developer to provide security, in a form reasonably acceptable to Connecting Transmission Owner (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Developer shall reimburse Connecting Transmission Owner for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Connecting Transmission Owner of the amount due, including detail about how the amount was calculated.

This indemnification obligation shall terminate at the earlier of (1) the expiration of the ten-year testing period and the applicable statute of limitation, as it may be extended by the Connecting Transmission Owner upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 Tax Gross-Up Amount.

Developer’s liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Developer will pay Connecting Transmission Owner, in addition to the amount paid for the Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades, an amount equal to (1) the current taxes imposed on Connecting Transmission Owner (“Current Taxes”) on the excess of (a) the gross income realized by Connecting Transmission Owner as a result of payments or property transfers made by Developer to Connecting Transmission Owner under this Agreement (without regard to any payments under this Article 5.17) (the “Gross Income Amount”) over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the “Present Value Depreciation Amount”), plus (2) an additional amount sufficient to permit the Connecting Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Connecting Transmission Owner’s composite federal and state tax rates at the time the payments or property transfers are received and Connecting Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the “Current Tax Rate”), and (ii) the Present Value Depreciation Amount shall be computed by discounting Connecting Transmission Owner’s anticipated tax depreciation deductions as a result of such payments or property transfers by Connecting Transmission Owner’s current weighted average cost of capital. Thus, the formula for calculating Developer’s liability to Connecting Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount - Present Value Depreciation Amount))/(1 - Current Tax Rate). Developer’s estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades.

5.17.5 Private Letter Ruling or Change or Clarification of Law.

At Developer's request and expense, Connecting Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Developer to Connecting Transmission Owner under this Agreement are subject to federal income taxation. Developer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Developer's knowledge. Connecting Transmission Owner and Developer shall cooperate in good faith with respect to the submission of such request.

Connecting Transmission Owner shall keep Developer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Developer to participate in all discussions with the IRS regarding such request for a private letter ruling. Connecting Transmission Owner shall allow Developer to attend all meetings with IRS officials about the request and shall permit Developer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 Subsequent Taxable Events.

If, within 10 years from the date on which the relevant Connecting Transmission Owner Attachment Facilities are placed in service, (i) Developer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this Agreement terminates and Connecting Transmission Owner retains ownership of the Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades, the Developer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Connecting Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 Contests.

In the event any Governmental Authority determines that Connecting Transmission Owner's receipt of payments or property constitutes income that is subject to taxation, Connecting Transmission Owner shall notify Developer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Developer and at Developer's sole expense, Connecting Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Developer's written request and sole expense, Connecting Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Connecting Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Connecting Transmission Owner shall keep Developer informed, shall consider in good faith suggestions from Developer about the conduct of the contest, and shall reasonably permit Developer or an Developer representative to attend contest proceedings.

Developer shall pay to Connecting Transmission Owner on a periodic basis, as invoiced by Connecting Transmission Owner, Connecting Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest, including any costs associated with obtaining the opinion of independent tax counsel described in this Article 5.17.7. The Connecting Transmission Owner may abandon any contest if the Developer fails to provide payment to the Connecting Transmission Owner within thirty (30) Calendar Days of receiving such invoice. At any time during the contest, Connecting Transmission Owner may agree to a settlement either with Developer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Connecting Transmission Owner, but reasonably acceptable to Developer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Developer's obligation shall be based on the amount of the settlement agreed to by Developer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. The Connecting Transmission Owner may also settle any tax controversy without receiving the Developer's consent or any such written advice; however, any such settlement will relieve the Developer from any obligation to indemnify Connecting Transmission Owner for the tax at issue in the contest (unless the failure to obtain written advice is attributable to the Developer's unreasonable refusal to the appointment of independent tax counsel).

5.17.8 Refund.

In the event that (a) a private letter ruling is issued to Connecting Transmission Owner which holds that any amount paid or the value of any property transferred by Developer to Connecting Transmission Owner under the terms of this Agreement is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Connecting Transmission Owner in good faith that any amount paid or the value of any property transferred by Developer to Connecting Transmission Owner under the terms of this Agreement is not taxable to Connecting Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Developer to Connecting Transmission Owner are not subject to federal income tax, or (d) if Connecting Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Developer to Connecting Transmission Owner pursuant to this Agreement, Connecting Transmission Owner shall promptly refund to Developer the following:

(i) Any payment made by Developer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) Interest on any amounts paid by Developer to Connecting Transmission Owner for such taxes which Connecting Transmission Owner did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R.

§35.19a(a)(2)(iii) from the date payment was made by Developer to the date Connecting Transmission Owner refunds such payment to Developer, and

(iii) With respect to any such taxes paid by Connecting Transmission Owner, any refund or credit Connecting Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to the Connecting Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Connecting Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Connecting Transmission Owner will remit such amount promptly to Developer only after and to the extent that Connecting Transmission Owner has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to the Connecting Transmission Owner's Attachment Facilities.

The intent of this provision is to leave both the Developer and Connecting Transmission Owner, to the extent practicable, in the event that no taxes are due with respect to any payment for Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes.

Upon the timely request by Developer, and at Developer's sole expense, Connecting Transmission Owner shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Connecting Transmission Owner for which Developer may be required to reimburse Connecting Transmission Owner under the terms of this Agreement. Developer shall pay to Connecting Transmission Owner on a periodic basis, as invoiced by Connecting Transmission Owner, Connecting Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Developer and Connecting Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Developer to Connecting Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Developer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Connecting Transmission Owner.

5.18 Tax Status; Non-Jurisdictional Entities.

5.18.1 Tax Status.

Each Party shall cooperate with the other Parties to maintain the other Parties' tax status. Nothing in this Agreement is intended to adversely affect the tax status of any Party including the status of NYISO, or the status of any Connecting Transmission Owner with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds. Notwithstanding any other provisions of this Agreement, LIPA, NYPA and Consolidated Edison Company of New York, Inc. shall not be required to comply with any provisions of this Agreement that would result in the loss of tax-exempt status of any of their Tax-Exempt Bonds or impair their ability to issue future tax-exempt obligations. For purposes of this provision, Tax-Exempt Bonds shall include the obligations of the Long Island Power Authority, NYPA and Consolidated Edison Company of New York, Inc., the interest on which is not included in gross income under the Internal Revenue Code.

5.18.2 Non-Jurisdictional Entities.

LIPA and NYPA do not waive their exemptions, pursuant to Section 201(f) of the FPA, from Commission jurisdiction with respect to the Commission's exercise of the FPA's general ratemaking authority.

5.19 Modification.

5.19.1 General.

Either the Developer or Connecting Transmission Owner may undertake modifications to its facilities covered by this Agreement. If either the Developer or Connecting Transmission Owner plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party, and to NYISO, sufficient information regarding such modification so that the other Party and NYISO may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be Confidential Information hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party and NYISO at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Developer to submit an Interconnection Request, the NYISO shall provide, within sixty (60) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the New York State Transmission System, Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades necessitated by such Developer modification and a good faith estimate of the costs thereof. The Developer shall be responsible for the cost of any such additional modifications, including the cost of studying the impact of the Developer modification.

5.19.2 Standards.

Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this Agreement, NYISO requirements and Good Utility Practice.

5.19.3 Modification Costs.

Developer shall not be assigned the costs of any additions, modifications, or replacements that Connecting Transmission Owner makes to the Connecting Transmission Owner's

Attachment Facilities or the New York State Transmission System to facilitate the interconnection of a third party to the Connecting Transmission Owner's Attachment Facilities or the New York State Transmission System, or to provide Transmission Service to a third party under the ISO OATT, except in accordance with the cost allocation procedures in Attachment S of the ISO OATT. Developer shall be responsible for the costs of any additions, modifications, or replacements to the Developer's Attachment Facilities that may be necessary to maintain or upgrade such Developer's Attachment Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

ARTICLE 6. TESTING AND INSPECTION

6.1 Pre-Commercial Operation Date Testing and Modifications.

Prior to the Commercial Operation Date, the Connecting Transmission Owner shall test the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades and Developer shall test the Large Generating Facility and the Developer's Attachment Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Developer and Connecting Transmission Owner shall each make any modifications to its facilities that are found to be necessary as a result of such testing. Developer shall bear the cost of all such testing and modifications. Developer shall generate test energy at the Large Generating Facility only if it has arranged for the injection of such test energy in accordance with NYISO procedures.

6.2 Post-Commercial Operation Date Testing and Modifications.

Developer and Connecting Transmission Owner shall each at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice and Applicable Reliability Standards as may be necessary to ensure the continued interconnection of the Large Generating Facility with the New York State Transmission System in a safe and reliable manner. Developer and Connecting Transmission Owner shall each have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing.

Developer and Connecting Transmission Owner shall each notify the other Party, and the NYISO, in advance of its performance of tests of its Attachment Facilities. The other Party, and the NYISO, shall each have the right, at its own expense, to observe such testing.

6.4 Right to Inspect.

Developer and Connecting Transmission Owner shall each have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review the other Party's maintenance records relative to the Attachment Facilities, the System Protection Facilities and other protective equipment. NYISO shall have these same rights of inspection as to the facilities and equipment of Developer and Connecting Transmission Owner. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Attachment Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be treated in accordance with Article 22 of this Agreement and Attachment F to the ISO OATT.

ARTICLE 7. METERING

7.1 General.

Developer and Connecting Transmission Owner shall each comply with applicable requirements of NYISO and the New York Public Service Commission when exercising its rights and fulfilling its responsibilities under this Article 7. Unless otherwise agreed by the Connecting Transmission Owner and NYISO approved meter service provider and Developer, the Connecting Transmission Owner shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Net power flows including MW and MVAR, MWHR and loss profile data to and from the Large Generating Facility shall be measured at the Point of Interconnection. Connecting Transmission Owner shall provide metering quantities, in analog and/or digital form, as required, to Developer or NYISO upon request. Where the Point of Interconnection for the Large Generating Facility is other than the generator terminal, the Developer shall also provide gross MW and MVAR quantities at the generator terminal. Developer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 Check Meters.

Developer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Connecting Transmission Owner’s meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this Agreement, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Connecting Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Developer in accordance with Good Utility Practice.

7.3 Standards.

Connecting Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment including potential transformers and current transformers in accordance with applicable ANSI and PSC standards as detailed in the NYISO Control Center Communications Manual and in the NYISO Revenue Metering Requirements Manual.

7.4 Testing of Metering Equipment.

Connecting Transmission Owner shall inspect and test all of its Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by NYISO or Developer, Connecting Transmission Owner shall, at Developer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Connecting Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and Developer and NYISO may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Developer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Connecting Transmission Owner's failure to maintain, then Connecting Transmission Owner shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Connecting Transmission Owner shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Developer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment. The NYISO shall reserve the right to review all associated metering equipment installation on the Developer's or Connecting Transmission Owner's property at any time.

7.5 Metering Data.

At Developer's expense, the metered data shall be telemetered to one or more locations designated by Connecting Transmission Owner, Developer and NYISO. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

ARTICLE 8. COMMUNICATIONS

8.1 Developer Obligations.

In accordance with applicable NYISO requirements, Developer shall maintain satisfactory operating communications with Connecting Transmission Owner and NYISO. Developer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Developer shall also provide the dedicated data circuit(s) necessary to provide Developer data to Connecting Transmission Owner and NYISO as set forth in Appendix D hereto. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Connecting Transmission Owner and NYISO. Any required maintenance of such communications equipment shall be performed by Developer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 Remote Terminal Unit.

Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Developer, or by Connecting Transmission Owner at Developer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Connecting Transmission Owner and NYISO through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Connecting Transmission Owner and NYISO. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Connecting Transmission Owner and NYISO.

Each Party will promptly advise the appropriate other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by that other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 No Annexation.

Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Party providing such equipment and the Party receiving such equipment.

ARTICLE 9. OPERATIONS

9.1 General.

Each Party shall comply with Applicable Laws and Regulations and Applicable Reliability Standards. Each Party shall provide to the other Parties all information that may reasonably be required by the other Parties to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 NYISO and Connecting Transmission Owner Obligations.

Connecting Transmission Owner and NYISO shall cause the New York State Transmission System and the Connecting Transmission Owner's Attachment Facilities to be operated, maintained and controlled in a safe and reliable manner in accordance with this Agreement and the NYISO Tariffs. Connecting Transmission Owner and NYISO may provide operating instructions to Developer consistent with this Agreement, NYISO procedures and Connecting Transmission Owner's operating protocols and procedures as they may change from time to time. Connecting Transmission Owner and NYISO will consider changes to their respective operating protocols and procedures proposed by Developer.

9.3 Developer Obligations.

Developer shall at its own expense operate, maintain and control the Large Generating Facility and the Developer's Attachment Facilities in a safe and reliable manner and in accordance with this Agreement. Developer shall operate the Large Generating Facility and the Developer's Attachment Facilities in accordance with NYISO and Connecting Transmission Owner requirements, as such requirements are set forth or referenced in Appendix C hereto. Appendix C will be modified to reflect changes to the requirements as they may change from time to time. Any Party may request that the appropriate other Party or Parties provide copies of the requirements set forth or referenced in Appendix C hereto.

9.4 Start-Up and Synchronization.

Consistent with the mutually acceptable procedures of the Developer and Connecting Transmission Owner, the Developer is responsible for the proper synchronization of the Large Generating Facility to the New York State Transmission System in accordance with NYISO and Connecting Transmission Owner procedures and requirements.

9.5 Real and Reactive Power Control.

9.5.1 Power Factor Design Criteria.

9.5.1.1 Synchronous Generation. Developer shall design the Large Generating Facility to maintain effective composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging unless the NYISO or the Transmission Owner in whose Transmission District the Large Generating Facility interconnects has established different requirements that apply to all generators in the New York Control Area or Transmission District (as applicable) on a comparable basis, in accordance with Good Utility Practice.

The Developer shall design and maintain the plant auxiliary systems to operate safely throughout the entire real and reactive power design range.

9.5.1.2 Non-Synchronous Generation. Developer shall design the Large Generating Facility to maintain composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the NYISO or the Transmission Owner in whose Transmission District the Large Generating Facility interconnects has established a different power factor range that applies to all non-synchronous generators in the Control Area or Transmission District (as applicable) on a comparable basis, in accordance with Good Utility Practice.   This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnection non-synchronous generators that have not yet executed a Facilities Study Agreement as of September 21, 2016.

The Developer shall design and maintain the plant auxiliary systems to operate safely throughout the entire real and reactive power design range.

9.5.2 Voltage Schedules.

Once the Developer has synchronized the Large Generating Facility with the New York State Transmission System, NYISO shall require Developer to operate the Large Generating Facility to produce or absorb reactive power within the design capability of the Large Generating Facility set forth in Article 9.5.1 (Power Factor Design Criteria). NYISO's voltage schedules shall treat all sources of reactive power in the New York Control Area in an equitable and not unduly discriminatory manner. NYISO shall exercise Reasonable Efforts to provide Developer with such schedules in accordance with NYISO procedures, and may make changes to such schedules as necessary to maintain the reliability of the New York State Transmission System. Developer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design capability of the Large Generating Facility set forth in Article 9.5.1 (Power Factor Design Criteria) as directed by the Connecting Transmission Owner's system operator or the NYISO. If Developer is unable to maintain the specified voltage or power factor, it shall promptly notify NYISO.

9.5.3 Payment for Reactive Power.

NYISO shall pay Developer for reactive power or voltage support service that Developer provides from the Large Generating Facility in accordance with the provisions of Rate Schedule 2 of the NYISO Services Tariff.

9.5.4 Governors and Regulators.

Whenever the Large Generating Facility is operated in parallel with the New York State Transmission System, the turbine speed governors and automatic voltage regulators shall be in automatic operation at all times. If the Large Generating Facility's speed governors or automatic voltage regulators are not capable of such automatic operation, the Developer shall immediately notify NYISO, or its designated representative, and ensure that such Large Generating Facility's real and reactive power are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits and NYISO system operating (thermal, voltage and transient stability) limits. Developer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the New York State Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the New York Control Area on a comparable basis.

9.6 Outages and Interruptions.

9.6.1 Outages.

9.6.1.1 Outage Authority and Coordination.

Developer and Connecting Transmission Owner may each, in accordance with NYISO procedures and Good Utility Practice and in coordination with the other Party, remove from service any of its respective Attachment Facilities or System Upgrade Facilities and System Deliverability Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency State, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to both the Developer and the Connecting Transmission Owner. In all circumstances either Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.6.1.2 Outage Schedules.

The Connecting Transmission Owner shall post scheduled outages of its transmission facilities on the NYISO OASIS. Developer shall submit its planned maintenance schedules for the Large Generating Facility to Connecting Transmission Owner and NYISO for a minimum of a rolling thirty-six month period. Developer shall update its planned maintenance schedules as necessary. NYISO may direct, or the Connecting Transmission Owner may request, Developer to reschedule its maintenance as necessary to maintain the reliability of the New York State Transmission System. Compensation to Developer for any additional direct costs that the Developer incurs as a result of rescheduling maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost the Developer would have incurred absent the request to reschedule maintenance, shall be in accordance with the ISO OATT. Developer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, the Developer had modified its schedule of maintenance activities other than at the direction of the NYISO or request of the Connecting Transmission Owner.

9.6.1.3 Outage Restoration.

If an outage on the Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades of the Connecting Transmission Owner or Developer adversely affects the other Party's operations or facilities, the Party that owns the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns the facility that is out of service shall provide the other Party and NYISO, to the extent such information is known, information on the nature of the Emergency State, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.6.2 Interruption of Service. If required by Good Utility Practice or Applicable Reliability Standards to do so, the NYISO or Connecting Transmission Owner may require Developer to interrupt or reduce production of electricity if such production of electricity could adversely affect the ability of NYISO and Connecting Transmission Owner to perform such activities as are necessary to safely and reliably operate and maintain the New York State Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.6.2:

9.6.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.6.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the New York State Transmission System;

9.6.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, NYISO or Connecting Transmission Owner shall notify Developer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.6.2.4 Except during the existence of an Emergency State, when the interruption or reduction can be scheduled without advance notice, NYISO or Connecting Transmission Owner shall notify Developer in advance regarding the timing of such scheduling and further notify Developer of the expected duration. NYISO or Connecting Transmission Owner shall coordinate with each other and the Developer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to the Developer, the Connecting Transmission Owner and the New York State Transmission System;

9.6.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Attachment Facilities, and the New York State Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.6.3 Under-Frequency and Over Frequency Conditions.

The New York State Transmission System is designed to automatically activate a load-shed program as required by the NPCC in the event of an under-frequency system disturbance. Developer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the NPCC to ensure "ride through" capability of the New York State Transmission System. Large Generating Facility response to frequency deviations of predetermined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with the NYISO and Connecting Transmission Owner in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the New York State Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and with NPCC Regional Reliability Reference Directory # 12, or its successor.

9.6.4 System Protection and Other Control Requirements.

9.6.4.1 System Protection Facilities. Developer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or Developer's Attachment Facilities. Connecting Transmission Owner shall install at Developer's expense any System Protection Facilities that may be required on the Connecting Transmission Owner's Attachment Facilities or the New York State Transmission System as a result of the interconnection of the Large Generating Facility and Developer's Attachment Facilities.

9.6.4.2 The protection facilities of both the Developer and Connecting Transmission Owner shall be designed and coordinated with other systems in accordance with Good Utility Practice and Applicable Reliability Standards.

9.6.4.3 The Developer and Connecting Transmission Owner shall each be responsible for protection of its respective facilities consistent with Good Utility Practice and Applicable Reliability Standards.

9.6.4.4 The protective relay design of the Developer and Connecting Transmission Owner shall each incorporate the necessary test switches to perform the tests required in Article 6 of this Agreement. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of the Developer's Large Generating Facility.

9.6.4.5 The Developer and Connecting Transmission Owner will each test, operate and maintain System Protection Facilities in accordance with Good Utility Practice, NERC and NPCC criteria.

9.6.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, the Developer and Connecting Transmission Owner shall each perform, or their agents shall perform, a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, the Developer and Connecting Transmission Owner shall each perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.6.5 Requirements for Protection.

In compliance with NPCC requirements and Good Utility Practice, Developer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the New York State Transmission System not otherwise isolated by Connecting Transmission Owner's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the New York State Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the New York State Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Developer and Connecting Transmission Owner. Developer shall be responsible for protection of the Large Generating Facility and Developer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Developer shall be solely responsible to disconnect the Large Generating Facility and Developer's other equipment if conditions on the New York State Transmission System could adversely affect the Large Generating Facility.

9.6.6 Power Quality.

Neither the facilities of Developer nor the facilities of Connecting Transmission Owner shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.7 Switching and Tagging Rules.

The Developer and Connecting Transmission Owner shall each provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a nondiscriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.8 Use of Attachment Facilities by Third Parties.

9.8.1 Purpose of Attachment Facilities.

Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Attachment Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the New York State Transmission System and shall be used for no other purpose.

9.8.2 Third Party Users.

If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use the Connecting Transmission Owner's Attachment Facilities, or any part thereof, Developer will be entitled to compensation for the capital expenses it incurred in connection with the Attachment Facilities based upon the pro rata use of the Attachment Facilities by Connecting Transmission Owner, all third party users, and Developer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Attachment Facilities, will be allocated between Developer and any third party users based upon the pro rata use of the Attachment Facilities by Connecting Transmission Owner, all third party users, and Developer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.9 Disturbance Analysis Data Exchange.

The Parties will cooperate with one another and the NYISO in the analysis of disturbances to either the Large Generating Facility or the New York State Transmission System by gathering and providing access to any information relating to any disturbance, including information from disturbance recording equipment, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

9.10 Phasor Measurement Units

A Developer shall install and maintain, at its expense, phasor measurement units ("PMUs") if it meets the following criteria: (1) completed a Class Year after Class Year 2017; and (2) proposes a new Large Facility that either (a) has a maximum net output equal to or greater than 100 MW or (b) requires, as Attachment Facilities or System Upgrade Facilities, a new substation of 230kV or above.

PMUs shall be installed on the Large Facility on the low side of the generator step-up transformer, unless it is a non-synchronous generation facility, in which case the PMUs shall be installed on the Developer side of the Point of Interconnection. The PMUs must be capable of performing phasor measurements at a minimum of 60 samples per second which are synchronized via a high-accuracy satellite clock. To the extent Developer installs similar quality equipment, such as relays or digital fault recorders, that can collect data at least at the same rate as PMUs and which data is synchronized via a high-accuracy satellite clock, such equipment would satisfy this requirement.

Developer shall be required to install and maintain, at its expense, PMU equipment which includes the communication circuit capable of carrying the PMU data to a local data concentrator, and then transporting the information continuously to the Connecting Transmission Owner and the NYISO; as well as store the PMU data locally for thirty days. Developer shall provide to Connecting Transmission Owner and the NYISO all necessary and requested information through the Connecting Transmission Owner's and the NYISO's synchrophasor system, including the following: (a) gross MW and MVAR measured at the Developer side of the generator step-up transformer (or, for a non-synchronous generation facility, to be measured at the Developer side of the Point of Interconnection); (b) generator terminal voltage and current magnitudes and angles; (c) generator terminal frequency and frequency rate of change; and (d) generator field voltage and current, where available; and (e) breaker status, if available. The Connecting Transmission Owner will provide for the ongoing support and maintenance of the network communications linking the data concentrator to the Connecting Transmission Owner and the NYISO, consistent with ISO Procedures detailing the obligations related to SCADA data.

ARTICLE 10. MAINTENANCE

10.1 Connecting Transmission Owner Obligations.

Connecting Transmission Owner shall maintain its transmission facilities and Attachment Facilities in a safe and reliable manner and in accordance with this Agreement.

10.2 Developer Obligations.

Developer shall maintain its Large Generating Facility and Attachment Facilities in a safe and reliable manner and in accordance with this Agreement.

10.3 Coordination.

The Developer and Connecting Transmission Owner shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Attachment Facilities. The Developer and Connecting Transmission Owner shall keep NYISO fully informed of the preventive and corrective maintenance that is planned, and shall schedule all such maintenance in accordance with NYISO procedures.

10.4 Secondary Systems.

The Developer and Connecting Transmission Owner shall each cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of Developer or Connecting Transmission Owner's facilities and equipment which may reasonably be expected to impact the other Party. The Developer and Connecting Transmission Owner shall each provide advance notice to the other Party, and to NYISO, before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses.

Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Developer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Developer's Attachment Facilities; and (2) operation, maintenance, repair and replacement of Connecting Transmission Owner's Attachment Facilities. The Connecting Transmission Owner shall be entitled to the recovery of incremental operating and maintenance expenses that it incurs associated with System Upgrade Facilities and System Deliverability Upgrades if and to the extent provided for under Attachment S to the ISO OATT.

ARTICLE 11. PERFORMANCE OBLIGATION

11.1 Developer's Attachment Facilities.

Developer shall design, procure, construct, install, own and/or control the Developer's Attachment Facilities described in Appendix A hereto, at its sole expense.

11.2 Connecting Transmission Owner's Attachment Facilities.

Connecting Transmission Owner shall design, procure, construct, install, own and/or control the Connecting Transmission Owner's Attachment Facilities described in Appendix A hereto, at the sole expense of the Developer.

11.3 System Upgrade Facilities and System Deliverability Upgrades.

Connecting Transmission Owner shall design, procure, construct, install, and own the System Upgrade Facilities and System Deliverability Upgrades described in Appendix A hereto. The responsibility of the Developer for costs related to System Upgrade Facilities and System Deliverability Upgrades shall be determined in accordance with the provisions of Attachment S to the ISO OATT.

11.4 Special Provisions for Affected Systems.

For the re-payment of amounts advanced to Affected System Operator for System Upgrade Facilities or System Deliverability Upgrades, the Developer and Affected System Operator shall enter into an agreement that provides for such re-payment, but only if responsibility for the cost of such System Upgrade Facilities or System Deliverability Upgrades is not to be allocated in accordance with Attachment S to the ISO OATT. The agreement shall specify the terms governing payments to be made by the Developer to the Affected System Operator as well as the re-payment by the Affected System Operator.

11.5 Provision of Security.

At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of a Connecting Transmission Owner's Attachment Facilities, Developer shall provide Connecting Transmission Owner, at Developer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Connecting Transmission Owner and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1 of this Agreement. Such security for payment shall be in an amount sufficient to cover the cost for the Developer's share of constructing, procuring and installing the applicable portion of Connecting Transmission Owner's Attachment Facilities, and shall be reduced on a dollar-for-dollar basis for payments made to Connecting Transmission Owner for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the commercially reasonable creditworthiness requirements of Connecting Transmission Owner, and contains terms and conditions that guarantee payment of any amount that may be due from Developer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Connecting Transmission Owner and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Connecting Transmission Owner and must specify a reasonable expiration date.

11.5.4 Attachment S to the ISO OATT shall govern the Security that Developer provides for System Upgrade Facilities and System Deliverability Upgrades.

11.6 Developer Compensation for Emergency Services.

If, during an Emergency State, the Developer provides services at the request or direction of the NYISO or Connecting Transmission Owner, the Developer will be compensated for such services in accordance with the NYISO Services Tariff.

11.7 Line Outage Costs.

Notwithstanding anything in the ISO OATT to the contrary, the Connecting Transmission Owner may propose to recover line outage costs associated with the installation of Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades on a case-by-case basis.

ARTICLE 12. INVOICE

12.1 General.

The Developer and Connecting Transmission Owner shall each submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Developer and Connecting Transmission Owner may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts one Party owes to the other Party under this Agreement, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice.

Within six months after completion of the construction of the Connecting Transmission Owner's Attachment Facilities and the System Upgrade Facilities and System Deliverability Upgrades, Connecting Transmission Owner shall provide an invoice of the final cost of the construction of the Connecting Transmission Owner's Attachment Facilities and the System Upgrade Facilities and System Deliverability Upgrades, determined in accordance with Attachment S to the ISO OATT, and shall set forth such costs in sufficient detail to enable Developer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Connecting Transmission Owner shall refund to Developer any amount by which the actual payment by Developer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment.

Invoices shall be rendered to the paying Party at the address specified in Appendix F hereto. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices will not constitute a waiver of any rights or claims the paying Party may have under this Agreement.

12.4 Disputes.

In the event of a billing dispute between Connecting Transmission Owner and Developer, Connecting Transmission Owner shall continue to perform under this Agreement as long as Developer: (i) continues to make all payments not in dispute; and (ii) pays to Connecting Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Developer fails to meet these two requirements for continuation of service, then Connecting Transmission Owner may provide notice to Developer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's Regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

ARTICLE 13. EMERGENCIES

13.1 Obligations.

Each Party shall comply with the Emergency State procedures of NYISO, the applicable Reliability Councils, Applicable Laws and Regulations, and any emergency procedures agreed to by the NYISO Operating Committee.

13.2 Notice.

NYISO or, as applicable, Connecting Transmission Owner shall notify Developer promptly when it becomes aware of an Emergency State that affects the Connecting Transmission Owner's Attachment Facilities or the New York State Transmission System that may reasonably be expected to affect Developer's operation of the Large Generating Facility or the Developer's Attachment Facilities. Developer shall notify NYISO and Connecting Transmission Owner promptly when it becomes aware of an Emergency State that affects the Large Generating Facility or the Developer's Attachment Facilities that may reasonably be expected to affect the New York State Transmission System or the Connecting Transmission Owner's Attachment Facilities. To the extent information is known, the notification shall describe the Emergency State, the extent of the damage or deficiency, the expected effect on the operation of Developer's or Connecting Transmission Owner's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.3 Immediate Action.

Unless, in Developer's reasonable judgment, immediate action is required, Developer shall obtain the consent of Connecting Transmission Owner, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or the Developer's Attachment Facilities in response to an Emergency State either declared by NYISO, Connecting Transmission Owner or otherwise regarding New York State Transmission System.

13.4 NYISO and Connecting Transmission Owner Authority.

13.4.1 General.

NYISO or Connecting Transmission Owner may take whatever actions with regard to the New York State Transmission System or the Connecting Transmission Owner's Attachment Facilities it deems necessary during an Emergency State in order to (i) preserve public health and safety, (ii) preserve the reliability of the New York State Transmission System or the Connecting Transmission Owner's Attachment Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

NYISO and Connecting Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or the Developer's Attachment Facilities. NYISO or Connecting Transmission Owner may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency State by taking actions necessary and limited in scope to remedy the Emergency State, including, but not limited to, directing Developer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.4.2; directing the Developer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and the Developer's Attachment Facilities. Developer shall comply with all of the NYISO and Connecting Transmission Owner's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.4.2 Reduction and Disconnection.

NYISO or Connecting Transmission Owner may reduce [______________] Interconnection Service or disconnect the Large Generating Facility or the Developer's Attachment Facilities, when such reduction or disconnection is necessary under Good Utility Practice due to an Emergency State. These rights are separate and distinct from any right of Curtailment of NYISO pursuant to the ISO OATT. When NYISO or Connecting Transmission Owner can schedule the reduction or disconnection in advance, NYISO or Connecting Transmission Owner shall notify Developer of the reasons, timing and expected duration of the reduction or disconnection. NYISO or Connecting Transmission Owner shall coordinate with the Developer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to the Developer and the New York State Transmission System. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Attachment Facilities, and the New York State Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.5 Developer Authority.

Consistent with Good Utility Practice and this Agreement, the Developer may take whatever actions or inactions with regard to the Large Generating Facility or the Developer's

Attachment Facilities during an Emergency State in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or the Developer's Attachment Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Developer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the New York State Transmission System and the Connecting Transmission Owner's Attachment Facilities. NYISO and Connecting Transmission Owner shall use Reasonable Efforts to assist Developer in such actions.

13.6 Limited Liability.

Except as otherwise provided in Article 11.6 of this Agreement, no Party shall be liable to another Party for any action it takes in responding to an Emergency State so long as such action is made in good faith and is consistent with Good Utility Practice and the NYISO Tariffs.

ARTICLE 14. REGULATORY REQUIREMENTS AND GOVERNING LAW

14.1 Regulatory Requirements.

Each Party's obligations under this Agreement shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this Agreement shall require Developer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act or the Public Utility Holding Company Act of 2005 or the Public Utility Regulatory Policies Act of 1978, as amended.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the state of New York, without regard to its conflicts of law principles.

14.2.2 This Agreement is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

ARTICLE 15. NOTICES

15.1 General.

Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by a Party to the other Parties and any instrument required or permitted to be tendered or delivered by a Party in writing to the other Parties shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F hereto.

A Party may change the notice information in this Agreement by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments.

Billings and payments shall be sent to the addresses set out in Appendix F hereto.

15.3 Alternative Forms of Notice.

Any notice or request required or permitted to be given by a Party to the other Parties and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F hereto.

15.4 Operations and Maintenance Notice.

Developer and Connecting Transmission Owner shall each notify the other Party, and NYISO, in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10 of this Agreement.

ARTICLE 16. FORCE MAJEURE

16.1 Economic hardship is not considered a Force Majeure event.

16.2 A Party shall not be responsible or liable, or deemed, in Default with respect to any obligation hereunder, (including obligations under Article 4 of this Agreement) , other than the obligation to pay money when due, to the extent the Party is prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Parties in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this Article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

ARTICLE 17. DEFAULT

17.1 General.

No Breach shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this Agreement or the result of an act or omission of the other Parties. Upon a Breach, the non-Breaching Parties shall give written notice of such to the Breaching Party. The Breaching Party shall have thirty (30) Calendar Days from receipt of the Breach notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the Breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Breach notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.2 Right to Terminate.

If a Breach is not cured as provided in this Article 17, or if a Breach is not capable of being cured within the period provided for herein, the non-Breaching Parties acting together shall thereafter have the right to declare a Default and terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not those Parties terminate this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which they are entitled at law or in equity. The provisions of this Article will survive termination of this Agreement.

ARTICLE 18. INDEMNITY, CONSEQUENTIAL DAMAGES AND INSURANCE

18.1 Indemnity.

Each Party (the "Indemnifying Party") shall at all times indemnify, defend, and save harmless, as applicable, the other Parties (each an "Indemnified Party") from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, the alleged violation of any Environmental Law, or the release or threatened release of any Hazardous Substance, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from (i) the Indemnified Party's performance of its obligations under this Agreement on behalf of the Indemnifying Party, except in cases where the Indemnifying Party can demonstrate that the Loss of the Indemnified Party was caused by the gross negligence or intentional wrongdoing of the Indemnified Party or (ii) the violation by the Indemnifying Party of any Environmental Law or the release by the Indemnifying Party of any Hazardous Substance.

18.1.1 Indemnified Party.

If a Party is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1.3, to assume the defense of such claim, such Indemnified Party may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party.

If an Indemnifying Party is obligated to indemnify and hold any Indemnified Party harmless under this Article 18, the amount owing to the Indemnifying Party shall be the amount of such Indemnified Party's actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures.

Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

Except as stated below, the Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Party. If the defendants in any such action include one or more Indemnified Parties and the Indemnifying Party and if the Indemnified Party reasonably concludes that there may be legal defenses available to it and/or other Indemnified Parties which are different from or additional to those available to the Indemnifying Party, the Indemnified Party shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Party or Indemnified Parties having such differing or additional legal defenses.

The Indemnified Party shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Party and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Party, or there exists a conflict or adversity of interest between the Indemnified Party and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Party, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Party, which shall not be unreasonably withheld, conditioned or delayed.

18.2 No Consequential Damages.

Other than the liquidated damages heretofore described and the indemnity obligations set forth in Article 18.1, in no event shall any Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under separate agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance.

Developer and Connecting Transmission Owner shall each, at its own expense, procure and maintain in force throughout the period of this Agreement and until released by the other Parties, the following minimum insurance coverages, with insurance companies licensed to write insurance or approved eligible surplus lines carriers in the state of New York with a minimum A.M. Best rating of A or better for financial strength, and an A.M. Best financial size category of VIII or better:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of New York State.

18.3.2 Commercial General Liability ("CGL") Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available using Insurance Services Office, Inc. Commercial General Liability Coverage ("ISO CG") Form CG 00 01 04 13 or a form equivalent to or better than CG 00 01 04 13, with minimum limits of Two Million Dollars ($2,000,000) per occurrence and Two Million Dollars ($2,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 If applicable, the Commercial General Liability and Comprehensive Automobile Liability Insurance policies should include contractual liability for work in connection with constructions or demolition work on or within 50 feet of a railroad, or a separate Railroad Protective Liability Policy should be provided.

18.3.5 Excess Liability Insurance over and above the Employers' Liability, Commercial General Liability and Comprehensive Automobile Liability Insurance coverages, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence and Twenty Million Dollars ($20,000,000) aggregate. The Excess policies should contain the same extensions listed under the Primary policies.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Liability Insurance policies of Developer and Connecting Transmission Owner shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insureds using ISO CG Endorsements: CG 20 33 04 13, and CG 20 37 04 13 or CG 20 10 04 13 and CG 20 37 04 13 or equivalent to or better forms. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this Agreement against the Other Party Group and provide thirty (30) Calendar days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Liability Insurance policies shall contain provisions that specify that the policies are primary and non-contributory. Developer and Connecting Transmission Owner shall each be responsible for its respective deductibles or retentions.

18.3.8 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for at least three (3) years after termination of this Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Developer and Connecting Transmission Owner.

18.3.9 If applicable, Pollution Liability Insurance in an amount no less than $7,500,000 per occurrence and $7,500,000 in the aggregate. The policy will provide coverage for claims resulting from pollution or other environmental impairment arising out of or in connection with work performed on the premises by the other party, its contractors and and/or subcontractors. Such insurance is to include coverage for, but not be limited to, cleanup, third party bodily injury and property damage and remediation and will be written on an occurrence basis. The policy shall name the Other Party Group as additional insureds, be primary and contain a waiver of subrogation.

18.3.10 The requirements contained herein as to the types and limits of all insurance to be maintained by the Developer and Connecting Transmission Owner are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by those Parties under this Agreement.

18.3.11 Within [insert term stipulated by the Parties] days following execution of this Agreement, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, Developer and Connecting Transmission Owner shall provide certificate of insurance for all insurance required in this Agreement, executed by each insurer or by an authorized representative of each insurer.

18.3.12 Notwithstanding the foregoing, Developer and Connecting Transmission Owner may each self-insure to meet the minimum insurance requirements of Articles 18.3.1 through 18.3.9 to the extent it maintains a self-insurance program; provided that, such Party's senior debt is rated at investment grade, or better, by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.1 through 18.3.9. . In the event that a Party is permitted to self-insure pursuant to this Article 18.3.10, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Articles 18.3.1 through 18.3.9 and provide evidence of such coverages. For any period of time that a Party's senior debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.21 through 18.3.9.

18.3.13 Developer and Connecting Transmission Owner agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Agreement.

18.3.14 Subcontractors of each party must maintain the same insurance requirements stated under Articles 18.3.1 through 18.3.9 and comply with the Additional Insured requirements herein . In addition, their policies must state that they are primary and non-contributory and contain a waiver of subrogation.

ARTICLE 19. ASSIGNMENT

This Agreement may be assigned by a Party only with the written consent of the other Parties; provided that a Party may assign this Agreement without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; provided further that a Party may assign this Agreement without the consent of the other Parties in connection with the sale, merger, restructuring, or transfer of a substantial portion or all of its assets, including the Attachment Facilities it owns, so long as the assignee in such a transaction directly assumes in writing all rights, duties and obligations arising under this Agreement; and provided further that the Developer shall have the right to assign this Agreement, without the consent of the NYISO or Connecting Transmission Owner, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that the Developer will promptly notify the NYISO and Connecting Transmission Owner of any such assignment. Any financing arrangement entered into by the Developer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the NYISO and Connecting Transmission Owner of the date and particulars of any such exercise of assignment right(s) and will provide the NYISO and Connecting Transmission Owner with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 20. SEVERABILITY

If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement; provided that if the Developer (or any third party, but only if such third party is not acting at the direction of the Connecting Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the rights and obligations of Developer and Connecting Transmission Owner shall be governed solely by the Standard Option (Article 5.1.1).

ARTICLE 21. COMPARABILITY

The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

ARTICLE 22. CONFIDENTIALITY

22.1 Confidentiality.

Certain information exchanged by the Parties during the term of this Agreement shall constitute confidential information ("Confidential Information") and shall be subject to this Article 22.

If requested by a Party receiving information, the Party supplying the information shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.2 Term.

During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.3 Confidential Information.

The following shall constitute Confidential Information: (1) any non-public information that is treated as confidential by the disclosing Party and which the disclosing Party identifies as Confidential Information in writing at the time, or promptly after the time, of disclosure; or (2) information designated as Confidential Information by the NYISO Code of Conduct contained in Attachment F to the ISO OATT.

22.4 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this Agreement; or (6) is required, in accordance with Article 22.1.8 of this Agreement, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.5 Release of Confidential Information.

No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by FERC Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be considering providing financing to or equity participation with Developer, or to potential purchasers or assignees of a Party, on a need-to-know basis in connection with this Agreement, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.6 Rights.

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Parties of Confidential Information shall not be deemed a waiver by any Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.7 No Warranties.

By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to the other Parties nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.8 Standard of Care.

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this Agreement or its regulatory requirements, including the ISO OATT and NYISO Services Tariff. The NYISO shall, in all cases, treat the information it receives in accordance with the requirements of Attachment F to the ISO OATT.

22.9 Order of Disclosure.

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of this Agreement. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.10 Termination of Agreement.

Upon termination of this Agreement for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Parties, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Parties) or return to the other Parties, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Parties pursuant to this Agreement.

22.11 Remedies.

The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.12 Disclosure to FERC, its Staff, or a State.

Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 C.F.R. section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement or the ISO OATT, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this Agreement prior to the release of the Confidential Information to the Commission or its staff. The Party shall notify the other Parties to the Agreement when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time the Parties may respond before such information would be made public, pursuant to 18 C.F.R. section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations. A Party shall not be liable for any losses, consequential or otherwise, resulting from that Party divulging Confidential Information pursuant to a FERC or state regulatory body request under this paragraph.

22.13 Required Notices Upon Requests or Demands for Confidential Information

Except as otherwise expressly provided herein, no Party shall disclose Confidential Information to any person not employed or retained by the Party possessing the Confidential Information, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this Agreement, the ISO OATT or the NYISO Services Tariff. Prior to any disclosures of a Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

ARTICLE 23. DEVELOPER AND CONNECTING TRANSMISSION OWNER NOTICES OF ENVIRONMENTAL RELEASES

Developer and Connecting Transmission Owner shall each notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Attachment Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

ARTICLE 24. INFORMATION REQUIREMENT

24.1 Information Acquisition.

Connecting Transmission Owner and Developer shall each submit specific information regarding the electrical characteristics of their respective facilities to the other, and to NYISO, as described below and in accordance with Applicable Reliability Standards.

24.2 Information Submission by Connecting Transmission Owner.

The initial information submission by Connecting Transmission Owner shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include New York State Transmission System information necessary to allow the Developer to select equipment and meet any system protection and stability requirements, unless otherwise mutually agreed to by the Developer and Connecting Transmission Owner. On a monthly basis Connecting Transmission Owner shall provide Developer and NYISO a status report on the construction and installation of Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Developer.

The updated information submission by the Developer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Developer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the Standard Large Facility Interconnection Procedures. It shall also include any additional information provided to Connecting Transmission Owner for the Interconnection Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with NYISO standard models. If there is no compatible model, the Developer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Developer's data is different from what was originally provided to Connecting Transmission Owner and NYISO pursuant to an Interconnection Study Agreement among Connecting Transmission Owner, NYISO and Developer and this difference may be reasonably expected to affect the other Parties' facilities or the New York State Transmission System, but does not require the submission of a new Interconnection Request, then NYISO will conduct appropriate studies to determine the impact on the New York State Transmission System based on the actual data submitted pursuant to this Article 24.3. Such studies will provide an estimate of any additional modifications to the New York State Transmission System, Connecting Transmission Owner's Attachment Facilities or System Upgrade Facilities or System Deliverability Upgrades based on the actual data and a good faith estimate of the costs thereof. The Developer shall not begin Trial Operation until such studies are completed. The Developer shall be responsible for the cost of any modifications required by the actual data, including the cost of any required studies.

24.4 Information Supplementation.

Prior to the Commercial Operation Date, the Developer and Connecting Transmission Owner shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Developer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Developer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to the Connecting Transmission Owner and NYISO for each individual generating unit in a station.

Subsequent to the Commercial Operation Date, the Developer shall provide Connecting Transmission Owner and NYISO any information changes due to equipment replacement, repair, or adjustment. Connecting Transmission Owner shall provide the Developer and NYISO any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Connecting Transmission Owner substation that may affect the Developer Attachment Facilities equipment ratings, protection or operating requirements. The Developer and Connecting Transmission Owner shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

ARTICLE 25. INFORMATION ACCESS AND AUDIT RIGHTS

25.1 Information Access.

Each Party ("Disclosing Party") shall make available to another Party ("Requesting Party") information that is in the possession of the Disclosing Party and is necessary in order for the Requesting Party to: (i) verify the costs incurred by the Disclosing Party for which the Requesting Party is responsible under this Agreement; and (ii) carry out its obligations and responsibilities under this Agreement. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 of this Agreement and to enforce their rights under this Agreement.

25.2 Reporting of Non-Force Majeure Events.

Each Party (the "Notifying Party") shall notify the other Parties when the Notifying Party becomes aware of its inability to comply with the provisions of this Agreement for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this Agreement.

25.3 Audit Rights.

Subject to the requirements of confidentiality under Article 22 of this Agreement, each Party shall have the right, during normal business hours, and upon prior reasonable notice to another Party, to audit at its own expense the other Party's accounts and records pertaining to the other Party's performance or satisfaction of its obligations under this Agreement. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, and each Party's actions in an Emergency State. Any audit authorized by this Article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to the Party's performance and satisfaction of obligations under this Agreement. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4 of this Agreement.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records**.**

Accounts and records related to the design, engineering, procurement, and construction of Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades shall be subject to audit for a period of twenty-four months following Connecting Transmission Owner's issuance of a final invoice in accordance with Article 12.2 of this Agreement.

25.4.2 Audit Rights Period for All Other Accounts and Records.

Accounts and records related to a Party's performance or satisfaction of its obligations under this Agreement other than those described in Article 25.4.1 of this Agreement shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 Audit Results.

If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

ARTICLE 26. SUBCONTRACTORS

26.1 General.

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

26.2 Responsibility of Principal.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the NYISO or Connecting Transmission Owner be liable for the actions or inactions of the Developer or its subcontractors with respect to obligations of the Developer under Article 5 of this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance.

The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

ARTICLE 27. DISPUTES

27.1 Submission.

In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with this Agreement or its performance (a "Dispute"), such Party shall provide the other Parties with written notice of the Dispute ("Notice of Dispute"). Such Dispute shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Parties. In the event the designated representatives are unable to resolve the Dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Parties' receipt of the Notice of Dispute, such Dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such Dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this Agreement.

27.2 External Arbitration Procedures.

Any arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the Dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. In each case, the arbitrator(s) shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions.

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Attachment Facilities, System Upgrade Facilities, or System Deliverability Upgrades.

27.4 Costs.

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel; or (2) one-third the cost of the single arbitrator jointly chosen by the Parties.

27.5 Termination.

Notwithstanding the provisions of this Article 27, any Party may terminate this Agreement in accordance with its provisions or pursuant to an action at law or equity. The issue of whether such a termination is proper shall not be considered a Dispute hereunder.

ARTICLE 28. REPRESENTATIONS, WARRANTIES AND COVENANTS

28.1 General.

Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing.

Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Attachment Facilities and System Upgrade Facilities and System Deliverability Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

28.1.2 Authority.

Such Party has the right, power and authority to enter into this Agreement, to become a Party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict.

The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 Consent and Approval.

Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

ARTICLE 29. MISCELLANEOUS

29.1 Binding Effect.

This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and permitted assigns of the Parties hereto.

29.2 Conflicts.

If there is a discrepancy or conflict between or among the terms and conditions of this cover agreement and the Appendices hereto, the terms and conditions of this cover agreement shall be given precedence over the Appendices, except as otherwise expressly agreed to in writing by the Parties.

29.3 Rules of Interpretation.

This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this Agreement or such Appendix to this Agreement, or such Section to the Standard Large Facility Interconnection Procedures or such Appendix to the Standard Large Facility Interconnection Procedures, as the case may be; (6) "hereunder", "hereof', "herein", "hereto" and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

29.4 Compliance.

Each Party shall perform its obligations under this Agreement in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, the ISO OATT and Good Utility Practice. To the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this Agreement for its compliance therewith. When any Party becomes aware of such a situation, it shall notify the other Parties promptly so that the Parties can discuss the amendment to this Agreement that is appropriate under the circumstances.

29.5 Joint and Several Obligations.

Except as otherwise stated herein, the obligations of NYISO, Developer and Connecting Transmission Owner are several, and are neither joint nor joint and several.

29.6 Entire Agreement.

This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

29.7 No Third Party Beneficiaries.

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and permitted their assigns.

29.8 Waiver.

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party. Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by the Developer shall not constitute a waiver of the Developer's legal rights to obtain Capacity Resource Interconnection Service and Energy Resource Interconnection Service from the NYISO and Connecting Transmission Owner in accordance with the provisions of the ISO OATT. Any waiver of this Agreement shall, if requested, be provided in writing.

29.9 Headings.

The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

29.10 Multiple Counterparts.

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

29.11 Amendment.

The Parties may by mutual agreement amend this Agreement, by a written instrument duly executed by all three of the Parties.

29.12 Modification by the Parties.

The Parties may by mutual agreement amend the Appendices to this Agreement, by a written instrument duly executed by all three of the Parties. Such an amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

29.13 Reservation of Rights.

NYISO and Connecting Transmission Owner shall have the right to make unilateral filings with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Developer shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

29.14 No Partnership.

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, any other Party.

29.15 Other Transmission Rights.

Notwithstanding any other provision of this Agreement, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, or transmission congestion rights that the Developer shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the System Upgrade Facilities and System Deliverability Upgrades.

IN WITNESS WHEREOF, the Parties have executed this LGIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

New York Independent System Operator, Inc.

By: ___________________________________

Title: _________________________________

Date: _________________________________

[Insert Name of Connecting Transmission Owner]

By: ___________________________________

Title: _________________________________

Date: ________________________________

[Insert Name of Developer]

By: ___________________________________

Title: _________________________________

Date: _________________________________

APPENDICES

Appendix A
Attachment Facilities and System Upgrade Facilities

Appendix B
Milestones

Appendix C
Interconnection Details

Appendix D
Security Arrangements Details

Appendix E
Commercial Operation Date

Appendix F
Addresses for Delivery of Notices and Billings

APPENDIX A – ATTACHMENT FACILITIES AND SYSTEM UPGRADE FACILITIES

1. Attachment Facilities:

(a) [insert Developer's Attachment Facilities]:

(b) [insert Connecting Transmission Owner's Attachment Facilities]:

2. System Upgrade Facilities:

(a) [insert Stand Alone System Upgrade Facilities]:

(b) [insert Other System Upgrade Facilities]:

3. System Deliverability Upgrades:

APPENDIX B – MILESTONES

APPENDIX C – INTERCONNECTION DETAILS

APPENDIX D – SECURITY ARRANGEMENTS DETAILS

Infrastructure security of New York State Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day New York State Transmission System reliability and operational security. The Commission will expect the NYISO, all Transmission Owners, all Developers and all other Market Participants to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

APPENDIX E – COMMERCIAL OPERATION DATE

[Date]

[NYISO Address]

[Connecting Transmission Owner Address]

Re: ______________ Large Generating Facility

Dear ___________________:

On **[Date] [Developer]** has completed Trial Operation of Unit No. ___. This letter confirms that [Developer] commenced Commercial Operation of Unit No. ___ at the Large Generating Facility, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Developer Representative]

APPENDIX F – ADDRESSES FOR DELIVERY OF NOTICES AND BILLINGS

Notices:.

NYISO:

[To be supplied.]

Connecting Transmission Owner:

[To be supplied.]

Developer:

[To be supplied.]

Billings and Payments:

Connecting Transmission Owner:

[To be supplied.]

Developer:

[To be supplied.]

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

NYISO:

[To be supplied.]

Connecting Transmission Owner:

[To be supplied.]

Developer:

[To be supplied.]

Appendix 7 – Interconnection Procedures for a Wind Generating Plant

Appendix 7 sets forth procedures specific to a wind generating plant. All other requirements of this LFIP continue to apply to wind generating plant interconnections.

A. Special Procedures Applicable to Wind Generators

The wind plant Developer, in completing the Interconnection Request required by section 30.3.3 of this LFIP, may provide to the ISO a set of preliminary electrical design specifications depicting the wind plant as a single equivalent generator. Upon satisfying these and other applicable Interconnection Request conditions, the wind plant may enter the queue and receive the base case data as provided for in this LFIP. No later than six months after submitting an Interconnection Request completed in this manner, the wind plant Developer must submit completed detailed electrical design specifications and other data (including collector system layout data) needed to allow the ISO to complete the System Reliability Impact Study..

31 Attachment Y - New York ISO Comprehensive System Planning Process

31.1 New York Comprehensive System Planning Process ("CSPP")

31.1.1 Definitions

Throughout Sections 31.1 through 31.12, the following capitalized terms shall have the meanings set forth in this subsection:

Affected TO: The Transmission Owner who receives written notification of a dispute related to a Local Transmission Planning Process pursuant to Section 31.2.1.4.1.

Bounded Region: A Load Zone or Zones within an area that is isolated from the rest of the NYCA as a result of constrained interface limits.

CARIS: The Congestion Assessment and Resource Integration Study for economic planning developed by the ISO in consultation with the Market Participants and other interested parties pursuant to Section 31.3 of this Attachment Y.

CRP: The Comprehensive Reliability Plan as approved by the ISO Board of Directors pursuant to this Attachment Y.

CSPP: The Comprehensive System Planning Process set forth in this Attachment Y, and in the Interregional Planning Protocol, which covers reliability planning, economic planning, Public Policy Requirements planning, cost allocation and cost recovery, and the interregional planning process.

Developer: A person or entity, including a Transmission Owner, sponsoring or proposing a project pursuant to this Attachment Y.

ESPWG: The Electric System Planning Work Group, or any successor work group or committee designated to fulfill the functions assigned to the ESPWG in this tariff.

Gap Solution: A solution to a Reliability Need that is designed to be temporary and to strive to be compatible with permanent market-based proposals. A permanent regulated solution, if appropriate, may proceed in parallel with a Gap Solution.

Interregional Planning Protocol: The Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol, or any successor to that protocol.

Interregional Transmission Project: A transmission facility located in two or more transmission planning regions that is evaluated under the Interregional Planning Protocol and proposed to address an identified Reliability Need, congestion identified in the CARIS, or a transmission need driven by a Public Policy Requirement pursuant to Order No. 1000 and the provisions of this Attachment Y.

IPTF: The Interregional Planning Task Force, or any successor ISO stakeholder working group or committee, designated to fulfill the functions assigned to the IPTF in this tariff.

ISO/RTO Region: One or more of the three ISO or RTO regions known as PJM, ISO-New England, and NYISO, which are the "Parties" to the Interregional Planning Protocol.

LCR: An abbreviation for the term Locational Minimum Installed Capacity Requirement, as defined in the ISO Open Access Transmission Tariff.

Local Transmission Owner Plan ("LTP"): The local Transmission Owner plan, developed by each Transmission Owner, which describes its respective plans that may be under consideration or finalized for its own Transmission District.

Local Transmission Owner Planning Process ("LTPP"): The local planning process conducted by each Transmission Owner for its own Transmission District.

Loss of Load Expectation ("LOLE"): A measure used to determine the amount of resources needed to minimize the possibility of an involuntary loss of firm electric load on the New York State Bulk Power Transmission Facilities.

LTP Dispute Resolution Process ("DRP"): The process for resolution of disputes relating to a Transmission Owner's LTP set out in Section 31.2.1.4.

Management Committee: The standing committee of the ISO of that name created pursuant to the ISO Agreement.

Net CONE: The value representing the cost of new entry, net of energy and ancillary services revenues, utilized by the ISO in establishing the ICAP Demand Curves pursuant to Section 5 of the ISO Market Services Tariff.

New York State Bulk Power Transmission Facilities ("BPTFs"): The facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to NPCC by the ISO pursuant to NPCC requirements.

NPCC: The Northeast Power Coordinating Council, or any successor organization.

NYCA Free Flow Test: A NYCA unconstrained internal transmission interface test, performed by the ISO to determine if a Reliability Need is the result of a statewide resource deficiency or a transmission limitation.

NYDPS: The New York State Department of Public Service, as defined in the New York Public Service Law.

NYISO Load and Capacity Data Report: As defined in Section 25 of the ISO OATT.

NYPSC: The New York Public Service Commission, as defined in the New York Public Service Law.

Operating Committee: The standing committee of the ISO of that name created pursuant to the ISO Agreement.

Order No. 1000: The Final Rule entitled Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, issued by the Commission on July 21, 2011, in Docket RM10-23-001, as modified on rehearing, or upon appeal. (See FERC Stats & Regs. ¶ 31,323 (2011) ("Order No. 1000"), on reh'g and clarification, 139 FERC ¶ 61,132 ("Order No. 1000-A"), on reh'g and clarification, 141 FERC ¶ 61,044 (2012) ("Order No. 1000-B").

Other Developers: Parties or entities sponsoring or proposing to sponsor regulated economic projects, transmission solutions driven by Public Policy Requirements, or regulated solutions to Reliability Needs who are not Transmission Owners.

Public Policy Transmission Planning Process: The process by which the ISO solicits needs for transmission driven by Public Policy Requirements, evaluates all solutions on a comparable basis, and selects the more efficient or cost effective transmission solution, if any, for eligibility for cost allocation under the ISO Tariffs.

Public Policy Transmission Need: A transmission need identified by the NYPSC that is driven by a Public Policy Requirement pursuant to Sections 31.4.2.1 through 31.4.2.3.

Public Policy Transmission Planning Report: The report approved by the ISO Board of Directors pursuant to this Attachment Y on the ISO's evaluation of all proposed solutions to an identified Public Policy Transmission Need pursuant to Section 31.4.6 and the ISO's selection of a proposed transmission solution, if any, that is the more efficient or cost effective solution to the identified Public Policy Transmission Need pursuant to Section 31.4.8.

Public Policy Requirement: A federal or New York State statute or regulation, including a NYPSC order adopting a rule or regulation subject to and in accordance with the State Administrative Procedure Act, any successor statute, or any duly enacted law or regulation passed by a local governmental entity in New York State, that may relate to transmission planning on the BPTFs.

Reliability Criteria: The electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules promulgated by the North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), and the New York State Reliability Council ("NYSRC"), as they may be amended from time to time.

Reliability Need: A condition identified by the ISO as a violation or potential violation of one or more Reliability Criteria.

Responsible Transmission Owner: The Transmission Owner or Transmission Owners designated by the ISO, pursuant to Section 31.2.4.3, to prepare a proposal for a regulated backstop solution to a Reliability Need or to proceed with a regulated solution to a Reliability Need. The Responsible Transmission Owner will normally be the Transmission Owner in whose Transmission District the ISO identifies a Reliability Need.

RNA: The Reliability Needs Assessment as approved by the ISO Board under this Attachment.

RNA Base Case: The model(s) representing the New York State Power System over the Study Period.

Site Control: Documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site or right of way for the purpose of constructing a proposed project; (2) an option to purchase or acquire a leasehold site or right of way for such purpose; or (3) an exclusivity or other business relationship between the Transmission Owner, or Other Developer, and the entity having the right to sell, lease, or grant the Transmission Owner, or Other Developer, the right to possess or occupy a site or right of way for such purpose.

Study Period: The ten-year time period evaluated in the RNA and the CRP.

Target Year: The calendar year in which a Reliability Need arises, as determined by the ISO pursuant to Section 31.2.

TPAS: The Transmission Planning Advisory Subcommittee, or any successor work group or committee designated to fulfill the functions assigned to TPAS pursuant to this Attachment.

Trigger Date: The date by which the ISO must request implementation of a regulated backstop solution or an alternative regulated solution pursuant to Section 31.2.8 in order to meet a Reliability Need.

Viability and Sufficiency Assessment: The results of the ISO's assessment of the viability and sufficiency of proposed solutions to a Reliability Need under Section 31.2.5 or a Public Policy Transmission Need under Section 31.4.6, as applicable.

All other capitalized terms shall have the meanings provided for them in the ISO's Tariffs.

31.1.2 Reliability Planning Process

Sections 31.2.1 through 31.2.13 of this Attachment Y describe the process that the ISO, the Transmission Owners, and Market Participants and other interested parties shall follow for conducting the Local Transmission Owner Planning Process, planning to meet the Reliability Needs of the BPTFs, and addressing the need for Gap Solutions. The objectives of the process are to: (1) evaluate the Reliability Needs of the BPTFs pursuant to Reliability Criteria (2) identify, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the BPTFs; (3) provide a process whereby solutions to identified needs are proposed, evaluated on a comparable basis, and implemented in a timely manner to ensure the reliability of the system; (4) provide a process by which the ISO will select the more efficient or cost effective regulated transmission solution to satisfy the Reliability Need for eligibility for cost allocation under the ISO Tariffs; (5) provide an opportunity first for the implementation of market-based solutions while ensuring the reliability of the BPTFs; and (6) coordinate the ISO's reliability assessments with neighboring Control Areas. To the extent the ISO cannot timely satisfy an identified Reliability Need in its biennial reliability planning process, the ISO will commence the Gap Solution Process in Section 31.2.11 to address the Reliability Need; *provided, however*, a Generator Deactivation Reliability Need or an immediate reliability need that results from a Generator becoming Retired, entering into a Mothball Outage, or being unavailable due to an ICAP Ineligible Forced Outage shall be addressed in the Generator Deactivation Process in Attachment FF of the ISO OATT.

The ISO will provide, through the analysis of historical system congestion costs, information about historical congestion including the causes for that congestion so that Market Participants and other stakeholders can make appropriately informed decisions. See Appendix A.

31.1.3 Transmission Owner Planning Process

The Transmission Owners will continue to plan for their transmission systems, including the BPTFs and other NYS Transmission System facilities. The planning process of each Transmission Owner is referred to herein as the LTPP, and the plans resulting from the LTPP are referred to herein as LTPs, whether under consideration or finalized. Each Transmission Owner will be responsible for administering its LTPP and for making provisions for stakeholder input into its LTPP. The ISO's role in the LTPP is limited to the procedural activities described in this Attachment Y.

The finalized portions of the LTPs periodically prepared by the Transmission Owners will be used as inputs to the CSPP described in this Attachment Y. Each Transmission Owner will prepare an LTP for its transmission system in accordance with the procedures described in Section 31.2.1.

31.1.4 Economic Planning Process

Sections 31.3.1 and 31.3.2 of this Attachment Y describe the process that the ISO, the Transmission Owners, and Market Participants shall follow for economic planning to identify and reduce current and future projected congestion on the BPTFs. The objectives of the economic planning process are to: (1) project congestion on the BPTFs over the ten-year planning period of this CSPP, (2) identify, through the development of appropriate scenarios, factors that might produce or increase congestion, (3) provide a process whereby projects to reduce congestion identified in the economic planning process are proposed and evaluated on a comparable basis in a timely manner, (4) provide an opportunity for the development of market-based solutions to reduce the congestion identified, and (5) coordinate the ISO's congestion assessments and economic planning process with neighboring Control Areas.

31.1.5 Public Policy Requirements Planning Process

Section 31.4 of this Attachment Y describes the planning process that the ISO, and all interested parties, shall follow to consider Public Policy Requirements that drive the need for expansions or upgrades to BPTFs. The objectives of the Public Policy Requirements planning process are to: (1) allow Market Participants and other interested parties to propose transmission needs that they believe are being driven by Public Policy Requirements and for which transmission solutions should be evaluated, (2) provide a process by which the NYPSC will, with input from the ISO, Market Participants, and other interested parties, identify the transmission needs, if any, for which transmission solutions should be evaluated, (3) provide a process whereby all solutions to Public Policy Transmission Needs are proposed and evaluated on a comparable basis, (4) provide a process by which the ISO will select the more efficient or cost effective regulated transmission solution, if any, to satisfy the Public Policy Transmission Need for eligibility for cost allocation under the ISO Tariffs; (5) provide a cost allocation methodology for regulated transmission projects that have been selected by the ISO, and (6) coordinate the ISO's Public Policy Transmission Planning Process with neighboring Control Areas.

31.1.6 Interregional Planning Process

The ISO, the Transmission Owners, and Market Participants and other interested parties shall coordinate system planning activities with neighboring planning regions (*i.e.*, the ISO/RTO Regions and adjacent portions of Canada). The Interregional Planning Protocol includes a description of the committee structure, processes, and procedures through which system planning activities are openly and transparently coordinated by the ISO/RTO Regions. The objective of the interregional planning process is to contribute to the on-going reliability and the enhanced operational and economic performance of the ISO/RTO Regions through: (1) exchange of relevant data and information; (2) coordination of procedures to evaluate certain interconnection and transmission service requests; (3) periodic comprehensive interregional assessments; (4) identification and evaluation of potential Interregional Transmission Projects that can address regional needs in a manner that may be more efficient or cost-effective than separate regional solutions, in accordance with the requirements of Order No. 1000; (5) allocation of costs among the ISO/RTO Regions of Interregional Transmission Projects, identified in accordance with the Interregional Planning Protocol and approved by each region, pursuant to the cost allocation methodology set forth in Section 31.5.7 herein. The planning activities of the ISO/RTO Regions shall be conducted consistent with the planning criteria of each ISO/RTO Region's regional reliability organization(s) as well as the relevant local reliability entities. The ISO/RTO Regions shall periodically produce a Northeastern Coordinated System Plan that integrates the system plans of all of the ISO/RTO Regions.

31.1.7 Enrollment in the ISO's Transmission Planning Region

For purposes of any matter addressed by this Attachment Y, participation in the ESPWG, IPTF and TPAS shall be open to any interested entity, irrespective of whether that entity has become a Party to the ISO Agreement. Any entity may enroll in the ISO's transmission planning region in order to fully participate in the ISO's governance process by becoming a Party to the ISO Agreement, as set forth in Section 2.02 of the ISO Agreement. An owner of transmission in New York State may become a Transmission Owner by: (i) satisfying the definition of a Transmission Owner in Article 1 of the ISO Agreement and (ii) executing the ISO/TO Agreement or an agreement with the ISO under terms comparable to the ISO/TO Agreement and turning over operational control of its transmission facilities to the ISO. As of October 15, 2013, the Transmission Owners are: (1) Central Hudson Gas & Electric Corporation, (2) Consolidated Edison Company of New York, Inc., (3) New York State Electric & Gas Corporation, (4) Niagara Mohawk Power Corporation, (5) Orange and Rockland Utilities, Inc., (6) Rochester Gas and Electric Corporation, (7) the Power Authority of the State of New York, and (8) Long Island Lighting Company d/b/a LIPA.

31.1.8 ISO Implementation and Administration

31.1.8.1 The ISO shall adopt procedures for the implementation and administration of the CSPP set forth in this Attachment Y and the Interregional Planning Protocol, and shall revise those procedures as and when necessary. Such procedures will be incorporated in the ISO's manuals, including ISO's Comprehensive System Planning Process Manual. The ISO Procedures shall provide for the open and transparent coordination of the CSPP to allow Market Participants and all other interested parties to have a meaningful opportunity to participate in each stage of the CSPP through the meetings conducted in accordance with the ISO system of collaborative governance. Confidential Information and Critical Energy Infrastructure Information exchanged through the CSPP shall be subject to the protections for such information contained in the ISO's tariffs and procedures, including this Attachment Y and Attachment F of the ISO OATT.

31.1.8.2 The ISO Procedures shall include a schedule for the collection and submission of data and the preparation of models to be used in the studies contemplated under this tariff. That schedule shall provide for a rolling two-year cycle of studies and reports conducted in each of the ISO planning processes (reliability, economic and public policy) as part of the Comprehensive System Planning Process. Each cycle commences with the LTPP providing input into the reliability planning process. The CARIS study under Section 31.3 of this Attachment Y will commence upon completion of the viability and sufficiency analysis performed pursuant to Section 31.2.5.7, as part of the CRP process. The Public Policy Transmission Planning Process will to the extent practicable run in parallel with the reliability planning process, provided that the NYPSC's issuance of a written statement pursuant to Section 31.4.2.1 will occur after the draft RNA study results are posted. If the CRP cannot be completed within a two-year cycle, the ISO will notify stakeholders and provide an estimated completion date and an explanation of the reasons the additional time is required. As further detailed in Sections 31.2, 31.3, 31.4, and 31.5, the interregional planning process shall be conducted in parallel with the reliability planning process, the economic planning process, and the Public Policy Requirements planning process to identify and evaluate Interregional Transmission Projects that may more efficiently or cost-effectively meet the needs of the region than a regional transmission project.

31.1.8.3 The ISO Procedures shall be designed to allow the coordination of the ISO's planning activities with those of the ISO/RTO Regions, NERC, NPCC, the NYSRC, and other regional reliability organizations so as to develop consistency of the models, databases, and assumptions utilized in making reliability and economic determinations.

31.1.8.4 The ISO Procedures shall facilitate the timely identification and resolution of all substantive and procedural disputes that arise out of the CSPP. Any party participating in the CSPP and having a dispute arising out of the CSPP may seek to have its dispute resolved in accordance with ISO governance procedures during the course of the CSPP. If the party's dispute is not resolved in this manner as a part of the plan development process, the party may invoke formal dispute resolution procedures administered by the ISO that are the same as those available to Transmission Customers under Section 11 of the ISO Market Administration and Control Area Services Tariff. Disputes arising out of the LTPP shall be addressed by the LTP DRP set forth in Section 31.2.1.4 of this Attachment Y.

31.1.8.5 Except for those cases where the ISO OATT provides that an individual customer shall be responsible for the cost, or a specified share of the cost, of an individually requested study related to interconnection or to system expansion or to congestion and resource integration, the study costs incurred by the ISO as a result of its administration of the CSPP will be recovered from all customers through and in accordance with Rate Schedule 1 of the ISO OATT.

31.2 Reliability Planning Process

31.2.1 Local Transmission Owner Planning Process

31.2.1.1 Scope

31.2.1.1.1 Criteria, Assumptions and Data

Each Transmission Owner will post on its website the planning criteria and assumptions currently used in its LTPP as well as a list of any applicable software and/or analytical tools currently used in the LTPP. Customers, Market Participants and other interested parties may review and comment on the planning criteria and assumptions used by each Transmission Owner, as well as other data and models used by each Transmission Owner in its LTPP. The Transmission Owners will take into consideration any comments received. Any planning criteria or assumptions for a Transmission Owner's BPTFs will meet or exceed any applicable NERC, NPCC or NYSRC criteria. The LTPP shall include a description of the needs addressed by the LTPP as well as the assumptions, applicable planning criteria and methodology utilized and the Public Policy Requirements considered. A link to each Transmission Owner's website will be posted on the ISO website.

31.2.1.1.2 Consideration of Transmission Needs Driven by Public Policy Requirements

31.2.1.1.2.1 Procedures for the Identification of Transmission Needs Driven by Public Policy Requirements in Local Transmission Plans and for the Consideration of Transmission Solutions

In developing its LTP, each Transmission Owner shall consider whether there is a transmission need on its system that is being driven by a Public Policy Requirement. The LTP will identify any transmission project included in the LTP as a solution to a transmission need being driven by a Public Policy Requirement. In evaluating potential transmission solutions, the

Transmission Owner will give consideration to the objectives of the Public Policy Requirement(s) driving the need for transmission.

31.2.1.1.2.2 Determination of Local Transmission Needs Driven by Public Policy Requirements

As part of its LTP process pursuant to Section 31.2.1.2 below, each Transmission Owner will consider whether there is a transmission need on its local system that is being driven by a Public Policy Requirement for which a local transmission solution should be evaluated, including needs proposed by market participants and other interested parties. A market participant or other interested party proposing a transmission need on a Transmission Owner's local system driven by a Public Policy Requirement shall submit its proposal to the ISO and the relevant Transmission Owner, and will identify the specific Public Policy Requirement that is driving the proposed transmission need and an explanation of why a local transmission upgrade is necessary to implement the Public Policy Requirement. Any proposed local system transmission need will be posted on the ISO website. The ISO will transmit proposed transmission needs on a Transmission Owner's local system driven by Public Policy Requirements to the NYDPS, with a request that the NYDPS review the proposals and provide the relevant Transmission Owner with input to assist the Transmission Owner in its determination. The Transmission Owner, after considering the input provided by the NYDPS and any information provided by a market participant or other party, will determine whether there are transmission needs driven by Public Policy Requirements for which local transmission solutions should be evaluated. The Transmission Owner will post on its website a list of the transmission needs driven by Public Policy Requirements for which local transmission solutions should be evaluated, with an explanation of why the Transmission Owner identified those transmission needs and declined to identify other proposed transmission needs.

31.2.1.1.2.3 Evaluation of Proposed Local Transmission Solutions

In evaluating potential transmission solutions, if any, the Transmission Owner will give consideration to the objectives of the Public Policy Requirement driving the need for a local transmission solution. The Transmission Owner will evaluate solutions to identified transmission needs, including transmission solutions proposed by market participants and other parties for inclusion in its LTP. The Transmission Owner, in consultation with the NYDPS, will evaluate proposed transmission solutions on its local system to determine the more efficient or cost-effective transmission solutions. The Transmission Owner will consider the relative costs and benefits of proposed transmission solutions and their impact on the Transmission Owner's transmission system and its customers. Any local transmission solution identified by the Transmission Owner through the LTP process will be reviewed with stakeholders as part of each Transmission Owner's regular LTP process and will be included in the Transmission Owner's subsequent LTP. In conducting its evaluation the Transmission Owner will use criteria that are relevant to the Public Policy Requirement driving the transmission need, which may include its published local planning criteria and assumptions.

31.2.1.2 Process Timeline

31.2.1.2.1 Each Transmission Owner, in accordance with a schedule set forth in the ISO Procedures, will post its current LTP on its website for review and comment by interested parties sufficiently in advance of the time for submission to the ISO for input to its RNA so as to allow adequate time for stakeholder review and comment. Each LTP will include:

- identification of the planning horizon covered by the LTP,
- data and models used,

- reliability needs, needs driven by Public Policy Requirements, and other needs addressed,
- potential solutions under consideration, and,
- a description of the transmission facilities covered by the plan.

31.2.1.2.2 To the extent the current LTP utilizes data or inputs, related to the ISO's planning process, not already reported by the ISO in Form 715 and referenced on its website, any such data will be provided to the ISO at the time each Transmission Owner posts criteria and planning assumptions in accordance with Section 31.2.1.1 and will be posted by the ISO on its website subject to any confidentiality or Critical Energy Infrastructure Information restrictions or requirements.

31.2.1.2.3 Each planning cycle, the ISO shall hold one or more stakeholder meetings of the ESPWG and TPAS at which each Transmission Owner's current LTP will be discussed. Such meetings will be held either at the Transmission Owner's Transmission District, or at an ISO location. The ISO shall post notice of the meeting and shall disclose the agenda and any other material distributed prior to the meeting.

31.2.1.2.4 Interested parties may submit written comments to a Transmission Owner with respect to its current LTP within thirty days after the meeting. Each Transmission Owner shall list on its website, as part of its LTP, the person and/or location to which comments should be sent by interested parties. All comments will be posted on the ISO website. Each Transmission Owner will consider comments received in developing any modifications to its LTP. Any such modification will be explained in its current LTP posted on its website pursuant to

Section 31.2.1.2.2 above and discussed at the next meeting held pursuant to Section 31.2.1.2.3 above.

31.2.1.2.5 Each planning cycle, each Transmission Owner will submit the finalized portions of its current LTP to the ISO as contemplated in Section 31.2.2.4.2 below for timely inclusion in the RNA.

31.2.1.3 ISO Evaluation of Transmission Owner Local Transmission Plans in Relation to Regional and Local Transmission Needs

The ISO will review the Transmission Owner LTPs as they relate to the BPTFs as set forth in Section 31.2.2.4.2. The ISO will also evaluate whether a regional transmission solution – including, but not limited to, regional transmission solutions proposed by Developers pursuant to this Attachment Y – could satisfy an identified regional transmission need on the BPTFs that impacts more than one Transmission District more efficiently or more cost effectively than a local transmission solution identified in a Transmission Owner's LTP in accordance with Section 31.2.6.4.2 for the satisfaction of a regional Reliability Need, Section 31.3.1.3.6 for the reduction of congestion identified in CARIS, or Section 31.4.7.2 for the satisfaction of a Public Policy Transmission Need. The ISO will report the results of its evaluation solely for informational purposes in the relevant ISO planning report prepared under this Attachment Y, and the Transmission Owners shall not be required to revise their LTPs based on the results of the ISO's evaluation.

31.2.1.4 LTP Dispute Resolution Process

31.2.1.4.1 Disputes Related to the LTPP; Objective; Notice

Disputes related to the LTPP are subject to the DRP. The objective of the DRP is to assist parties having disputes in communicating effectively and resolving disputes as expeditiously as possible. Within fifteen (15) calendar days of the presentation by a Transmission Owner of its LTP to the ESPWG and TPAS, a party with a dispute shall notify in writing the Affected TO, the ISO, the ESPWG and TPAS of its intention to utilize the DRP. The notice shall identify the specific issue in dispute and describe in sufficient detail the nature of the dispute.

31.2.1.4.2 Review by the ESPWG/TPAS

The issue raised by a party with a dispute shall be reviewed and discussed at a joint meeting of the ESPWG and the TPAS in an effort to resolve the dispute. The party with a dispute and the Affected TO shall have an opportunity to present information concerning the issue in dispute to the ESPWG and the TPAS.

31.2.1.4.3 Information Discussions

To the extent the ESPWG and the TPAS are unable to resolve the dispute, the dispute will be subject to good faith informal discussions between the party with a dispute and the Affected TO. Each of those parties will designate a senior representative authorized to enter into informal discussions and to resolve the dispute. The parties to the dispute shall make a good faith effort to resolve the dispute through informal discussions as promptly as practicable.

31.2.1.4.4 Alternative Dispute Resolution

In the event that the parties to the dispute are unable to resolve the dispute through informal discussions within sixty (60) days, or such other period as the parties may agree upon, the parties may, by mutual agreement, submit the dispute to mediation or any other form of alternative dispute resolution. The parties shall attempt in good faith to resolve the dispute in accordance with a mutually agreed upon schedule but in no event may the schedule extend beyond ninety (90) days from the date on which the parties agreed to submit the dispute to alternative dispute resolution.

31.2.1.4.5 Notice of Results of Dispute Resolution

The Affected TO shall notify the ISO and ESPWG and TPAS of the results of the DRP and update its LTP to the extent necessary. The ISO shall use in its planning process the LTP provided by the Affected TO.

31.2.1.4.6 Rights Under the Federal Power Act

Nothing in the DRP shall affect the rights of any party to file a complaint with the Commission under relevant provisions of the FPA.

31.2.1.4.7 Confidentiality

All information disclosed in the course of the DRP shall be subject to the same protections accorded to confidential information and CEII by the ISO under its confidentiality and CEII policies.

31.2.2 Reliability Needs Assessment

31.2.2.1 General

The ISO shall prepare and publish the RNA as described below. The RNA will identify Reliability Needs. The ISO shall also designate in the RNA the Responsible Transmission Owner with respect to each Reliability Need.

31.2.2.2 Interested Party Participation in the Development of the RNA

The ISO shall develop the RNA in consultation with Market Participants and all other interested parties. TPAS will have responsibility consistent with ISO Procedures for review of the ISO's reliability analyses. ESPWG will have responsibility consistent with ISO Procedures for providing commercial input and assumptions to be used in the development of reliability assessment scenarios provided under Section 31.2.2.5, and in the reporting and analysis of historic congestion costs. Coordination and communication will be established and maintained between these two groups and ISO staff to allow Market Participants and other interested parties to participate in a meaningful way during each stage of the CSPP. The ISO staff shall report any majority and minority views of these collaborative governance work groups when it submits the RNA to the Operating Committee for a vote, as provided below.

31.2.2.3 Preparation of the Reliability Needs Assessment

31.2.2.3.1 The ISO shall evaluate bulk power system needs in the RNA over the Study Period.

31.2.2.3.2 The starting point for the development of the RNA Base Case will be the system as defined for the FERC Form No. 715 Base Case. The ISO shall develop this system representation to be used for its evaluations of the Study Period by primarily using: (1) the most recent NYISO Load and Capacity Data Report published by the ISO on its web site; (2) the most recent versions of ISO reliability analyses and assessments provided for or published by NERC, NPCC, NYSRC, and neighboring Control Areas; (3) information reported by neighboring Control Areas such as power flow data, forecasted load, significant new or modified generation and transmission facilities, and anticipated system conditions that the ISO determines may impact the BPTFs; and (4) data submitted pursuant to paragraph 31.2.2.4 below; *provided, however*, the ISO shall not include in the RNA Base Case an Interim Sercice Provider, an RMR Generator, or any other interim Generator Deactivation Solution selected by the ISO pursuant to

Attachment FF of the ISO OATT; *provided, further,* the ISO will include in the RNA Base Case a permanent transmission Generator Deactivation Solution selected by the ISO pursuant to Attachment FF of the ISO OATT if it meets the base case inclusion requirements in the ISO Procedures.. The details of the development of the RNA Base Case are contained in the ISO Procedures. The RNA Base Case shall also include Interregional Transmission Projects that have been approved by the NYPSC transmission siting process and meet the base case inclusion requirements in the ISO Procedures.

31.2.2.3.3 The ISO shall assess the RNA Base Case to determine whether the BPTFs meet all Reliability Criteria for both resource and transmission adequacy in each year, and report the results of its evaluation in the RNA. Transmission analyses will include thermal, voltage, short circuit, and stability studies. Then, if any Reliability Criteria are not met in any year, the ISO shall perform additional analyses to determine whether additional resources and/or transmission capacity expansion are needed to meet those requirements, and to determine the Target Year of need for those additional resources and/or transmission. A short circuit assessment will be performed for the tenth year of the Study Period. The study will not seek to identify specific additional facilities. Reliability Needs will be defined in terms of total deficiencies relative to Reliability Criteria and not necessarily in terms of specific facilities.

31.2.2.4 Planning Participant Data Input

31.2.2.4.1 At the ISO's request, Market Participants, Developers, and other parties shall provide, in accordance with the schedule set forth in the ISO Procedures, the data necessary for the development of the RNA. This data will include but not be limited to (1) existing and planned additions to the New York State Transmission System (to be provided by Transmission Owners and municipal electric utilities); (2) proposals for merchant transmission facilities (to be provided by merchant Developers); (3) generation additions and retirements (to be provided by generator owners and Developers); (4) demand response programs (to be provided by demand response providers); and (5) any long-term firm transmission requests made to the ISO.

31.2.2.4.2 The Transmission Owners shall submit their current LTPs referenced in Section 31.1.3 and Section 31.2.1 to the ISO. The Transmission Owners and the ISO will coordinate with each other in reviewing the LTPs. The ISO will review the Transmission Owners' LTPs, as they relate to BPTFs, to determine whether they will meet reliability needs identified in the LTPs, recommend an alternate means to resolve the local needs from a regional perspective pursuant to Section 31.2.6.4, and indicate if it is not in agreement with a Transmission Owner's proposed additions. The ISO shall report its determinations under this section in the RNA and in the CRP.

31.2.2.4.3 All data received from Market Participants, Developers, and other parties shall be considered in the development of the system representation for the Study Period in accordance with the ISO Procedures.

31.2.2.5 Reliability Scenario Development

The ISO, in consultation with the ESPWG and TPAS, shall develop reliability scenarios addressing the Study Period. Variables for consideration in the development of these reliability scenarios include but are not limited to: load forecast uncertainty, fuel prices and availability, new resources, retirements, transmission network topology, and limitations imposed by proposed environmental or other legislation.

31.2.2.6 Evaluation of Reliability Scenarios

The ISO will conduct additional reliability analyses for the reliability scenarios developed pursuant to paragraph 31.2.2.5. These evaluations will test the robustness of the needs assessment studies conducted under paragraphs 31.2.2.3. This evaluation will only identify conditions under which Reliability Criteria may not be met. It will not identify or propose additional Reliability Needs. In addition, the ISO will perform appropriate sensitivity studies to determine whether Reliability Needs previously identified can be mitigated through alternate system configurations or operational modes. The Reliability Needs may increase in some reliability scenarios and may decrease, or even be eliminated, in others. The ISO shall report the results of these evaluations in the RNA.

31.2.2.7 Consequences for Other Regions

The ISO will coordinate with the ISO/RTO Regions to identify the consequences of the reliability transmission projects on such ISO/RTO Regions using the respective planning criteria of such ISO/RTO Regions. The ISO shall report the results in the CRP. The ISO shall not bear the costs of required upgrades in another region.

31.2.2.8 Reliability Needs Assessment Report Preparation

Once all the analyses described above have been completed, ISO staff will prepare a draft of the RNA including discussion of its assumptions, Reliability Criteria, and results of the analyses and, if necessary, designate the Responsible Transmission Owner. One or more compensatory MW/ Load adjustment scenarios will be developed by the ISO as a guide to the development of proposed solutions to meet the identified Reliability Need.

31.2.3 RNA Review Process

31.2.3.1 Collaborative Governance Process

The draft RNA shall be submitted to both TPAS and the ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to replicate the results of the draft RNA. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Market Participants and other interested parties may submit at any time optional suggestions for changes to ISO rules or procedures which could result in the identification of additional resources or market alternatives suitable for meeting Reliability Needs. Following completion of the TPAS and ESPWG review, the draft RNA reflecting the revisions resulting from the TPAS and ESPWG review, shall be forwarded to the Operating Committee for discussion and action. The ISO shall notify the Business Issues Committee of the date of the Operating Committee meeting at which the draft RNA is to be presented. Following the Operating Committee vote, the draft RNA will be transmitted to the Management Committee for discussion and action.

31.2.3.2 Board Action

Following the Management Committee vote, the draft RNA, with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft RNA will be provided to the Market Monitoring Unit for its review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. The Board may approve the RNA as submitted, or propose modifications on its own motion. If any changes are proposed by the Board, the revised RNA shall be returned to the Management Committee for comment. The Board shall not make a final determination on a revised RNA until it has reviewed the Management Committee comments. Upon approval by the Board, the ISO shall issue the final RNA to the marketplace by posting it on its web site.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of this Attachment are also addressed in Section 30.4.6.8.2 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

31.2.3.3 Needs Assessment Disputes

Notwithstanding any provision to the contrary in this Attachment, the ISO OATT, or the NYISO Services Tariff, in the event that a Market Participant raises a dispute solely within the NYPSC's jurisdiction relating to the final conclusions or recommendations of the RNA, a Market Participant may refer such dispute to the NYPSC for resolution. The NYPSC's final determination shall be binding, subject only to judicial review in the courts of the State of New York pursuant to Article 78 of the NYCPLR.

31.2.3.4 Public Information Sessions

In order to provide ample exposure for the marketplace to understand the identified Reliability Needs, the ISO will provide various opportunities for Market Participants and other potentially interested parties to discuss the final RNA. Such opportunities may include presentations at various ISO Market Participant committees, focused discussions with various industry sectors, and/or presentations in public venues.

31.2.4 Development of Solutions to Reliability Needs

31.2.4.1 Eligibility and Qualification Criteria for Developers and Projects

For purposes of fulfilling the requirements of the Developer qualification criteria in this Section 31.2.4.1 and its subsections, the term "Developer" includes Affiliates, as that term is defined in Section 2 of the ISO Services Tariff and Section 1 of the ISO OATT. To the extent that a Developer relies on Affiliate(s) to satisfy any or all of the qualification criteria set forth in Section 31.2.4.1.1.1, the Affiliate(s) shall provide to the ISO: (i) the information required in Section 31.2.4.1.1.1 to demonstrate its capability to satisfy the applicable qualification criteria, and (ii) a notarized officer's certificate, signed by an authorized officer of the Affiliate with signatory authority, in a form acceptable to the ISO, certifying that the Affiliate will participate in the Developer's project in the manner described by the Developer and will abide by the requirements set forth in this Attachment Y, the ISO Tariffs, and ISO Procedures related and applicable to the Affiliate's participation.

31.2.4.1.1 Developer Qualification and Timing

The ISO shall provide each Developer with an opportunity to demonstrate that it has or can draw upon the financial resources, technical expertise, and experience needed to finance, develop, construct, operate and maintain a transmission project to meet identified Reliability Needs. The ISO shall consider the qualifications of each Developer in an evenhanded and non-discriminatory manner, treating Transmission Owners and Other Developers alike.

31.2.4.1.1.1 Developer Qualification Criteria

The ISO shall make a determination on the qualification of a Developer to propose to develop a transmission project as a solution to an identified Reliability Need based on the following criteria:

31.2.4.1.1.1.1 The technical and engineering qualifications and experience of the Developer relevant to the development, construction, operation and maintenance of a transmission facility, including evidence of the Developer's demonstrated capability to adhere to standardized construction, maintenance, and operating practices and to contract with third parties to develop, construct, maintain, and/or operate transmission facilities;

31.2.4.1.1.1.2 The current and expected capabilities of the Developer to develop and construct a transmission facility and to operate and maintain it for the life of the facility. If the Developer has previously developed, constructed, maintained or operated transmission facilities, the Developer shall provide the ISO a description of the transmission facilities (not to exceed ten) that the Developer has previously developed, constructed, maintained or operated and the status of those facilities, including whether the construction was completed, whether the facility entered into commercial operations, whether the facility has been suspended or terminated for any reason, and evidence demonstrating the ability of the Developer to address and timely remedy any operational failure of the facilities; and

31.2.4.1.1.1.3 The Developer's current and expected capability to finance, or its experience in arranging financing for, transmission facilities. For purposes of the ISO's determination, the Developer shall provide the ISO:

(1) evidence of its demonstrated experience financing or arranging financing for transmission facilities, if any, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financial structure of such projects, a description of any financing obtained for these projects through

rates approved by the Commission or a state regulatory agency, the financing closing date of such projects, and whether any of the projects are in default;

(2) its audited annual financial statements from the most recent three years and its most recent quarterly financial statement, or equivalent information;

(3) its credit rating from Moody's Investor Services, Standard & Poor's, or Fitch, or equivalent information, if available;

(4) a description of any prior bankruptcy declarations, material defaults, dissolution, merger or acquisition by the Developer or its predecessors or subsidiaries occurring within the previous five years; and

(5) such other evidence that demonstrates its current and expected capability to finance a project to solve a Reliability Need.

31.2.4.1.1.1.4 A detailed plan describing how the Developer – in the absence of previous experience financing, developing, constructing, operating, or maintaining transmission facilities – will finance, develop, construct, operate, and maintain a transmission facility, including the financial, technical, and engineering qualifications and experience and capabilities of any third parties with which it will contract for these purposes.

31.2.4.1.1.2 Developer Qualification Determination

Any Developer seeking to become qualified may submit the required information, or update any previously submitted information, at any time. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any non-public financial qualification information that is submitted to the ISO by the Developer under Section 31.2.4.1.1.1.3 and is designated by the Developer as "Confidential

Information." The ISO shall within 15 days of a Developer's submittal, notify the Developer if the information is incomplete. If the submittal is deemed incomplete, the Developer shall submit the additional information within 30 days of the ISO's request. The ISO shall notify the Developer of its qualification status within 30 days of receiving all necessary information. A Developer shall retain its qualification status for a three-year period following the notification date; *provided, however*, that the ISO may revoke this status if it determines that there has been a material change in the Developer's qualifications and the Developer no longer meets the qualification requirements. A Developer that has been qualified shall inform the ISO within thirty days of any material change to the information it provided regarding its qualifications and shall submit to the ISO each year its most recent audited annual financial statement when available. At the conclusion of the three-year period or following the ISO's revocation of a Developer's qualification status, the Developer may re-apply for a qualification status under this section.

Any Developer determined by the ISO to be qualified under this section shall be eligible to propose a regulated transmission project as a solution to an identified Reliability Need and shall be eligible to use the cost allocation and cost recovery mechanism for regulated transmission projects set forth in Section 31.5 of this Attachment Y and Rate Schedule 10, Section 6.10, of the ISO OATT for any approved project.

31.2.4.2 Interregional Transmission Projects

Interregional Transmission Projects may be proposed under Section 31.2.5.1 of this Attachment Y as regulated backstop solutions, alternative regulated solutions, or market-based solutions, in response to a request by the ISO for solutions to a Reliability Need under the relevant provisions of Section 31.2.4. Interregional Transmission Projects proposed as regulated backstop solutions, alternative regulated solutions or market-based solutions shall be: (i) evaluated by the ISO in accordance with the applicable requirements of the reliability planning process of this Attachment Y, and (ii) jointly evaluated by the ISO and the relevant adjacent transmission planning region(s) in accordance with Section 7.3 of the Interregional Planning Protocol.

31.2.4.3 Regulated Backstop Solutions

31.2.4.3.1 When a Reliability Need is identified in any RNA issued under this tariff, the ISO shall request and the Responsible Transmission Owner shall provide to the ISO, as set forth in Section 31.2.5 below, a proposal for a regulated solution or combination of solutions that shall serve as a backstop to meet the Reliability Need if requested by the ISO due to the lack of sufficient viable market-based solutions to meet such Reliability Needs identified for the Study Period. The Responsible Transmission Owner shall be eligible to recover its costs for developing its proposal and seeking necessary approvals under Rate Schedule 10 of the ISO OATT. Regulated backstop solutions may include generation, transmission, or demand side resources. Such proposals may include reasonable alternatives that would effectively address the Reliability Need; provided however, the Responsible Transmission Owner’s obligation to propose and implement regulated backstop solutions under this tariff is limited to regulated transmission solutions. Prior to providing its response to the RNA, each Responsible Transmission Owner will present for discussion at the ESPWG and TPAS any updates in its LTP that impact a Reliability Need identified in the RNA. The ISO will present at the ESPWG and TPAS any updates to its determination under Section 31.2.2.4.2 with respect to the Transmission Owners' LTPs. Should more than one regulated backstop solution be proposed by a Responsible Transmission Owner to address a Reliability Need, it will be the responsibility of that Responsible Transmission Owner to determine which of the regulated backstop solutions will proceed following a finding by the ISO under Section 31.2. of this Attachment Y. The determination by the Responsible Transmission Owner will be made prior to the approval of the CRP which precedes the Trigger Date for the regulated backstop solution with the longest lead time. Contemporaneous with the request to the Responsible Transmission Owner, the ISO shall solicit market-based and alternative regulated responses as set forth in Sections 31.2.4.5 and 31.2.4.7, which shall not be a formal RFP process.

31.2.4.4 Qualifications for Regulated Backstop Solutions

31.2.4.4.1 The submission of a regulated backstop solution to a Reliability Need for purposes of the ISO's evaluation under Section 31.2.5 of the viability and sufficiency of the proposed solution and the determination of the Trigger Date for the proposed solution shall include, at a minimum, the following details: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Responsible Transmission Owner can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications and drawings as appropriate; (4) evidence of a commercially viable technology, (5) a major milestone schedule; (6) the schedule for obtaining any permits and other certifications, if available; (7) status of ISO interconnection studies and interconnection agreement, if available; and (8) status of equipment availability and procurement, if available.

31.2.4.4.2 The submission of a regulated backstop solution to a Reliability Need for purposes of the ISO's evaluation of the proposed solution for possible selection as the more efficient or cost effective solution to the Reliability Need shall include, at a minimum, the following details: (1) updates to the information required under Section 31.2.4.4.1; (2) the schedule for obtaining required permits and other certifications; (3) a demonstration of Site Control or a schedule for obtaining such control; (4) the status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place , including any contracts with third-party contractors (5) status of ISO interconnection studies and interconnection agreement; (6) status of equipment availability and procurement; (7) evidence of financing or ability to finance the project; (8) capital cost estimates for the project; (9) a description of permitting or other risks facing the project at the stage of project development, including evidence of the reasonableness of project cost estimates, all based on the information available at the time of the submission; and (10) any other information requested by the ISO.

A Responsible Transmission Owner shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Responsible Transmission Owner as "Confidential Information."

A Responsible Transmission Owner shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

A Responsible Transmission Owner shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) evidence of self-financing or project financing through approved rates or the ability to do so, (ii) copies of all loan commitment letter(s) and signed financing contract(s), or (iii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts or approved rates shall be submitted to the ISO when available.

31.2.4.4.3 If the regulated backstop solution does not meet the Reliability Needs, the ISO will provide sufficient information to the Responsible Transmission Owner to determine how the regulated backstop should be modified to meet the identified Reliability Needs. The Responsible Transmission Owner will make necessary changes to its proposed regulated backstop solution to address reliability deficiencies identified by the ISO, and submit a revised proposal to the ISO for review and approval.

31.2.4.5 Market-Based Responses

At the same time that a proposal for a regulated backstop solution is requested from the Responsible Transmission Owner under Section 31.2.4.3, the ISO shall also request market-based responses from the market place. Subject to the execution of appropriately drawn confidentiality agreements and the Commission's standards of conduct, the ISO and the appropriate Transmission Owner or Transmission Owners shall provide any party who wishes to develop such a response access to the data that is necessary to develop its response. Such data shall only be used for the purposes of preparing a market-based response to a Reliability Need under this section. Such responses will be open on a comparable basis to all resources, including generation, demand response providers, and merchant transmission Developers.

31.2.4.6 Qualifications for a Valid Market-Based Response

The submission of a proposed market-based solution must include, at a minimum: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Developer can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications and drawings as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) a schedule for obtaining any required permits and other certifications; (7) a demonstration of Site Control or a schedule for obtaining Site Control; (8) the status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place; (9) the status of ISO interconnection studies and interconnection agreement; (10) the status of equipment availability and procurement; (11) evidence of financing or ability to finance the project; and (12) any other information requested by the ISO.

A Developer shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Developer as “Confidential Information.”

A Developer shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

A Developer shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) copies of all loan commitment letter(s) and signed financing contract(s), or (ii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available.

Failure to provide any data requested by the ISO within the timeframe set forth in Section 31.2.5.1 of this Attachment Y will result in the rejection of the proposed market-based solution from further consideration during that planning cycle.

31.2.4.7 Alternative Regulated Responses

31.2.4.7.1 The ISO will request alternative regulated responses to Reliability Needs at the same time that it requests market-based responses and regulated backstop solutions. Such proposals may include reasonable alternatives that would effectively address the identified Reliability Need.

31.2.4.7.2 In response to the ISO's request, Other Developers may develop alternative regulated proposals for generation, demand side alternatives, and/or other solutions to address a Reliability Need and submit such proposals to the ISO. Transmission Owners, at their option, may submit additional proposals for regulated solutions to the ISO. Transmission Owners and Other Developers may submit such proposals to the NYDPS for review at any time. Subject to the execution of appropriately drawn confidentiality agreements and the Commission's standards of conduct, the ISO and the appropriate Transmission Owner(s) shall provide Other Developers access to the data that is needed to develop their proposals. Such data shall be used only for purposes of preparing an alternative regulated proposal in response to a Reliability Need.

31.2.4.8 Qualifications for Alternative Regulated Solutions

31.2.4.8.1 The submission of an alternative regulated solution to a Reliability Need for purposes of the ISO's evaluation under Section 31.2.5 of the viability and sufficiency of the proposed solution and the determination of the Trigger Date for the proposed solution shall include, at a minimum, the following details: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Other Developer or Transmission Owner can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications and drawings as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) the schedule for obtaining any permits and other certifications, if available; (7) status of ISO interconnection studies and interconnection agreement, if available; and (8) status of equipment availability and procurement, if available.

31.2.4.8.2 The submission of a proposed alternative regulated solution to a Reliability Need for purposes of the ISO's evaluation of the proposed solution for possible selection as the more efficient or cost effective solution for the Reliability Need must include, at a minimum: (1) updates to the information required under Section 31.2.4.8.1; (2) a demonstration of Site Control or a schedule for obtaining Site Control; (3) the status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place, including any contracts with third-party contractors (4) the status of any interconnection studies and interconnection agreement; (5) the schedule for obtaining any required permits and other certifications; (6) the status of equipment availability and procurement; (7) evidence of financing or ability to finance the project; (8) capital cost estimates for the project; (9) a description of permitting or other risks facing the project at the stage of project development, including evidence of the reasonableness of project cost estimates, all based on the information available at the time of the submission; and (10) any other information requested by the ISO.

An Other Developer or Transmission Owner shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Other Developer or Transmission Owner as "Confidential Information."

An Other Developer or Transmission Owner shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

An Other Developer or Transmission Owner shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) evidence of self-financing or project financing through approved rates or the ability to do so, (ii) copies of all loan commitment letter(s) and signed financing contract(s), or (iii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts or approved rates shall be submitted to the ISO when available.

31.2.4.8.3 Failure to provide any data requested by the ISO within the timeframe provided in Sections 31.2.5.1 and 31.2.6.1 of this Attachment Y will result in the rejection of the proposed alternative regulated solution from further consideration during that planning cycle. A proponent of a proposed alternative regulated solution must notify the ISO immediately of any material change in status of a proposed alternative regulated solution. For purposes of this provision, a material change includes, but is not limited to, a change in the financial viability of the developer, a change in the siting status of the project, or a change in a major element of the project's development. If the ISO, at any time, learns of a material change in the status of a proposed alternative regulated solution, it may, at that time, make a determination as to the continued viability of the proposed alternative regulated solution.

31.2.4.9 Additional Solutions

Should the ISO determine that it has not received adequate regulated backstop or market-based solutions to satisfy the Reliability Need, the ISO may, in its discretion, solicit additional regulated backstop or market-based solutions. Other Developers or Transmission Owners may submit additional alternative regulated solutions for the ISO's consideration at that time.

31.2.5 ISO Evaluation of Viability, Sufficiency, and Trigger Date of Proposed Solutions to Reliability Needs

31.2.5.1 Timing for Submittal of Project Information and Developer Qualification Information and Opportunity to Provide Additional Information

Within 60 days after a request for solutions to a Reliability Need is made by the ISO after completion of the RNA, which time period may be extended by the ISO pursuant to Section 31.1.8.7, all Developers proposing solutions to an identified Reliability Need shall submit to the ISO for purposes of its evaluation the project information, as applicable, for: (i) a proposed regulated backstop solution under Section 31.2.4.4.1, (ii) a proposed market-based solution under Section 31.2.4.6, or (iii) a proposed alternative regulated solution under Section 31.2.4.8.1 of this Attachment Y.

Any Developer that the ISO has determined under Section 31.2.4.1.1.2 or as set forth in this Section 31.2.5.1 below to be qualified to propose to develop a project as a transmission solution to an identified Reliability Need may submit the required project information; *provided, however,* that: (i) the Developer shall provide a non-refundable application fee of $10,000 and (ii) based on the actual identified need, the ISO may request that the qualified Developer provide additional Developer qualification information. Any Developer that has not been determined by the ISO to be qualified, but that wants to propose to develop a project, must submit to the ISO the information required for Developer qualification under Section 31.2.4.1.1 within 30 days after a request for solutions is made by the ISO. The ISO shall within 30 days of a Developer's submittal of its Developer qualification information, notify the Developer if this information is incomplete. The Developer shall submit additional Developer qualification information or project information required by the ISO within 15 days of the ISO's request. A Developer that fails to submit the additional Developer qualification information or the required project information will not be eligible for its project to be considered in that planning cycle.

31.2.5.2 Comparable Evaluation of All Proposed Solutions

The ISO shall evaluate: (i) any proposed market-based solution submitted by a Developer pursuant to Section 31.2.4.5, (ii) any proposed regulated backstop solution submitted by a Responsible Transmission Owner pursuant to Section 31.2.4.3, and (iii) any proposed alternative regulated solution submitted by a Transmission Owner or Other Developer pursuant to Section 31.2.4.7. The ISO will evaluate whether each proposed solution is viable and is sufficient to satisfy the identified Reliability Need by the need date pursuant to Sections 31.2.5.3 and 31.2.5.4. The proposed solutions may include multiple components and resource types. When evaluating proposed solutions to Reliability Needs from any Developer, all resource types – generation, transmission, demand response, or a combination of these resource types – shall be considered on a comparable basis as potential solutions to the Reliability Needs identified. All solutions will be evaluated in the same general time frame.

31.2.5.3 Evaluation of Viability of Proposed Solution

The ISO will determine the viability of a solution – transmission, generation, demand response, or a combination of these resource types – proposed to satisfy a Reliability Need. For purposes of its analysis, the ISO will evaluate whether: (i) the Developer has provided the required Developer qualification data pursuant to Section 31.2.4.1 and the required project information data under Sections 31.2.4.4.1, 31.2.4.6, or 31.2.4.8.1; (ii) the proposed solution is technically practicable; (iii) the Developer has indicated possession of, or an approach for acquiring, any necessary rights-of-way, property, and facilities that will make the proposal reasonably feasible in the required timeframe; and (iv) the proposed solution can be completed in the required timeframe. If the ISO determines that the proposed solution is not viable and, for regulated solutions, the Developer does not address any identified deficiency pursuant to Section 31.2.5.6, the ISO shall reject the proposed solution from further consideration during that planning cycle.

31.2.5.4 Evaluation of Sufficiency of Proposed Solution

The ISO will perform a comparable analysis of each proposed solution – transmission, generation, demand response, or a combination of these resource types – through the Study Period to identify whether it satisfies the Reliability Need(s). The ISO will evaluate each solution to determine whether the solution proposed by the Developer fully eliminates the Reliability Need(s). If the ISO determines that a proposed regulated solution is not sufficient and, the Developer does not address any identified deficiency pursuant to Section 31.2.5.6, the ISO shall reject the proposed regulated solution from further consideration during that planning cycle.

31.2.5.5 Establishment of Trigger Date of Proposed Regulated Solutions

Upon receipt of all Developers' proposed regulated solutions pursuant to Section 31.2.5.1, the ISO will notify all Developers if any Developer has proposed a lead time for the implementation of its regulated solution that could result in a Trigger Date for the regulated solution within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment, provided that the ISO will not disclose the identity of such Developer or the details of its project at that time. The ISO will independently analyze the lead time proposed by each Developer for the implementation of its regulated solution. The ISO will use the Developer's estimate and the ISO's analysis to establish the ISO's Trigger Date for each regulated solution. The ISO will also establish benchmark lead times for proposed market-based solutions.

31.2.5.6 Resolution of Deficiencies

Following initial review of the proposals, as described above, ISO staff will identify any reliability deficiencies in each of the proposed solutions. The Responsible Transmission Owner, Transmission Owner or Other Developer will discuss any identified deficiencies with the ISO staff. Other Developers and Transmission Owners that propose alternative regulated solutions shall have the option to remedy their proposals to address any deficiency within 30 days of notification by the ISO. With respect to regulated backstop solutions proposed by a Responsible Transmission Owner pursuant to Section 31.2.4.3, the Responsible Transmission Owner shall make necessary changes to its proposed backstop solution to address any reliability deficiencies identified by the ISO, and submit a revised proposal to the ISO for review within 30 days. The ISO shall review all such revised proposals to determine whether the identified deficiencies have been resolved.

31.2.5.7 ISO Report of Evaluation Results

The ISO shall present its Viability and Sufficiency Assessment to stakeholders, interested parties, and the NYDPS for comment and will indicate at that time whether any of the proposed regulated solutions found to be viable and sufficient under this Section 31.2.5 will have a Trigger Date within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG.

The ISO shall report in the CRP the results of its evaluation under this Section 31.2.5: (i) whether each proposed regulated backstop solution, alternative regulated solution, and market-based solution is viable and is sufficient to satisfy the identified Reliability Need by the need date, and (ii) the Trigger Dates for the proposed regulated solutions.

31.2.6 ISO Evaluation and Selection of Proposed Regulated Transmission Solutions

31.2.6.1 Submission of Project Information for Selection of Proposed Regulated Transmission Solution

If the ISO determines that the Trigger Date of any Developer's proposed regulated solution that was found to be viable and sufficient under Section 31.2.5 will occur within thirty-six months of the date of the ISO's presentation of the of the Viability and Sufficiency Assessment to the ESPWG, the ISO will request that all Developers of regulated transmission solutions that the ISO determined were viable and sufficient submit to the ISO their project information, as applicable, for: (i) a proposed regulated backstop transmission solution under Section 31.2.4.4.2, or (ii) a proposed alternative regulated transmission solution under Section 31.2.4.8.2. If the ISO determines that none of the Developers' proposed regulated solutions that were found to be viable and sufficient under Section 31.2.5 have a Trigger Date that will occur within the thirty-six month period, the ISO will not request further project information perform the evaluation or make a selection of a more efficient or cost effective regulated solution under this Section 31.2.6 for that planning cycle.

The ISO will make its request, if necessary, for project information under this Section 31.2.6.1 sufficiently in advance of the earliest Trigger Date of the viable and sufficient regulated solutions to enable the ISO to evaluate and select the more efficient or cost effective transmission solution. Upon the ISO's request for project information, the Developers shall submit such information for their regulated transmission solutions within thirty (30) days, which time period may be extended by the ISO pursuant to Section 31.1.8.7. A Developer shall submit additional project information required by the ISO within 15 days of the ISO's request. A Developer that fails to submit the required project information will not be eligible for its project to be considered in that planning cycle.

31.2.6.2 Study Deposit for Proposed Regulated Transmission Solutions

A Developer that proposes a regulated backstop transmission solution or an alternative regulated transmission solution to satisfy the identified Reliability Need shall submit to the ISO, at the same time that it provides the project information required pursuant to Section 31.2.6.1, a study deposit of $100,000, which shall be applied to study costs and subject to refund as described in this Section 31.2.6.2.

The ISO shall charge, and a Developer proposing a regulated backstop transmission solution or an alternative regulated transmission solution shall pay, the actual costs of the ISO's evaluation of the Developer's proposed transmission solution for purposes of the ISO selection of the more efficient or cost effective transmission solution to satisfy a Reliability Need for cost allocation purposes, including costs associated with the ISO's use of subcontractors. The ISO will track its staff and administrative costs, including any costs associated with using subcontractors, that it incurs in performing the evaluation of a Developer's proposed transmission solution under this Section 31.2.6 and any supplemental evaluation or re-evaluation of the proposed transmission solution. If the ISO or its subcontractors perform study work for multiple proposed transmission solutions on a combined basis, the ISO will allocate the costs of the combined study work equally among the applicable Developers.

The ISO shall invoice the Developer monthly for study costs incurred by the ISO in evaluating the Developer's proposed transmission solution as described above. Such invoice shall include a description and an account of the study costs incurred by the ISO and estimated subcontractor costs. The Developer shall pay the invoiced amount within thirty (30) calendar days of the ISO's issuance of the monthly invoice. The ISO shall continue to hold the full amount of the study deposit until settlement of the final monthly invoice; *provided, however,* if a Developer: (i) does not pay its monthly invoice within the timeframe described above, or (ii) does not pay a disputed amount into an independent escrow account as described below, the ISO may draw upon the study deposit to recover the owed amount. If the ISO must draw on the study deposit, the ISO shall provide notice to the Developer, and the Developer shall within thirty (30) calendar days of such notice make payments to the ISO to restore the full study deposit amount. If the Developer fails to make such payments, the ISO may halt its evaluation of the Developer's proposed transmission solution and may disqualify the Developer's proposed transmission solution from further consideration. After the conclusion of the ISO's evaluation of the Developer's proposed transmission solution or if the Developer; (i) withdraws its proposed transmission solution or, or (ii) fails to pay an invoiced amount and the ISO halts its evaluation of the proposed transmission solution, the ISO shall issue a final invoice and refund to the Developer any portion of the Developer's study deposit submitted to the ISO under this Section 31.2.6.2 that exceeds outstanding amounts that the ISO has incurred in evaluating that Developer's proposed transmission solution, including interest on the refunded amount calculated in accordance with Section 35.19a(a)(2) of FERC's regulations. The ISO shall refund the remaining portion within sixty (60) days of the ISO's receipt of all final invoices from its subcontractors and involved Transmission Owners.

In the event of a Developer's dispute over invoiced amounts, the Developer shall: (i) timely pay any undisputed amounts to the ISO, and (ii) pay into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Developer fails to meet these two requirements, then the ISO shall not be obligated to perform or continue to perform its evaluation of the Developer's proposed transmission solution. Disputes arising under this section shall be addressed through the Dispute Resolution Procedures set forth in Section 2.16 of the ISO OATT and Section 11 of the ISO Services Tariff. Within thirty (30) Calendar Days after resolution of the dispute, the Developer will pay the ISO any amounts due with interest calculated in accordance with Section 35.19a(a)(2) of FERC's regulations.

31.2.6.3 Evaluation of System Impact of Proposed Regulated Transmission Solution

A proposed regulated transmission solution that will have a significant adverse impact on the reliability of the New York State Transmission System shall not be eligible for selection by the ISO under Section 31.2.6.5. The ISO shall evaluate the system impacts for the entire Study Period of a proposed regulated transmission solution that the ISO has determined under Section 31.2.5 is viable and sufficient. The ISO shall perform power flow and short circuit studies for the proposed regulated transmission solutions and additional studies, as appropriate. If the ISO identifies a significant adverse impact based on these studies, the ISO shall request that the Developer make an adjustment to its proposed regulated transmission solution to address this impact and remain eligible for selection. The Developer shall submit the adjustment within 30 days of the ISO's notification.

If the Developer modifies its proposed regulated transmission solution, the ISO shall confirm that the adjusted solution still satisfies the viability and sufficiency requirements set forth in Section 31.2.5. If the ISO determines that the proposed regulated transmission solution does not satisfy the viability and sufficiency requirements or continues to have a significantly adverse impact on the reliability of the New York State Transmission System, the ISO shall remove the proposed solution from further consideration during that planning cycle.

31.2.6.4 Evaluation of Regional Transmission Solutions to Address Local and Regional Reliability Needs More Efficiently or More Cost Effectively Than Local Transmission Solutions

The ISO will review the LTPs as they relate to BPTFs. The results of the ISO's analysis will be reported in the CRP.

31.2.6.4.1 Evaluation of Regional Transmission Solutions to Address Local Reliability Needs Identified in Local Transmission Plans More Efficiently or More Cost Effectively than Local Transmission Solutions

The ISO, using engineering judgment, will determine whether proposed regional transmission solutions on the BPTFs may more efficiently or cost effectively satisfy reliability needs identified in the LTPs. If the ISO identifies that a regional transmission solution on the BPTFs has the potential to more efficiently or cost effectively satisfy the reliability need identified in the LTPs, it will perform a sensitivity analysis to determine whether the proposed regional transmission solution on the BPTFs would satisfy the reliability needs identified in the LTPs. If the ISO determines that the proposed regional transmission solutions on the BPTFs would satisfy the reliability need, the ISO will evaluate the proposed regional transmission solution using the metrics set forth in Section 31.2.6.5.1 to determine whether it may be a more efficient or cost effective solution on the BPTFs to satisfy the reliability needs identified in the LTPs than the local solutions proposed in the LTPs.

31.2.6.4.2 Evaluation of Regional Transmission Solutions to Address Regional Reliability Needs More Efficiently or More Cost Effectively than Local Transmission Solutions

As referenced in Section 31.2.1.3, the ISO, using engineering judgment, will determine whether a regional transmission solution might more efficiently or more cost effectively satisfy an identified regional Reliability Need on the BPTFs that impacts more than one Transmission District than any local transmission solutions identified by the Transmission Owners in their LTPs in the event the LTPs specify such transmission solutions are included to address local reliability needs.

31.2.6.5 ISO Selection of More Efficient or Cost Effective Transmission Solution for Cost Allocation Purposes

A proposed regulated transmission solution – including a regulated backstop transmission solution submitted by a Responsible Transmission Owner pursuant to Section 31.2.4.3 and an alternative regulated transmission solution submitted by a Transmission Owner or Other Developer pursuant to Section 31.2.4.7 – that the ISO has determined satisfies the viability and sufficiency requirements in Section 31.2.5 and the system impact requirements in Section 31.2.6.3 shall be eligible under this Section 31.2.6.5 for selection in the CRP for the purpose of cost allocation and recovery under the ISO Tariffs. The ISO shall evaluate any eligible proposed regulated transmission solutions for the planning cycle using the metrics set forth in Section 31.2.6.5.1 below. For purposes of this evaluation, the ISO will review the information submitted by the Developer and determine whether it is reasonable and how such information should be used for purposes of the ISO evaluating each metric. The ISO may engage an independent consultant to review the reasonableness and comprehensiveness of the information submitted by the Developer and may rely on the independent consultant's analysis in evaluating each metric. The ISO shall select in the CRP for cost allocation purposes the more efficient or cost effective transmission solution to satisfy a Reliability Need in the manner set forth in Section 31.2.6.5.2 below.

31.2.6.5.1 Metrics for Evaluating More Efficient or Cost Effective Regulated Transmission Solution to Satisfy Reliability Need

In determining which of the eligible proposed regulated transmission solutions is the more efficient or cost effective solution to satisfy the Reliability Need, the ISO will consider, and will consult with the NYDPS regarding, the following metrics set forth in this Section 31.2.6.5.1 and rank each proposed solution based on the quality of its satisfaction of these metrics:

31.2.6.5.1.1 The capital cost estimates for the proposed regulated transmission solutions, including the accuracy of the proposed estimates. For this evaluation, the Developer shall provide the ISO with credible capital cost estimates for its proposed solution, with itemized supporting work sheets that identify all material and labor cost assumptions, and related drawings to the extent applicable and available. The work sheets should include an estimated quantification of cost variance, providing an assumed plus/minus range around the capital cost estimate.

The estimate shall include all components that are needed to meet the Reliability Need throughout the Study Period. To the extent information is available, the Developer should itemize: material and labor cost by equipment, engineering and design work, permitting, site acquisition, procurement and construction work, and commissioning needed for the proposed solution, all in accordance with Good Utility Practice. For each of these cost categories, the Developer should specify the nature and estimated cost of all major project components and estimate the cost of the work to be done at each substation and/or on each feeder to physically and electrically connect each facility to the existing system. The work sheets should itemize to the extent applicable and available all equipment for: (i) the proposed project; (ii) interconnection facilities (including Attachment Facilities and Direct Assignment Facilities); and (iii) System Upgrade Facilities, System Deliverability Upgrades, Network Upgrades, and Distribution Upgrades.

31.2.6.5.1.2 The cost per MW ratio of the proposed regulated transmission solutions. For this evaluation, the ISO will first determine the present worth, in dollars, of the total capital cost of the proposed solution in current year dollars. The ISO will then determine the MW value of the solution by summing the Reliability Need, in MW, with the additional improvement, in MW, that the proposed solution offers beyond serving the Reliability Need. The ISO will then determine the cost per MW ratio by dividing the present worth of the total capital cost by the MW value.

31.2.6.5.1.3 The expandability of the proposed regulated transmission solution. The ISO will consider the impact of the proposed solution on future construction. The ISO will also consider the extent to which any subsequent expansion will continue to use this proposed solution within the context of system expansion.

31.2.6.5.1.4 The operability of the proposed regulated transmission solution. The ISO will consider how the proposed solution may affect additional flexibility in operating the system, such as dispatch of generation, access to operating reserves, access to ancillary services, or ability to remove transmission for maintenance. The ISO will also consider how the proposed solution may affect the cost of operating the system, such as how it may affect the need for operating generation out of merit for reliability needs, reducing the need to cycle generation, or providing more balance in the system to respond to system conditions that are more severe than design conditions.

31.2.6.5.1.5 The performance of the proposed regulated transmission solution. The ISO will consider how the proposed project may affect the utilization of the system (*e.g.* interface flows, percent loading of facilities).

31.2.6.5.1.6 The extent to which the Developer of a proposed regulated transmission solution has the property rights, or ability to obtain the property rights, required to implement the solution. The ISO will consider whether the Developer: (i) already possesses the rights of way necessary to implement the solution; (ii) has completed a transmission routing study, which (a) identifies a specific routing plan with alternatives, (b) includes a schedule indicating the timing for obtaining siting and permitting, and (c) provides specific attention to sensitive areas (e.g., wetlands, river crossings, protected areas, and schools); or (iii) has specified a plan or approach for determining routing and acquiring property rights.

31.2.6.5.1.7 The potential issues associated with delay in constructing the proposed regulated transmission solution consistent with the major milestone schedule and the schedule for obtaining any permits and other certifications as required to timely meet the need.

31.2.6.5.2 ISO Selection of More Efficient or Cost Effective Regulated Transmission Solution to Satisfy Reliability Need

The ISO shall select under this Section 31.2.6.5.2 the proposed regulated transmission solution, if any, that is the more efficient or cost effective transmission solution proposed in the planning cycle to satisfy the identified Reliability Need. The ISO shall report the selected regulated transmission solution in the CRP. The selected regulated transmission solution reported in the CRP shall be eligible to be triggered by the ISO to satisfy the identified Reliability Need pursuant to Section 31.2.8 at any point within thirty-six months of the date of he ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG. An Other Developer or Transmission Owner of an alternative regulated transmission project shall not be eligible for cost allocation and cost recovery under the ISO OATT for its project unless its project is selected pursuant to this Section 31.2.6.5.2. Once such project is selected, the Other Developer or Transmission Owner shall be eligible for cost allocation and cost recovery under the ISO OATT for its project. Within thirty (30) days of the ISO's selection of an alternative regulated transmission solution, the Other Developer or Transmission Owner shall submit to the ISO for the ISO's approval a proposed schedule and scope of work that describe the preparation work, if any, that the Developer must perform prior to the Trigger Date of the project, including a good faith estimate of the costs of such work. Costs will be recovered when the project enters into service is halted, or as otherwise determined by the Commission in accordance with the cost recovery requirements set forth in Section 31.5.6 of this Attachment Y and Rate Schedule 10 of the ISO OATT. Actual project cost recovery, including any issues related to cost recovery and project cost overruns, will be submitted to and decided by the Commission.

31.2.7 Comprehensive Reliability Plan

Following the ISO's evaluation of the proposed market-based and regulated solutions to Reliability Need(s), the ISO will prepare a draft CRP that sets forth the ISO's findings regarding the viability and sufficiency of solutions, the trigger dates of regulated solutions, and any recommendations that implementation of regulated solutions (which may be a Gap Solution) is necessary to ensure system reliability. The draft CRP will reflect any input from the NYDPS. If the CRP cannot be completed in the two-year planning cycle, the ISO will notify stakeholders and provide an estimated completion date and an explanation of the reasons the additional time is required.

The ISO will include in the draft CRP the list of Developers that qualify pursuant to Section 31.2.4.1 and will identify the proposed solutions that it has determined under Section 31.2.5 are viable and sufficient to satisfy the identified Reliability Need(s) by the need date. The ISO will identify in the CRP the regulated backstop solution that the ISO has determined will meet the Reliability Need by the need date and the Responsible Transmission Owner. If the ISO determines at the time of the issuance of the CRP that sufficient market-based solutions will not be available in time to meet a Reliability Need, and finds that it is necessary to take action to ensure reliability, it will state in the CRP that the development of regulated solution (regulated backstop or alternative regulated solution) is necessary. The draft CRP will also include the results of the ISO's analysis of the LTPs consistent with Section 31.2.6.4.

The draft CRP shall indicate whether the ISO has determined that the Trigger Date to any proposed regulated solution will occur within thirty-six months of the date of ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG. If the Trigger Date of any proposed regulated solution will occur within the thirty-six month period and the ISO makes a selection of the more efficient or cost effective transmission solution under Section 31.2.6.5.2, the draft CRP shall include the regulated transmission solution selected for cost allocation purposes pursuant to Section 31.2.6.5.2 as the more efficient or cost effective transmission solution to satisfy the Reliability Need(s) and shall indicate whether that transmission solution should be triggered. If: (i) none of the proposed regulated solutions has a Trigger Date within the thirty-six month period, or (ii) the Trigger Date of any proposed regulated solution will occur within the thirty-six month period but the ISO determines in its discretion that it is not necessary at that time to select a more efficient or cost effective transmission solution under Section 31.2.6.5.2 prior to the completion of the CRP, the draft CRP will not select a regulated transmission solution. If: (i) the Trigger Date of any proposed regulated solution will occur within the thirty-six month period, and (ii) the ISO selects a more efficient or cost effective solution subsequent to the completion of the CRP but prior to the completion of that thirty-six month period, the ISO shall issue an updated CRP report pursuant to Section 31.2.7.3 that includes the regulated transmission solution selected for cost allocation purposes pursuant to Section 31.2.6.5.2 as the more efficient or cost effective transmission solution to satisfy the Reliability Need(s) and shall indicate whether that transmission solution should be triggered.

The draft CRP shall include a comparison of a proposed regional solution to an identified Reliability Need to an Interregional Transmission Project identified and evaluated under the "Analysis and Consideration of Interregional Transmission Projects" section of the Interregional Planning Protocol, if any. An Interregional Transmission Project proposed in the ISO's reliability planning process may be selected as a market based response, regulated backstop solution, or an alternative regulated solution under the provisions of the ISO's reliability planning process.

31.2.7.1 Collaborative Governance Process

The ISO staff shall submit the draft CRP to the TPAS and ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to replicate the results of the draft CRP. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of the TPAS and ESPWG review, the draft CRP reflecting the revisions resulting from the TPAS and ESPWG review shall be forwarded to the Operating Committee for a discussion and action. The ISO shall notify the Business Issues Committee of the date of the Operating Committee meeting at which the draft CRP is to be presented. Following the Operating Committee vote, the draft CRP will be transmitted to the Management Committee for a discussion and action.

31.2.7.2 Board Review, Consideration, and Approval of CRP

Following the Management Committee vote, the draft CRP, with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CRP will also be provided to the Market Monitoring Unit for its review and consideration of whether market rule changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. The Board may approve the draft CRP as submitted or propose modifications on its own motion, including the recommendations regarding the selection of transmission projects for cost allocation and cost recovery under the ISO Tariffs if such selection will occur during that planning cycle. If any changes are proposed by the Board, the revised CRP shall be returned to the Management Committee for comment. The Board shall not make a final determination on the draft CRP until it has reviewed the Management Committee comments. Upon final approval by the Board, the ISO shall issue the CRP to the marketplace by posting the CRP on its website. The ISO will provide the CRP to the appropriate regulatory agency(ies) for consideration and appropriate action.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Attachment Y to the ISO OATT are also addressed in Section 30.4.6.8.3 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

31.2.7.3 Updated CRP Report

If, pursuant to Section 31.2.7, the ISO identifies a proposed regulated transmission solution as the more efficient or cost effective transmission solution following the completion of the CRP, the ISO will prepare a draft updated CRP report that indicates the regulated transmission solution recommended for selection for cost allocation purposes pursuant to Section 31.2.6.5.2 as the more efficient or cost effective transmission solution to satisfy the Reliability Need(s) and shall indicate whether that transmission solution should be triggered at that time. The draft updated CRP report shall be reviewed in accordance with the stakeholder process set forth in Section 31.2.7.1 and will be then forwarded to the ISO Board for its review and action pursuant to Section 31.2.7.2.

31.2.7.4 Reliability Disputes

Notwithstanding any provision to the contrary in this Attachment, the ISO OATT, or the ISO Services Tariff, in the event that a Market Participant or other interested party raises a dispute solely within the NYPSC's jurisdiction concerning ISO's final determination in the CRP that a proposed solution will or will not meet a Reliability Need, a Market Participant or other interested party seeking further review shall refer such dispute to the NYPSC for resolution, as provided for in the ISO Procedures. The NYPSC's final determination of such disputes shall be binding, subject only to judicial review in the courts of the State of New York pursuant to Article 78 of the New York Civil Practice Law and Rules.

31.2.7.5 Posting of Approved Solutions

The ISO shall post on its website a list of all Developers that have undertaken a commitment to the ISO to build a project (which may be a regulated backstop solution, market-based response, alternative regulated response or gap solution) that is necessary to ensure system reliability, as identified in the CRP and approved by the appropriate governmental agency(ies) and/or authority(ies).

31.2.8 Determination of Necessity

31.2.8.1 Determination of Necessity of a Regulated Solution

31.2.8.1.1 The ISO shall review proposals for market-based solutions pursuant to Sections 31.2.5, 31.2.8.3, and 31.2.13.1 of this Attachment Y. The ISO will not trigger a regulated solution if, based on this review, it determines prior to or at the Trigger Date for a regulated solution that sufficient market-based solutions are timely progressing to meet the Reliability Need by the need date. If the ISO decides not to trigger a regulated backstop solution or selected alternative regulated transmission solution, the Responsible Transmission Owner, Other Developer, or Transmission Owner will be eligible to recover its costs incurred up to that point in the same manner it may recover the costs of a halted project in accordance with Section 31.2.8.2.1 for the Responsible Transmission Owner and Section 31.2.8.2.2 for the Other Developer or Transmission Owner.

31.2.8.1.2 If: (i) the ISO determines that there are not sufficient market-based solutions to meet the identified Reliability Need by the need date, (ii) the regulated backstop solution proposed by the Responsible Transmission Owner is the only proposed viable and sufficient regulated solution or is selected by the ISO as the more efficient or cost effective transmission solution to meet the identified Reliability Need, and (iii) the Trigger Date for the regulated backstop solution has or will occur within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, the ISO will trigger the regulated backstop solution at its Trigger Date. The ISO will inform the Responsible Transmission Owner that it should submit the regulated backstop solution to the appropriate governmental agency(ies) and/or authority(ies) to begin the necessary approval process to site, construct, and operate the solution. In response to the ISO's request, the Responsible Transmission Owner shall make such a submission to the appropriate governmental agency(ies) and/or authority(ies).

31.2.8.1.3 If: (i) the ISO determines that there are not sufficient market-based solutions to meet the identified Reliability Need by the need date; (ii) the ISO selects an alternative regulated transmission solution as the more efficient or cost-effective transmission solution to meet the identified Reliability Need; (iii) the Trigger Date for the regulated backstop solution is later than the Trigger Date for the selected alternative regulated transmission solution; and (iv) the Trigger Date for the selected alternative regulated transmission solution has or will occur within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, the ISO shall trigger the selected alternative regulated transmission solution at its Trigger Date. The ISO will inform the Other Developer or Transmission Owner that it should submit the selected alternative regulated transmission solution to the appropriate governmental agency(ies) and/or authority(ies) to begin the necessary approval process to site, construct, and operate the solution. In response to the ISO's request, the Other Developer or Transmission Owner shall make such a submission to the appropriate governmental agency(ies) and/or authority(ies). Prior to the Trigger Date for the regulated backstop solution, the ISO will review the status of the development by the Other Developer or Transmission Owner of the selected alternative regulated transmission solution, including, but not limited to, reviewing: (i) whether the Developer has executed a Development Agreement or requested that it be filed unexecuted with the Commission pursuant to Section 31.2.8.1.6; (ii) whether the Developer is timely progressing against the milestones set forth in the Development Agreement; and (iii) the status of the Developer's obtaining required permits or authorizations, including whether the Developer has received its Article VII certification or other applicable siting permits or authorizations under New York State law. If, based on its review, the ISO determines prior to or at the Trigger Date for the regulated backstop solution that it is necessary for the Responsible Transmission Owner to proceed with a regulated backstop solution in parallel with the selected alternative regulated transmission solution to ensure the identified Reliability Need is satisfied by the need date, the ISO will trigger the regulated backstop solution and report to stakeholders the reasons for its determination. The Responsible Transmission Owner shall proceed with due diligence to develop its regulated backstop solution in accordance with Good Utility Practice and to submit its proposed solution to the appropriate governmental agency(ies) and/or authority(ies), unless or until notified by the ISO that it has determined that the regulated backstop solution is no longer needed as described in Section 31.2.8.2.1 below. If, based on its review, the ISO decides not to trigger the regulated backstop solution, the ISO will notify the Responsible Transmission Owner that its regulated backstop solution is no longer needed and will not be triggered. In such case, the Responsible Transmission Owner shall be eligible to recover its costs incurred up to that point in the same manner as it may recover the costs of a halted project in accordance with Section 31.2.8.2.1.

31.2.8.1.4 If: (i) the ISO determines that there are not sufficient market-based solutions to meet the identified Reliability Need by the need date; (ii) the ISO selects an alternative regulated transmission solution as the more efficient or cost-effective transmission solution to meet the identified Reliability Need; (iii) the Trigger Date for the regulated backstop solution is earlier than the Trigger Date for the selected alternative regulated transmission solution; and (iv) the Trigger Date for the regulated backstop solution has or will occur within thirty-six months of the date of the ISO's presentation of the Viability and Sufficiency Assessment to the ESPWG, the ISO shall trigger both the selected alternative regulated transmission solution and the regulated backstop solution at the Trigger Date for the regulated backstop solution. The ISO will inform the Responsible Transmission Owner that proposed the regulated backstop solution and the Other Developer or Transmission Owner that proposed the selected alternative regulated transmission solution that they should submit the proposed solutions to the appropriate governmental agency(ies) and/or authority(ies) to begin the necessary approval process to site, construct, and operate the solution. In response to the ISO's request, the Responsible Transmission Owner, Other Developer or Transmission Owner shall make such a submission to the appropriate governmental agency(ies) and/or authority(ies).

31.2.8.1.5 The ISO may make its determination regarding the triggering of a regulated solution pursuant to Sections 31.2.8.1.1 through 31.2.8.1.4 in the CRP or at any time before the approval of the next CRP.

31.2.8.1.6 If selected regulated transmission solution is an alternative regulated transmission solution the ISO shall tender the Other Developer or Transmission Owner that proposed the selected alternative regulated transmission solution as soon as reasonably practicable considering the project's Trigger Date following the ISO's selection of the proposed solution a draft Development Agreement with draft appendices completed by the ISO to the extent practicable for review and completion by the Developer. The draft Development Agreement shall be in the form of the ISO's Commission-approved Development Agreement, which is in Appendix C in Section 31.7 of this Attachment Y. The ISO and the Developer shall finalize the Development Agreement and appendices and negotiate concerning any disputed provisions. For purposes of finalizing the Development Agreement, the ISO shall provide the Developer with the date by which the selected project must be in service to satisfy the Reliability Need, and the ISO and Developer shall develop the description and dates for the milestones necessary to develop and construct the selected project by the required in-service date including the milestones for obtaining all necessary authorizations. Unless otherwise agreed by the ISO and the Developer, the Developer must execute the Development Agreement within three (3) months of the ISO's tendering of the draft Development Agreement; *provided, however*, if, during the negotiation period, the Developer determines that negotiations are at an impasse, it may request in writing that the ISO file the Development Agreement in unexecuted form with the Commission. If the Development Agreement resulting from the negotiation between the ISO and the Developer does not conform with the Commission-approved standard form in Appendix C in Section 31.7 of this Attachment Y, the ISO shall file the agreement with the Commission for its acceptance within thirty (30) Business Days after the execution of the Development Agreement by both parties. If the Developer requests that the Development Agreement be filed unexecuted, the ISO shall file the agreement at the Commission within thirty (30) Business Days of receipt of the request from the Developer. The ISO will draft to the extent practicable the portions of the Development Agreement and appendices that are in dispute and will provide an explanation to the Commission of any matters as to which the parties disagree. The Developer will provide in a separate filing any comments that it has on the unexecuted agreement, including any alternative positions it may have with respect to the disputed provisions.

31.2.8.1.7 Upon the ISO's and Developer's execution of the Development Agreement or the ISO's filing of an unexecuted Development Agreement with the Commission pursuant to Section 31.2.8.1.6, the ISO and Developer shall perform their respective obligations in accordance with the terms of the Development Agreement that are not in dispute, subject to modifications by the Commission. The Connecting Transmission Owner(s) and Affected Transmission Owner(s) that are identified in Attachment X of the ISO OATT in connection with the selected alternative regulated transmission solution shall act in good faith in timely performing their obligations that are required for the Developer to satisfy its obligations under the Development Agreement.

31.2.8.1.8 Other Developers and Transmission Owners proposing alternative regulated solutions that the ISO has determined will resolve the identified Reliability Need may submit these proposals to the appropriate governmental agency(ies) and/or authority(ies) for review. The ISO does not determine the solution that will be permitted by the appropriate governmental agency(ies) and/or authority(ies) with jurisdiction over siting or whether the regulated backstop solution or an alternative regulated solution will be constructed to address the identified Reliability Need. If the appropriate governmental agency(ies) and/or authority(ies) makes a final determination that an alternative regulated solution should be permitted and constructed to satisfy a Reliability Need and that the regulated backstop solution should not proceed, implementation of the alternative regulated solution will be the responsibility of the Transmission Owner or Other Developer that proposed the alternative regulated solution, and the Responsible Transmission Owner will not be responsible for addressing the Reliability Need through the implementation of its regulated backstop solution. Should a regulated solution not be implemented, the ISO may request a Gap Solution pursuant to Section 31.2.11 of this Attachment Y.

31.2.8.2 Halting and Related Cost Recovery Requirements

31.2.8.2.1 If the ISO has triggered a regulated backstop solution under Sections 31.2.8.1.2, 31.2.8.1.3, 31.2.8.1.4, or 31.2.8.1.5, the ISO will immediately notify the Responsible Transmission Owner, post such notice on its website, and will state in the next CRP if it determines that the regulated backstop solution is no longer needed and should be halted because either: (i) the ISO has determined that there are sufficient market-based solutions to ensure that the identified Reliability Need is met by the need date, or (ii) the ISO: (A) has triggered an alternative regulated transmission solution that the ISO selected in the CRP as the more efficient or cost effective transmission solution and (B) has determined that it is no longer necessary for the Responsible Transmission Owner to proceed with a regulated backstop solution in parallel with the selected alternative regulated transmission solution to ensure the identified Reliability Need is satisfied by the need date. In making its determination under Section 31.2.8.2.1(ii), the ISO will review the status of the development by the Other Developer or Transmission Owner of the selected alternative regulated transmission solution, including, but not limited to, reviewing: (i) whether the Developer has executed a Development Agreement or requested that it be filed unexecuted with the Commission pursuant to Section 31.2.8.1.6; (ii) whether the Developer is timely progressing against the milestones set forth in the Development Agreement; and (iii) the status of the Developer's obtaining required permits or authorizations, including whether the Developer has received its Article VII certification or other applicable siting permits or authorizations under New York State law.

If a regulated backstop solution is halted by the ISO, all of the costs incurred and commitments made by the Responsible Transmission Owner up to that point, including reasonable and necessary expenses incurred to implement an orderly termination of the project, to the extent permitted by the Commission in accordance with its regulations on abandoned plant recovery, will be recoverable by the Responsible Transmission Owner under the cost recovery mechanism in Rate Schedule 10 of this tariff regardless of the nature of the solution.

31.2.8.2.2 If the ISO has triggered an alternative regulated transmission project under Sections 31.2.8.1.3 or 31.2.8.1.4 that the ISO has selected as the more efficient or cost effective solution, the ISO will immediately notify the Other Developer or Transmission Owner, post such notice on its website, and will state in the next CRP if it determines that the regulated transmission solution is no longer needed and should be halted because the ISO has determined that there are sufficient market-based solutions to ensure that the identified Reliability Need is met by the need date.

If a selected alternative regulated transmission solution is halted by the ISO, all of the costs incurred and commitments made by the Other Developer or Transmission Owner up to that point, including reasonable and necessary expenses incurred to implement an orderly termination of the project, to the extent permitted by the Commission in accordance with its regulations on abandoned plant recovery, will be recoverable by the Other Developer or Transmission Owner under the cost recovery mechanism in Rate Schedule 10 of this tariff.

31.2.8.2.3 Once the Responsible Transmission Owner receives state regulatory approval of the regulated backstop solution, or, if state regulatory approval is not required, once the Responsible Transmission Owner receives necessary regulatory approval, the entry of a market-based solution or an alternative regulated transmission solution will not result in the halting by the ISO of the regulated backstop solution pursuant to Section 31.2.8.2.1. Similarly, once the Other Developer or Transmission Owner receives its state regulatory approval or any other necessary regulatory approval of its triggered alternative regulated transmission solution, the entry of a market-based solution will not result in the halting by the ISO of the regulated transmission solution pursuant to Section 31.2.8.2.2.

31.2.8.2.4 The ISO is not required to review market-based solutions to determine whether they will meet the identified Reliability Need by the need date after the triggered alternative regulated transmission solution or regulated backstop solution has received federal and state regulatory approval, unless a federal or state regulatory agency requests the ISO to conduct such a review. The ISO will report the results of its review to the federal or state regulatory agency, with copies to the Responsible Transmission Owner, Other Developer, or Transmission Owner.

31.2.8.2.5 If the appropriate federal, state or local agency(ies) does not approve a necessary authorization for the triggered regulated backstop solution or alternative regulated transmission solution, all of the necessary and reasonable costs incurred and commitments made up to the final federal, state or local regulatory decision, including reasonable and necessary expenses incurred to implement an orderly termination of the project, to the extent permitted by the Commission in accordance with its regulations on abandoned plant recovery, will be recoverable by the Responsible Transmission Owner, Other Developer, or Transmission

Owner under the ISO cost recovery mechanism in Rate Schedule 10 of the ISO OATT regardless of the nature of the solution.

31.2.8.2.6 If a necessary federal, state or local authorization for a triggered alternative regulated transmission solution or regulated backstop solution is withdrawn, all expenditures and commitments made up to that point including reasonable and necessary expenses incurred to implement an orderly termination of the project, to the extent permitted by the Commission in accordance with its regulations on abandoned plant recovery, will be recoverable under the ISO cost recovery mechanism in Rate Schedule 10 of the ISO OATT by the Responsible Transmission Owner, Other Developer, or Transmission Owner regardless of the nature of the solution.

31.2.8.2.7 If a material modification to the regulated backstop solution or the alternative regulated transmission solution is proposed by any federal, state or local agency, the Responsible Transmission Owner, Other Developer, or Transmission Owner will request the ISO to conduct a supplemental reliability review. If the ISO identifies any reliability deficiency in the modified solution, the ISO will so advise the Responsible Transmission Owner, Other Developer, or Transmission Owner and the appropriate federal, state or local regulatory agency(ies).

31.2.8.3 Criteria for Cutoff Date of Market-Based Solution

31.2.8.3.1 The ISO will apply the criteria in this Section 31.2.8.3 for determining the cutoff date for a determination that a market-based solution will not be available to meet a Reliability Need by the need date.

31.2.8.3.2 In the first instance, the ISO shall employ its procedures for monitoring the viability of a market-based solution to determine when it may no longer be viable. Under the conditions where a market-based solution is proceeding after the Trigger Date for the relevant regulated solution, it becomes even more critical for the ISO to conduct a continued analysis of the viability of such market-based solutions.

31.2.8.3.3 The Developer of such a market-based solution shall submit updated information to the ISO twice during each reliability planning process cycle, first during the input phase of the RNA, and again during the solutions phase during the period allowed for the solicitation for market-based and regulated solutions. If no solutions are requested in a particular year, then the second update will be provided during the ISO's analysis of whether existing solutions continue to meet identified Reliability Needs. The updated information of the project status shall include: status of final permits, status of major equipment, current status of construction schedule, estimated in-service date, any potential impediments to completion by the Target Year, and any other information requested by the ISO.

31.2.8.3.4 The Developer shall immediately report to the ISO when it has any indication of a material change in the project status or that the project in-service date may slip beyond the Target Year. A material change shall include, but not be limited to, a change in the financial viability of the Developer, a change in siting status, or a change in a major element of the project development.

31.2.8.3.5 Based upon the above information, the ISO will perform an independent review of the development status of the market-based solution to determine whether it remains viable to meet the identified Reliability Need by the need date. If the ISO, at any time, learns of a material change in the project status of a market-based solution, it may, at that time, make a determination as to the continued viability of such project.

31.2.8.3.6 The ISO, prior to making a determination about the viability of a specific proposed solution, will communicate its intended determination to the project Developer along with the basis for its intended determination. The ISO shall provide the Developer a reasonable period (not more than 2 weeks) to respond to the ISO's intended determination, including an opportunity to provide additional information to the ISO to support the continued viability of the proposed solution.

31.2.8.3.7 If the ISO determines that a market-based solution that is needed to meet an identified Reliability Need is no longer viable, it will request that a regulated solution proceed or seek other measures including, but not limited to, a Gap Solution, to ensure the reliability of the system.

31.2.8.3.8 If the ISO determines that the market-based solution is still viable, but that its in-service date is likely to slip beyond the Target Year, the ISO may, if needed, request the Responsible Transmission Owner to prepare a Gap Solution in accordance with the provisions of Section 31.2.11 of this Attachment Y.

31.2.9 Process for Consideration of Regulated Backstop Solution and Alternative Regulated Solutions

Upon a determination by the ISO under Section 31.2.8 that a regulated solution should proceed, the Responsible Transmission Owner, Other Developer, or Transmission Owner will make a presentation to the ESPWG that will provide a description of the regulated solution. The presentation will include a non-binding preliminary cost estimate of that regulated solution;

provided, however, that the Responsible Transmission Owner, Other Developer or Transmission Owner shall be entitled to full recovery of all reasonably incurred costs as described in Rate Schedule 10 of the ISO OATT. The ISO and stakeholders through this process will have the opportunity to review and discuss the scope of the projects and their associated non-binding preliminary cost estimates prior to implementation.

31.2.10 Process for Addressing Inability of Responsible Transmission Owner, Other Developer, or Transmission Owner to Complete Triggered Regulated Solution

31.2.10.1 If: (i) the regulated transmission solution selected and triggered by the ISO is an alternative regulated transmission solution, and (ii) one of the following events occur: (A) the Other Developer or Transmission Owner that proposed the alternative regulated transmission solution does not execute the Development Agreement, or does not request that it be filed unexecuted with the Commission, within the timeframes set forth in Section 31.2.8.1.6, or (B) an effective Development Agreement is terminated under the terms of the agreement prior to the completion of the term of the agreement, the ISO may take the following actions as soon as practicable after the occurrence of the event:

31.2.10.1.1 If the Development Agreement has been filed with and accepted by the Commission, the ISO shall, upon terminating the Development Agreement under the terms of the agreement, file a notice of termination with the Commission.

31.2.10.1.2 The ISO may revoke its selection of the alternative regulated transmission solution and the eligibility of the Other Developer or Transmission Owner to recover its costs for the project; *provided, however*, the Other Developer or Transmission Owner may recover its costs to the extent provided in Sections

31.2.8.2.2, 31.2.8.2.5, and 31.2.8.2.6 or as otherwise determined by the Commission.

31.2.10.1.3 If the ISO determines that it must identify a solution prior to the approval of the CRP for the next planning cycle to satisfy the Reliability Need by the need date, the ISO may; (i) direct the Responsible Transmission Owner to proceed with its regulated backstop solution if it has not yet been halted by the ISO pursuant to Section 31.2.8.2.1; (ii) request that the Responsible Transmission Owner complete the selected alternative regulated transmission solution; and/or (iii) proceed with the Gap Solution process under Section 31.2.11.

31.2.10.1.4 If the Responsible Transmission Owner agrees to complete the selected alternative regulated transmission solution, the Responsible Transmission Owner and the Other Developer or Transmission Owner that proposed the selected alternative regulated transmission solution shall work cooperatively with each other to implement the transition, including negotiating in good faith with each other to transfer the project; *provided, however*, that the transfer is subject to: (i) any required approvals by the appropriate governmental agency(ies) and/or authority(ies), (ii) any requirements or restrictions on the transfer of Developer's rights-of-way under law, conveyance, or contract, and (iii), if the Developer is a New York public authority, any requirements or restrictions on the transfer under the New York Public Authorities Law; *provided, further*, that the Responsible Transmission Owner and the Developer will address any disputes regarding the transfer of the project in accordance with the dispute resolution provisions in Article 11 of the ISO Services Tariff.

31.2.10.2 If: (i) the regulated transmission solution selected and triggered by the ISO is the Responsible Transmission Owner's regulated backstop solution or the regulated backstop solution has been triggered by the ISO under Sections 31.2.8.1.2, 31.2.8.1.3, or 31.2.8.1.4, and the regulated backstop solution has not been halted by the ISO under Section 31.2.8.2.1, and (ii) the ISO determines that the Responsible Transmission Owner: (A) has not submitted its proposed regulated backstop solution for necessary regulatory action within a reasonable period of time, (B) is unable to or fails to obtain the approvals or property rights necessary to construct the project, or (C) is otherwise not taking the actions necessary to construct the project to satisfy the Reliability Need by the need date, the ISO shall: (i) submit a report to the Commission for its consideration and determination of whether action is appropriate under federal law, and (ii) take such action as it reasonably considers is appropriate to ensure that the Reliability Need is satisfied by the need date.

31.2.11 Gap Solutions

31.2.11.1 If the ISO determines that neither market-based proposals nor regulated proposals can satisfy the Reliability Needs by the need date, the ISO will set forth its determination that a Gap Solution is necessary in the CRP. The ISO will also request the Responsible Transmission Owner to seek a Gap Solution. Gap Solutions may include generation, transmission, or demand side resources.

31.2.11.2 If there is an imminent threat to the reliability of the New York State Power System, the ISO Board, after consultation with the NYDPS, may request the appropriate Transmission Owner or Transmission Owners to propose a Gap Solution outside of the normal planning cycle.

31.2.11.3 Notwithstanding Sections 31.2.11.1 and 31.2.11.2, if a Market Participant notifies the ISO of its intent for its Generator to be Retired or to enter into a Mothball Outage pursuant to Section 38.3.1 of Attachment FF of the ISO OATT or if a Market Participant's Generator enters into an ICAP Ineligible Forced Outage pursuant to Section 5.18.2.1 of the ISO Services Tariff, the ISO will evaluate whether a Generator Deactivation Reliability Need or an immediate reliability need will result from the Generator's deactivation and will address any resulting Generator Deactivation Reliability Need or immediate reliability need in accordance with the Generator Deactivation Process set forth in Attachment FF of the ISO OATT.

31.2.11.4 Upon the ISO's determination of the need for a Gap Solution, pursuant to Sections 31.2.11.1 or 31.2.11.2 above, the Responsible Transmission Owner will propose such a solution as soon as reasonably possible, for consideration by the ISO and NYDPS. The Responsible Transmission Owner shall be eligible to recover its costs for developing its Gap Solution proposal and seeking necessary approvals pursuant to the cost recovery requirements in Section 31.5.6 of this Attachment Y and Rate Schedule 10 of the ISO OATT.

31.2.11.5 Any party may submit an alternative Gap Solution proposal to the ISO and the NYDPS for their consideration. The ISO shall evaluate all Gap Solution proposals to determine whether they will meet the Reliability Need or imminent threat. The ISO will also evaluate, as an alternative Gap Solution proposal, any

Generator in a Mothball Outage or an ICAP Ineligible Forced Outage to determine whether its return to service would meet the Reliability Need or imminent threat; provided, however, that the Mothball Outage began on or after May 1, 2015 and the ICAP Ineligible Forced Outage followed a Forced Outage that began after May 1, 2015. The ISO will report the results of its evaluation to the party making the proposal, or to the Generator when evaluating its return to service, as well as to the NYDPS and/ or other appropriate governmental agency(ies) and/or authority(ies) for consideration in their review of the proposals. The appropriate governmental agency(ies) and/or authority(ies) with jurisdiction over the implementation or siting of Gap Solutions will determine whether the Gap Solution or an alternative Gap Solution will be implemented to address the identified Reliability Need. When the return to service of a Generator in a Mothball Outage or an ICAP Ineligible Forced Outage has been selected as either the Gap Solution or to resolve a reliability issue arising on a non-New York State Bulk Power Transmission Facility during its outage, the compensation and return to service procedures set forth in Section 5.18.4 of the Services Tariff shall apply.

31.2.11.6 A Responsible Transmission Owner, Other Developer, or Transmission Owner may recover its costs with respect to a transmission Gap Solution that is implemented pursuant to Section 31.2.11.5 in accordance with the cost recovery requirements in Section 31.5.6 of this Attachment Y and Rate Schedule 10 of the ISO OATT.

31.2.11.7 Gap Solution proposals submitted under Sections 31.2.11.4 and 31.2.11.5 shall be designed to be temporary solutions and to strive to be compatible with permanent market-based proposals.

31.2.11.8 A permanent regulated solution, if appropriate, may proceed in parallel with a Gap Solution.

31.2.12 Confidentiality of Solutions

31.2.12.1 The term “Confidential Information” shall include all types of solutions to Reliability Needs that are submitted to the ISO as a response to Reliability Needs identified in any RNA issued by the ISO as part of the reliability planning process if the Developer of that solution designates such reliability solutions as “Confidential Information.”

31.2.12.2 For regulated backstop solutions and plans submitted by the Responsible Transmission Owner in response to the findings of the RNA, the ISO shall maintain the confidentiality of same until the ISO and the Responsible Transmission Owner have agreed that the Responsible Transmission Owner has submitted viable and sufficient regulated backstop solutions and plans to meet the Reliability Needs identified in an RNA and the Responsible Transmission Owner consents to the ISO’s inclusion of the proposed solution in the CRP. Thereafter, the ISO shall disclose the regulated backstop solutions and plans to the Market Participants; however, any preliminary cost estimates that may have been provided to the ISO shall not be disclosed.

31.2.12.3 For an alternative regulated response, the ISO shall determine, after consulting with the Developer thereof, whether the response would meet a

Reliability Need identified in an RNA, whether the response is viable and sufficient to meet all or part of the Reliability Need, and the Developer consents to the ISO's inclusion of the proposed solution in the CRP. Thereafter, the ISO shall disclose the alternative regulated response to the Market Participants and other interested parties; however, any preliminary cost estimates that may have been provided to the ISO shall not be disclosed.

31.2.12.4 For a market-based response, the ISO shall maintain the confidentiality of same during the reliability planning process and in the CRP, except for the following information which may be disclosed by the ISO: (i) the type of resource proposed (e.g., generation, transmission, demand side); (ii) the size of the resource expressed in megawatts of equivalent load that would be served by that resource; (iii) the subzone in which the resource would interconnect or otherwise be located; and (iv) the proposed in-service date of the resource.

31.2.12.5 In the event that the Developer of a market-based response has made a public announcement of its project or has submitted a proposal for interconnection with the ISO, the ISO shall disclose the identity of the market-based Developer and the specific project during the reliability planning process and in the CRP.

31.2.13 Monitoring of Reliability Project Status

31.2.13.1 The ISO will monitor and report on the status of market-based solutions to ensure their continued viability to meet Reliability Needs by the need date in the CRP. The ISO shall assess the continued viability of such projects using the following criteria:

31.2.13.1.1 Between three and five years before the Trigger Date for a regulated solution, the ISO will use a screening analysis to verify the feasibility of the proposed market-based solution (this analysis will not require final permit approvals or final contract documents).

31.2.13.1.2 Between one and two years before the Trigger Date for a regulated solution, the ISO will perform a more extensive review of the proposed market-based solution, including such elements as: status of the required interconnection studies, contract negotiations, permit applications, financing, and Site Control.

31.2.13.1.3 Less than one year before the Trigger Date of a regulated solution, the ISO will perform a detailed review of the market-based solution's status and schedule, including the status of: (1) final permits; (2) required interconnection studies; (3) the status of an interconnection agreement; (4) financing; (5) equipment; and (6) the implementation of construction schedules.

31.2.13.1.4 If the ISO, following its analysis, determines that a proposed market-based solution is no longer viable to meet the Reliability Need, the proposed market-based solution will be removed from the list of potential market-based solutions.

31.2.13.2 The ISO will monitor and report on the status of regulated solutions to ensure their continued viability to meet Reliability Needs by the need date in the CRP. The ISO shall assess the continued viability of regulated solutions using the following criteria:

31.2.13.2.1 Between three and five years before the Trigger Date for the regulated solution, the ISO will use a screening analysis to verify the feasibility of the regulated solution.

31.2.13.2.2 Between one and two years before the Trigger Date for the regulated solution, the ISO will perform a more extensive review of the proposed regulated solution, including such elements as: the status of the required interconnection studies, contract negotiations, permit applications, financing, and Site Control.

31.2.13.2.3 Less than one year before the Trigger Date for the regulated solution, the ISO will perform a detailed review of the regulated solution's status, including the status of: (1) final permits; (2) required interconnection studies; (3) the status of an interconnection agreement; (4) financing; (5) equipment; and (6) the implementation of construction schedules.

31.2.13.2.4 Prior to making a determination about the viability of a regulated solution, the ISO will communicate its intended determination to the project sponsor along with the basis for its intended determination, and will provide the sponsor a reasonable period (not more than two weeks) to respond to the ISO's intended determination, including an opportunity to provide additional information to the ISO to support the continued viability of the proposed regulated solution. If the ISO, following its analysis, determines that a proposed regulated solution is no longer viable to meet the Reliability Need, the proposed regulated solution will be removed from the list of potential regulated solutions.

31.3 Economic Planning Process[1]

31.3.1 Congestion Assessment and Resource Integration Study for Economic Planning

31.3.1.1 General

The ISO shall prepare and publish the CARIS as described below. Each CARIS shall (1) develop a ten-year projection of congestion and shall identify, rank, and group the most congested elements on the New York bulk power system based on historic and projected congestion; and (2) include three studies, selected pursuant to Section 31.3.1.2.2, of the potential impacts of generic solutions to mitigate the identified congestion.

The CARIS process shall determine whether to approve an Interregional Transmission Project, identified and evaluated under the "Analysis and Consideration of Interregional Transmission Projects" section of the Interregional Planning Protocol, if any, and proposed in the NYISO's economic planning process, as an economic transmission project in lieu of a proposed regional economic transmission project for regulated cost allocation and recovery under the ISO Tariff.

The CARIS will align with the reliability planning process.

31.3.1.2 Interested Party Participation in the Development of the CARIS

31.3.1.2.1 The ISO shall develop the CARIS in consultation with Market Participants and all other interested parties. The TPAS will have responsibilities consistent with ISO Procedures for review of the ISO's technical analyses. ESPWG will have responsibilities consistent with ISO Procedures for providing commercial input and assumptions to be used in the development of the congestion assessment and the congestion assessment scenarios provided for under Section 31.3.1.5, and in the reporting and analysis of congestion costs. Coordination and communication will be established and maintained between these two groups and ISO staff to allow Market Participants and other interested parties to participate in a meaningful way during each stage of the economic planning process. The ISO staff shall report any majority and minority views of these collaborative governance work groups when it submits the CARIS to the Business Issues Committee for a vote, as provided below.

31.3.1.2.2 The ISO, in conjunction with ESPWG, will develop criteria for the selection and grouping of the three congestion and resource integration studies that comprise each CARIS, as well as for setting the associated timelines for completion of the selected studies. Study selection criteria may include congestion estimates, and shall include a process to prioritize the three studies that comprise each CARIS. Criteria shall also include a process to set the cut off date for inputs into and completion of each CARIS study cycle.

31.3.1.2.3 The ISO, in conjunction with ESPWG, will develop a process by which interested parties can request and fund other congestion and resource integration studies, in addition to those included in each CARIS. These individual congestion and resource integration studies are in addition to those studies that a customer can request related to firm point-to-point transmission service pursuant to Section 3.7 of the ISO OATT, or studies that a customer can request related to Network Integration Transmission Service pursuant to Section 4.5 of the ISO OATT, or studies related to interconnection requests under Attachment X or Attachment Z of the ISO OATT.

31.3.1.2.4 The ISO shall post all requests for congestion and resource integration studies on its website.

31.3.1.3 Preparation of the CARIS

31.3.1.3.1 The Study Period for the CARIS shall be the same ten-year Study Period covered by the most recently approved CRP.

31.3.1.3.2 The CARIS will assume a reliable system throughout the Study Period, based first upon the solutions identified in the most recently completed viability and sufficiency analysis performed pursuant to 31.2.5.7, as part of the CRP process, and reported to stakeholders and the NYDPS for comment. The baseline system for the CARIS shall first incorporate sufficient viable market-based solutions to meet the identified Reliability Needs as well as any regulated backstop solutions triggered by an ISO request pursuant to Section 31.2.8 of this Attachment Y. The ISO, in conjunction with the ESPWG, will develop methodologies to scale back market-based solutions to the minimum needed to meet the identified Reliability Needs, if more have been proposed than are necessary to meet the identified Reliability Needs. Regulated backstop solutions that have been proposed but not triggered pursuant to Section 31.2.8 shall also be used if there are insufficient market-based solutions for the ten-year Study Period. Multiple market-based solutions, as well as regulated solutions to Reliability Needs, may be included in the scenario assessments described in Section 31.3.1.5.

31.3.1.3.3 In conducting the CARIS, the ISO shall combine the component studies selected and assess system congestion and resource integration over the Study Period, measuring congestion by the metrics discussed in Appendix A to this

Attachment Y. The ISO, in conjunction with the ESPWG, will develop the specific production costing model to be used in the CARIS. All resource types shall be considered on a comparable basis as potential solutions to the congestion identified: generation, transmission, demand response, and energy efficiency. The CARIS may include consideration of the economic impacts of advancing a regulated back stop solution contained in the CRP.

31.3.1.3.4 In conducting the CARIS, the ISO shall conduct benefit/cost analysis of each potential solution to the congestion identified, applying benefit/cost metrics that are described in this Section 31.3.1.3. The principal benefit metric for the CARIS analysis will be expressed as the present value of the NYCA-wide production cost reduction that would result from each potential solution. The present value of the NYCA-wide production cost reduction will be determined in accordance with the following formula:

Present Value in year 1 = Sum of the Present Values from each of the 10 years of the Study Period.

The discount rate to be used for the present value analysis shall be the current after-tax weighted average cost of capital for the Transmission Owners.

31.3.1.3.5 Additional benefit metrics shall include estimates of reductions in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs, and TCC payments. The ISO will work with the ESPWG to determine the most useful metrics for each CARIS cycle, given overall ISO resource requirements. The additional metrics will estimate the benefits of the potential generic solutions in mitigating the congestion identified for information purposes only. All the quantities, except ICAP, will be the result of the forward looking production cost simulation. The additional benefit metrics will be determined by measuring the difference between the CARIS base case system value and a system value when the potential generic solution is added. All four resource types will be considered as potential generic solutions to the congestion identified, such as generation, transmission, and/or demand response. The value of the additional metrics will be expressed in present value by using the following formula:

Present Value in year 1 = Sum of the Present Values from each of the 10 years of the Study Period.

The discount rate to be used for the present value analysis shall be the current after-tax weighted average cost of capital for the Transmission Owners. The definitions of the LBMP load cost metric, generator payments metric, reduction in losses metric, Ancillary Services costs metric, and TCC payment metric are set forth below.

31.3.1.3.5.1 LBMP load costs measure the change in total load payments and unhedged load payments. Total load payments will include the LBMP payments (energy, congestion and losses) paid by electricity demand (forecasted load, exports, and wheeling). Exports will be consistent with the input assumptions for each neighboring control area. Unhedged load payments will represent total load payments minus the TCC payments.

31.3.1.3.5.2 Reductions in losses measure the change in marginal losses payments. Losses payments will be based upon the loss component of the zonal LBMP load payments.

31.3.1.3.5.3 Generator payments measure the change in generation payments. Generation payments will include the LBMP payments (energy, congestion, losses), and Ancillary Services payments made to electricity suppliers. Ancillary Services costs will include payments for Regulation Services and Operating Reserves, including 10 Minute Synchronous, 10 Minute Non-synchronous and 30 Minute Non-synchronous. Generator payments will be the sum of the LBMP payments and Ancillary Services payments to generators and imports. Imports will be consistent with the input assumptions for each neighboring Control Area.

31.3.1.3.5.4 The TCC payment metric set forth below will be used for purposes of the study phase of the CARIS process, and will not be used for regulated economic transmission project cost allocation under Section 31.5.4.4 of this Attachment Y. The TCC payment metric will measure the change in total congestion rents collected in the day-ahead market. These congestion rents shall be calculated as the product of the Congestion Component of the Day-Ahead LBMP in each Load Zone or Proxy Generator Bus and the withdrawals scheduled in each hour at that Load Zone or Proxy Generator Bus, minus the product of the Congestion Component of the Day-Ahead LBMP at each Generator Bus or Proxy Generator Bus and the injections scheduled in each hour at that Generator bus or Proxy Generator Bus, summed over all locations and hours.

31.3.1.3.5.5 The emission metric will measure the change in CO_2, NOx, and SO_2, emissions in tons on a zonal basis as well as the change in emission cost by emission type. Emission costs will be reflected in the development of the production cost curve.

31.3.1.3.5.6 The calculation of the ICAP cost metric will be determined as set forth below. The ICAP cost metric will be highly dependent on the rules and procedures guiding the calculation of the IRM, LCR, and the ICAP Demand Curves, both for the next capability period and future capability periods. In each CARIS cycle, the ISO will review, with the ESPWG and, as appropriate, other ISO committees, the results of the ICAP cost metric.

31.3.1.3.5.6.1 The ICAP metric, in the form of a megawatt impact, will be computed for both generic and actual economic project proposals based on a methodology that: (1) determines the base system LOLE for the applicable horizon year; (2) adds the proposed project; and (3) calculates the LOLE for the system with the addition of the proposed project. If the system LOLE is lower than that of the base system, the ISO will reduce generation in all NYCA zones proportionally (*i.e.*, based on proportion of zonal capacity to total NYCA capacity) until the base system LOLE is achieved. That amount of reduced generation is the NYCA megawatt impact.

31.3.1.3.5.6.2 The ISO will calculate both of the following ICAP cost metrics described in subsections (1) and (2) below by first determining the megawatt impact described above in Section 31.3.1.3.5.6.1 and then:

(1) For Rest of State, the ISO will measure the cost impact of a proposed generic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in Rest of State under the assumption that the proposed generic project is not in place, with that forecast based on the latest available ICAP Demand Curve for the NYCA and the amount of Installed Capacity available in the NYCA, as shown in the NYISO Load and Capacity Data Report developed for

that year; and (ii) multiplying that forecasted cost per megawatt-year for Rest of State in that year by the sum of the megawatt impact for all Load Zones contained within Rest of State, as calculated in accordance with subsection (A) of this Section 31.3.1.3.5.4.

For each Locality, the ISO will measure the cost impact of a proposed generic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in that Locality under the assumption that the proposed generic project is not in place, with that forecast based on the latest available ICAP Demand Curve for that Locality and the amount of Installed Capacity available in that Locality as shown in the relevant NYISO Load and Capacity Data Report developed for that year, and (ii) multiplying that forecasted cost per megawatt-year for that Locality in each year by the sum of the megawatt impact for all Load Zones contained within that Locality, as calculated in accordance with subsection (A) of this Section 31.3.1.3.5.4.

This ICAP cost metric will then be presented for each applicable planning year as a stream of present value benefits for each Locality and for Rest of State. The applicable planning years start with the proposed commercial operation date of the proposed generic project and end ten years after the proposed commercial operation date of the proposed generic project.

(2) For Rest of State, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in Rest of State under the assumption that the proposed generic project is in place, with that forecast based on the latest available ICAP Demand

Curve for the NYCA and the amount of Installed Capacity available in the NYCA; (ii) subtracting that forecasted cost per megawatt-year from the forecasted cost per megawatt-year of Installed Capacity in Rest of State calculated in subsection (1) under the assumption that the proposed generic project is not in place; and (iii) multiplying that difference by fifty percent (50%) of the assumed amount of Installed Capacity available in Rest of State as calculated from the relevant NYISO Load and Capacity Data Report developed for the CARIS process.

For each Locality, the ISO will measure the cost impact of a proposed generic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in that Locality under the assumption that the proposed generic project is in place, with that forecast based on the latest available ICAP Demand Curve for that Locality and the amount of Installed Capacity available in that Locality as shown in the relevant NYISO Load and Capacity Data Report developed for that year; (ii) subtracting the greater of that forecasted cost per megawatt-year with the proposed generic project in place or the forecasted Rest of State Installed Capacity cost per megawatt-year with the proposed generic project in place from the forecasted cost of Installed Capacity in that Locality calculated in subsection (1) under the assumption that the proposed generic project is not in place; and (iii) multiplying that difference by fifty percent (50%) of assumed amount of Installed Capacity available in that Locality, as taken from the relevant Load and Capacity tables developed for the CARIS process.

This ICAP cost metric will then be represented for each applicable planning year as a stream of present value benefits for each Locality and for Rest of State. The applicable planning years start with the proposed commercial operation date of the proposed generic project and end with the earlier of: (i) the year when the system, with the proposed generic project in place, reaches an LOLE of 0.1, or (ii) ten years after the proposed commercial operation date of the proposed generic project.

(3) The forecast of Installed Capacity costs per megawatt-year are developed by: first, escalating the Net Cost of New Entry ("CONE") for the NYCA or a Locality from the most recently completed ICAP Demand Curves for each year of the planning period; second, determining the future proxy Locational Minimum Installed Capacity Requirement or Minimum Installed Capacity Requirement for the NYCA as the actual amount of Installed Capacity in the Locality or the NYCA for the year that NYCA reaches 0.1 LOLE; third, reducing the cost per megawatt-year in each year from the escalated Net CONE to reflect the excess Installed Capacity from the NYISO Load and Capacity Data Report above the future proxy Minimum Installed Capacity Requirement with the adjustment calculated from the excess and the slope of the ICAP Demand Curve.

The forecasts of Installed Capacity costs for Localities or Rest of State performed in subsections (1) and (2) above shall, in addition to the assumptions listed above, be based upon: (i) the forecasted Net CONE for the Locality (the NYCA in the case of the Rest of State forecast); (ii) the amount of Installed Capacity required to meet the future proxy Locational Minimum Installed Capacity Requirement (the Minimum Installed Capacity Requirement for the NYCA in the case of the Rest of State forecast); (iii) the slope of the relevant ICAP Demand Curve, and (iv) the smallest quantity where the cost of Installed Capacity on that ICAP Demand Curve reaches zero.

31.3.1.3.6 As referenced in Section 31.2.1.3, the ISO, using engineering judgment, will determine whether a regional alternative transmission solution might more efficiently or more cost effectively address congestion on the BPTFs identified in the CARIS that impacts more than one Transmission District than any local transmission solutions identified by the Transmission Owners in their LTPs in the event the LTPs specify that such transmission solutions are included to address congestion for economic reasons.

31.3.1.4 Planning Participant Data Input

At the ISO's request, Market Participants, Developers, and other parties shall provide, in accordance with the schedule set forth in the ISO Procedures, the data necessary for the development of the CARIS. This input will include but not be limited to existing and planned additions and modifications to the New York State Transmission System (to be provided by Transmission Owners and municipal electric utilities); proposals for merchant transmission facilities (to be provided by merchant Developers); generation additions and retirements (to be provided by generator owners and Developers); demand response programs (to be provided by demand response providers); and any long-term firm transmission requests made to the ISO. The relevant Transmission Owners will assist the ISO in developing the potential solution cost estimates to be used by the ISO to conduct benefit/cost analysis of each of the potential solutions.

31.3.1.5 Congestion and Resource Integration Scenario Development

The ISO, in consultation with the ESPWG, shall develop congestion and resource integration scenarios addressing the Study Period. Variables for consideration in the development of these congestion and resource integration scenarios include but are not limited to: load forecast uncertainty, fuel price uncertainty, new resources, retirements, emission data, the cost of allowances and potential requirements imposed by proposed environmental and energy efficiency mandates, as well as overall ISO resource requirements. The ISO shall report the results of these scenario analyses in the CARIS.

31.3.1.6 Consequences for Other Regions

The ISO will coordinate with the ISO/RTO Regions to identify the consequences of an economic transmission project on such neighboring ISO/RTO Regions using the respective planning criteria of such ISO/RTO Regions. The ISO shall report the results in the CARIS. The ISO shall not bear the costs of required upgrades in another region.

31.3.1.7 CARIS Report Preparation

Once all the analyses described above have been completed, ISO staff will prepare a draft of the CARIS including a discussion of its assumptions, inputs, methodology, and the results of its analyses.

31.3.2 CARIS Review Process and Actual Project Proposals[17]

31.3.2.1 Collaborative Governance Process

The draft CARIS shall be submitted to both TPAS and the ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to

[17] This OATT subsection 31.3.2 is subject to revision per Order on Rehearing and Compliance, 148 FERC ¶ 61,044 (July 17, 2014).

replicate the results of the draft CARIS. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of that review, the draft CARIS reflecting the revisions resulting from the TPAS and ESPWG review shall be forwarded to the Business Issues Committee and the Management Committee for discussion and action.

31.3.2.2 Board Action

Following the Management Committee vote, the draft CARIS, with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CARIS will be provided to the Market Monitoring Unit for its review and consideration. The Board may approve the CARIS as submitted, or propose modifications on its own motion. If any changes are proposed by the Board, the revised CARIS shall be returned to the Management Committee for comment. The Board shall not make a final determination on a revised CARIS until it has reviewed the Management Committee comments. Upon approval by the Board, the ISO shall issue the CARIS to the marketplace by posting it on its website.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Attachment Y to the ISO OATT are also addressed in Section 30.4.6.8.4 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

31.3.2.3 Public Information Sessions

In order to provide ample exposure for the market place to understand the content of the CARIS, the ISO will provide various opportunities for Market Participants and other potentially interested parties to discuss final CARIS. Such opportunities may include presentations at various ISO Market Participant committees, focused discussions with various industry sectors, and /or presentations in public venues.

31.3.2.4 Actual Project Proposals

As discussed in Section 31.3.1 of this Attachment Y, the CARIS analyzes system congestion over the Study Period and, for informational purposes, provides benefit/cost analysis and other analysis of potential generic solutions to the congestion identified. If, in response to the CARIS, a Developer proposes an actual project, including an Interregional Transmission Project, to address specific congestion identified in the CARIS, then the ISO will: (I) process that project proposal in accordance with the relevant provisions of Sections 31.5.1, 31.5.4 and 31.5.6 of this Attachment Y, and (ii) for Interregional Transmission Projects, jointly evaluate the project proposal with the relevant adjacent transmission planning region(s) in accordance with Section 7.3 of the Interregional Planning Protocol.

31.3.2.4.1 Eligibility and Qualification Criteria for Developers and Projects

For purposes of fulfilling the requirements of the Developer qualification criteria in this Section 31.3.2.4.1. and its subsections, the term "Developer" includes Affiliates, as that term is defined in Section 2 of the ISO Services Tariff and Section 1 of the ISO OATT. To the extent that a Developer relies on Affiliate(s) to satisfy any or all of the qualification criteria set forth in Section 31.3.2.4.1.1.1, the Affiliate(s) shall provide to the ISO: (i) the information required in Section 31.3.2.4.1.1.1 to demonstrate its capability to satisfy the applicable qualification criteria, and (ii) a notarized officer's certificate, signed by an authorized officer of the Affiliate with signatory authority, in a form acceptable to the ISO, certifying that the Affiliate will participate in the Developer's project in the manner described by the Developer and will abide by the requirements set forth in this Attachment Y, the ISO Tariffs, and ISO Procedures related and applicable to the Affiliate's participation.

31.3.2.4.1.1 Developer Qualification and Timing

The ISO shall provide each Developer with an opportunity to demonstrate that it has or can draw upon the financial resources, technical expertise, and experience needed to finance, develop, construct, operate and maintain a transmission project proposed to address specific congestion identified in the CARIS. The ISO shall consider the qualifications of each Developer in an even-handed and non-discriminatory manner, treating Transmission Owners and Other Developers alike.

31.3.2.4.1.1.1 Developer Qualification Criteria

The ISO shall make a determination on the qualification of a Developer to propose to develop a transmission project as a solution to address specific congestion identified in the CARIS based on the following criteria:

31.3.2.4.1.1.1.1 The technical and engineering qualifications and experience of the Developer relevant to the development, construction, operation and maintenance of a transmission facility, including evidence of the Developer's demonstrated capability to adhere to standardized construction, maintenance, and operating practices and to contract with third parties to develop, construct, maintain, and/or operate transmission facilities;

31.3.2.4.1.1.1.2 The current and expected capabilities of the Developer to, develop and construct a transmission facility and to operate and maintain it for the life of the facility. If the Developer has previously developed, constructed, maintained or operated transmission facilities, the Developer shall provide the ISO a description of the transmission facilities (not to exceed ten) that the Developer has previously developed, constructed, maintained or operated and the status of those facilities, including whether the construction was completed, whether the facility entered into commercial operations, whether the facility has been suspended or terminated for any reason, and evidence demonstrating the ability of the Developer to address and timely remedy any operational failure of the facilities; and

31.3.2.4.1.1.1.3 The Developer's current and expected capability to finance, or its experience in arranging financing for, transmission facilities. For purposes of the ISO's determination, the Developer shall provide the ISO:

(1) evidence of its demonstrated experience financing or arranging financing for transmission facilities, if any including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financial structure of such projects, a description of any financing obtained for these projects through rates approved by the Commission or a state regulatory agency, the financing closing date of such projects, and whether any of the projects are in default;

(2) its audited annual financial statements from the most recent three years and its most recent quarterly financial statement or equivalent information;

(3) its credit rating from Moody's Investor Services, Standard & Poor's, or Fitch or equivalent information, if available;

(4) a description of any prior bankruptcy declarations, material defaults, dissolution, merger or acquisition by the Developer or its predecessors or subsidiaries occurring within the previous five years; and

(5) such other evidence that demonstrates its current and expected capability to finance a project to address specific congestion identified in the CARIS.

31.3.2.4.1.1.1.4 A detailed plan describing how the Developer – in the absence of previous experience financing, developing, constructing, operating, or maintaining transmission facilities – will finance, develop, construct, operate, and maintain a transmission facility, including the financial, technical, and engineering qualifications and experience and capabilities of any third parties with which it will contract for these purposes.

31.3.2.4.1.1.2 Developer Qualification Determination

Any Developer seeking to become qualified may submit the required information, or update any previously submitted information, at any time. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any non-public financial qualification information that is submitted to the ISO by the Developer under Section 31.3.2.4.1.1.1.3 and is designated by the Developer as "Confidential Information." The ISO shall within 15 days of a Developer's submittal, notify the Developer if the information is incomplete. If the submittal is deemed incomplete, the Developer shall submit the additional information within 30 days of the ISO's request. The ISO shall notify the Developer of its qualification status within 30 days of receiving all necessary information. A Developer shall retain its qualification status for a three-year period following the notification date; *provided, however*, that the ISO may revoke this status if it determines that there has been a material change in the Developer's qualifications and the Developer no longer meets the qualification requirements. A Developer that has been qualified shall inform the ISO within thirty days of any material change to the information it provided regarding its qualifications and shall submit to the ISO each year its most recent audited annual financial statement when available. At the conclusion of the three-year period or following the ISO's revocation of a Developer's qualification status, the Developer may re-apply for a qualification status under this section.

Any Developer determined by the ISO to be qualified under this section shall be eligible to propose a regulated transmission project as a solution to address specific congestion identified in the CARIS and shall be eligible to use the cost allocation and cost recovery mechanism for regulated transmission projects set forth in Section 31.5 of this Attachment Y and Rate Schedule 10 of the ISO OATT for any approved project.

31.3.2.4.1.2 Information Requirements for Projects

The ISO shall consider the criteria in Section 31.3.2.4.2 when determining whether a proposed project is eligible to be offered as a regulated economic transmission project.

31.3.2.4.1.3 Timing for Submittal of Project Information and Entity Qualification Information and Opportunity to Provide Additional Information

The required project information may be submitted at any time, but the proposed regulated economic transmission project will be evaluated against the most recently available CARIS Phase II database. Any Developer that the ISO has determined under Section 31.3.2.4.1.1.2 to be qualified to propose to develop a transmission project to address specific congestion identified in the CARIS may submit the required project information; *provided, however*, that based on the specific congestion identified that requires a solution, the ISO may request that the qualified Developer provide additional Developer information. Any Developer that the ISO has not determined to be qualified, but that wants to propose to develop a project, must submit to the ISO the information required for Developer qualification under Section

31.3.2.4.1.1. The ISO shall within 30 days of a Developer's submittal of its Developer qualification information, notify the Developer if this information is incomplete. The Developer shall submit additional Developer or project information required by the ISO within 15 days of the ISO's request. A Developer that fails to submit the additional Developer qualification information or the required project information will not be eligible for its project to be considered in that planning cycle.

31.3.2.4.2 Project Information Requirements

Any Developer seeking to offer a regulated economic transmission project as a solution to address specific congestion identified in the CARIS must provide, at a minimum, the following details: (1) contact information; (2) the lead time necessary to complete the project including, if available, the construction windows in which the Developer can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) a schedule for obtaining any required permits and other certifications; (7) a demonstration of Site Control or a schedule for obtaining such control; (8) status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place, including any contracts with third-party contractors; (9) status of ISO interconnection studies and interconnection agreement; (10) status of equipment availability and procurement; (11) evidence of financing or ability to finance the project; (12) detailed capital cost estimates for each segment of the project; (13) a description of permitting or other risks facing the project at the stage of project development, including evidence of the reasonableness of project cost estimates, all based on the information available at the time of the submission; and (14) any other information requested by the ISO.

A Developer shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Developer as "Confidential Information."

A Developer shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

A Developer shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) evidence of self-financing or project financing through approved rates or the ability to do so, (ii) copies of all loan commitment letter(s) and signed financing contract(s), or (iii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts or approved rates shall be submitted to the ISO when available.

Failure to provide any data requested by the ISO within the timeframe provided in Section 31.3.2.4.1.3 of this Attachment Y will result in the rejection of the proposed solution from further consideration during that planning cycle.

31.3.2.5 Posting of Approved Solutions

The ISO shall post on its website a list of all Developers who have undertaken a commitment to build a project that has been approved by project beneficiaries, in accordance with Section 31.5.4.6 of this Attachment Y.

[1]This OATT Section 31.3 is subject to revision per Order on Rehearing and Compliance, 148 FERC ¶ 61,044 (July 17, 2014). Subsequent footnotes identify specific subsections that the NYISO currently anticipates will be revised in its compliance filing. Please be advised that in revising its tariffs in accordance with FERC's directives, the NYISO may be required to revise additional subsections that are not designated by footnotes.

31.4 Public Policy Transmission Planning Process

31.4.1 General

The Public Policy Transmission Planning Process shall consist of three steps: (1) identification of Public Policy Transmission Needs; (2) requests for proposed Public Policy Transmission Projects and Other Public Policy Projects to address those Public Policy Transmission Needs and the evaluation of those projects; and (3) selection of the more efficient or cost-effective Public Policy Transmission Project, if any, to satisfy each Public Policy Transmission Need to be eligible for cost allocation under the ISO OATT. Sections 31.4.2.1 through 31.4.2.3 provide for the identification of transmission needs driven by Public Policy Requirements and warranting evaluation by the ISO. The ISO shall request and evaluate proposed Public Policy Transmission Projects and Other Public Policy Projects to address such needs. The ISO shall select the more efficient or cost-effective Public Policy Transmission Project, if any, to satisfy each need. The Public Policy Transmission Planning Process will be conducted on a two-year cycle, unless requested by the NYPSC to be conducted out of that cycle. If the Public Policy Transmission Planning Process cannot be completed in the two-year cycle, the ISO will notify stakeholders and provide an estimated completion date and an explanation of the reasons the additional time is required. The NYPSC's issuance of a written statement pursuant to Section 31.4.2.1 below will occur after the draft RNA study results are posted.

31.4.2 Identification and Posting of Proposed Transmission Needs Driven by Public Policy Requirements

At the start of each cycle for the Public Policy Transmission Planning Process, the ISO will provide a 60-day period, which time period may be extended by the ISO pursuant to Section

31.1.8.7, to allow any stakeholders or interested parties to submit to the ISO, or for the ISO on its own initiative to identify, any proposed transmission need(s) that it believes are being driven by Public Policy Requirement(s) and for which transmission solutions should be requested and evaluated. Each submittal will identify the Public Policy Requirement(s) that the party believes is driving the need for transmission, propose criteria for the evaluation of transmission solutions to that need, and describe how the construction of transmission will fulfill the Public Policy Requirement(s).

For submittals to identify transmission needs pursuant to Section 31.4.2.1, the ISO will post all submittals on its website after the end of the needs solicitation period, and will submit to the NYPSC all submittals proposed by stakeholders, other interested parties, and any additional transmission needs and criteria identified by the ISO. For submittals to identify transmission needs that require a physical modification to transmission facilities in the Long Island Transmission District pursuant to Section 31.4.2.3, the ISO will post all submittals on its website after the end of the needs solicitation period, and will provide to the NYPSC and the Long Island Power Authority all submittals proposed by stakeholders, other interested parties, and any additional transmission needs and criteria identified by the ISO.

31.4.2.1 Identification and Determination of Transmission Needs Driven by Public Policy Requirements

The NYPSC will review all proposed transmission need(s) and, with input from the ISO and interested parties, identify the transmission needs, if any, for which specific transmission solutions should be requested and evaluated. The NYPSC will maintain procedures to govern the process by which it will review proposed transmission need(s), which procedures shall: ensure that such process is open and transparent, provide the ISO and interested parties a meaningful opportunity to participate in such process, provide input regarding the NYPSC's considerations, and result in the development of a written determination as required by law, inclusive of the input provided by the ISO and interested parties. In addition, the NYPSC may, on its own, identify a transmission need driven by a Public Policy Requirement. Any such transmission need identified by the NYPSC on its own shall be described by the NYPSC in accordance with the requirements for stakeholder submittals set forth in Section 31.4.2, and shall be identified and posted to the ISO's website prior to NYPSC's issuance of the required written statement discussed below in this Section 31.4.2.1 so as to provide the ISO and interested parties an opportunity to provide input to the NYPSC relating thereto.

The ISO shall assist the NYPSC in its analyses as requested. The NYPSC may also request that the ISO, pursuant to Section 3.8.1 of the ISO OATT, conduct an evaluation of alternative options to address the transmission needs.

The NYPSC shall issue a written statement that identifies the relevant Public Policy Requirements driving transmission needs and explains why it has identified the Public Policy Transmission Needs for which transmission solutions will be requested by the ISO. The statement shall also explain why transmission solutions to other suggested transmission needs should not be requested. The NYPSC's statement may also provide: (i) additional criteria for the evaluation of transmission solutions and non-transmission projects, (ii) the required timeframe, if any, for completion of the proposed solution, and (iii) the type of analyses that it will request from the ISO.

If the NYPSC does not identify any transmission needs driven by Public Policy Requirements, it will provide confirmation of that conclusion to the ISO, and the ISO shall not request solutions. The ISO shall post the NYPSC's statement on the ISO's website.

31.4.2.2 Disputes of NYPSC Determinations

In the event that a dispute is raised solely within the NYPSC's jurisdiction relating to any NYPSC decision to either accept or deny a proposed transmission need as one for which transmission solutions should be requested, the dispute shall be addressed through judicial review in the courts of the State of New York pursuant to Article 78 of the New York Civil Practice Law and Rules.

31.4.2.3 Identification and Determination of Transmission Needs Within the Long Island Transmission District Driven by Public Policy Requirements

The Long Island Power Authority, pursuant to its jurisdiction under Title 1-A of Article 5 (§1020 et seq.) of the Public Authorities Law of the State of New York, shall identify and determine whether a Public Policy Requirement drives the need for a physical modification to transmission facilities in the Long Island Transmission District. The identification and determination of such transmission needs shall be consistent with Section 31.4.2.1, as further supplemented by this Section 31.4.2.3. The Long Island Power Authority shall have no authority to identify a transmission need outside of the Long Island Transmission District.

Based on the information provided by the ISO pursuant to Section 31.4.2, the Long Island Power Authority shall review whether a proposed Public Policy Requirement drives the need for a physical modification to transmission facilities in the Long Island Transmission District. In addition, the following requirements shall apply to the Long Island Power Authority:

(i) The Long Island Power Authority shall consult with the NYDPS on the identification of transmission needs driven by a Public Policy Requirement solely within the Long Island Transmission District;

(ii) Upon completion of its review, the Long Island Power Authority shall issue a written statement explaining whether a Public Policy Requirement does or does not drive the need for a physical modification to transmission facilities solely within the Long Island Transmission District, and describing the consultation undertaken with the NYDPS;

(iii) In conjunction with the issuance of its written statement, the Long Island Power Authority shall transmit to the NYPSC and request that it review and determine whether a transmission need solely within the Long Island Transmission District identified by the Long Island Power Authority as being driven by a Public Policy Requirement should be considered a Public Policy Transmission Need for purposes of the evaluation of solutions by the ISO and the potential eligibility of transmission solutions for selection and regional cost allocation under the ISO OATT. Any transmission need within the Long Island Transmission District that has been identified by the Long Island Power Authority, but which the NYPSC has not determined to be a Public Policy Transmission Need that would be evaluated by the ISO, shall be addressed under the Long Island Power Authority's Local Transmission Plan.

(iv) The determination of whether there is a transmission need solely within the Long Island Transmission District is the sole responsibility of the Long Island Power Authority;

(v) The NYDPS and Long Island Power Authority shall consult and coordinate on procedures to be adopted by the NYPSC and Long Island Power Authority to ensure that their respective determinations under this Section 31.4.2.3, including any NYPSC determination that there is a Public Policy Transmission Need within the Long Island Transmission District for which solutions should be evaluated by the ISO, are completed, publicly posted and transmitted to the ISO at the same time as the NYPSC makes its final determinations pursuant to Section 31.4.2.1; and

(vi) In the event that a dispute is raised solely within the Long Island Power Authority's jurisdiction relating to a decision by the Long Island Power Authority to either accept or deny a proposed transmission need solely within the Long Island Transmission District, the dispute shall be addressed through judicial review in the courts of the State of New York pursuant to Article 78 of the New York Civil Practice Law and Rules.

31.4.3 Request for Proposed Solutions

The ISO will request proposed Public Policy Transmission Projects, including Interregional Transmission Projects, to satisfy each Public Policy Transmission Need identified pursuant to Sections 31.4.2.1 through 31.4.2.3. An Interregional Transmission Project shall be: (i) evaluated in accordance with the applicable requirements of the Public Policy Transmission Planning Process of this Attachment Y, and (ii) jointly evaluated by the ISO and the relevant adjacent transmission planning region(s) in accordance with Section 7.3 of the Interregional Planning Protocol. The ISO shall also accept specific proposed Other Public Policy Projects to satisfy a Public Policy Transmission Need identified pursuant to Sections 31.4.2.1 through 31.4.2.3.

31.4.3.1 Timing of ISO Request for Proposed Solutions

Following posting of a determination pursuant to Sections 31.4.2.1 through 31.4.2.3, the ISO will provide a 60-day period, which time period may be extended by the ISO pursuant to Section 31.1.8.7, for Developers to propose specific solutions, whether Public Policy

Transmission Project(s) or Other Public Policy Project(s), to satisfy each identified Public Policy Transmission Need in accordance with the requirements set forth in Section 31.4.4.3. Any proposed transmission needs that are under appeal pursuant to Section 31.4.2.2 or Section 31.4.2.3(vi) may be addressed with proposed solutions, if required, except where the NYPSC order has been stayed pending the resolution of that appeal.

31.4.3.2 NYPSC and LIPA Requests for Solutions

To ensure that there will be a response to a Public Policy Transmission Need, the NYPSC may request the appropriate Transmission Owner(s) or Other Developer, as identified by the NYPSC, to propose a Public Policy Transmission Project. With respect to a transmission need identified by the Long Island Power Authority and determined to be a Public Policy Transmission Need by the NYPSC pursuant to Section 31.4.2.3, the Long Island Power Authority's Board of Trustees may request that an appropriate Transmission Owner(s) or Other Developer propose a Public Policy Transmission Project or Other Public Policy Project. A request for the provision of a Public Policy Transmission Project or Other Public Policy Project by either the NYPSC or the Long Island Power Authority's Board of Trustees, pursuant to this section, is supplementary to, and not to the exclusion of, the submission of proposed projects pursuant to Section 31.4.3.1. Costs incurred by a Transmission Owner or Other Developer in preparing a proposed transmission solution in response to a request under this Section 31.4.3.2 will be recoverable under Section 31.5.6 and Rate Schedule 10 of the ISO OATT. The ISO shall allocate these costs among Load Serving Entities in accordance with Section 31.5.5.4.3, except as otherwise determined by the Commission.

31.4.4 Eligibility and Qualification Criteria for Developers and Projects

For purposes of fulfilling the requirements of the Developer qualification criteria in this Section 31.4.4 and its subsections, the term "Developer" includes Affiliates, as that term is defined in Section 2 of the ISO Services Tariff and Section 1 of the ISO OATT. To the extent that a Developer relies on Affiliate(s) to satisfy any or all of the qualification criteria set forth in Section 31.4.4.1.1, the Affiliate(s) shall provide to the ISO: (i) the information required in Section 31.4.4.1.1 to demonstrate its capability to satisfy the applicable qualification criteria and (ii) a notarized officer's certificate, signed by an authorized officer of the Affiliate with signatory authority, in a form acceptable to the ISO, certifying that the Affiliate will participate in the Developer's project in the manner described by the Developer and will abide by the requirements set forth in this Attachment Y, the ISO Tariffs, and ISO Procedures, related and applicable to the Affiliate's participation.

31.4.4.1 Developer Qualification and Timing

The ISO shall provide each Developer with an opportunity to demonstrate that it has or can draw upon the financial resources, technical expertise, and experience needed to finance, develop, construct, operate, and maintain a Public Policy Transmission Project. The ISO shall consider the qualification of each Developer in an evenhanded and non-discriminatory manner, treating Transmission Owners and Other Developers alike.

31.4.4.1.1 Developer Qualification Criteria

The ISO shall make a determination on the qualification of a Developer to propose to develop a Public Policy Transmission Project based on the following criteria:

31.4.4.1.1.1 The technical and engineering qualifications and experience of the Developer relevant to the development, construction, operation and maintenance of a transmission facility, including evidence of the Developer's demonstrated capability to adhere to standardized construction, maintenance, and operating practices and to contract with third parties to develop, construct, maintain, and/or operate transmission facilities;

31.4.4.1.1.2 The current and expected capabilities of the Developer to develop and construct a transmission facility and to operate and maintain it for the life of the facility. If the Developer has previously developed, constructed, maintained or operated transmission facilities, the Developer shall provide the ISO a description of the transmission facilities (not to exceed ten) that the Developer has previously developed, constructed, maintained or operated and the status of those facilities, including whether the construction was completed, whether the facility entered into commercial operations, whether the facility has been suspended or terminated for any reason, and evidence demonstrating the ability of the Developer to address and timely remedy any operational failure of the facilities; and

31.4.4.1.1.3 The Developer's current and expected capability to finance, or its experience in arranging financing for, transmission facilities. For purposes of the ISO's determination, the Developer shall provide the ISO:

(1) evidence of its demonstrated experience financing or arranging financing for transmission facilities, if any, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financial structure of such projects, a description of any financing obtained for these projects through rates approved by the Commission or a state regulatory agency, the financing closing date of such projects, and whether any of the projects are in default;

(2) its audited annual financial statements from the most recent three years and its most recent quarterly financial statement or equivalent information, if available;

(3) its credit rating from Moody's Investor Services, Standard & Poor's, or Fitch or equivalent information, if available;

(4) a description of any prior bankruptcy declarations, material defaults, dissolution, merger or acquisition by the Developer or its predecessors or subsidiaries occurring within the previous five years; and

(5) such other evidence that demonstrates its current and expected capability to finance a project to solve a Public Policy Transmission Need.

31.4.4.1.1.4 A detailed plan describing how the Developer – in the absence of previous experience financing, developing, constructing, operating, or maintaining transmission facilities – will finance, develop, construct, operate, and maintain a transmission facility, including the financial, technical, and engineering qualifications and experience and capabilities of any third parties with which it will contract for these purposes.

31.4.4.1.2 Developer Qualification Determination

Any Developer seeking to be qualified may submit the required information, or update any previously submitted information, at any time. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any non-public financial qualification information that is submitted to the ISO by the Developer under Section 31.4.4.1.1.3 and is designated by the Developer as "Confidential Information." The ISO shall within 15 days of a Developer's submittal, notify the Developer if the information is incomplete. If the submittal is deemed incomplete, the Developer shall submit the additional information within 30 days of the ISO's request. The ISO shall notify the Developer of its qualification status within 30 days of receiving all necessary information. A Developer shall retain its qualification status for a three-year period following the notification date; *provided, however*, that the ISO may revoke this status if it determines that there has been a material change in the Developer's qualifications and the Developer no longer meets the qualification requirements. A Developer that has been qualified shall inform the ISO within thirty days of any material change to the information it provided regarding its qualifications and shall submit to the ISO each year its most recent audited annual financial statement when available. At the conclusion of the three-year period or following the ISO's revocation of a Developer's qualification status, the Developer may re-apply for a qualification status under this section.

Any Developer determined by the ISO to be qualified under this section shall be eligible to propose a regulated Public Policy Transmission Project and shall be eligible to use the cost allocation and cost recovery mechanism for regulated Public Policy Transmission Projects set forth in Section 31.5 of this Attachment Y and the Rate Schedule 10 of the ISO OATT for any approved project.

31.4.4.3 Timing for Submittal of Project Information and Developer Qualification Information and Opportunity to Provide Additional Information

31.4.4.3.1 All Developers of Public Policy Transmission Projects or Other Public Policy Projects proposed to satisfy a Public Policy Transmission Need shall submit to the ISO within 60 days of the ISO's request for solutions to a Public Policy Transmission Need, which time period may be extended by the ISO pursuant to Section 31.1.8.7, the project information required under Section 31.4.5. If: (i) the ISO determines that a Developer's submission of its project information is incomplete, or (ii) the ISO determines at any time in the planning process that additional project information is required, the ISO shall request that the Developer provide additional project information within the timeframe set forth in Section 31.4.4.3.4. A Developer's failure to provide the data requested by the ISO within the timeframes provided in Sections 31.4.4.3.1 and 31.4.4.3.4 of this Attachment Y will result in the rejection of the Developer's proposed Public Policy Transmission Project or Other Public Policy Project from further consideration during that planning cycle.

31.4.4.3.2 Any Developer that the ISO has determined under Section 31.4.4.1.2 of this Attachment Y to be qualified to propose to develop a transmission project as a transmission solution to a Public Policy Transmission Need may submit the required project information for its proposed Public Policy Transmission Project; *provided, however,* that based on the actual identified need that requires resolution, the ISO may request that the qualified Developer provide additional Developer qualification information within the timeframe set forth in Section 31.4.4.3.4.

31.4.4.3.3 Any Developer that has not been determined by the ISO to be qualified, but that wants to propose to develop a Public Policy Transmission Project, must submit to the ISO the information required for Developer qualification under Section 31.4.4.1 within 30 days after a request for solutions is made by the ISO. The ISO shall within 30 days of a Developer's submittal of its Developer qualification information, notify the Developer if this information is incomplete and request that the Developer provide additional Developer qualification information within the timeframe set forth in Section 31.4.4.3.4. The ISO shall notify a Developer that has submitted the requested Developer qualification information whether it is qualified to propose to develop a Public Policy Transmission Project to be considered in that planning cycle.

31.4.4.3.4 The Developer shall submit additional Developer qualification information or project information required by the ISO within 15 days of the ISO's request.

31.4.4.3.5 If a Developer fails to timely submit the additional Developer qualification information requested by the ISO, the Developer will not be eligible for its proposed Public Policy Transmission Project to be considered in that planning cycle.

31.4.4.4. Application Fee and Study Deposit for Proposed Regulated Public Policy Transmission Project

Within sixty (60) days of the ISO's request for solutions to a Public Policy Transmission Need, which time period may be extended by the ISO pursuant to Section 31.1.8.7, all Developers that propose Public Policy Transmission Projects shall, at the same time that they provide project information pursuant to Section 31.4.4.3.1, (i) execute a study agreement with the ISO in the form set forth in Section 31.12 (Appendix I) of this Attachment Y for purposes of the ISO's evaluation of the proposed Public Policy Transmission Project under Sections 31.4.7, 31.4.8, 31.4.9, and 31.4.10, and (ii) submit to the ISO: (A) a non-refundable application fee of $10,000, and (B) a study deposit of $100,000, which shall be applied to study costs and subject to refund as described in this Section 31.4.4.4.

The ISO shall charge, and a Developer proposing a regulated Public Policy Transmission Project shall pay, the actual costs of the ISO's evaluation of the Developer's proposed Public Policy Transmission Project for purposes of the ISO's selection of the more efficient or cost effective Public Policy Transmission Project to satisfy a Public Policy Transmission Need for cost allocation purposes, including costs associated with the ISO's use of subcontractors. The ISO will track its staff and administrative costs, including any costs associated with using subcontractors, that it incurs in performing the evaluation of a Developer's proposed Public Policy Transmission Project under Sections 31.4.7, 31.4.8, 31.4.9, and 31.4.10 and any supplemental evaluation or re-evaluation of the proposed Public Policy Transmission Project. If the ISO or its subcontractors perform study work for multiple proposed Public Policy Transmission Projects on a combined basis, the ISO will allocate the costs of the combined study work equally among the applicable Developers.

The ISO shall invoice the Developer monthly for study costs incurred by the ISO in evaluating the Developer's proposed Public Policy Transmission Projects as described above. Such invoice shall include a description and an accounting of the study costs incurred by the ISO and estimated subcontractor costs. The Developer shall pay the invoiced amount within thirty (30) calendar days of the ISO's issuance of the monthly invoice. The ISO shall continue to hold the full amount of the study deposit until settlement of the final monthly invoice; *provided, however,* if a Developer: (i) does not pay its monthly invoice within the timeframe described above, or (ii) does not pay a disputed amount into an independent escrow account as described below, the ISO may draw upon the study deposit to recover the owed amount. If the ISO must draw on the study deposit, the ISO shall provide notice to the Developer, and the Developer shall within thirty (30) calendar days of such notice make payments to the ISO to restore the full study deposit amount. If the Developer fails to make such payments, the ISO may halt its evaluation of the Developer's proposed Public Policy Transmission Project and may disqualify the Developer's proposed Public Policy Transmission Project from further consideration. After the conclusion of the ISO's evaluation of the Developer's proposed Public Policy Transmission Project or if the Developer: (i) withdraws its proposed Public Policy Transmission Project or (ii) fails to pay an invoiced amount and the ISO halts its evaluation of the proposed Public Policy Transmission Project, the ISO shall issue a final invoice and refund to the Developer any portion of the Developer's study deposit submitted to the ISO under this Section 31.4.4.4 that exceeds outstanding amounts that the ISO has incurred in evaluating that Developer's proposed Public Policy Transmission Project, including interest on the refunded amount calculated in accordance with Section 35.19a(a)(2) of FERC's regulations. The ISO shall refund the remaining portion within sixty (60) days of the ISO's receipt of all final invoices from its subcontractors and involved Transmission Owners.

In the event of a Developer's dispute over invoiced amounts, the Developer shall: (i) timely pay any undisputed amounts to the ISO, and (ii) pay into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Developer fails to meet these two requirements, then the ISO shall not be obligated to perform or continue to perform its evaluation of the Developer's proposed Public Policy Transmission Project. Disputes arising under this section shall be addressed through the Dispute Resolution Procedures set forth in Section 2.16 of the ISO OATT and Section 11 of the ISO Services Tariff. Within thirty (30) Calendar Days after resolution of the dispute, the Developer will pay the ISO any amounts due with interest calculated in accordance with Section 35.19a(a)(2) of FERC's regulations.

31.4.5 Project Information Requirements

31.4.5.1 Requirements for Public Policy Transmission Projects

31.4.5.1.1 A Developer proposing a Public Policy Transmission Project to satisfy a Public Policy Transmission Need must provide, at a minimum, the following details: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Developer can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) a schedule for obtaining any required permits and other certifications; (7) a demonstration of Site Control or a schedule for obtaining such control; (8) status of any contracts (other than an interconnection agreement) that are under negotiations or in place, including any contracts with third-party contractors; (9) status of ISO interconnection studies and interconnection agreement; (10) status of equipment availability and procurement; (11) evidence of financing or ability to finance the project; (12) capital cost estimates for the project; (13) a description of permitting or other risks facing the project at the stage of project development, including evidence of the reasonableness of project cost estimates all based on the information available at the time of the submission; and (14) any other information requested by the ISO.

31.4.5.1.2 A Developer shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Developer as "Confidential Information."

31.4.5.1.3 A Developer shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

31.4.5.1.4 A Developer shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) evidence of self-financing or project financing through approved rates or the ability to do so, (ii) copies of all loan commitment letter(s) and signed financing contract(s), or (iii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts or approved rates shall be submitted to the ISO when available.

31.4.5.2 Requirements for Other Public Policy Projects

31.4.5.2.1 A Developer proposing an Other Public Policy Project to satisfy a Public Policy Transmission Need must provide, at a minimum: (1) contact information; (2) the lead time necessary to complete the project, including, if available, the construction windows in which the Developer can perform construction and what, if any, outages may be required during these periods; (3) a description of the project, including type, size, and geographic and electrical location, as well as planning and engineering specifications and drawings as appropriate; (4) evidence of a commercially viable technology; (5) a major milestone schedule; (6) a schedule for obtaining any required permits and other certifications; (7) a demonstration of Site Control or a schedule for obtaining Site Control, as applicable; (8) the status of any contracts (other than an interconnection agreement) that are under negotiation or in place; (9) the status of ISO interconnection studies and interconnection agreement, as applicable; (10) the status of equipment availability and procurement, as applicable; (11) evidence of financing or ability to finance the project; and (12) any other information requested by the ISO.

31.4.5.2.2 A Developer shall submit the following information to indicate the status of any contracts: (i) copies of all final contracts the ISO determines are relevant to its consideration, or (ii) where one or more contracts are pending, a timeline on the status of discussions and negotiations with the relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available. The ISO shall treat on a confidential basis in accordance with the requirements of its Code of Conduct in Attachment F of the ISO OATT any contract that is submitted to the ISO and is designated by the Developer as "Confidential Information."

31.4.5.2.3 A Developer shall submit the following information to indicate the status of any required permits: (i) copies of all final permits received that the ISO determines are relevant to its consideration, or (ii) where one or more permits are pending, the completed permit application(s) with information on what additional actions must be taken to meet the permit requirements and a timeline providing the expected timing for finalization and receipt of the final permit(s). The final permits shall be submitted to the ISO when available.

31.4.5.2.4 A Developer shall submit the following information, as appropriate, to indicate evidence of financing by it or any Affiliate upon which it is relying for financing: (i) copies of all loan commitment letter(s) and signed financing contract(s), or (ii) where such financing is pending, the status of the application for any relevant financing, including a timeline providing the status of discussions and negotiations of relevant documents and when the negotiations are expected to be completed. The final contracts shall be submitted to the ISO when available.

31.4.6 ISO Evaluation of Proposed Solutions to Public Policy Transmission Needs

31.4.6.1 Evaluation Time Period

The ISO will study proposed Public Policy Transmission Projects and Other Public Policy Projects using: (i) the most recent base case from the reliability planning process, (ii) updates in accordance with ISO Procedures, and (iii) compensatory MWs as needed to resolve the Reliability Needs over the ten-year Study Period. The ISO will extend the most recent reliability and economic planning models for modeling solutions for Public Policy Transmission

Needs by up to an additional twenty years following the Study Period, as appropriate based upon the Public Policy Requirement and the identified Public Policy Transmission Need.

31.4.6.2 Comparable Evaluation of All Proposed Solutions

The ISO shall evaluate any proposed Public Policy Transmission Project or Other Public Policy Project submitted by a Developer to a Public Policy Transmission Need. The ISO will evaluate whether each proposed solution is viable pursuant to Section 31.4.6.3 below and is sufficient to satisfy the Public Policy Transmission Need pursuant to Section 31.4.6.4. The proposed solution may include multiple components and resource types. When evaluating proposed solutions to a Public Policy Transmission Need from any Developer, the ISO shall consider all resource types – including generation, transmission, demand response, or a combination of these resource types – on a comparable basis as potential solutions. All solutions will be evaluated in the same general time frame.

31.4.6.3 Evaluation of Viability of Proposed Solution

The ISO will determine the viability of a Public Policy Transmission Project or Other Public Policy Project – whether transmission, generation, demand response, or a combination of these resource types – proposed to satisfy a Public Policy Transmission Need. For purposes of its analysis, the ISO will consider: (i) the Developer qualification data provided pursuant to Section 31.4.4 and the project information data provided under Section 31.4.5; (ii) whether the proposed solution is technically practicable; (iii) the Developer's possession of, or approach for acquiring, any necessary rights-of-way, property, and facilities that will make the proposal reasonably feasible in the required timeframe; and (iv) whether the proposed solution can be completed in the required timeframe, if any. If the ISO determines that the proposed solution is not viable, the ISO shall reject the proposed solution from further consideration during that planning cycle.

31.4.6.4 Evaluation of Sufficiency of Proposed Solution

The ISO will perform a comparable analysis of each proposed Public Policy Transmission Project or Other Public Policy Project – whether transmission, generation, demand response, or a combination of these resource types – to confirm that the proposed solution satisfies the Public Policy Transmission Need. The ISO will evaluate each solution to measure the degree to which the proposed solution independently satisfies the Public Policy Transmission Need, including the evaluation criteria provided by the NYPSC. If the ISO determines that the proposed solution is not sufficient, the ISO shall reject the proposed solution from further consideration during that planning cycle.

31.4.6.5 Viability and Sufficiency Assessment

The ISO will present its Viability and Sufficiency Assessment to stakeholders, interested parties, and the NYPSC for comment. The ISO shall report in the Public Policy Transmission Planning Report the results of its evaluation under this Section 31.4.6 of whether each proposed Public Policy Transmission Project or Other Public Policy Project is viable and is sufficient to satisfy the identified Public Policy Transmission Need.

31.4.6.6 Developer's Determination to Proceed

Within 30 Calendar Days following the ISO's presentation of the Viability and Sufficiency Assessment pursuant to Section 31.4.6.5, which time period may be extended by the ISO pursuant to Section 31.1.8.7, all Developers of proposed Public Policy Transmission Projects that the ISO has determined satisfy the viability and sufficiency requirements in this

Section 31.4.6 shall notify the ISO whether they intend for their projects to proceed to be evaluated by the ISO for purposes of the ISO's selection of the more efficient or cost effective Public Policy Transmission Project to satisfy an identified Public Policy Transmission Need. To proceed, a Developer must include with its notification to the ISO under this Section 31.4.6.6 its consent to the ISO's disclosure of the details of its proposed Public Policy Transmission Project in the Public Policy Transmission Planning Report, except for the information that shall remain confidential in accordance with Section 31.4.15. If a Developer: (i) notifies the ISO that it does not intend for its proposed Public Policy Transmission Project to proceed to be evaluated for purposes of the ISO's selection, or (ii) does not provide the required notification to the ISO under this Section 31.4.6.6, the ISO will remove the project from further consideration during that planning cycle.

31.4.6.7 NYPSC Determination on Whether to Proceed with Evaluation of Transmission Solutions to a Public Policy Transmission Need

31.4.6.7.1 Following the ISO's presentation of the Viability and Sufficiency Assessment, the NYPSC will review the Viability and Sufficiency Assessment and will issue an order, subject to and in accordance with the State Administrative Procedure Act, explaining whether the ISO should continue to evaluate transmission solutions to a Public Policy Transmission Need or whether non-transmission solutions should be pursued. If the NYPSC concludes that non-transmission solutions should be pursued outside of the Public Policy Transmission Planning Process, the NYPSC will indicate in its order that either: (i) there is no longer a transmission need driven by a Public Policy Requirement that requires the ISO's evaluation of potential transmission solutions, or (ii) the transmission need should be modified.

31.4.6.7.2 If the NYPSC concludes that there is no longer a transmission need driven by a Public Policy Requirement in its order as set forth in Section 31.4.6.7.1, the ISO will not perform an evaluation, or make a selection of, a more efficient or cost-effective transmission solution under Sections 31.4.7 through 31.4.11 for the Public Policy Transmission Need initially identified by the NYPSC for that planning cycle pursuant to Section 31.4.2.1.

31.4.6.7.3 If the NYPSC modifies the transmission need driven by a Public Policy Requirement in its order as set forth in Section 31.4.6.7.1, the ISO will re-start its Public Policy Transmission Planning Process as an out-of-cycle process to evaluate Public Policy Transmission Projects to address the modified Public Policy Transmission Need. This out-of-cycle process will begin with the ISO's solicitation for Public Policy Transmission Projects to address the modified Public Policy Transmission Need in accordance with Sections 31.4.3 and 31.4.4.3. The ISO shall evaluate the viability and sufficiency of the proposed Public Policy Transmission Projects in accordance with Sections 31.4.6.3 and 31.4.6.4. Within 30 Calendar Days following the ISO's presentation of the Viability and Sufficiency Assessment for the out-of-cycle process, which time period may be extended by the ISO pursuant to Section 31.1.8.7, all Developers of proposed Public Policy Transmission Projects that the ISO has determined satisfy the viability and sufficiency requirements in this Section 31.4.6 shall notify the ISO whether they intend for their projects to proceed to be evaluated for purposes of selection in accordance with the requirements in Section 31.4.6.6. The ISO will then proceed to evaluate the viable and sufficient Public Policy Transmission

Projects that have elected to proceed in accordance with Sections 31.4.7 through 31.4.11 for purposes of selecting the more efficient or cost-effective transmission solution to the modified Public Policy Transmission Need. The requirements in Section 31.4.6.7.1 that the NYPSC review the Viability and Sufficiency Assessment and issue an order concerning the Public Policy Transmission Need do not apply in this out-of-cycle process.

31.4.7 Evaluation of Regional Public Policy Transmission Projects to Address Local and Regional Needs Driven by Public Policy Requirements More Efficiently or More Cost Effectively Than Local Transmission Solutions

The ISO will review the LTPs as they relate to the BPTFs. The ISO will include the results of its analysis in its Public Policy Transmission Planning Report, as approved by the ISO Board.

31.4.7.1 Evaluation of Regional Public Policy Transmission Projects to Address Local Needs Driven By Public Policy Requirements Identified in Local Transmission Plans More Efficiently or More Cost Effectively than Local Transmission Solutions

The ISO, using engineering judgment, will determine whether any proposed regional Public Policy Transmission Project on the BPTFs more efficiently or cost-effectively satisfies any needs driven by a Public Policy Requirement identified in the LTPs. If the ISO identifies that a regional Public Policy Transmission Project has the potential to more efficiently or cost effectively satisfy the needs driven by a Public Policy Requirement identified in the LTPs, it will perform a sensitivity analysis to determine whether the proposed regional Public Policy Transmission Project on the BPTFs would satisfy the needs driven by a Public Policy Requirement identified in the LTPs. If the ISO determines that the proposed regional Public Policy Transmission Project would satisfy the need, the ISO will evaluate the proposed regional

Public Policy Transmission Project using the metrics set forth in Section 31.4.8.1 below to determine whether it may be a more efficient or cost effective solution on the BPTFs to the needs driven by a Public Policy Requirement identified in the LTPs than the local solutions proposed in the LTPs.

31.4.7.2 Evaluation of Regional Public Policy Transmission Project to Address Regional Pubic Policy Transmission Needs More Efficiently or More Cost Effectively than Local Transmission Solutions

As referenced in Section 31.2.1.3, the ISO, using engineering judgment, will determine whether a regional Public Policy Transmission Project might more efficiently or more cost effectively satisfy an identified regional Public Policy Transmission Need on the BPTFs that impacts more than one Transmission District than any local transmission solutions identified by the Transmission Owners in their LTPs in the event the LTPs specify that such transmission solutions are included to address local transmission needs driven by Public Policy Requirements.

31.4.8 ISO Selection of More Efficient or Cost Effective Public Policy Transmission Project to Satisfy a Public Policy Transmission Need

A proposed regulated Public Policy Transmission Project submitted by a Developer that the ISO has determined has provided the required notification to proceed under Section 31.4.6.6 shall be eligible under this Section 31.4.8 for selection in the Public Policy Transmission Planning Report for the purpose of cost allocation under the ISO Tariffs. The ISO shall evaluate any proposed regulated Public Policy Transmission Projects that are eligible for selection in the planning cycle of the Public Policy Transmission Planning Process using the metrics set forth in Section 31.4.8.1 below. For purposes of this evaluation, the ISO will review the information submitted by the Developer and determine whether it is reasonable and how such information should be used for purposes of the ISO evaluating each metric. The ISO may engage an independent consultant to review the reasonableness and comprehensiveness of the information submitted by the Developer and may rely on the independent consultant's analysis in evaluating each metric. The ISO shall select in the Public Policy Transmission Planning Report for cost allocation purposes the more efficient or cost effective transmission solution to satisfy a Public Policy Transmission Need in the manner set forth in Section 31.4.8.2 below.

31.4.8.1 Metrics for Evaluating More Efficient or Cost Effective Regulated Public Policy Transmission Project to Satisfy Public Policy Transmission Need

In determining which of the eligible proposed regulated Public Policy Transmission Projects is the more efficient or cost effective solution to satisfy a Public Policy Transmission Need, the ISO will consider, and will consult with the NYDPS regarding, the metrics set forth below in this Section 31.4.8.1 and rank each proposed project based on the quality of its satisfaction of these metrics:

31.4.8.1.1 The capital cost estimates for the proposed regulated Public Policy Transmission Project, including the accuracy of the proposed estimates. For this evaluation, the Developer shall provide the ISO with credible capital cost estimates for its proposed project, with itemized supporting work sheets that identify all material and labor cost assumptions, and related drawings to the extent applicable and available. The work sheets should include an estimated quantification of cost variance, providing an assumed plus/minus range around the capital cost estimate.

The estimate shall include all components that are needed to meet the Public Policy Transmission Need. To the extent information is available, the Developer should itemize: material and labor cost by equipment, engineering and design work, permitting, site acquisition, procurement and construction work, and commissioning needed for the proposed project, all in accordance with Good Utility Practice. For each of these cost categories, the Developer should specify the nature and estimated cost of all major project components and estimate the cost of the work to be done at each substation and/or on each feeder to physically and electrically connect each facility to the existing system. The work sheets should itemize to the extent applicable and available all equipment for: (i) the proposed project, (ii) interconnection facilities (including Attachment Facilities and Direct Assignment Facilities), and (iii) System Upgrade Facilities, System Deliverability Upgrades, Network Upgrades, and Distribution Upgrades.

31.4.8.1.2 The cost per MW ratio of the proposed regulated Public Policy Transmission Project. For this evaluation, the ISO will first determine the present worth, in dollars, of the total capital cost of the proposed project in current year dollars. The ISO will then determine the cost per MW ratio by dividing the capital cost by the MW value of increased transfer capability.

31.4.8.1.3 The expandability of the proposed regulated Public Policy Transmission Project. The ISO will consider the impact of the proposed project on future construction. The ISO will also consider the extent to which any subsequent expansion will continue to use this proposed project within the context of system expansion.

31.4.8.1.4 The operability of the proposed regulated Public Policy Transmission Project. The ISO will consider how the proposed project may affect additional flexibility in operating the system, such as dispatch of generation, access to operating reserves, access to ancillary services, or ability to remove transmission for maintenance. The ISO will also consider how the proposed project may affect the cost of operating the system, such as how it may affect the need for operating generation out of merit for reliability needs, reducing the need to cycle generation, or providing more balance in the system to respond to system conditions that are more severe than design conditions.

31.4.8.1.5 The performance of the proposed regulated Public Policy Transmission Project. The ISO will consider how the proposed project may affect the utilization of the system (e.g. interface flows, percent loading of facilities).

31.4.8.1.6 The extent to which the Developer of a proposed regulated Public Policy Transmission Project has the property rights, or ability to obtain the property rights, required to implement the project. The ISO will consider whether the Developer: (i) already possesses the rights of way necessary to implement the project; (ii) has completed a transmission routing study, which (a) identifies a specific routing plan with alternatives, (b) includes a schedule indicating the timing for obtaining siting and permitting, and (c) provides specific attention to sensitive areas (e.g., wetlands, river crossings, protected areas, and schools); or (iii) has specified a plan or approach for determining routing and acquiring property rights.

31.4.8.1.7 The potential issues associated with delay in constructing the proposed regulated Public Policy Transmission Project consistent with the major milestone schedule and the schedule for obtaining any permits and other certifications as required to timely meet the need.

31.4.8.1.8 The ISO shall apply any criteria specified by the Public Policy Requirement or provided by the NYPSC and perform the analyses requested by the NYPSC, to the extent compliance with such criteria and analyses are feasible.

31.4.8.1.9 The ISO, in consultation with stakeholders, shall, as appropriate, consider other metrics in the context of the Public Policy Requirement, such as: change in production costs; LBMP; losses; emissions; ICAP; TCC; congestion; impact on transfer limits; and deliverability.

31.4.8.2 ISO Selection of More Efficient or Cost Effective Regulated Public Policy Transmission Project to Satisfy a Public Policy Transmission Need

The ISO shall identify under this Section 31.4.8 the proposed regulated Public Policy Transmission Project, if any, that is the more efficient or cost effective transmission solution proposed in the planning cycle for the Public Policy Transmission Planning Process to satisfy a Public Policy Transmission Need. The ISO shall include the more efficient or cost effective transmission solution in the Public Policy Transmission Planning Report. The Developer of a regulated Public Policy Transmission Project shall be eligible to recover costs for the project only if the project is selected by the ISO, except as otherwise provided in Section 31.4.3.2 or as otherwise determined by the Commission. Costs will be recovered when the project enters into service, is halted, or as otherwise determined by the Commission in accordance with the cost recovery requirements set forth in Section 31.5.6 of this Attachment Y and Rate Schedule 10 of the ISO OATT. Actual project cost recovery, including any issues related to cost recovery and project cost overruns, will be submitted to and decided by the Commission.

Any selection of a Public Policy Transmission Project by the ISO under Section 31.4.8, including but not limited to the selection of a project that involves the physical modification of facilities within the Long Island Transmission District, shall not affect the obligation and responsibility of the Developer to apply for, and receive, all necessary authorizations or permits required by federal or state law for such project.

31.4.9 Consequences for Other Regions

The ISO will coordinate with the ISO/RTO Regions to identify the consequences of a transmission solution driven by Public Policy Requirements on neighboring ISO/RTO Regions using the respective planning criteria of such ISO/RTO Regions. The ISO shall report the results in its Public Policy Transmission Planning Report. The ISO shall not bear the costs of required upgrades in another region.

31.4.10 Evaluation of Impact of Proposed Public Policy Transmission Project on ISO Wholesale Electricity Markets

The ISO shall evaluate using the metrics set forth in Section 31.4.8.1.9 the impacts on the ISO-administered wholesale electricity markets of a proposed Public Policy Transmission Project that the ISO has determined under Section 31.4.6 is viable and sufficient. The ISO shall include the results of its analysis in the Public Policy Transmission Planning Report.

31.4.11 Public Policy Transmission Planning Report

Following the ISO's evaluation of the proposed solutions to Public Policy Transmission Need(s), the ISO will prepare a draft Public Policy Transmission Planning Report that sets forth the ISO's assumptions, inputs, methodologies and the results of its analyses. The draft Public Policy Transmission Planning Report will reflect any input from the NYDPS.

Except as otherwise provided in the confidentiality requirements in Section 31.4.15, the ISO will include in the draft Public Policy Transmission Planning Report: (i) the list of Developers and their proposed Public Policy Transmission Projects and Other Public Policy Projects that qualify pursuant to Sections 31.4.4 and 31.4.5; (ii) the proposed Public Policy

Transmission Projects and Other Public Policy Projects that the ISO has determined under Section 31.4.6 are viable and sufficient to satisfy the identified Public Policy Transmission Need(s); and (iii) the regulated Public Policy Transmission Project, if any, that the ISO staff recommends for selection for cost allocation purposes pursuant to Section 31.4.8 as the more efficient or cost effective transmission solution to satisfy each identified Public Policy Transmission Need. The draft Public Policy Transmission Planning Report will also include the results of the ISO's analysis of the LTPs consistent with Section 31.4.7.

The draft Public Policy Transmission Planning Report shall include a comparison of a proposed Public Policy Transmission Project to an Interregional Transmission Project proposed in the Public Policy Transmission Planning Process, if any, identified and evaluated under the "Analysis and Consideration of Interregional Transmission Projects" section of the Interregional Planning Protocol. An Interregional Transmission Project proposed in the ISO's Public Policy Transmission Planning Process may be selected as a regulated Public Policy Transmission Project under the provisions of this process.

31.4.11.1 Collaborative Governance Process

The draft Public Policy Transmission Planning Report shall be submitted to both TPAS and the ESPWG for review and comment. Concurrently, the draft report will be provided to the Market Monitoring Unit for its review and consideration. The Market Monitoring Unit's evaluation will be provided to the Management Committee prior to the Management Committee's advisory vote. The ISO shall make available to any interested party sufficient information to replicate the results of the draft Public Policy Transmission Planning Report. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any

Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of that review, the draft report reflecting the revisions resulting from the TPAS and ESPWG review shall be forwarded to the Business Issues Committee and the Management Committee for discussion and an advisory vote.

31.4.11.2 Board Review, Consideration, and Approval of Public Policy Transmission Planning Report

Following the Management Committee vote, the draft Public Policy Transmission Planning Report, with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the Market Monitoring Unit's evaluation will be provided to the Board. The Board may approve the Public Policy Transmission Planning Report as submitted or propose modifications on its own motion, including a determination not to select a Public Policy Transmission Project to satisfy a Public Policy Transmission Need. If any changes are proposed by the Board, the revised report shall be returned to the Management Committee for comment. The Board shall not make a final determination on a revised report until it has reviewed the Management Committee comments, including comments regarding the Market Monitoring Unit's evaluation. Upon approval by the Board, the ISO shall issue the report to the marketplace by posting it on its website. If the ISO Board determines not to select a Public Policy Transmission Project under this Section 31.4.11.2, the Board shall state the reasons for its determination.

The responsibilities of the Market Monitoring Unit that are addressed in the above Section of Attachment Y to the ISO OATT are also addressed in Section 30.4.6.8.5 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

31.4.12 Developer's Responsibilities Following Selection of Its Public Policy Transmission Project

31.4.12.1 Developer's Responsibility to Obtain Necessary Approvals and Authorizations

Upon its selection of a Public Policy Transmission Project, the ISO will inform the Developer that it should submit the selected Public Policy Transmission Project to the appropriate governmental agency(ies) and/or authority(ies) to begin the necessary approval process to the site, construct, and operate the project. In response to the ISO's request, the Developer shall make such a submission to the appropriate governmental agency(ies) and/or authority(ies) to the extent such authorization has not already been requested or obtained.

If the appropriate federal, state or local agency(ies) either rejects a necessary authorization, or approves and later withdraws authorization, for the selected Public Policy Transmission Project, the Developer may recover all of the necessary and reasonable costs incurred and commitments made up to the final federal, state or local regulatory decision, including reasonable and necessary expenses incurred to implement an orderly termination of the project, to the extent permitted by the Commission in accordance with its regulations on abandoned plant recovery. The ISO shall allocate these costs among Load Serving Entities in accordance with Section 31.5.5.4.3, except as otherwise determined by the Commission. The ISO shall recover such costs in accordance with Section 31.5.6. of this Attachment Y and Rate Schedule 10 of the ISO OATT.

31.4.12.2 Development Agreement

As soon as reasonably practicable following the ISO's selection of the proposed project, the ISO shall tender to the Developer that proposed the selected Public Policy Transmission Project a draft Development Agreement with draft appendices completed by the ISO to the extent practicable for review and completion by the Developer. The draft Development Agreement shall be in the form of the ISO's Commission-approved Development Agreement, which is in Appendix D in Section 31.7 of this Attachment Y. The ISO and the Developer, as applicable, shall finalize the Development Agreement and appendices and negotiate concerning any disputed provisions. Unless otherwise agreed by the ISO and the Developer, the Developer must execute the Development Agreement within three (3) months of the ISO's tendering of the draft Development Agreement; *provided*, *however*, if, during the negotiation period, the Developer determines that negotiations are at an impasse, it may request in writing that the ISO file the Development Agreement in unexecuted form with the Commission. If the Development Agreement resulting from the negotiation between the ISO and the Developer does not conform with the Commission-approved standard form in Appendix D in Section 31.7 of this Attachment Y, the ISO shall file the agreement with the Commission for its acceptance within thirty (30) Business Days after the execution of the Development Agreement by both parties. If the Developer requests that the Development Agreement be filed unexecuted, the ISO shall file the agreement at the Commission within thirty (30) Business Days of receipt of the request from the Developer. The ISO will draft to the extent practicable the portions of the Development Agreement and appendices that are in dispute and will provide an explanation to the Commission of any matters as to which the parties disagree. The Developer will provide in a separate filing any comments that it has on the unexecuted agreement, including any alternative positions it may have with respect to the disputed provisions. Upon the ISO's and the Developer's execution of the Development Agreement or the ISO's filing of an unexecuted Development Agreement with the Commission, the ISO and the Developer shall perform their respective obligations in accordance with the terms of the Development Agreement that are not in dispute, subject to modification by the Commission.

31.4.12.3 Process for Addressing Inability of Developer to Complete Selected Public Policy Transmission Project

31.4.12.3.1 If one of the following events occur: (i) the Developer that proposed the selected Public Policy Transmission Project does not execute the Development Agreement, or does not request that it be filed unexecuted with the Commission, within the timeframes set forth in Section 31.4.12.2, or (ii) an effective Development Agreement is terminated under the terms of the agreement prior to the completion of the term of the agreement, the ISO may take the following actions as soon as practicable after the occurrence of the event:

31.4.12.3.1.1 If the Development Agreement has been filed with and accepted by the Commission, the ISO shall, upon terminating the Development Agreement under the terms of the agreement, file a notice of termination with the Commission.

31.4.12.4 Execution of ISO/TO Agreement or Comparable Agreement

The Developer of a selected Public Policy Transmission Project shall execute the ISO/TO Agreement or an agreement with the ISO under terms comparable to the ISO/TO Agreement prior to energizing the Public Policy Transmission Project.

31.4.13 ISO Monitoring of Selected Public Policy Transmission Projects

The ISO shall monitor Public Policy Transmission Projects selected by the ISO as the more efficient or cost effective transmission solutions to Public Policy Transmission Needs to confirm that they continue to develop consistent with the conditions, actions, or schedules for the projects.

31.4.14 Posting of Approved Solutions

The ISO shall post on its website a list of all Developers who have accepted the terms and conditions of an Article VII certificate under the New York Public Service Law, or any successor statute, or any other applicable permits to build a Public Policy Transmission Project in response to a need driven by a Public Policy Requirement.

31.4.15 Confidentiality of Solutions

31.4.15.1 The term "Confidential Information" shall include all proposed solutions to Public Policy Transmission Needs that are submitted to the ISO in response to a request for solutions under Section 31.4.3 of this Attachment Y if the Developer of that solution designates the solution as "Confidential Information"; *provided, however,* that "Confidential Information" shall not include: (i) the identity of the Developer, (ii) the proposed facility type, (iii) the proposed facility size, (iv) the proposed location of the facility, and (v) the proposed in-service date for the facility.

31.4.15.2 The ISO shall maintain the confidentiality of the Developer's proposed solution and plans designated as "Confidential Information" until the ISO determines that the Developer's proposed solution and plans are viable and sufficient to meet the Public Policy Transmission Need and the Developer provides its consent to the ISO's inclusion of the proposed solution in the Public Policy Transmission Planning Report under Section 31.4.6.6. Thereafter, the ISO shall disclose the proposed solution and plans to Market Participants and other interested parties; *provided, however,* any preliminary cost estimates that may have been provided to the ISO, any non-public financial qualification information provided under Section 31.4.4.1.2, and any contract provided under Sections 31.4.5.1.2 or 31.4.5.2.2 that is designated as "Confidential Information" shall not be disclosed.

31.5 Cost Allocation and Cost Recovery[1]

31.5.1 The Scope of Attachment Y Cost Allocation

31.5.1.1 Regulated Responses

The cost allocation principles and methodologies in this Attachment Y cover only regulated transmission solutions to Reliability Needs, regulated transmission responses to congestion identified in the CARIS, and regulated Public Policy Transmission Projects whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer. The cost allocation principles and methodology for : (i) regulated transmission solutions to Reliability Needs are contained in Sections 31.5.3.1 and 31.5.3.2 of this Attachment Y: (ii) regulated transmission responses to congestion identified in the CARIS are contained in Sections 31.5.4.1 and 31.5.4.2 of this Attachment Y : and (iii) Public Policy Transmission Projects are contained in Sections 31.5.5 and 31.5.6 of this Attachment Y.

31.5.1.2 Market-Based Responses

The cost allocation principles and methodologies in this Attachment Y do not apply to market-based solutions to Reliability Needs, to market-based responses to congestion identified in the CARIS, or to Other Public Policy Projects. The cost of a market-based project shall be the responsibility of the developer of that project.

31.5.1.3 Interconnection Cost Allocation

The cost allocation principles and methodologies in this Attachment Y do not apply to the interconnection costs of generation and merchant transmission projects. Interconnection costs are determined and allocated in accordance with Attachment S, Attachment X and Attachment Z of the ISO OATT. Cost related to the deliverability of a resource will be addressed under the ISO's deliverability procedures in Attachment S of the ISO OATT. Cost related to the deliverability of a resource will be addressed under the ISO's deliverability procedures in Attachment S of the ISO OATT.

31.5.1.4 Individual Transmission Service Requests

The cost allocation principles and methodologies in this Attachment Y do not apply to the cost of transmission expansion projects undertaken in connection with an individual request for Transmission Service. The cost of such a project is determined and allocated in accordance with Section 3.7 or Section 4.5 of the ISO OATT.

31.5.1.5 LTP Facilities

The cost allocation principles and methodologies in this Attachment Y do not apply to the cost of transmission projects included in LTPs or LTP updates. Each Transmission Owner will recover the cost of such transmission projects in accordance with its then existing rate recovery mechanisms.

31.5.1.6 Regulated Non-Transmission Projects

Costs related to regulated non-transmission projects will be recovered by Responsible Transmission Owners, Transmission Owners and Other Developers in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law. Nothing in this section shall affect the Commission's jurisdiction over the sale and transmission of electric energy subject to the jurisdiction of the Commission.

31.5.1.7 Eligibility for Cost Allocation and Cost Recovery

Any entity, whether a Responsible Transmission Owner, Other Developer, or Transmission Owner, shall be eligible for cost allocation and cost recovery as set forth in Section 31.5 of this Attachment Y and Rate Schedule 10 of the ISO OATT for any transmission project proposed to satisfy an identified Reliability Need, regulated economic transmission project , or Public Policy Transmission Project that is determined by the ISO to be eligible. Interregional Transmission Projects identified in accordance with the Interregional Planning Protocol, and that have been accepted in each region's planning process, shall be eligible for interregional cost allocation and cost recovery, as set forth in Section 31.5 of this Attachment Y and Rate Schedule 10 of the ISO OATT. The ISO's share of the cost of an Interregional Transmission Project selected pursuant to this Attachment Y to meet a Reliability Need, congestion identified in the CARIS, or a transmission need driven by a Public Policy Requirement shall be eligible for cost allocation consistent with the cost allocation methodology applicable to the type of regional transmission project that would be replaced through the construction of such Interregional Transmission Project under Sections 31.2, 31.3, or 31.4, as applicable.

31.5.2 Cost Allocation Principles Required Under Order No. 1000

31.5.2.1 In compliance with Commission Order No. 1000, the ISO shall implement the specific cost allocation methodology in Section 31.5.3.2, 31.5.4.4, and 31.5.5.4 in accordance with the following Regional Cost Allocation Principles ("Order No. 1000 Regional Cost Allocation Principles"):

Regional Cost Allocation Principle 1: The ISO shall allocate the cost of transmission facilities to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, the ISO's CSPP will consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.

Regional Cost Allocation Principle 2: The ISO shall not involuntarily allocate any of the costs of transmission facilities to those that receive no benefit from transmission facilities.

Regional Cost Allocation Principle 3: In the event that the ISO adopts a benefit to cost threshold in its CSPP to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, such benefit to cost threshold will not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. If the ISO chooses to adopt such a threshold in its CSPP it will not include a ratio of benefits to costs that exceeds 1.25 unless the ISO justifies and the Commission approves a higher ratio.

Regional Cost Allocation Principle 4: The ISO's allocation method for the cost of a transmission facility selected pursuant to the process in the CSPP shall allocate costs solely within the ISO's transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. Costs for an Interregional Transmission Project must be assigned only to regions in which the facility is physically located. Costs cannot be assigned involuntarily to another region. The ISO shall not bear the costs of required upgrades in another region.

Regional Cost Allocation Principle 5: The ISO's cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility shall be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility, as consistent with confidentiality requirements set forth in this Attachment Y and the ISO Code of Conduct in Attachment F of the OATT.

Regional Cost Allocation Principle 6: The ISO's CSPP provides a different cost allocation method for different types of transmission facilities in the regional transmission plan and each cost allocation method is set out clearly and explained in detail in this Section 31.5.

31.5.2.2 In compliance with Commission Order No. 1000, the ISO shall implement the specific cost allocation methodology in Section 31.5.7 of this Attachment Y in accordance with the following Interregional Cost Allocation Principles:

Interregional Cost Allocation Principle 1: The ISO shall allocate the cost of new Interregional Transmission Projects to each region in which an Interregional Transmission Project is located in a manner that is at least roughly commensurate with estimated benefits of the Interregional Transmission Project in each of the regions. In determining the beneficiaries of Interregional Transmission Projects, the ISO will consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.

Interregional Cost Allocation Principle 2: The ISO shall not involuntarily allocate any of the costs of an Interregional Transmission Project to a region that receives no benefit from an Interregional Transmission Project that is located in that region, either at present or in a likely future scenario.

Interregional Cost Allocation Principle 3: In the event that the ISO adopts a benefit-cost threshold ratio to determine whether an Interregional Transmission Project has sufficient net benefits to qualify for interregional cost allocation, this ratio shall not be so large as to exclude an Interregional Transmission Project with significant positive net benefits from cost allocation. If the ISO chooses to adopt such a threshold, they will not include a ratio of benefits to costs that exceeds 1.25 unless the Parties justify and the Commission approves a higher ratio.

Interregional Cost Allocation Principle 4: The ISO's allocation of costs for an Interregional Transmission Project shall be assigned only to regions in which the Interregional Transmission Project is located. The ISO shall not assign costs involuntarily to a region in which that Interregional Transmission Project is not located. The ISO shall, however, identify consequences for other regions, such as upgrades that may be required in a third region. The ISO's interregional cost allocation methodology includes provisions for allocating the costs of upgrades among the beneficiaries in the region in which the Interregional Transmission Project is located to the transmission providers in such region that agree to bear the costs associated with such upgrades.

Interregional Cost Allocation Principle 5: The ISO's cost allocation methodology and data requirements for determining benefits and identifying beneficiaries for an Interregional Transmission Project shall be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed Interregional Transmission Project, as consistent with the confidentiality requirements set forth in this Attachment Y and the ISO Code of Conduct in Attachment F of the OATT.

Interregional Cost Allocation Principle 6: Though Order No. 1000 allows the ISO to provide a different cost allocation methodology for different types of interregional transmission facilities, such as facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements, the ISO has chosen to adopt one interregional cost allocation methodology for all Interregional Transmission Planning Projects. The interregional cost allocation methodology is set out clearly and explained in detail in Section 31.5.7 of this Attachment Y. The share of the cost related to any Interregional Transmission Project assigned to the ISO shall be allocated as described in Section 31.5.1.7.

31.5.3 Regulated Responses to Reliability Needs[18]

31.5.3.1 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.3.2 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1. This methodology shall apply to cost allocation for a regulated transmission solution to an identified Reliability Need, including the ISO's share of the costs of an Interregional Transmission Project proposed as a regulated transmission solution to an identified Reliability Need allocated in accordance with Section 31.5.7 of this Attachment Y.

The specific cost allocation methodology in Section 31.5.3.2 incorporates the following elements:

31.5.3.1.1 The focus of the cost allocation methodology shall be on solutions to Reliability Needs.

31.5.3.1.2 Potential impacts unrelated to addressing the Reliability Needs shall not be considered for the purpose of cost allocation for regulated solutions.

[18] This OATT subsection 31.5.3 is subject to revision per Order on Rehearing and Compliance, 148 FERC ¶ 61,044 (July 17, 2014).

31.5.3.1.3 Primary beneficiaries shall initially be those Load Zones or Subzones identified as contributing to the reliability violation.

31.5.3.1.4 The cost allocation among primary beneficiaries shall be based upon their relative contribution to the need for the regulated solution.

31.5.3.1.5 The ISO will examine the development of specific cost allocation rules based on the nature of the reliability violation (*e.g.*, thermal overload, voltage, stability, resource adequacy and short circuit).

31.5.3.1.6 Cost allocation shall recognize the terms of prior agreements among the Transmission Owners, if applicable.

31.5.3.1.7 Consideration should be given to the use of a materiality threshold for cost allocation purposes.

31.5.3.1.8 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.5.3.1.9 Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

31.5.3.1.10 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.5.3.1.11 The methodology shall apply, to the extent possible, to Gap Solutions.

31.5.3.1.12 Cost allocation is independent of the actual triggered project(s), except when allocating cost responsibilities associated with meeting a Locational Minimum Installed Capacity Requirement ("LCR"), and is based on a separate process that results in NYCA meeting its LOLE requirement.

31.5.3.1.13 Cost allocation for a solution that meets the needs of a Target Year assumes that backstop solutions of prior years have been implemented.

31.5.3.1.14 Cost allocation will consider the most recent values for LCRs. LCRs must be met for the Target Year.

31.5.3.2 Cost Allocation Methodology

The cost allocation mechanism under this Section 31.5.3.2 sets forth the basis for allocating costs associated with a Responsible Transmission Owner's regulated backstop solution or an Other Developer's or Transmission Owner's alternative regulated transmission solution selected by the ISO as the more efficient or cost-effective transmission solution to an identified Reliability Need.

The formula is not applicable to that portion of a project beyond the size of the solution needed to provide the more efficient or cost effective solution appropriate to the Reliability Need identified in the RNA. Nor is the formula applicable to that portion of the cost of a regulated transmission reliability project that is, pursuant to Section 25.7.12 of Attachment S to the ISO OATT, paid for with funds previously committed by or collected from Developers for the installation of System Deliverability Upgrades required for the interconnection of generation or merchant transmission projects.

This Section 31.5.3.2 establishes the allocation of the costs related to resolving Reliability Needs resulting from resource adequacy, BPTF thermal transmission security, BPTF voltage security, dynamic stability, and short circuit issues. Costs will be allocated in accordance with the following hierarchy: (i) resource adequacy pursuant to Section 31.5.3.2.1, (ii) BPTF thermal transmission security pursuant to Section 31.5.3.2.2, (iii) BPTF voltage security pursuant to Section 31.5.3.2.3, (iv) dynamic stability pursuant to Section 31.5.3.2.4, and (v) short circuit pursuant to Section 31.5.3.2.5.

31.5.3.2.1 Resource Adequacy Reliability Solution Cost Allocation Formula

For purposes of solutions eligible for cost allocation under this Section 31.5.3.2, this section sets forth the cost allocation methodology applicable to that portion of the costs of the solution attributable to resolving resource adequacy. The same cost allocation formula is applied regardless of the project or sets of projects being triggered; however, the nature of the solution set may lead to some terms equaling zero, thereby dropping out of the equation. To ensure that appropriate allocation to the LCR and non-LCR zones occurs, the zonal allocation percentages are developed through a series of steps that first identify responsibility for LCR deficiencies, followed by responsibility for remaining need. The following formula shall apply to the allocation of the costs of the solution attributable to resource adequacy:

$$\text{Resource Adequacy } Cost\ Allocation_{i=} \left[\frac{LCRdef_i}{Soln\ Size} + \left(\frac{Concident\ Peak_i * (1 + IRM - LCR_i)}{\sum_{k=1}^{n} Coincident\ Peak_k * (1 + IRM - LCR_k)} * \frac{Soln\ STWdef}{Soln\ Size} \right) + \left(\frac{Concident\ Peak_i * (1 + IRM - LCR_i)}{\sum_{l=1}^{m} \text{Coincident Peak}_l * (1 + \text{IRM} - \text{LCR}_l)} * \frac{Soln\ CIdef}{\text{Soln Size}} \right) \right] *100\%$$

Where *i* is for each applicable zone, *n* represent the total zones in NYCA, *m* represents the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, $LCRdef_i$ is the applicable zonal LCR deficiency, SolnSTWdef is the STWdef for each applicable project, SolnCIdef is the CIdef for each applicable project, and Soln_Size represents the total compensatory MW addressed by each applicable project for all reliability cost allocation steps in this Section 31.5.3.2.

Three step cost allocation methodology for regulated reliability solutions:

31.5.3.2.1.1 Step 1 - LCR Deficiency

31.5.3.2.1.1.1 Any deficiencies in meeting the LCRs for the Target Year will be referred to as the LCRdef. If the reliability criterion is met once the LCR deficiencies have been addressed, that is LOLE ≤ 0.1 for the Target Year is achieved, then the only costs allocated will be those related to the LCRdef MW. Cost responsibility for the LCRdef MW will be borne by each deficient locational zone(s), to the extent each is individually deficient.

For a single solution that addresses only an LCR deficiency in the applicable LCR zone, the equation would reduce to:

$$Allocation_i = \frac{LCRdef_i}{Soln\_Size} * 100\%$$

Where *i* is for each applicable LCR zone, $LCRdef_i$ represents the applicable zonal LCR deficiency, and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.1.1.2 Prior to the LOLE calculation, voltage constrained interfaces will be recalculated to determine the resulting transfer limits when the LCRdef MW are added.

31.5.3.2.1.2 Step 2 - Statewide Resource Deficiency. If the reliability criterion is not met after the LCRdef has been addressed, that is an LOLE > 0.1, then a NYCA Free Flow Test will be conducted to determine if NYCA has sufficient resources to meet an LOLE of 0.1.

31.5.3.2.1.2.1 If NYCA is found to be resource limited, the ISO, using the transfer limits and resources determined in Step 1, will determine the optimal distribution of additional resources to achieve a reduction in the NYCA LOLE to 0.1.

31.5.3.2.1.2.2 Cost allocation for compensatory MW added for cost allocation purposes to achieve an LOLE of 0.1, defined as a Statewide MW deficiency (STWdef), will be prorated to all NYCA zones, based on the NYCA coincident peak load. The allocation to locational zones will take into account their locational requirements. For a single solution that addresses only a statewide deficiency, the equation would reduce to:

$$Allocation_i = \left[\frac{Concident\ Peak_i * (1 + IRM - LCR_i)}{\sum_{k=1}^{n} Coincident\ Peak_k * (1 + IRM - LCR_k)} * \frac{Soln\ STWdef}{Soln\ Size} \right] *100\%$$

Where *i* is for each applicable zone, *n* is for the total zones in NYCA, IRM is the statewide reserve margin, and LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, Soln STWdef is the STWdef for the applicable project, and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.1.3 Step 3 - Constrained Interface Deficiency. If the NYCA is not resource limited as determined by the NYCA Free Flow Test, then the ISO will examine constrained transmission interfaces, using the Binding Interface Test.

31.5.3.2.1.3.1 The ISO will provide output results of the reliability simulation program utilized for the RNA that indicate the hours that each interface is at limit in each flow direction, as well as the hours that coincide with a loss of load event. These values will be used as an initial indicator to determine the binding interfaces that are impacting LOLE within the NYCA.

31.5.3.2.1.3.2 The ISO will review the output of the reliability simulation program utilized for the RNA along with other applicable information that may be available to make the determination of the binding interfaces.

31.5.3.2.1.3.3 Bounded Regions are assigned cost responsibility for the compensatory MW, defined as CIdef, needed to reach an LOLE of 0.1.

31.5.3.2.1.3.4 If one or more Bounded Regions are isolated as a result of binding interfaces identified through the Binding Interface Test, the ISO will determine the optimal distribution of compensatory MW to achieve a NYCA LOLE of 0.1. Compensatory MW will be added until the required NYCA LOLE is achieved.

31.5.3.2.1.3.5 The Bounded Regions will be identified by the ISO's Binding Interface Test, which identifies the bounded interface limits that can be relieved and have the greatest impact on NYCA LOLE. The Bounded Region that will have the greatest benefit to NYCA LOLE will be the area to be first allocated costs in this step. The ISO will determine if after the first addition of compensating MWs the Bounded Region with the greatest impact on LOLE has changed. During this iterative process, the Binding Interface Test will look across the state to identify the appropriate Bounded Region. Specifically, the Binding Interface Test will be applied starting from the interface that has the greatest benefit to LOLE (the greatest LOLE reduction per interface compensatory MW addition), and then extended to subsequent interfaces until a NYCA LOLE of 0.1 is achieved.

31.5.3.2.1.3.6 The CIdef MW are allocated to the applicable Bounded Region isolated as a result of the constrained interface limits, based on their NYCA coincident peaks. Allocation to locational zones will take into account their locational requirements. For a single solution that addresses only a binding interface deficiency, the equation would reduce to:

$$Allocation_i = \left[\frac{Concident\ Peak_i * (1 + IRM - LCR_i)}{\sum_{l=1}^{m} Coincident\ Peak_l * (1 + IRM - LCR_l)} * \frac{SolnCIdef}{Soln\ Size} \right] *100\%$$

Where *i* is for each applicable zone, *m* is for the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, SolnCIdef is the CIdef for the applicable project and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.2 BPTF Thermal Transmission Security Cost Allocation Formula

For purposes of solutions eligible for cost allocation under this Section 31.5.3.2, this section sets forth the cost allocation methodology applicable to that portion of the costs of the solution attributable to resolving BPTF thermal transmission security issues. If, after consideration of the compensatory MW identified in the resource adequacy reliability solution cost allocation in accordance with Section 31.5.3.2.1, there remains a BPTF thermal transmission security issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the BPTF thermal transmission security issue(s) to the Subzones that contribute to the BPTF thermal transmission security issue(s) in the following manner.

31.5.3.2.2.1 Calculation of Nodal Distribution Factors. The ISO will calculate the nodal distribution factor for each load bus modeled in the power flow case utilizing the output of the reliability simulation program that identified the Reliability Need, including the NYCA generation dispatch and NYCA coincident peak Load. The nodal distribution factor represents the percentage of the Load that flows across the facility subject to the Reliability Need. The sign (positive or negative) of the nodal distribution factor represents the direction of flow.

31.5.3.2.2.2 Calculation of Nodal Flow. The ISO will calculate the nodal megawatt flow, defined as Nodal Flow, for each load bus modeled in the power flow case by multiplying the amount of Load in megawatts for the bus, defined as Nodal Load, by the nodal distribution factor for the bus. Nodal Flow represents the number of megawatts that flow across the facility subject to the Reliability Need due to the Load.

31.5.3.2.2.3 Calculation of Contributing Load and Contributing Flow. The Nodal Load for a load bus with a positive nodal distribution factor is a contributing Load, defined as CLoad, and the Nodal Flow for that Load is contributing flow, defined as CFlow. To identify contributing Loads that have a material impact on the Reliability Need, the ISO will calculate a contributing materiality threshold, defined as CMT, as follows:

$$CMT = \frac{\sum_{k=1}^{m}\sum_{Lk=1}^{n} CFlow_{Lk}}{\sum_{k=1}^{m}\sum_{Lk=1}^{n} CLoad_{Lk}}$$

Where *m* is for the total number of Subzones and *n* is for the total number of load buses in a given Subzone.

31.5.3.2.2.4 Calculation of Helping Load and Helping Flow. The Nodal Load for a load bus with a negative or zero nodal distribution factor is a helping Load, defined as HLoad, and the Nodal Flow for that Load is helping flow, defined as HFlow. To identify helping Loads that have a material impact on the Reliability Need, the ISO will calculate a helping materiality threshold, defined as HMT, as follows:

$$HMT = \frac{\sum_{k=1}^{m} \sum_{Lk=1}^{n} HFlow_{Lk}}{\sum_{k=1}^{m} \sum_{Lk=1}^{n} HLoad_{Lk}}$$

Where *m* is for the total number of Subzones and *n* is for the total number of load buses in a given Subzone.

31.5.3.2.2.5 Calculation of Net Material Flow for Each Subzone. The ISO will identify material Nodal Flow for each Subzone and calculate the net material flow for each Subzone. For each load bus, the Nodal Flow will be identified as material flow, defined as MFlow, if the nodal distribution factor is (i) greater than or equal to CMT, or (ii) less than or equal to HMT. The net material flow for each Subzone, defined as SZ_NetFlow, is calculated as follows:

$$SZ\_NetFlow_j = \sum_{Lj=1}^{n} MFlow_{Lj}$$

Where *j* is for each Subzone and *n* is for the total number of load buses in a given Subzone.

31.5.3.2.2.6 Identification of Allocated Flow for Each Subzone. The ISO will identify the allocated flow for each Subzone and verify that sufficient contributing flow is being allocated costs. For each Subzone, if the SZ_NetFlow is greater than zero, that Subzone has a net material contribution to the Reliability Need and the

SZ_NetFlow is identified as allocated flow, defined as SZ_AllocFlow. If the SZ_NetFlow is less than or equal to zero, that Subzone does not have a net material contribution to the Reliability Need and the SZ_AllocFlow is zero for that Subzone. If the total SZ_AllocFlow for all Subzones is less than 60% of the total CFlow for all Subzones, then the CMT will be reduced and SZ_NetFlow recalculated until the total SZ_AllocFlow for all Subzones is at least 60% of the total CFlow for all Subzones.

31.5.3.2.2.7 Cost Allocation for a Single BPTF Thermal Transmission Security Issue. For a single solution that addresses only a BPTF thermal transmission security issue, the equation for cost allocation would reduce to:

$$BPTF\ Thermal\ Cost\ Alloction_j = \frac{SZ\_AllocFlow_j}{\sum_{k=1}^{m} SZ\_AllocFlow_k} \times \frac{SolnBTSdef}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones; SZ_AllocFlow is the allocated flow for each Subzone; SolnBTSdef is the number of compensatory MW for the BPTF thermal transmission security issue for the applicable project; and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.2.8 Cost Allocation for Multiple BPTF Thermal Transmission Security Issues. If a single solution addresses multiple BPTF thermal transmission security issues, the ISO will calculate weighting factors based on the ratio of the present value of the estimated costs for individual solutions to each BPTF thermal transmission security issue. The present values of the estimated costs for the individual solutions shall be based on a common base date that will be the beginning of the calendar month in which the cost allocation analysis is performed (the “Base

Date"). The ISO will apply the weighting factors to the cost allocation calculated for each Subzone for each individual BPTF thermal transmission security issue. The following example illustrates the cost allocation for such a solution:

- A cost allocation analysis for the selected solution is to be performed during a given month establishing the beginning of that month as the Base Date.
- The ISO has identified two BPTF thermal transmission security issues, Overload X and Overload Y, and the ISO has selected a single solution (Project Z) to address both BPTF thermal transmission security issues.
- The cost of a solution to address only Overload X (Project X) is Cost(X), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is N(X).
- The cost of a solution to address only Overload Y (Project Y) is Cost(Y), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project Y is N(Y).
- The discount rate, D, to be used for the present value analysis shall be the current after-tax weighted average cost of capital for the Transmission Owners.
- Based on the foregoing assumptions, the following formulas will be used:
    - Present Value of Cost (X) = PV Cost (X) = Cost (X) / $(1+D)^{N(X)}$
    - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / $(1+D)^{N(Y)}$
    - Overload X weighting factor = PV Cost (X)/[PV Cost (X) + PV Cost (Y)]
    - Overload Y weighting factor = PV Cost (Y)/[PV Cost (X) + PV Cost (Y)]
- Applying those formulas, if:

    Cost (X) = $100 Million and N(X) = 6.25 years

Cost (Y) = $25 Million and N(Y) = 4.75 years

D = 7.5% per year

Then:

PV Cost (X) = $100/(1+0.075)^{6.25}$ = 63.635 Million

PV Cost (Y) = $25/(1+0.075)^{4.75}$ = 17.732 Million

Overload X weighting factor = 63.635 / (63.635 + 17.732) = 78.21%

Overload Y weighting factor = 17.732 / (63.635 + 17.732) = 21.79%

- Applying those weighing factors, if:

Subzone A cost allocation for Overload X is 15%

Subzone A cost allocation for Overload Y is 70%

Then:

Subzone A cost allocation % for Project Z =

(15% * 78.21%) + (70% * 21.79%) = 26.99%

31.5.3.2.2.9 Exclusion of Subzone(s) Based on De Minimis Impact. If a Subzone is assigned a BPTF thermal transmission security cost allocation less than a *de minimis* dollar threshold of the total project costs, that Subzone will not be allocated costs; *provided however,* that the total *de minimis* Subzones may not exceed 10% of the total BPTF thermal transmission security cost allocation. The *de minimis* threshold is initially $10,000. If the total allocation percentage of all *de minimis* Subzones is greater than 10%, then the *de minimis* threshold will be reduced until the total allocation percentage of all *de minimis* Subzones is less than or equal to 10%.

31.5.3.2.3 BPTF Voltage Security Cost Allocation

If, after consideration of the compensatory MW identified in the resource adequacy cost allocation in accordance with Section 31.5.3.2.1 and BPTF thermal transmission security cost allocation in accordance with Section 31.5.3.2.2, there remains a BPTF voltage security issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the BPTF voltage security issue(s) to the Subzones that contribute to the BPTF voltage security issue(s). The cost responsibility for the portion (MW or MVAr) of the solution attributable to resolving the BPTF voltage security issue(s), defined as SolnBVSdef, will be allocated on a Load-ratio share to each Subzone to which each bus with a voltage issue is connected, as follows:

$$BPTF\ Voltage\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{SolnBVSdef}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones that are subject to BPTF voltage cost allocation; Coincident Peak is for the total peak Load for each Subzone; SolnBVSdef is for the portion of the solution necessary to resolve the BPTF voltage security issue(s); and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.4 Dynamic Stability Cost Allocation

If, after consideration of the compensatory MW identified in the resource adequacy cost allocation in accordance with Section 31.5.3.2.1, BPTF thermal transmission security cost allocation in accordance with Section 31.5.3.2.2, and BPTF voltage security cost allocation in accordance with Section 31.5.3.2.3, there remains a dynamic stability issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the dynamic stability issue(s) to all Subzones in the NYCA on a Load-ratio share basis, as follows:

$$Dynamic\ Stability\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{DynamicMW}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones; Coincident Peak is for the total peak Load for each Subzone; DynamicMW is for the megawatt portion of the solution necessary to resolve the dynamic stability issue(s) for the applicable project; and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.5 Short Circuit Issues

If, after the completion of the prior reliability cost allocation steps, there remains a short circuit issue, the short circuit issue will be deemed a local issue and related costs will not be allocated under this process.

31.5.4 Regulated Economic Projects

31.5.4.1 The Scope of Section 31.5.4

As discussed in Section 31.5.1 of this Attachment Y, the cost allocation principles and methodologies of this Section 31.5.4 apply only to regulated economic transmission projects (“RETPs) proposed in response to congestion identified in the CARIS.

This Section 31.5.4 does not apply to generation or demand side management projects, nor does it apply to any market-based projects. This Section 31.5.4 does not apply to regulated backstop solutions triggered by the ISO pursuant to the CSPP, provided, however, the cost allocation principles and methodologies in this Section 31.5.4 will apply to regulated backstop solutions when the implementation of the regulated backstop solution is accelerated solely to reduce congestion in earlier years of the Study Period. The ISO will work with the ESPWG to develop procedures to deal with the acceleration of regulated backstop solutions for economic reasons.

Nothing in this Attachment Y mandates the implementation of any project in response to the congestion identified in the CARIS.

31.5.4.2 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.4.4 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1 The specific cost allocation methodology in Section 31.5.4.4 incorporates the following elements:

31.5.4.2.1 The focus of the cost allocation methodology shall be on responses to specific conditions identified in the CARIS.

31.5.4.2.2 Potential impacts unrelated to addressing the identified congestion shall not be considered for the purpose of cost allocation for RETPs.

31.5.4.2.3 Projects analyzed hereunder as proposed RETPs may proceed on a market basis with willing buyers and sellers at any time.

31.5.4.2.4 Cost allocation shall be based upon a beneficiaries pay approach. Cost allocation under the ISO tariff for a RETP shall be applicable only when a super majority of the beneficiaries of the project, as defined in Section 31.5.4.6 of this Attachment Y, vote to support the project.

31.5.4.2.5 Beneficiaries of a RETP shall be those entities economically benefiting from the proposed project. The cost allocation among beneficiaries shall be based upon their relative economic benefit.

31.5.4.2.6 Consideration shall be given to the proposed project's payback period.

31.5.4.2.7 The cost allocation methodology shall address the possibility of cost overruns.

31.5.4.2.8 Consideration shall be given to the use of a materiality threshold for cost allocation purposes.

31.5.4.2.9 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.5.4.2.10 Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

31.5.4.2.11 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.5.4.2.12 Benefits determination shall consider various perspectives, based upon the agreed-upon metrics for analyzing congestion.

31.5.4.2.13 Benefits determination shall account for future uncertainties as appropriate (e.g., load forecasts, fuel prices, environmental regulations).

31.5.4.2.14 Benefits determination shall consider non-quantifiable benefits as appropriate (*e.g.*, system operation, environmental effects, renewable integration).

31.5.4.3 Project Eligibility for Cost Allocation

The methodologies in this Section 31.5.4.3 will be used to determine the eligibility of a proposed RETP to have its cost allocated and recovered pursuant to the provisions of this Attachment Y.

31.5.4.3.1 The ISO will evaluate the benefits against the costs (as provided by the Developer) of each proposed RETP over a ten-year period commencing with the proposed commercial operation date for the project. The Developer of each project will pay the cost incurred by the ISO to conduct the ten-year benefit/cost analysis of its project. The ISO, in conjunction with the ESPWG, will develop methodologies for extending the most recently completed CARIS database as necessary to evaluate the benefits and costs of each proposed RETP.

31.5.4.3.2 The benefit metric for eligibility under the ISO's benefit/cost analysis will be expressed as the present value of the annual NYCA-wide production cost savings that would result from the implementation of the proposed project, measured for the first ten years from the proposed commercial operation date for the project.

31.5.4.3.3 The cost for the ISO's benefit/cost analysis will be supplied by the Developer of the project, and the cost metric for eligibility will be expressed as the present value of the first ten years of annual total revenue requirements for the project, reasonably allocated over the first ten years from the proposed commercial operation date for the project.

31.5.4.3.4 For informational purposes only, the ISO will also calculate the present value of the annual total revenue requirement for the project over a 30 year period commencing with the proposed commercial operation date of the project.

31.5.4.3.5 To be eligible for cost allocation and recovery under this Attachment Y, the benefit of the proposed project must exceed its cost measured over the first ten years from the proposed commercial operation date for the project, and the requirements of section 31.5.4.2 must be met. The total capital cost of the project must exceed $25 million. In addition, a super-majority of the beneficiaries must vote in favor of the project, as specified in Section 31.5.4.6 of this Attachment Y.

31.5.4.3.6 In addition to calculating the benefit metric as defined in Section 31.5.4.3.2, the ISO will calculate additional metrics to estimate the potential benefits of the proposed project, for information purposes only, in accordance with Section 31.3.1.3.5, for the applicable metric. These additional metrics shall include those that measure reductions in LBMP load costs, changes to generator payments, ICAP costs, Ancillary Service costs, emissions costs, and losses. TCC revenues will be determined in accordance with Section 31.5.4.4.2.3. The ISO will provide information on these additional metrics to the maximum extent practicable considering its overall resource commitments.

31.5.4.3.7 In addition to the benefit/cost analysis performed by the ISO under this Section 31.5.4.3, the ISO will work with the ESPWG to consider the development and implementation of scenario analyses, for information only, that shed additional light on the benefit/cost analysis of a proposed project. These additional scenario analyses may cover fuel and load forecast uncertainty, emissions data and the cost of allowances, pending environmental or other regulations, and alternate resource and energy efficiency scenarios. Consideration of these additional scenarios will take into account the resource commitments of the ISO.

31.5.4.4 Cost Allocation for Eligible Projects

As noted in Section 31.5.4.2 of this Attachment Y, the cost of a RETP will be allocated to those entities that would economically benefit from implementation of the proposed project. This methodology shall apply to cost allocation for a RETP, including the ISO’s share of the costs of an Interregional Transmission Project proposed as a RETP allocated in accordance with Section 31.5.7 of this Attachment Y.

31.5.4.4.1 The ISO will identify the beneficiaries of the proposed project over a ten-year time period commencing with the proposed commercial operation date for the project. The ISO, in conjunction with the ESPWG, will develop methodologies for extending the most recently completed CARIS database as necessary for this purpose.

31.5.4.4.2 The ISO will identify beneficiaries of a proposed project as follows:

31.5.4.4.2.1 The ISO will measure the present value of the annual zonal LBMP load savings for all Load Zones which would have a load savings, net of reductions in TCC revenues, and net of reductions from bilateral contracts (based on available information provided by Load Serving Entities to the ISO as set forth in subsection 31.5.4.4.2.5 below) as a result of the implementation of the proposed project. For purposes of this calculation, the present value of the load savings will be equal to the sum of the present value of the Load Zone's load savings for each year over the ten-year period commencing with the project's commercial operation date. The load savings for a Load Zone will be equal to the difference between the zonal LBMP load cost without the project and the LBMP load cost with the project, net of reductions in TCC revenues and net of reductions from bilateral contracts.

31.5.4.4.2.2 The beneficiaries will be those Load Zones that experience net benefits measured over the first ten years from the proposed commercial operation date for the project. If the sum of the zonal benefits for those Load Zones with load savings is greater than the revenue requirements for the project (both load savings and revenue requirements measured in present value over the first ten years from the commercial operation date of the project), the ISO will proceed with the development of the zonal cost allocation information to inform the beneficiary voting process.

31.5.4.4.2.3 Reductions in TCC revenues will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, not including the congestion rents that accrue to any Incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: (1) the total impact of that project on the Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); (2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and (3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item (1) above. These forecasts shall be performed using the procedure described in Appendix B to this Attachment Y.

31.5.4.4.2.4 Estimated TCC revenues from any Incremental TCCs created by a proposed RETP over the ten-year period commencing with the project's commercial operation date will be added to the Net Load Savings used for the cost allocation and beneficiary determination.

31.5.4.4.2.5 The ISO will solicit bilateral contract information from all Load Serving Entities, which will provide the ISO with bilateral energy contract data for modeling contracts that do not receive benefits, in whole or in part, from LBMP reductions, and for which the time period covered by the contract is within the ten-year period beginning with the commercial operation date of the project. Bilateral contract payment information that is not provided to the ISO will not be included in the calculation of the present value of the annual zonal LBMP savings in section 31.5.4.4.2.1 above.

31.5.4.4.2.5.1 All bilateral contract information submitted to the ISO must identify the source of the contract information, including citations to any public documents including but not limited to annual reports or regulatory filings

31.5.4.4.2.5.2 All non-public bilateral contract information will be protected in accordance with the ISO's Code of Conduct, as set forth in Section 12.4 of Attachment F of the ISO OATT, and Section 6 of the ISO Services Tariff.

31.5.4.4.2.5.3 All bilateral contract information and information on LSE-owned generation submitted to the ISO must include the following information:

(1) Contract quantities on an annual basis:

(a) For non-generator specific contracts, the Energy (in MWh) contracted to serve each Zone for each year.

(b) For generator specific contracts or LSE-owned generation, the name of the generator(s) and the MW or percentage output contracted or self-owned for use by Load in each Zone for each year.

(2) For all Load Serving Entities serving Load in more than one Load Zone, the quantity (in MWh or percentage) of bilateral contract Energy to be applied to each Zone, by year over the term of the contract.

(3) Start and end dates of the contract.

(4) Terms in sufficient detail to determine that either pricing is not indexed to LBMP, or, if pricing is indexed to LBMP, the manner in which prices are connected to LBMP.

(5) Identify any changes in the pricing methodology on an annual basis over the term of the contract.

31.5.4.4.2.5.4 Bilateral contract and LSE-owned generation information will be used to calculate the adjusted LBMP savings for each Load Zone as follows:

$AdjLBMPS_{y,z}$, the adjusted LBMP savings for each Load Zone *z* in each year *y*, shall be calculated using the following equation:

$$AdjLBMPS_{y,z} = max\left[0, TL_{\mathrm{y,z}} - \sum_{b \in B_{y,z}} \left(BCL_{\mathrm{b,y,z}} * \left(1 - Ind_{\mathrm{b,y,z}}\right)\right) - SG_{\mathrm{y,z}}\right] * \left(LBMP1_{\mathrm{y,z}} - LBMP2_{\mathrm{y,z}}\right)$$

Where:

$TL_{y,z}$ is the total annual amount of Energy forecasted to be consumed by Load in year *y* in Load Zone *z*;

$B_{y,z}$ is the set of blocks of Energy to serve Load in Load Zone *z* in year *y* that are sold under bilateral contracts for which information has been provided to the ISO that meets the requirements set forth elsewhere in this Section 31.5.4.4.2.5

$BCL_{b,y,z}$ is the total annual amount of Energy sold into Load Zone *z* in year *y* under bilateral contract block *b*;

$Ind_{b,y,z}$ is the ratio of (1) the increase in the amount paid by the purchaser of Energy, under bilateral contract block *b*, as a result of an increase in the LBMP in Load Zone *z* in year *y* to (2) the increase in the amount that a purchaser of that amount of Energy would pay if the purchaser paid the LBMP for that Load Zone in that year for all of that Energy (this ratio shall be zero for any bilateral contract block of Energy that is sold at a fixed price or for which the cost of Energy purchased under that contract otherwise insensitive to the LBMP in Load Zone *z* in year *y*);

$SG_{y,z}$ is the total annual amount of Energy in Load Zone *z* that is forecasted to be served by LSE-owned generation in that Zone in year *y*;

$LBMP1_{y,z}$ is the forecasted *annual load-weighted average LBMP* for Load Zone *z* in year *y*, calculated under the assumption that the project is not in place; and

$LBMP2_{y,z}$ is the forecasted annual load-weighted average LBMP for Load Zone *z* in year *y*, calculated under the assumption that the project is in place.

31.5.4.4.2.6 NZS_z, the Net Zonal Savings for each Load Zone *z* resulting from a given project, shall be calculated using the following equation:

$$NZS_z = max\left[0, \sum_{y=PS}^{PS+9}\left(\left(AdjLBMPS_{y,z} - TCCRevImpact_{y,z}\right) * DF_y\right)\right]$$

Where:

PS is the year in which the project is expected to enter commercial operation;

$AdjLBMPS_{y,z}$is as calculated in Section 31.5.4.4.2.5;

$TCCRevImpact_{y,z}$ is the forecasted impact of TCC revenues allocated to Load Zone *z* in year *y*, calculated using the procedure described in Appendix B in Section 31.7 of this Attachment Y; and

DF_y is the discount factor applied to cash flows in year *y* to determine the present value of that cash flow in year *PS*.

31.5.4.4.3 Load Zones not benefiting from a proposed RETP will not be allocated any of the costs of the project under this Attachment Y. There will be no "make whole" payments to non-beneficiaries.

31.5.4.4.4 Costs of a project will be allocated to beneficiaries as follows:

31.5.4.4.4.1 The ISO will allocate the cost of the RETP based on the zonal share of total savings to the Load Zones determined pursuant to Section 31.5.4.4.2 to be beneficiaries of the proposed project. Total savings will be equal to the sum of load savings for each Load Zone that experiences net benefits pursuant to Section 31.5.4.4.2. A Load Zone's cost allocation will be equal to the present value of the following calculation:

$$Zonal\ Cost\ Allocation = Project\ Cost * \left(\frac{(Zonal\ Benefits)}{Total\ Zonal\ Benefits\ for\ zone\ with\ positive\ net\ benefits}\right)$$

31.5.4.4.4.2 Zonal cost allocation calculations for a RETP will be performed prior to the commencement of the ten-year period that begins with the project's commercial operation date, and will not be adjusted during that ten-year period.

31.5.4.4.4.3 Within zones, costs will be allocated to LSEs based on MWhs calculated for each LSE for each zone using data from the most recent available 12 month period. Allocations to an LSE will be calculated in accordance with the following formula:

$$\text{LSE Intrazonal Cost Allocation} = \text{Zonal Cost Allocation} * \left(\frac{\text{LSE Zonal MWh}}{\text{Total Zonal MWh}}\right)$$

31.5.4.4.5 Project costs allocated under this Section 31.5.4.4 will be determined as follows:

31.5.4.4.5.1 The project cost allocated under this Section 31.5.4.4 will be based on the total project revenue requirement, as supplied by the Developer of the project, for the first ten years of project operation. The total project revenue requirement will be determined in accordance with the formula rate on file at the Commission. If there is no formula rate on file at the Commission, then the Developer shall provide to the ISO the project-specific parameters to be used to calculate the total project revenue requirement.

31.5.4.4.5.2 Once the benefit/cost analysis is completed the amortization period and the other parameters used to determine the costs that will be recovered for the project should not be changed, unless so ordered by the Commission or a court of applicable jurisdiction, for cost recovery purposes to maintain the continued validity of the benefit/cost analysis.

31.5.4.4.5.3 The ISO, in conjunction with the ESPWG, will develop procedures to allocate the risk of project cost increases that occur after the ISO completes its benefit/cost analysis under this Attachment Y. These procedures may include consideration of an additional review and vote prior to the start of construction and whether the developer should bear all or part of the cost of any overruns**.**

31.5.4.4.6 The Commission must approve the cost of a proposed RETP for that cost to be recovered through Rate Schedule 10 of the ISO OATT. The developer's filing of its project revenue requirement with the Commission pursuant to Rate Schedule 10 must be consistent with the project proposal evaluated by the ISO under this Attachment Y in order to be cost allocated to beneficiaries.

31.5.4.5 Collaborative Governance Process and Board Action

31.5.4.5.1 The ISO shall submit the results of its project benefit/cost analysis and beneficiary determination to the ESPWG and TPAS, and to the identified beneficiaries of the proposed RETP for comment. The ISO shall make available to any interested party sufficient information to replicate the results of the benefit/cost analysis and beneficiary determination. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of the review by the ESPWG and TPAS of the project benefit/cost analysis, the ISO's analysis reflecting any revisions resulting from the TPAS and ESPWG review shall be forwarded to the Business Issues Committee and Management Committee for discussion and action.

31.5.4.5.2 Following the Management Committee vote, the ISO's project benefit/cost analysis and beneficiary determination will be forwarded, with the input of the Business Issues Committee and Management Committee, to the ISO Board for review and action. In addition, the ISO's determination of the beneficiaries' voting shares will be forwarded to the ISO Board for review and action. The Board may approve the analysis and beneficiary determinations as submitted or propose modifications on its own motion. If any changes to the benefit/cost analysis or the beneficiary determinations are proposed by the Board, the revised analysis and beneficiary determinations shall be returned to the Management Committee for comment. If the Board proposes any changes to the ISO's voting share determinations, the Board shall so inform the LSE or LSEs impacted by the proposed change and shall allow such an LSE or LSEs an opportunity to comment on the proposed change. The Board shall not make a final determination on the project benefit/cost analysis and beneficiary determination until it has reviewed the Management Committee comments. Upon final approval of the Board, project benefit/cost analysis and beneficiary determinations shall be posted by the ISO on its website and shall form the basis of the beneficiary voting described in Section 31.5.4.6 of this Attachment Y.

31.5.4.6 Voting by Project Beneficiaries

31.5.4.6.1 Only LSEs serving Load located in a beneficiary zone determined in accordance with the procedures in Section 31.5.4.4 of this Attachment Y shall be eligible to vote on a proposed project. The ISO will, in conjunction with the ESPWG, develop procedures to determine the specific list of voting entities for each proposed project.

31.5.4.6.2 The voting share of each LSE shall be weighted in accordance with its share of the total project benefits, as allocated by Section 31.5.4.4 of this Attachment Y.

31.5.4.6.3 The costs of a RETP shall be allocated under this Attachment Y if eighty percent (80%) or more of the actual votes cast on a weighted basis are cast in favor of implementing the project.

31.5.4.6.4 If the proposed RETP meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting “no,” will pay their proportional share of the cost of the project.

31.5.4.6.5 The ISO will tally the results of the vote in accordance with procedures set forth in the ISO Procedures, and report the results to stakeholders. Beneficiaries voting against approval of a project must submit to the ISO their rationale for their vote within 30 days of the date that the vote is taken. Beneficiaries must provide a detailed explanation of the substantive reasons underlying the decision, including, where appropriate: (1) which additional benefit metrics, either identified in the tariff or otherwise, were used; (2) the actual quantification of such benefit metrics or factors; (3) a quantification and explanation of the net benefit or net cost of the project to the beneficiary; and (4) data supporting the metrics and other factors used. Such explanation may also include uncertainties, and/or alternative scenarios and other qualitative factors considered, including state public policy goals. The ISO will report this information to the Commission in an informational filing to be made within 60 days of the vote. The informational filing will include: (1) a list of the identified beneficiaries; (2) the results of the benefit/cost analysis; and (3) where a project is not approved, whether the developer has provided any formal indication to the ISO as to the future development of the project.

31.5.5 Regulated Transmission Solutions to Public Policy Transmission Needs[19]

31.5.5.1 The Scope of Section 31.5.5

As discussed in Section 31.5.1 of this Attachment Y, the cost allocation principles and methodologies of this Section 31.5.5 apply only to regulated Public Policy Transmission Projects. This Section 31.5.5 does not apply to Other Public Policy Projects, including

[19] This OATT subsection 31.5.5 is subject to revision per Order on Rehearing and Compliance, 148 FERC ¶ 61,044 (July 17, 2014).

generation or demand side management projects, or any market-based projects. This Section 31.5.5 does not apply to regulated reliability solutions implemented pursuant to the reliability planning process, nor does it apply to RETPs proposed in response to congestion identified in the CARIS.

A regulated transmission solution shall only utilize the cost allocation methodology set forth in Section 31.5.3 where it is: (1) a Responsible Transmission Owner's regulated backstop solution, (2) an alternative regulated transmission solution selected by the ISO as the more efficient or cost effective regulated transmission solution to satisfy a Reliability Need, or (3) seeking cost recovery where it has been halted or cancelled pursuant to the provisions of Section 31.2.8.2. A regulated economic transmission solution proposed in response to congestion identified in the CARIS, and approved pursuant to Section 31.5.4.6, shall only be eligible to utilize the cost allocation principles and methodologies set forth in Section 31.5.4.

31.5.5.2 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.5.4 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1 The specific cost allocation methodology in Section 31.5.5.4 incorporates the following elements:

31.5.5.2.1 The focus of the cost allocation methodology shall be on regulated Public Policy Transmission Projects.

31.5.5.2.2 Projects analyzed hereunder as Public Policy Transmission Projects may proceed on a market basis with willing buyers and sellers at any time.

31.5.5.2.3 Cost allocation shall be based on a beneficiaries pay approach.

31.5.5.2.4 Project benefits will be identified in accordance with Section 31.5.4.4.

31.5.5.2.5 Identification of beneficiaries for cost allocation and cost allocation among those beneficiaries shall be according to the methodology specified in Section 31.5.5.4.

31.5.5.3 Project Eligibility for Cost Allocation

The Developer of a Public Policy Transmission Project will be eligible for cost allocation in accordance with the process set forth in Section 31.5.5.4 when its project is selected by the ISO as the more efficient or cost effective regulated Public Policy Transmission Project; *provided, however*, that if the appropriate federal, state, or local agency(ies) rejects the selected project's necessary authorizations, or such authorizations are withdrawn, the costs the Developer is eligible to recover under Section 31.4.12.1 shall be allocated in accordance with Section 31.5.5.4.3, except as otherwise determined by the Commission. The Developer of the selected regulated transmission solution may recover its costs in accordance with Section 31.5.6 and Rate Schedule 10 of the ISO OATT. If the Developer proposed its Public Policy Transmission Project in response to a request by the NYPSC or Long Island Power Authority pursuant to Section 31.4.3.2 and its project was not selected by the ISO, the costs that the Developer is eligible to recover pursuant to Section 31.4.3.2 shall be allocated in accordance with Section 31.5.5.4.3, except as otherwise determined by the Commission. The Developer may recover these costs in accordance with Section 31.5.6 and Rate Schedule 10 of the ISO OATT.

31.5.5.4 Cost Allocation for Eligible Projects

As noted in Section 31.5.5.2 of this Attachment Y, the identification of beneficiaries for cost allocation and the cost allocation of a selected transmission Project driven by a Public Policy Requirement will be conducted in accordance with the process described in this Section 31.5.5.4. This Section will also apply to the allocation within New York of the ISO's share of the costs of an Interregional Transmission Project proposed as a solution to a Public Policy Transmission Need allocated in accordance with Section 31.5.7 of this Attachment Y. The establishment of a cost allocation methodology and rates for a proposed solution that is undertaken by LIPA or NYPA as an Unregulated Transmitting Utility to a Public Policy Transmission Need as determined in Sections 31.4.2.1 through 31.4.2.3, as applicable, or an Interregional Transmission Project shall occur pursuant to Section 31.5.5.4.4 through 31.5.5.4.6, as applicable. Nothing herein shall deprive a Transmission Owner or Other Developer of any rights it may have under Section 205 of the Federal Power Act to submit filings proposing any other cost allocation methodology to the Commission or create any Section 205 filing rights for any Transmission Owner, Other Developer, the ISO, or any other entity. The ISO shall apply the cost allocation methodology accepted by the Commission. The cost allocation methodology that is accepted or approved by the Commission for a particular Public Policy Transmission Project in accordance with this Section 31.5.5.4 will be set forth in Appendix E (Section 31.8) of this Attachment Y.

31.5.5.4.1 If the Public Policy Requirement that results in the identification by the NYPSC of a Public Policy Transmission Need prescribes the use of a particular cost allocation and recovery methodology, then the ISO shall file that methodology with the Commission within 60 days of the issuance by the NYPSC of its identification of a Public Policy Transmission Need. Nothing herein shall deprive a Transmission Owner or Other Developer of any rights it may have under Section 205 of the Federal Power Act to submit filings proposing any other cost allocation methodology to the Commission or create any Section 205 filing rights for any Transmission Owner, Other Developer, the ISO, or any other entity. If the Developer files a different proposed cost allocation methodology under Section 205 of the Federal Power Act, it shall have the burden of demonstrating that its proposed methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles taking into account the methodology specified in the Public Policy Requirement.

31.5.5.4.2 Subject to the provisions of Section 31.5.5.4.1, the Developer may submit to the NYPSC for its consideration – no later than 30 days after the ISO's selection of the regulated transmission solution – a proposed cost allocation methodology, which may include a cost allocation based on load ratio share, adjusted to reflect, as applicable, the Public Policy Requirement or Public Policy Transmission Need, the party(ies) responsible for complying with the Public Policy Requirement, and the party(ies) who benefit from the transmission facility.

31.5.5.4.2.1 The NYPSC shall have 150 days to review the Developer's proposed cost allocation methodology and to inform the Developer regarding whether it supports the methodology.

31.5.5.4.2.2 If the NYPSC supports the proposed cost allocation methodology, Developer shall file that cost allocation methodology with the Commission for its acceptance under Section 205 of the Federal Power Act within 30 days of the NYPSC informing the Transmission Owner or Other Developer of its support. The Developer shall have the burden of demonstrating that the proposed cost allocation methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles.

31.5.5.4.2.3 If the NYPSC does not support the proposed cost allocation methodology, then Other Developer shall take reasonable steps to respond to the NYPSC's concerns and to develop a mutually agreeable cost allocation methodology over a period of no more than 60 days after the NYPSC informing Other Developer that it does not support the methodology.

31.5.5.4.2.4 If a mutually acceptable cost allocation methodology is developed during the timeframe set forth in Section 31.5.5.4.2.3, the Developer shall file it with the Commission for acceptance under Section 205 of the Federal Power Act no later than 30 days after the conclusion of the 60 day discussion period with the NYPSC. The Other Developer shall have the burden of demonstrating that the proposed cost allocation methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles.

31.5.5.4.2.5 If no mutually agreeable cost allocation methodology is developed, the Developer shall file its preferred cost allocation methodology with the Commission for acceptance under Section 205 of the Federal Power Act no later than 30 days after the conclusion of the 60 day discussion period with the NYPSC. The Other Developer shall have the burden of demonstrating that its proposed methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles in consideration of the position of the NYPSC. The filing shall include the methodology supported by NYPSC for the Commission's consideration. If the Other Developer elects to use the load ratio share cost allocation methodology referenced below in Section 31.5.5.4.3, the Other Developer shall notify the Commission of its intent to utilize the load ratio share methodology and shall include in its notice the NYPSC supported methodology for the Commission's consideration.

31.5.5.4.3. Unless the Commission has accepted an alternative cost allocation methodology pursuant to this Section, the ISO shall allocate the costs of the Public Policy Transmission Project to all Load Serving Entities in the NYCA using the default cost allocation methodology, based upon a load ratio share methodology.

31.5.5.4.4 The NYISO will make any Section 205 filings related to this Section on behalf of NYPA to the extent requested to do so by NYPA. NYPA shall bear the burden of demonstrating that such a filing is compliant with the Order No. 1000 Regional Cost Allocation Principles. NYPA shall also be solely responsible for making any jurisdictional reservations or arguments related to their status as non-Commission-jurisdictional utilities that are not subject to various provisions of the Federal Power Act.

31.5.5.4.5 The cost allocation methodology and any rates for cost recovery for a proposed solution to a Public Policy Transmission Need undertaken by LIPA, as an Unregulated Transmitting Utility (for purposes of this section a "LIPA project"), shall be established and recovered as follows:

31.5.5.4.5.1 *For costs solely to LIPA customers.* The cost allocation methodology and rates to be established for a LIPA project, for which cost recovery will only occur from LIPA customers, will be established pursuant to Article 5, Title 1-A of the

New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Prior to the adoption of any cost allocation mechanism or rates for such a LIPA project, and pursuant to Section 1020-f(u), the Long Island Power Authority's Board of Trustees shall request that the NYDPS provide a recommendation with respect to the cost allocation methodology and rate that LIPA has proposed and the Board of Trustees shall consider such recommendation in accordance with the requirements of Section 1020-f(u). Upon approval of the cost allocation mechanism and/or rates by the Long Island Power Authority's Board of Trustees, LIPA shall provide to the ISO, for purposes of inclusion within the ISO OATT and filing with FERC on an informational basis only, a description of the cost allocation mechanism and the rate that LIPA will charge and collect within the Long Island Transmission District.

31.5.5.4.5.2 *For Costs for a LIPA Project That May be Allocated to Other Transmission Districts.* A LIPA project that meets a Public Policy Transmission Need as determined by the NYPSC pursuant to Section 31.4.2.3(iii) may be allocated to market participants outside of the Long Island Transmission District. The cost allocation methodology and rate for such a LIPA project shall be established in accordance with the following procedures. LIPA's proposed cost allocation methodology and/or rate shall be reviewed and approved by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Prior to the adoption of any cost allocation mechanism or rates for such project and pursuant to Section 1020-f(u), the Long Island Power Authority's Board of Trustees shall request that the NYDPS provide a recommendation with respect to the cost allocation methodology and rate that LIPA has proposed and the Board of Trustees shall consider such recommendation in accordance with the requirements of Section 1020-f(u). LIPA shall inform the ISO of the cost allocation methodology and rate that has been approved by the Long Island Power Authority's Board of Trustees for filing with the Commission.

Upon approval by the Long Island Power Authority's Board of Trustees, LIPA shall submit and request that the ISO file the LIPA cost allocation methodology for approval with the Commission. Any cost allocation methodology for a LIPA project that allocates costs to market participants outside of the Long Island Transmission District shall be reviewed as to whether there is comparability in the derivation of the cost allocation for market participants such that LIPA has demonstrated that the proposed cost allocation is compliant with the Order No. 1000 cost allocation principles, there are benefits provided by the project to market participants outside of the Long Island Transmission District, and that the proposed allocation is roughly commensurate to the identified benefits.

Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s, requires that LIPA's rates be established at the lowest level consistent with sound fiscal and operating practices of the Long Island Power Authority and which provide for safe and adequate service. Upon approval of a LIPA rate by the Long Island Power Authority's Board of Trustees pursuant to Section 1020-f(u), LIPA shall submit, and request that the ISO file, the LIPA rate with the Commission for review under the same comparability standard as applied to the review of changes in LIPA's TSC under Attachment H of this tariff.

In the event that the cost allocation methodology or rate approved by the Long Island Power Authority's Board of Trustees did not adopt the NYDPS recommendation, the NYDPS recommendation shall be included in the filing for the Commission's consideration.

31.5.5.4.5.3 *Support for Filing*. LIPA shall intervene in support of the filing(s) made pursuant to Section 31.5.5.4.5 at the Commission and shall take the responsibility to demonstrate that: (i) the cost allocation methodology and/or rate approved by the Long Island Power Authority's Board of Trustees meets the applicable standard of comparability, and (ii) the Commission should accept such methodology or rate for filing. LIPA shall also be responsible for responding to, and seeking to resolve, concerns about the contents of the filing that might be raised in such proceeding.

31.5.5.4.5.4 *Billing of LIPA Charges Outside of the Long Island Transmission District*. For Transmission Districts other than the Long Island Transmission District, the ISO shall bill for LIPA, as a separate charge, the costs incurred by LIPA for a solution to a Public Policy Transmission Need allocated using the cost allocation methodology and rates established pursuant to Section 31.5.5.4.5.2 and accepted for filing by the Commission and shall remit the revenues collected to LIPA each Billing Period in accordance with the ISO's billing and settlement procedures.

31.5.5.4.6 The inclusion in the ISO OATT or in a filing with the Commission basis of the cost allocation and charges for recovery of costs incurred by NYPA or

LIPA related to a solution to a transmission need driven by a Public Policy Requirement or Interregional Transmission Project as provided for in Sections 31.5.5.4.4 and 31.5.5.4.5 shall not be deemed to modify the treatment of such rates as non-jurisdictional pursuant to Section 201(f) of the FPA.

31.5.6 Cost Recovery for Regulated Projects

31.5.6.1 Cost Recovery for Regulated Transmission Project to Address a Reliability Need

31.5.6.1.1 A Responsible Transmission Owner, a Transmission Owner, or an Other Developer may recover in accordance with Rate Schedule 10 of the ISO OATT the costs incurred with respect to the implementation of: (i) a regulated backstop transmission solution proposed by a Responsible Transmission Owner pursuant to Section 31.2.4.3.1 of this Attachment Y and the ISO/TO Reliability Agreement or an Operating Agreement; (ii) an alternative regulated transmission solution that the ISO has selected pursuant to Section 31.2.6.5.2 of this Attachment Y as the more efficient or cost-effective solution to a Reliability Need; (iii) a regulated transmission Gap Solution proposed by a Responsible Transmission Owner pursuant to Section 31.2.11.4 of this Attachment Y; or (iv) an alternative regulated transmission Gap Solution that has been determined by the appropriate state regulatory agency(ies) as the preferred solution(s) to a Reliability Need pursuant to Section 31.2.11.5 of Attachment Y of the ISO OATT.

31.5.6.1.2 If a regulated solution: (i) is eligible for cost recovery as described in Section 31.5.6.1.1 and (ii) is not triggered or is halted pursuant to Sections 31.2.8 or 31.2.10.1.2 of this Attachment Y, the Responsible Transmission Owner, Transmission Owner or Other Developer of that solution may recover the costs that it eligible to recover pursuant to Sections 31.2.8 or 31.2.10.1.2 in accordance with Rate Schedule 10 of the ISO OATT.

31.5.6.1.3 Costs related to non-transmission regulated solutions to Reliability Needs will be recovered by a Responsible Transmission Owner, Transmission Owner, or Other Developer in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law. A Responsible Transmission Owner, a Transmission Owner, or Other Developer may propose and undertake a regulated non-transmission solution, provided that the appropriate state agency(ies) has established cost recovery procedures comparable to those provided in this tariff for regulated transmission solutions to ensure the full and prompt recovery of all reasonably-incurred costs related to such non-transmission solutions. Nothing in this section shall affect the Commission's jurisdiction over the sale and transmission of electric energy subject to the jurisdiction of the Commission.

31.5.6.2 Cost Recovery for Regulated Economic Transmission Project

A Transmission Owner or an Other Developer may recover in accordance with Rate Schedule 10 of the ISO OATT the costs incurred with respect to the implementation a regulated economic transmission project that has been approved pursuant to Section 31.5.4.6 of this Attachment Y.

31.5.6.3 Cost Recovery for Regulated Transmission Project to Address a Public Policy Transmission Need

31.5.6.3.1 A Transmission Owner or an Other Developer may recover in accordance with Rate Schedule 10 of the ISO OATT the costs incurred with respect to the implementation of: (i) a Public Policy Transmission Project that the ISO has selected as the more efficient or cost-effective solution to a Public Policy Transmission Need, or (ii) a Public Policy Transmission Project proposed by a Developer in response to a request by the NYPSC or Long Island Power Authority in accordance with Section 31.4.3.2 of Attachment Y of the ISO OATT. Such cost recovery will also include reasonable costs incurred by the Developer to provide a more detailed study or cost estimate for such project at the request of the NYPSC, and to prepare the application required to comply with New York Public Service Law Article VII, or any successor statute or any other applicable permits, and to seek other necessary authorizations..

31.5.6.3.2 If a regulated solution that: (i) is eligible for cost recovery as described in Section 31.5.6.3.1 and (ii) is halted as described in Section 31.4.12.1 of this Attachment Y, the Transmission Owner or Other Developer of that solution may recover the costs that it is eligible to recover pursuant to Section 31.4.12.1 in accordance with Rate Schedule 10 of the ISO OATT.

31.5.6.4 Cost Recovery for Interregional Transmission Project

A Responsible Transmission Owner, a Transmission Owner, or an Other Developer may recover in accordance with Rate Schedule 10 of the ISO OATT the costs incurred with respect to the implementation of the portion of an Interregional Transmission Project selected by the ISO in the CSPP that is allocated to the NYISO region pursuant to Section 31.5.7 of Attachment Y of the ISO OATT.

31.5.7 Cost Allocation for Eligible Interregional Transmission Projects

31.5.7.1 Costs of Approved Interregional Transmission Projects

The cost allocation methodology reflected in this Section 31.5.7.1 shall be referred to as the "Northeastern Interregional Cost Allocation Methodology" (or "NICAM"), and shall not be modified without the mutual consent of the Section 205 rights holders in each region.

The costs of Interregional Transmission Projects, as defined in the Interregional Planning Protocol, evaluated under the Interregional Planning Protocol and selected by ISO-NE, PJM and the ISO in their regional transmission plans for purposes of cost allocation under their respective tariffs shall, when applicable, be allocated to the ISO-NE region, PJM region and the ISO region in accordance with the cost allocation principles of FERC Order No. 1000, as follows:

(a) To be eligible for interregional cost allocation, an Interregional Transmission Project must be selected in the regional transmission plan for purposes of cost allocation in each of the transmission planning regions in which the transmission project is proposed to be located, pursuant to agreements and tariffs on file at FERC for each region. With respect to Interregional Transmission Projects and other transmission projects involving the ISO and PJM, the cost allocation of such projects shall be in accordance with the Joint Operating Agreement ("JOA") among and between the ISO and PJM. With respect to Interregional Transmission Projects and other transmission projects involving the ISO and ISO-NE, the cost allocation for such projects shall be in accordance with this Section 31.5.7 of Attachment Y of the NYISO Open Access Transmission Tariff and with the respective tariffs of ISO-NE.

(b) The share of the costs of an Interregional Transmission Project allocated to a region will be determined by the ratio of the present value of the estimated costs of such region's displaced regional transmission project to the total of the present values of the estimated costs of the displaced regional transmission projects in all regions that have selected the Interregional Transmission Project in their regional transmission plans.

(i) The present values of the estimated costs of each region's displaced regional transmission project shall be based on a common base date that will be the beginning of the calendar month of the cost allocation analysis for the subject Interregional Transmission Project (the "Base Date").

(ii) In order to perform the analysis in this Section 31.5.7.1(b), the estimated cost of the displaced regional transmission projects shall specify the year's dollars in which those estimates are provided.

(iii) The present value analysis for all displaced regional transmission projects shall use a common discount rate. The regions having displaced projects will mutually agree, in consultation with their respective transmission owners, and for purposes of the ISO, its other stakeholders, on the discount rate to be used for the present value analysis.

(iv) For the purpose of this allocation, cost estimates shall use comparable cost estimating procedures. In the Interregional Planning Stakeholder Advisory Committee review process, the regions having displaced projects will review and determine, in consultation with their respective transmission owners, and for purposes of the NYISO, its other stakeholders, that reasonably comparable estimating procedures have been used prior to applying this cost allocation.

(c) No cost shall be allocated to a region that has not selected the Interregional Transmission Project in its regional transmission plan.

(d) When a portion of an Interregional Transmission Project evaluated under the Interregional Planning Protocol is included by a region (Region 1) in its regional transmission plan but there is no regional need or displaced regional transmission project in Region 1, and the neighboring region (Region 2) has a regional need or displaced regional project for the Interregional Transmission Project and selects the Interregional Transmission Project in its regional transmission plan, all of the costs of the Interregional Transmission Project shall be allocated to Region 2 in accordance with the NICAM and none of the costs shall be allocated to Region 1. However, Region 1 may voluntarily agree, with the mutual consent of the Section 205 rights holders in the other affected region(s) (including the Long Island Power Authority and the New York Power Authority in the NYISO region) to use an alternative cost allocation method filed with and accepted by the Commission.

(e) The portion of the costs allocated to a region pursuant to the NICAM shall be further allocated to that region's transmission customers pursuant to the applicable provisions of the region's FERC-filed documents and agreements, for the ISO in accordance with Section 31.5.1.7 of Attachment Y of the ISO OATT.

(f) The following example illustrates the cost allocation for such an Interregional Transmission Project:

- A cost allocation analysis of the costs of Interregional Transmission Project Z is to be performed during a given month establishing the beginning of that month as the Base Date.

- Region A has identified a reliability need in its region and has selected a transmission project (Project X) as the preferred solution in its regional plan. The estimated cost of Project X is: Cost (X), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is: N(X).
- Region B has identified a reliability need in its region and has selected a transmission project (Project Y) as the preferred solution in its Regional Plan. The estimated cost of Project Y is: Cost (Y), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (Y) is: N(Y).
- Regions A and B, through the interregional planning process have determined that an Interregional Transmission Project (Project Z) will address the reliability needs in both regions more efficiently and cost-effectively than the separate regional projects. The estimated cost of Project Z is: Cost (Z). Regions A and B have each determined that Interregional Transmission Project Z is the preferred solution to their reliability needs and have adopted that Interregional Transmission Project in their respective regional plans in lieu of Projects X and Y respectively. If Regions A and B have agreed to bear the costs of upgrades in other affected transmission planning regions, these costs will be considered part of Cost (Z).
- The discount rate used for all displaced regional transmission projects is: D
- Based on the foregoing assumptions, the following formulas will be used:
  - Present Value of Cost (X) = PV Cost (X) = Cost (X) / $(1+D)^{N(X)}$
  - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / $(1+D)^{N(Y)}$

- Cost Allocation to Region A = Cost (Z) x PV Cost (X)/[PV Cost (X) + PV Cost (Y)]
- Cost Allocation to Region B = Cost (Z) x PV Cost (Y)/[PV Cost (X) + PV Cost (Y)]

- Applying those formulas, if:

Cost (X) = $60 Million and N(X) = 8.25 years

Cost (Y) = $40 Million and N(Y) = 4.50 years

Cost (Z) = $80 Million

D = 7.5% per year

Then:

PV Cost (X) = $60/(1+0.075)^{8.25}$ = 33.039 Million

PV Cost (Y) = $40/(1+0.075)^{4.50}$ = 28.888 Million

Cost Allocation to Region A = $80 x 33.039/(33.039 + 28.888) = $42,681 Million

Cost Allocation to Region B = $80 x 28.888/(33.039+28.888) = $37.319 Million

31.5.7.2 Other Cost Allocation Arrangements

(a) Except as provided in Section 31.5.7.2(b), the NICAM is the exclusive means by which any costs of an Interregional Transmission Project may be allocated between or among PJM, the ISO, and ISO-NE.

(b) Nothing in the FERC-filed documents of ISO-NE, the ISO or PJM shall preclude agreement by entities with cost allocation rights under Section 205 of the Federal Power Act for their respective regions (including the Long Island Power Authority and the New York Power Authority in the ISO region) to enter into separate agreements to allocate the cost-of Interregional Transmission Projects proposed to be located in their regions as an alternative to the NICAM, or other transmission projects identified pursuant to assessments and studies conducted pursuant to Section 6 of the Interregional Planning Protocol. Such other cost-allocation methodologies must be approved in each region pursuant to the Commission-approved rules in each region, filed with and accepted by the Commission, and shall apply only to the region's share of the costs of an Interregional Transmission Project or other transmission projects pursuant to Section 6 of the Interregional Planning Protocol, as applicable.

31.5.7.3 Filing Rights

Nothing in this Section 31.5.7 will convey, expand, limit or otherwise alter any rights of ISO-NE, the ISO, PJM, each region's transmission owners, market participants , or other entities to submit filings under Section 205 of the Federal Power Act regarding interregional cost allocation or any other matter.

Where applicable, the regions have been authorized by entities that have cost allocation rights for their respective regions to implement the provisions of this Section 31.5.7.

31.5.7.4. Merchant Transmission and Individual Transmission Owner Projects

Nothing in this Section 31.5.7 shall preclude the development of Interregional Transmission Projects that are funded solely by merchant transmission developers or by individual transmission owners.

31.5.7.5 Consequences to Other Regions from Regional or Interregional Transmission Projects

Except as provided herein in Sections 31.5.7.1 and 31.5.7.2, or where cost responsibility is expressly assumed by ISO-NE, the ISO or PJM in other documents, agreements or tariffs on file with FERC, neither the ISO-NE region, the ISO region nor the PJM region shall be responsible for compensating another region or each other for required upgrades or for any other consequences in another planning region associated with regional or interregional transmission facilities, including but not limited to, transmission projects identified pursuant to Section 6 of the Interregional Planning Protocol and Interregional Transmission Projects identified pursuant to Section 7 of the Interregional Planning Protocol.

[1]This OATT Section 31.5 is subject to revision per Order on Rehearing and Compliance, 148 FERC ¶ 61,044 (July 17, 2014). Subsequent footnotes identify specific subsections that the NYISO currently anticipates will be revised in its compliance filing. Please be advised that in revising its tariffs in accordance with FERC's directives, the NYISO may be required to revise additional subsections that are not designated by footnotes.

31.6 Other Provisions

31.6.1 The Commission's Role in Dispute Resolution

Disputes directly relating to the ISO's compliance with its tariffs that are not resolved in the internal ISO collaborative governance appeals process or ISO dispute resolution process, and all disputes relating to matters that fall within the exclusive jurisdiction of the Commission, shall be reviewed at the Commission pursuant to the Federal Power Act if such review is sought by any party to the dispute. The NYPSC or any party to a dispute regarding matters over which both the NYPSC and the Commission have jurisdiction and responsibility for action may submit a request to the Commission for a joint or concurrent hearing to resolve the dispute.

31.6.2 Non-Jurisdictional Entities

LIPA's and NYPA's participation in the CSPP shall in no way be considered to be a waiver of their non-jurisdictional status pursuant to Section 201(f) of the Federal Power Act, including with respect to the Commission's exercise of the Federal Power Act's general ratemaking authority.

31.6.3 Tax Exempt Financing Provisions

Con Edison, NYPA and LIPA shall not be required to construct, or cause to construct, a transmission facility identified through the ISO reliability planning process if such construction would result in the loss of tax-exempt status of any tax-exempt bond issued by Con Edison, NYPA or LIPA, or impair their ability to secure future tax-exempt financing.

31.6.4 Rights of Incumbent Transmission Owners

Nothing in this Attachment Y affects the right of an incumbent Transmission Owner to: (1) build, own, and recover costs for upgrades to the facilities it owns, regardless of whether the upgrade has been selected in the regional transmission plan for purposes of cost allocation; (2)

retain, modify, or transfer rights-of-way subject to relevant law or regulation granting such rights-of-way; or (3) develop a local transmission solution that is not eligible for regional cost allocation to meet its reliability needs or service obligations in its own service territory or footprint. For purposes of Section 31.6.4, the term "upgrade" shall refer to an improvement to, addition to, or replacement of a part of an existing transmission facility and shall not refer to an entirely new transmission facility.

31.6.5 Notice of Reliability Requirements

The Developer of a project selected pursuant to the provisions in this Attachment Y is hereby notified that it must comply with all applicable reliability criteria, policies, standards, rules, regulations, and other requirements of NERC, NPCC, NYSRC, Transmission Owners, and any other applicable reliability entities or their successors, to the extent required by, and in accordance with, their procedures.

31.7 Appendices

APPENDIX A - REPORTING OF HISTORIC AND PROJECTED CONGESTION

1.0 General

As part of its CSPP, the ISO will prepare summaries and detailed analysis of historic and projected congestion across the NYS Transmission System. This will include analysis to identify the significant causes of historic congestion in an effort to help Market Participants and other interested parties distinguish persistent and addressable congestion from congestion that results from one time events or transient adjustments in operating procedures that may or may not recur. This information will assist Market Participants and other stakeholders to make appropriately informed decisions.

2.0 Definition of Cost of Congestion

The ISO will report the cost of congestion as the change in bid production costs that results from transmission congestion. The following elements of congestion-related costs also will be reported: (i) impact on load payments; (ii) impact on generator payments; and (iii) hedged and unhedged congestion payments.

The determination of the change in bid production costs and the other elements of congestion will be based upon the difference in costs between the actual constrained system prices computed in the ISO's Day-Ahead Market and a simulation of an unconstrained system. The simulation shall be developed by the use of the PROBE model approved by the ISO Operating Committee on January 22, 2004 or by such other software as may provide the required congestion information.

3.0 Analysis

Each RNA will include the ISO's summaries and detailed analysis of the prior year's congestion across the NYS Transmission System. The ISO's analysis will identify the significant causes of the historic congestion.

Each study of projected congestion for economic planning will include the results of the ISO's analysis conducted in accordance with Section 31.3.1 of this Attachment Y. The ISO's analysis will identify the significant causes of the projected congestion.

4.0 Detailed Cause Analysis for Unusual Events

The ISO will perform an analysis to identify unusual events causing significant congestion levels. Such analysis will include the following elements: (i) identification of major transmission or generation outages; and (ii) quantification of the market impact of relieving historic constraints.

Some of the information necessary to this analysis may constitute critical energy infrastructure information and will need to be handled with appropriate confidentiality limitations to protect national security interests.

5.0 Summary Reports

The ISO will prepare various reports of historic and projected congestion costs. Historic congestion reports will be based upon the actual congestion data from the ISO Day-Ahead Market, and will include summaries, aggregated by month and calendar year, such as: (i) NYCA; (ii) by zone; (iii) by contingency in rank order; (iv) by constraint in rank order; (v) total dollars; and (vi) number of hours. Results of projected congestion studies conducted pursuant to Section 31.3.1 of this Attachment Y will include summaries of selected additional metrics and scenarios.

These reports will be based upon the foregoing definitions of congestion.

APPENDIX B - PROCEDURE FOR FORECASTING THE NET REDUCTIONS IN TCC REVENUES THAT WOULD RESULT FROM A PROPOSED PROJECT

For the purpose of determining the allocation of costs associated with a proposed project as described in Section 31.5.4.4 of this Attachment Y, the ISO shall use the procedure described herein to forecast the net reductions in TCC revenues allocated to Load in each Load Zone as a result of a proposed project.

Definitions

The following definitions will apply to this appendix:

Pre-CARIS Centralized TCC Auction: The last Centralized TCC Auction that had been completed as of the date the input assumptions were determined for the CARIS in which the Project was identified as a candidate for development under the provisions of this Attachment Y.

Project: The proposed transmission project for which the evaluation of the net benefits forecasted for Load in each Load Zone, as described in Section 31.5.4.4.2 of this Attachment Y, is being performed.

TCC Revenue Factor: A factor that is intended to reflect the expected ratio of (1) revenue realized in the TCC auction from the sale of a TCC to (2) the Congestion Rents that a purchaser of that TCC would expect to realize. The value to be used for the TCC Revenue Factor shall be stated in the ISO Procedures.

Steps 1 Through 6 of the Procedure

For each Project, the ISO will perform Steps 1 through 6 of this procedure twice for each of the ten (10) years following the proposed commercial operation date of the Project: once under the assumption that the Project is in place in each of those years, and once under the assumption that the Project is not in place in each of those years.

Forecasting the Value of Grandfathered TCCs and TCC Auction Revenue

Step 1. The ISO shall forecast Congestion Rents collected on the New York electricity system in each year, which shall be equal to:

(a) the product of:

(i) the forecasted Congestion Component of the Day-Ahead LBMP for each hour at each Load Zone or Proxy Generator Bus and

(ii) forecasted withdrawals scheduled in that hour in that Load Zone or Proxy Generator Bus, summed over all locations and over all hours in that year, minus:

(b) the product of:

(i) the forecasted Congestion Component of the Day-Ahead LBMP for each hour at each Generator bus or Proxy Generator Bus and

(ii) forecasted injections scheduled in that hour at that Generator bus or Proxy Generator Bus,

summed over all locations and over all hours in that year.

Step 2. The ISO shall forecast:

(a) payments in each year associated with any Incremental TCCs that the ISO projects would be awarded in conjunction with that Project (which will be zero for the calculation that is performed under the assumption that the Project is not in place);

(b) payments in each year associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation; and

(c) payments that would be made to holders of Grandfathered Rights and imputed payments that would be made to the Primary Holders of Grandfathered TCCs that would be in effect in each year, under the following assumptions:

(i) all Grandfathered Rights and Grandfathered TCCs expire at their stated expiration dates;

(ii) imputed payments to holders of Grandfathered Rights are equal to the payments that would be made to the Primary Holder of a TCC with the same Point of Injection and Point of Withdrawal as that Grandfathered Right; and

(iii) in cases where a Grandfathered TCC is listed in Table 1 of Attachment M of the ISO OATT, the number of those TCCs held by their Primary Holders shall be set to the number of such TCCs remaining at the conclusion of the ETCNL reduction procedure conducted before the Pre-CARIS Centralized TCC Auction.

Step 3. The ISO shall forecast TCC auction revenues for each year by subtracting:

(a) the forecasted payments calculated for that year in Steps 2(a), 2(b) and 2(c) of this procedure

from:

(b) the forecasted Congestion Rents calculated for that year in Step 1 of this procedure, and multiplying the difference by the TCC Revenue Factor.

Forecasting the Allocation of TCC Auction Revenues Among the Transmission Owners

Step 4. The ISO shall forecast the following:

(a) payments in each year to the Primary Holders of Original Residual TCCs and

(b) payments in each year to the Primary Holders of TCCs that correspond to the amount of ETCNL remaining at the conclusion of the ETCNL reduction procedure conducted before the Pre-CARIS Centralized TCC Auction,

and multiply each by the TCC Revenue Factor to determine the forecasted payments to the Primary Holders of Original Residual TCCs and the Transmission Owners that have been allocated ETCNL.

Step 5. The ISO shall forecast residual auction revenues for each year by subtracting:

(a) the sum of the forecasted payments for each year to the Primary Holders of Original Residual TCCs and the Transmission Owners that have been allocated ETCNL, calculated in Step 4 of this procedure

from:

(b) forecasted TCC auction revenues for that year calculated in Step 3 of this procedure.

Step 6. The ISO shall forecast each Transmission Owner’s share of residual auction revenue for each year by multiplying:

(a) the forecast of residual auction revenue calculated in Step 5 of this procedure and

(b) the ratio of:

(i) the amount of residual auction revenue allocated to that Transmission Owner in the Pre-CARIS Centralized TCC Auction to

(ii) the total amount of residual auction revenue allocated in the Pre-CARIS Centralized TCC Auction.

Steps 7 Through 10 of the Procedure

The ISO will perform Steps 7 through 10 of this procedure once for each of the ten (10) years following the proposed commercial operation date of the Project, using the results of the preceding calculations performed both under the assumption that the Project is in place in each of those years, and under the assumption that the Project is not in place in each of those years.

Forecasting the Impact of the Project on TSC Offsets and the NTAC Offset

Step 7. The ISO shall calculate the forecasted net impact of the Project on the TSC offset for each megawatt-hour of electricity consumed by Load in each Transmission District (other than the NYPA Transmission District) in each year by:

(a) summing the following, each forecasted for that Transmission District for that year under the assumption that the Project is in place:

(i) forecasted Congestion Rents associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, as calculated in Step 2(b) of this procedure, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation, if those Congestion Rents would affect the TSC for that Transmission District;

(ii) forecasted Congestion Rents associated with any Grandfathered TCCs and forecasted imputed Congestion Rents associated with any Grandfathered Rights held by the Transmission Owner serving that Transmission District that would be paid to that Transmission Owner for that year, as calculated in Step 2(c) of this procedure, if those Congestion Rents would affect the TSC for that Transmission District;

(iii) the payments that are forecasted to be made for that year to the Primary Holders of Original Residual TCCs and ETCNL that have been allocated to the Transmission Owner serving that Transmission District, as calculated in Step 4 of this procedure; and

(iv) that Transmission District's forecasted share of residual auction revenues for that year, as calculated in Step 6 of this procedure for the Transmission Owner serving that Transmission District;

(b) subtracting the sum of items (i) through (iv) above, each forecasted for that Transmission District for that year under the assumption that the Project is not in place; and

(c) dividing this difference by the amount of Load forecasted to be served in that Transmission District in that year, stated in terms of megawatt-hours, net of any Load served by municipally owned utilities that is not subject to the TSC.

Step 8. The ISO shall calculate the forecasted net impact of the Project on the NTAC offset for each megawatt-hour of electricity consumed by Load in each year by:

(a) summing the following, each forecasted for that year under the assumption that the Project is in place:

(i) forecasted Congestion Rents associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, as calculated in Step 2(b) of this procedure, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation, if those Congestion Rents would affect the NTAC;

(ii) forecasted Congestion Rents associated with any Grandfathered TCCs and forecasted imputed Congestion Rents associated with any Grandfathered Rights held by NYPA that would be paid to NYPA for that year, as calculated in Step 2(c) of this procedure, if those Congestion Rents would affect the NTAC;

(iii) the payments that are forecasted to be made for that year to NYPA in association with Original Residual TCCs allocated to NYPA, as calculated in Step 4 of this procedure; and

(iv) NYPA's forecasted share of residual auction revenues for that year, as calculated in Step 6 of this procedure;

(b) subtracting the sum of items (i) through (iv) above, each forecasted for that year under the assumption that the Project is not in place; and

(c) dividing this difference by the amount of Load expected to be served in the NYCA in that year, stated in terms of megawatt-hours, net of any Load served by municipally owned utilities that is not subject to the NTAC.

Forecasting the Net Impact of the Project on TCC Revenues Allocated to Load in Each Zone

Step 9. The ISO shall calculate the forecasted net impact of the Project in each year in each Load Zone on payments made in conjunction with TCCs and Grandfathered Rights that benefit Load but which do not affect TSCs or the NTAC, which shall be the sum of:

(a) Forecasted Congestion Rents paid or imputed to municipally owned utilities serving Load in that Load Zone that own Grandfathered Rights or Grandfathered TCCs that were not included in the calculation of the TSC offset in Step 7(a)(ii) of this procedure or the NTAC offset in Step 8(a)(ii) of this procedure, which the ISO shall calculate by:

(i) summing forecasted Congestion Rents that any such municipally owned utilities serving Load in that Load Zone would be paid for that year in association with any such Grandfathered TCCs and any forecasted imputed Congestion Rents that such a municipally owned utility would be paid for that year in association with any such Grandfathered Rights, as calculated in Step 2(c) of this procedure under the assumption that the Project is in place; and

(ii) subtracting forecasted Congestion Rents that any such municipally owned utilities would be paid for that year in association with any such Grandfathered TCCs, and any forecasted imputed Congestion Rents that such a municipally owned utility would be paid for that year in association with any such Grandfathered Rights, as calculated in Step 2(c) of this procedure under the assumption that the Project is not in place.

(b) Forecasted Congestion Rents collected from Incremental TCCs awarded in conjunction with projects that were previously funded through this procedure, if those Congestion Rents are used to reduce the amount that Load in that Load Zone must pay to fund such projects, which the ISO shall calculate by:

(i) summing forecasted Congestion Rents that would be collected for that year in association with any such Incremental TCCs, as calculated in Step 2(b) of this procedure under the assumption that the Project is in place; and

(ii) subtracting forecasted Congestion Rents that would be collected for that year in association with any such Incremental TCCs, as calculated in Step 2(b) of this procedure under the assumption that the Project is not in place.

Step 10. The ISO shall calculate the forecasted net reductions in TCC revenues allocated to Load in each Load Zone as a result of a proposed Project by summing the following:

(a) the product of:

(i) the forecasted net impact of the Project on the TSC offset for each megawatt-hour of electricity consumed by Load, as calculated for each Transmission District (other than the NYPA Transmission District) in Step 7 of this procedure; and

(ii) the number of megawatt-hours of energy that are forecasted to be consumed by Load in that year, in the portion of that Transmission District that is in that Load Zone, for Load that is subject to the TSC;

summed over all Transmission Districts;

(b) the product of:

(i) the forecasted net impact of the Project on the NTAC offset for each megawatt-hour of electricity consumed by Load, as calculated in Step 8 of this procedure; and

(ii) the number of megawatt-hours of energy that are forecasted to be consumed by Load in that year in that Load Zone, for Load that is subject to the NTAC; and

(c) the forecasted net impact of the Project on payments and imputed payments made in conjunction with TCCs and Grandfathered Rights that benefit Load but which do not affect TSCs or the NTAC, as calculated in Step 9 of this procedure.

Additional Notes Concerning the Procedure

For the purposes of Steps 2(c) and 4(b) of this procedure, the ISO will utilize the currently effective version of Attachment L of the ISO OATT to identify Existing Transmission Agreements and Existing Transmission Capacity for Native Load.

Each Transmission Owner, other than NYPA, will inform the ISO of any Grandfathered Rights and Grandfathered TCCs it holds whose Congestion Rents should be taken into account in Step 7 of this procedure because those Congestion Rents affect its TSC.

NYPA will inform the ISO of any Grandfathered Rights and Grandfathered TCCs it holds whose Congestion Rents should be taken into account in Step 8 of this procedure because those Congestion Rents affect the NTAC.

APPENDIX C – RELIABILITY PLANNING PROCESS DEVELOPMENT AGREEMENT

APPENDIX D – PUBLIC POLICY TRANSMISSION PLANNING PROCESS DEVELOPMENT AGREEMENT

This Appendix is reserved for future use.

31.8 Appendix E – Public Policy Transmission Need Cost Allocation Methodologies

31.8.1 General

Under the Public Policy Transmission Planning Process, Section 31.5.5.4 of Attachment Y to the ISO OATT provides the process for prescribing an alternative to the default cost allocation methodology for Public Policy Transmission Projects that the ISO selected pursuant to Section 31.4.8.2 of Attachment Y to the ISO OATT. This Appendix E contains the Commission-accepted alternative cost allocation methodologies that the ISO will apply instead of the default cost allocation methodology set forth in Section 31.5.5.4.3 of Attachment Y to the ISO OATT for selected Public Policy Transmission Projects.

31.8.2 AC Transmission Public Policy Transmission Need Cost Allocation Methodology

This Section 31.8.2 of Appendix E sets forth the Commission-accepted methodology prescribed by the Public Policy Requirement for allocating costs associated with the Public Policy Transmission Project that the ISO has selected pursuant to Section 31.4.8.2 of Attachment Y to the ISO OATT to satisfy the AC Transmission Public Policy Transmission Need identified by the NYPSC in an order issued on December 17, 2015 (“AC Transmission Project”). For purposes of this Section 31.8.2, the aforementioned costs are collectively referred to as the “AC Transmission Costs.”

The AC Transmission Costs to be allocated pursuant to this cost allocation methodology under this Section 31.8.2 of Appendix E will be determined in accordance with Sections 31.4 and 31.5.6.5 of Attachment Y to the ISO OATT. This cost allocation methodology is not applicable to any costs not approved by the Commission.

The ISO will apply the cost allocation methodology set forth under this Section 31.8.2 of Appendix E in the absence of the Commission accepting a different methodology. The ISO will perform the calculations prescribed under this Section 31.8.2 of Appendix E one time no earlier than thirty (30) days following the ISO's selection of the AC Transmission Project; provided, however, if the Developer of the selected AC Transmission Project proposes an alternative cost allocation methodology pursuant to Section 31.5.5.4 of Attachment Y to the ISO OATT, the NYISO will perform the calculations under this cost allocation methodology following the Commission's determination not to accept a methodology proposed in the filing by the Developer, or on behalf of the Developer, of the AC Transmission Project.

The cost allocation methodology set forth under this Section 31.8.2 of Appendix E will use the forecasts and assumptions identified in the Public Policy Transmission Planning Report for the AC Transmission Public Policy Transmission Need as the set of forecasts and assumptions to be used in the cost allocation methodology calculation. This methodology will be applied over a ten-year period beginning with the calendar year following the in-service date for the AC Transmission Project specified in the Public Policy Transmission Planning Report in accordance with Section 31.4.11 of Attachment Y to the ISO OATT. Recovery of the revenue requirements based upon the AC Transmission Costs resulting from this cost allocation methodology will be based on real-time usage data in accordance with NYISO's Billing and Settlements process under the applicable rate schedule in the ISO OATT.

The AC Transmission Costs will be allocated in accordance with the following methodology: (i) 25 percent of the costs will be allocated to all Load Zones in the NYCA based upon load-ratio share, and (ii) 75 percent of the costs will be allocated to those Load Zones that would economically benefit from the implementation of the AC Transmission Project based on the relative reduction in energy payments.

31.8.2.1 NYCA-Wide Load-Ratio Share Allocation

For purposes of allocating 25 percent of the AC Transmission Costs, the ISO will allocate such costs based on a load-ratio share to each Load Zone in the NYCA. The ISO will use the forecasted coincident summer peak demand contained in the forecasts and assumptions identified in the Public Policy Transmission Planning Report for the AC Transmission Public Policy Transmission Need as the set of forecasts and assumptions to be used in the cost allocation methodology calculation over the ten-year period beginning with the calendar year following the in-service date specified in accordance with Section 31.4.11 of Attachment Y to the ISO OATT, as follows:

$$\mathrm{NYCAWideCostAllocation_z} = \left(\frac{\sum_{y=1}^{10} \mathrm{CoincidentPeak_{z,y}}}{\sum_{y=1}^{10} \mathrm{CoincidentPeak_{NYCA,y}}}\right) \mathrm{x}\ (25\%)$$

Where: z = an individual Load Zone in the NYCA;

y = forecast year 1 through 10, beginning with the calendar year following the in-service date for the AC Transmission Project specified in the Public Policy Transmission Planning Report in accordance with Section 31.4.11 of Attachment Y to the ISO OATT;

$\mathrm{CoincidentPeak_{z,y}}$ = the forecasted coincident summer peak demand in Load Zone z and year y; and

$\mathrm{CoincidentPeak_{NYCA,y}}$ = the forecasted coincident summer peak demand for the NYCA in year y.

31.8.2.2 Economic Beneficiaries Allocation

For purposes of allocating 75 percent of the AC Transmission Costs to the Load Zones that would economically benefit from the implementation of the AC Transmission Project, the ISO will identify those Load Zones and allocate the costs as follows:

31.8.2.2.1 The ISO will identify the Load Zones that would economically benefit from the AC Transmission Project over the ten-year period beginning with the calendar year following the in-service date for the project specified in the Public Policy Transmission Planning Report in accordance with Section 31.4.11 of Attachment Y to the ISO OATT.

31.8.2.2.2 The ISO will measure the present value of the annual zonal LBMP load savings for all Load Zones that would have a load savings net of changes in TCC revenues as a result of the implementation of the AC Transmission Project. For purposes of this calculation, the present value of the load savings will be equal to the sum of the present value of the Load Zone's load savings for each year over the ten-year period beginning with the calendar year following the in-service date for the project specified in the Public Policy Transmission Planning Report in accordance with Section 31.4.11 of Attachment Y to the ISO OATT. The discount rate to be used for the present value analysis shall be the discount rate identified in the Public Policy Transmission Planning Report for the AC Transmission Public Policy Transmission Need. The load savings for a Load Zone will be equal to the difference between the zonal LBMP load cost without the AC Transmission Project and the LBMP load cost with the AC Transmission Project, net of changes in TCC revenues. For the purposes of this methodology under this Section 31.8.2.2.2, the ISO will not account for load served by generation owned by LSEs or bilateral contracts in calculating a Load Zone's LBMP benefit and, for the purpose of cost allocation, will treat all load as being priced at the zonal LBMP.

31.8.2.2.2.1 The economic beneficiaries will be those Load Zones that experience net zonal benefits measured over the ten-year period beginning with the calendar year following the in-service date for the AC Transmission Project specified in the Public Policy Transmission Planning Report in accordance with Section 31.4.11 of Attachment Y to the ISO OATT.

31.8.2.2.2.2 Reductions in TCC revenues will reflect the forecasted impact of the AC Transmission Project on TCC auction revenues and day-ahead residual congestion rents allocated to Load in each Load Zone, not including the congestion rents that accrue to the ISO's projection of any potential Incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: (i) the total impact of the AC Transmission Project on the Transmission Service Charge offset applicable to loads in each Load Zone (which may vary for loads in a given Load Zone that are in different Transmission Districts); (ii) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that Load Zone; and (iii) the total impact of that project on payments made to LSEs serving load in that Load Zone and that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item (i) above. These forecasts shall be performed using the procedure described in Appendix B in Section 31.7 of Attachment Y to the ISO OATT.

31.8.2.2.2.3 Estimated TCC revenues from the ISO's projection of any potential Incremental TCCs created by the AC Transmission Project over the ten-year period commencing with the calendar year following the in-service date for the project, as specified in the Public Policy Transmission Planning Report in accordance with Section 31.4.11 of Attachment Y to the ISO OATT, will be added to the net load savings used for the economic beneficiaries cost allocation determination. Any actual Incremental TCCs ultimately awarded to the AC Transmission Project shall be determined in accordance with the requirements of Section 19.2.4 of Attachment M to the ISO OATT.

31.8.2.2.2.4 The ISO will calculate the net zonal benefits for each Load Zone in the NYCA as the difference between the zonal LBMP load cost without the AC Transmission Project and the zonal LBMP load cost with the AC Transmission Project, net of reductions in TCC revenues, using the following equation:

$$\mathrm{NetZonalBenefits}_z = \max\left[0, \sum_{y=1}^{10}\left(\left(\mathrm{LBMP}_{z,y,base} - \mathrm{LBMP}_{z,y,project} - \mathrm{TCCRevImpact}_{z,y}\right) \text{ x DF}\right)\right]$$

Where: z = an individual Load Zone in the NYCA;

y = forecast year 1 through 10, beginning with the calendar year following in-service date for the AC Transmission Project specified in the Public Policy Transmission Planning Report in accordance with Section 31.4.11 of Attachment Y to the ISO OATT;

$\mathrm{LBMP}_{z,y,base}$ = forecasted load LBMP cost for Load Zone z in year y assuming the AC Transmission Project is not in service;

$\mathrm{LBMP}_{z,y,project}$ = forecasted load LBMP cost for Load Zone z in year y assuming the AC Transmission Project is in service;

$\mathrm{TCCRevImpact}_{z,y}$ = the forecasted impact of TCC revenues allocated to Load Zone z in year y, calculated using the procedure described in Appendix B in Section 31.7 of Attachment Y to the ISO OATT; and

DF = is the discount factor identified in the Public Policy Transmission Planning Report for the AC Transmission Public Policy Transmission Need.

31.8.2.2.2.5 Any Load Zone that does not have a net zonal benefit is not considered an economic beneficiary and will not be allocated any portion of the 75 percent of the AC Transmission Costs. There will be no "make whole" payments to non-economic beneficiary Load Zones.

31.8.2.2.3 Those Load Zones identified in Section 31.8.2.2 of this Appendix E as economically benefiting from the AC Transmission Project will be allocated 75 percent of the AC Transmission Costs as follows:

$$\mathrm{EconomicCostAllocation}_z = \left(\frac{\mathrm{NetZonalBenefits}_z}{\sum_{k=1}^{m}\mathrm{NetZonalBenefits}_k}\right) \mathrm{x}\ (75\%)$$

Where: z = an individual Load Zone in the NYCA;

k = a Load Zone in the NYCA with net zonal benefits as calculated under Section 31.8.2.2.2.4 of this Appendix E; and

m = the total number of Load Zones in the NYCA with net zonal benefits as calculated under Section 31.8.2.2.2.4 of this Appendix E.

38.1.2.3 Zonal Cost Allocation

The NYISO will calculate the proportion of the AC Transmission Costs allocated to each individual Load Zone to be used in the applicable rate schedule under the ISO OATT, as follows:

$$\mathrm{ZonalCostAllocation}_z = (\mathrm{NYCAWideCostAllocation}_z + \mathrm{EconomicCostAllocation}_z)$$

Where: z = an individual Load Zone in the NYCA.

31.9 This section is reserved for future use.

31.10 This section is reserved for future use.

31.12 Appendix I – Study Agreement for Evaluation of Public Policy Transmission Projects

STUDY AGREEMENT FOR EVALUATION OF PUBLIC POLICY TRANSMISSION PROJECTS

THIS AGREEMENT is made and entered into this ____ day of _________, 20__ by and between ____________, a _____________ organized and existing under the laws of the State of ___________ ("Developer"), and the New York Independent System Operator, Inc., a not-for-profit corporation organized and existing under the laws of the State of New York ("NYISO"). Developer and NYISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Developer is proposing to develop a Public Policy Transmission Project to satisfy one or more identified Public Policy Transmission Needs ("Transmission Project");

WHEREAS, pursuant to Sections 31.4.3.1, 31.4.4.3, and 31.4.4.4 of Attachment Y to the ISO OATT, the NYISO has requested that all entities interested in proposing a Transmission Project submit specific solutions to the Public Policy Transmission Need, including: (i) submitting their project information and an application fee for purposes of being evaluated in the NYISO's Public Policy Transmission Planning Process, and (ii) executing this Agreement and submitting a study deposit for purposes of the NYISO's evaluation and selection of the more efficient or cost-effective transmission solution to the identified Public Policy Transmission Need(s);

WHEREAS, Developer has requested the NYISO to evaluate its Transmission Project for the purpose of selecting the more efficient or cost-effective transmission solution to the identified Public Policy Transmission Need(s);

WHEREAS, pursuant to Sections 31.4.3.1, 31.4.4.3, and 31.4.4.4 of Attachment Y to the ISO OATT, Developer will submit, together with the execution of this Agreement, its project information, application fee, and study deposit for the purpose of the NYISO evaluating its Transmission Project.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified but not otherwise defined herein shall have the meanings indicated in Section 31.1.1 of Attachment Y to the ISO OATT, or if not defined therein, in the ISO OATT.

2.0 Developer elects, and the NYISO shall cause to be performed, an evaluation of the Transmission Project in accordance with Sections 31.4.7, 31.4.8, 31.4.9, and 31.4.10 of Attachment Y to the ISO OATT, along with any required additional evaluation or re-evaluation of the Transmission Project, for the purpose of the NYISO's selection of the more efficient or cost-effective transmission solution to satisfy the identified Public Policy Transmission Need(s) ("Evaluation"). The terms of Sections 31.4.7, 31.4.8, 31.4.9, and 31.4.10 of Attachment Y to the ISO OATT, as applicable, are hereby incorporated by reference herein. The NYISO will not commence its Evaluation of the Transmission Project prior to determining that: (i) Developer's Transmission Project is viable and sufficient in accordance with Section 31.4.6 of Attachment Y to the ISO OATT, and (ii) Developer has provided to the NYISO the required notification to proceed with the Evaluation of the Transmission Project in accordance with Section 31.4.6.6 of Attachment Y to the ISO OATT.

3.0 Upon the execution of this Agreement, Developer shall provide the NYISO with the project information for its Transmission Project in accordance with Section 31.4.4.3 of Attachment Y to the ISO OATT. Developer shall provide the project information required under Section 31.4.5.1 of Attachment Y to the ISO OATT.

4.0 Upon the execution of this Agreement, Developer shall also provide the NYISO with a deposit of $100,000 in accordance with Section 31.4.4.4 of Attachment Y to the ISO OATT to secure Developer's payment of the NYISO's expenses incurred in performing the Evaluation. The NYISO will not commence its Evaluation of the Transmission Project prior to its receipt of Developer's study deposit. The NYISO shall invoice, and Developer shall pay to the NYISO, the actual costs of the Evaluation in accordance with Section 31.4.4.4 of Attachment Y to the ISO OATT. Upon settlement of the final invoice, the NYISO will return to Developer any remaining portion of the study deposit, including any accrued interest, in accordance with Section 31.4.4.4 of Attachment Y to the ISO OATT.

5.0 The NYISO will use the project information provided by Developer as described in Section 3.0 above as an input for its Evaluation; *provided, however*, that pursuant to Section 31.4.8 of Attachment Y to the ISO OATT, the ISO may engage an independent subcontractor consultant to review the reasonableness and comprehensiveness of the project information provided by Developer and may rely on the independent subcontractor consultant's analysis of the project information in performing its Evaluation. The NYISO reserves the right to request additional project information from Developer as may become necessary in accordance with Section 31.4.4.3.1 of Attachment Y to the ISO OATT, and Developer shall submit such additional information within 15 days of the NYISO's request as required under Section 31.4.4.3.4 of Attachment Y to the ISO OATT. Developer shall meet with the NYISO, as the NYISO deems necessary, to discuss Developer's project information.

6.0 The scope of the Evaluation shall be subject to the study purposes and criteria set forth in Attachment Y to the ISO OATT and to the assumptions set forth in Attachment A to this Agreement.

7.0 As part of the NYISO's Evaluation of the Transmission Project and prior to identifying the more efficient or cost-effective transmission solution to meet the Public Policy Transmission Need(s), the NYISO will provide Developer with a summary of its findings regarding the project information submitted by Developer and will meet with Developer to discuss its findings and to address any questions regarding the project information. After completing the required analysis of all of the proposed regulated transmission solutions and identifying the more efficient or cost-effective transmission solution, the NYISO will provide all stakeholders with the results of its analysis, including which regulated transmission solution has been identified as the more efficient or cost-effective transmission solution to the Public Policy Transmission Need(s), in the Public Policy Transmission Planning Report pursuant to Section 31.4.11 of Attachment Y to the ISO OATT.

8.0 Miscellaneous.

8.1 Accuracy of Information. Except as Developer may otherwise specify in writing when it provides information to the NYISO under this Agreement, Developer represents and warrants that to the best of its knowledge and belief the information it has provided or subsequently provides to the NYISO is and shall be accurate and complete as of the date the information is provided. Developer shall promptly provide the NYISO with any additional information needed to update information previously provided.

8.2 Disclaimer of Warranty. In performing the Evaluation, the NYISO and any subcontractor consultants engaged by the NYISO will have to rely on information provided by Developer, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, neither the NYISO nor any subcontractor consultant engaged by the NYISO makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy, content, or conclusions of the Evaluation performed pursuant to this Agreement and the ISO OATT. Developer acknowledges that it has not relied on any representations or warranties by the NYISO or its subcontractor consultants not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

8.3 Limitation of Liability. The NYISO or any subcontractor consultants engaged by the NYISO shall not be liable for direct damages, including money damages or other compensation, for actions or omissions by the

NYISO or a subcontractor consultant in performing its obligations under this Agreement, except to the extent such act or omission by the NYISO or a subcontractor consultant is found to result from its gross negligence or willful misconduct. In no event shall either Party or its subcontractor consultants be liable for indirect, special, incidental, punitive, or consequential damages of any kind including loss of profits, arising under or in connection with this Agreement and the ISO OATT or any reliance on the Evaluation by any Party or third parties, even if one or more of the Parties or its subcontractor consultants have been advised of the possibility of such damages. Nor shall either Party or its subcontractor consultants be liable for any delay in delivery or for the non-performance or delay in performance of its obligations under this Agreement.

8.4 Third-Party Beneficiaries. Without limitation of Sections 8.2 and 8.3 of this Agreement, Developer further agrees that subcontractor consultants hired by NYISO to conduct or review, or to assist in the conducting or reviewing, the Evaluation of the Transmission Project shall be deemed third party beneficiaries of these Sections 8.2 and 8.3.

8.5 Term and Termination. This Agreement shall be effective from the date hereof and, unless earlier terminated in accordance with this Section 8.5, shall continue in effect until completion of the Evaluation, which shall be the later of: (i) the date on which the NYISO Board of Directors' approval of the Public Policy Transmission Planning Process report for the planning cycle is final and not the subject of dispute resolution or a challenge before a court or regulatory body, and (ii) the date on which the New York State Public Service Commission issues the Article VII certification for a regulated transmission solution that satisfies the identified Public Policy Transmission Need(s). Developer or NYISO may end the Evaluation and terminate this Agreement upon: (i) the withdrawal by Developer of its Transmission Project, including its failure to provide the required notification to proceed under Section 31.4.6.6 of Attachment Y to the ISO OATT; (ii) the rejection by the NYISO of the Transmission Project from further consideration during the planning cycle in accordance with the ISO OATT; or (iii) any changes by the New York State Public Service Commission to the identified Public Policy Transmission Need(s), including withdrawal of the Public Policy Transmission Need(s), that eliminate the need for the Transmission Project.

8.6 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of New York, without regard to any choice of laws provisions.

8.7 Severability. In the event that any part of this Agreement is deemed as a matter of law to be unenforceable or null and void, such unenforceable or void part shall be deemed severable from this Agreement and the Agreement shall continue in full force and effect as if each part was not contained herein.

8.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument. A signed copy of this Agreement delivered by facsimile, e-mail or other means of electronic transmission shall be deemed to have the same legal effect as delivery of an original signed copy of this Agreement.

8.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing signed by the Parties hereto.

8.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein and the payment obligations provided under Section 4.0 shall survive the expiration or termination of this Agreement.

8.11 Independent Contractor. NYISO shall at all times be deemed to be an independent contractor for purposes of this Agreement and none of its employees or the employees of its subcontractors shall be considered to be employees of Developer as a result of this Agreement.

8.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such party’s right to insist or rely on any such provision, rights and remedies in that or any other instances; rather, the same shall be and remain in full force and effect.

8.13 Successors and Assigns. This Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns.

8.14 Confidentiality. NYISO shall maintain the project information submitted by Developer under this Agreement in accordance with the requirements set forth in Sections 31.4.15 of Attachment Y to the ISO OATT.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents and to be effective from the day and year first above written.

NYISO	**[Insert name of Developer]**
By: ____________________	By: ____________________
Name: ____________________	Name: ____________________
Title: ____________________	Title: ____________________
Date: ____________________	Date: ____________________

32 Attachment Z – Small Generator Interconnection Procedures (SGIP) (Applicable to Generating Facilities No Larger Than 20 MW)

32.1 Application

32.1.1 Applicability

32.1.1.1 These Small Generator Interconnection Procedures ("SGIP") apply to interconnections of Small Generating Facilities to the New York State Transmission System, and interconnections to the Distribution System subject to Federal Energy Regulatory Commission jurisdiction. These procedures do not apply to interconnections made simply to receive power from the New York State Transmission System and/or the Distribution System, nor to interconnections made solely for the purpose of generation with no wholesale sale for resale nor to net metering. These procedures do not apply to interconnections to LIPA's distribution facilities. LIPA will continue to administer the interconnection process for generators connecting to its distribution facilities and perform all required studies on its distribution system under its own tariffs and procedures. Under these procedures, a request to interconnect a certified Small Generating Facility (See Appendices 3 and 4 for description of certification criteria) to the Connecting Transmission Owner's Distribution System shall be evaluated under the Section 32.2 Fast Track Process if the eligibility requirements of Section 32.2.1 are met. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kilowatts (kW) shall be evaluated under the Appendix 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility no larger than 20 megawatts (MW) that does not meet the eligibility requirements of Section 32.2.1, or does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the Section 32.3 Study Process.

32.1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Appendix I or the body of these procedures. Capitalized terms used herein that are not defined in the Glossary of Terms in Appendix I or in the body of these procedures shall have the meanings specified in Section 32.1 or Attachment S or Attachment X of the ISO OATT.

32.1.1.3 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to 60 Business Days after the effective date of these procedures, provided, however, that requests to interconnect Small Generating Facilities submitted after that effective date must be made pursuant to these procedures. These procedures shall apply to any existing interconnected Small Generating Facility to the extent that there is a material modification to the facility or the Interconnection Facility, if that facility as modified remains a Small Generating Facility.

32.1.1.4 Prior to submitting its Interconnection Request (Appendix 2), the Interconnection Customer may ask the ISO's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The ISO, after consultation with the appropriate Transmission Owner, shall respond within 15 Business Days. Upon request from the ISO, a Transmission Owner shall provide requested information to the ISO necessary to make this determination (*e.g.*, whether the proposed interconnection point is on a distribution or transmission facility and if distribution, whether there is already one or more generators connecting to that facility making wholesale sales).

32.1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Federal Energy Regulatory Commission expects all ISOs and RTOs, Connecting Transmission Owners, Market Participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

32.1.1.6 References in these procedures to an interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

32.1.1.7 A new Small Generating Facility wishing to sell Energy and Ancillary Services must first elect Energy Resource Interconnection Service and satisfy the NYISO Minimum Interconnection Standard, which does not impose any deliverability requirement. All new Small Generating Facilities must satisfy the NYISO Minimum Interconnection Standard.

A new Small Generating Facility larger than 2 MW wishing to become a qualified Installed Capacity Supplier in accordance with the ISO Services Tariff and related ISO Procedures must first elect Capacity Resource Interconnection Service and satisfy the NYISO Deliverability Interconnection Standard in addition to the NYISO Minimum Interconnection Standard. A Small Generating Facility larger than 2 MW electing Capacity Resource Interconnection Service must execute a Class Year Interconnection Facilities Study Agreement in the form of Appendix 2 to Attachment X of the ISO OATT. At that time, the Interconnection Customer must specify the MW of Capacity Resource Interconnection Service that it is requesting. The ISO will then place the Small Generating Facility in the then Open Class Year and evaluate the Small Generating Facility for deliverability, as a Class Year Project, following the same rules and procedures in Attachment S to the ISO OATT applicable to other Class Year Projects being evaluated for deliverability. Inclusion in the Class Year will only be for the determination of System Deliverability Upgrade costs and Deliverable MW unless the Small Generating Facility is being included in the Class Year for the determination of System Upgrade Facility cost responsibility pursuant to Section 32.3.5.3.2 of the SGIP. For Small Generating Facilities interconnected or completely studied for interconnection before the projects in Class Year 2007, the Capacity Resource Interconnection Service capacity level for those Small Generating Facilities will be set at the highest DMNC recorded during five Summer Capability periods measured in accordance with the rules set forth in Section 25.9.3.1 of Attachment S to the ISO OATT. Prior to the establishment of a Small Generating Facility's first DMNC value for a Summer Capability Period, the Capacity Resource Interconnection Service capacity level will be set at the Small Generating Facility's nameplate MW. A Small Generating Facility 2 MW or smaller may elect Capacity Resource Interconnection Service without being evaluated for deliverability under Attachment S to the ISO OATT. In all cases, the new Small Generating Facility will interconnect using the SGIA contained in this Attachment Z. Once it is established for them, Small Generating Facilities may retain their Capacity Resource Interconnection Service in accordance with the rules set forth in Section 25.9.3 of Attachment S to the ISO OATT.

32.1.2 Pre-Application

32.1.2.1 The ISO shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the ISO's Internet web site. Electric system information provided to the Interconnection Customer should include relevant system studies, Interconnection Studies, Base Case Data and other materials useful to an understanding of an interconnection at a particular point on the New York State Transmission System or Distribution System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The ISO, with the required information about distribution facilities from the appropriate Connecting Transmission Owner, shall comply with reasonable requests for such information pursuant to this Section 32.1.2.

32.1.2.2 In addition to the information described in Section 32.1.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form along with a non-refundable fee of $1000 for a pre-application report on a proposed project at a specific site. The pre-application fee shall be divided between the ISO and the Connecting Transmission Owner as follows: one-third to the ISO and two-thirds to the Connecting Transmission Owner. Within two (2) Business Days of receiving the pre-application report request form, the ISO shall provide a copy of the pre-application request form to the appropriate Connecting Transmission Owner. The

Connecting Transmission Owner shall return the pre-application report, completed to the extent required under this section 32.1.2.2 within fifteen (15) Business Days of receipt of the pre-application request form from the ISO. The ISO, with the required information about distribution facilities from the appropriate Connecting Transmission Owner, shall provide the pre-application data described in Section 32.1.2.3 to the Interconnection Customer within 20 Business Days of receipt of the completed request form and payment of the $1000 fee. The pre-application report produced by the ISO, in consultation with the appropriate Connecting Transmission Owner, is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Connecting Transmission Owner's system. The written pre-application report request form shall include the information in Sections 32.1.2.2.1 through 32.1.2.2.9 below to clearly and sufficiently identify the location of the proposed Point of Interconnection.

32.1.2.2.1 Project contact information, including name, address, phone number, and email address.

32.1.2.2.2 Project location (street address with nearby cross streets, town, and county).

32.1.2.2.3 Meter number, pole number, or other equivalent information identifying proposed Point of Interconnection, if available (*e.g.*, .

32.1.2.2.4 Generator type (*e.g.,* solar, wind, combined heat and power, etc.).

32.1.2.2.5 Size (alternating current kW).

32.1.2.2.6 Single or three phase generator configuration.

32.1.2.2.7 Stand-alone generator (no outside load, not including station service – Yes or No?).

32.1.2.2.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

32.1.2.2.9 Indication as to whether the requestor intends to use the facility to engage in wholesale sales over the New York State Transmission System or Distribution System.

32.1.2.3 Using the information provided in the pre-application report request form in Section 32.1.2.2, the ISO, in consultation with the appropriate Connecting Transmission Owner, will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the ISO, in consultation with the appropriate Connecting Transmission Owner, does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional pre-application reports if information about multiple Points of Interconnection is requested. The ISO, in consultation with the Connecting Transmission Owner, shall determine whether the proposed interconnection is subject to the interconnection procedures set forth in this Attachment Z of the ISO OATT. If the pre-application report request form seeks information about a Point of Interconnection that is not subject to the interconnection procedures set forth in this Attachment Z of the ISO OATT, the Connecting Transmission Owner Customer shall follow the applicable state tariff, rules or procedures regarding generator interconnections. Subject to Section 32.1.2.4, the pre-application report will include the following information:

32.1.2.3.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

32.1.2.3.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (*i.e.,* amount of generation online) likely to serve the proposed Point of Interconnection.

32.1.2.3.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (*i.e.,* amount of generation in the queue) likely to serve the proposed Point of Interconnection.

32.1.2.3.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Interconnection (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

32.1.2.3.5 Substation nominal distribution voltage and/or transmission line nominal voltage if applicable.

32.1.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.

32.1.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

32.1.2.3.8 Relevant line section(s)/station(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in Section 32.2.4.4.1.1 below and absolute minimum load, when available.

32.1.2.3.9 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

32.1.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

32.1.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

32.1.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

32.1.2.3.13 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

32.1.2.4 The pre-application report need only include existing data. A pre-application report request does not obligate the ISO or the Connecting Transmission Owner to conduct a study or other analysis of the proposed generator in the event the data is not readily available. If the ISO, in consultation with the Connecting Transmission Owner, cannot complete all or some of a pre-application report due to lack of available data, the ISO shall provide the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on “available capacity” pursuant to Section 32.1.2.3.4 does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the ISO, in consultation with the Connecting Transmission Owner, shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

32.1.3 Interconnection Request

An Interconnection Customer proposing to interconnect a new Small Generating Facility to the New York State Transmission System or to the Distribution System, or proposing to materially increase the capacity of, or make a material modification to the operating characteristics of, an existing Small Generating Facility that is interconnected to the New York State Transmission System or to the Distribution System shall submit its Interconnection Request to the ISO together with a non-refundable $1,000 application fee. The application fee shall be divided equally between the NYISO and Connecting Transmission Owner(s). An Interconnection Customer seeking to return a Small Generating Facility to service after it is Retired must submit a new Interconnection Request as a new facility. An Interconnection Customer returning a Small Generating Facility to service prior to the expiration or termination of its Mothball Outage or ICAP Ineligible Forced Outage need not submit a new Interconnection Request unless the Small Generating Facility is proposing to materially increase the capacity of, or make a material modification to the operating characteristics of, an existing Small Generating Facility such as would otherwise trigger a new Interconnection Request.

An increase in the capacity of an existing Small Generating Facility is a material increase for purposes of this Section 32.1.3 unless the increase (a) is not associated with any equipment changes or is associated with equipment changes determined by the ISO to be non-material; and (b) is an increase in the Small Generating Facility's baseline ERIS level that is equal to or less than two (2) megawatts and which provides for a total output of the Small Generating Facility of no more than twenty (20) megawatts. For purposes of this Section 32.1.3, the baseline ERIS level of an existing Small Generating Facility is (a) the greater of (i) the existing Small Generating Facility's CRIS level determined as a facility pre-dating Class Year 2007 pursuant to Section 25.9.3.1 of Attachment S of the OATT, if applicable; or (ii) the final maximum summer megawatt electrical output studied for ERIS in the ISO's interconnection process for the existing Small Generating Facility; or (b) if neither (a)(i) nor (a)(ii) are applicable, the baseline ERIS level is the value reflected in the Small Generating Facility's interconnection agreement or other applicable documentation governing the Small Generating Facility's interconnection; however, if the Small Generating Facility has requested a modification to its facility to decrease its size, and such modification has been deemed nonmaterial by the ISO, the decreased MW level will be a cap on its baseline ERIS. If the existing Small Generating Facility is a BTM:NG Resource, the increase in existing capacity will be measured based on the increase from the existing gross capability of the generator to the proposed gross capability. Notwithstanding the above, if the existing Small Generating Facility is a temperature sensitive unit, the maximum capacity of which varies based on ambient temperature, the increase in existing capacity will be measured based on the largest increase from the existing capacity to the proposed capacity at the same temperature, *i.e.*, at the same temperature along the maximum megawatt electrical output versus temperature curves.

The Interconnection Request shall be date- and time-stamped by the ISO upon receipt and a copy shall be sent by the ISO to the Connecting Transmission Owner. The ISO's date- and time-stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the ISO within three Business Days of receiving the Interconnection Request. The ISO, after consulting with the Connecting Transmission Owner, shall notify the Interconnection Customer within ten Business Days of the receipt of the Interconnection Request as to whether the Interconnection Request is complete or incomplete. If the Interconnection Request is incomplete, the ISO shall provide along with the notice that the Interconnection Request is incomplete, a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will have ten Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the ISO.

32.1.3.1 If the Interconnection Request is to interconnect to a distribution facility, the ISO will consult with the Connecting Transmission Owner to determine whether the SGIPs apply.

32.1.3.2 The expected Commercial Operation Date of the new Small Generating Facility or proposed increase in capacity of the existing Small Generating Facility provided in the Interconnection Request shall be no more than ten (10) years from the date the Interconnection Request is received by the ISO. Extensions of

Commercial Operation Dates for Small Generating Facilities are subject to the provisions of Section 30.4.4.5 of Attachment X to the OATT.

32.1.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the ISO, the Connecting Transmission Owner, and the Interconnection Customer shall be deemed a withdrawal of the Interconnection Request and shall require submission of a new Interconnection Request, unless, following notification by the ISO, the Interconnection Customer cures the problems created by the changes in a reasonable period of time.

32.1.5 Site Control

Documentation of site control must be submitted with the Interconnection Request. Site control may be demonstrated through:

32.1.5.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

32.1.5.2 An option to purchase or acquire a leasehold site for such purpose; or

32.1.5.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

32.1.6 Queue Position

The ISO shall assign a Queue Position based upon the date- and time-stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the order of initiating Interconnection Studies, and the study assumptions to be used in the analyses conducted under Section 32.2 and Section 32.3 of these procedures. Provided, however, Attachment S of the ISO OATT will be used to determine the cost responsibility for any System Upgrade Facilities or System Deliverability Upgrades necessary to accommodate the interconnection, as required by Section 32.3.5.3.2 of these procedures. The ISO shall maintain a single interconnection queue that combines Interconnection Requests evaluated under these procedures and those evaluated under Attachment X to the OATT. Interconnection Requests may be studied serially or in clusters for the purpose of the system impact study or facilities study. The ISO may evaluate Small Generating Facilities moving forward in the same time frame that contribute to Local System Upgrade Facilities to determine their *pro rata* cost responsibility for such Local System Upgrade Facilities. Small Generating Facilities evaluated in a cluster study that trigger non-Local System Upgrade Facilities must be evaluated in a Class Year Interconnection Facilities Study pursuant to Section 32.3.5.3.2 of this Attachment Z.

32.1.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP

Nothing in this SGIP affects an Interconnection Customer's Queue Position assigned before the effective date of this SGIP. The Parties agree to complete work on any interconnection study agreement executed prior to the effective date of this SGIP in accordance with the terms and conditions of that interconnection study agreement. Any new studies or additional work will be completed pursuant to this SGIP.

32.2 Fast Track Process

32.2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with a Connecting Transmission Owner's Distribution System if the Small Generating Facility's capacity does not exceed the size limits identified in the table below. Small Generating Facilities below these limits are eligible for review under the Fast Track Process. However, eligibility for the Fast Track Process is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Fast Track Process screens in Section 32.2.2.1 below or the supplemental review screens in Section 32.2.4.4 below.

Eligibility for the Fast Track Process is determined based upon the generator type, the size of the generator, voltage of the line and the location of and type of line at the Point of Interconnection. All Small Generating Facilities connecting to lines greater than 69 kilovolt (kV) are ineligible for the Fast Track Process regardless of size. All synchronous and induction machines must be no larger than 2 MW to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Small Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition to the size threshold, the Interconnection Customer's proposed Small Generating Facility must meet the codes, standards, and certification requirements of Appendices 3 and 4 of these procedures, or the ISO, in consultation with the Connecting

Transmission Owner, has to have reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline[1] and ≤ 2.5 Electrical Circuit Miles from Substation[2]
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

[1] For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[2] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to Section 32.1.2.

32.2.2 Initial Review

Within 15 Business Days after the ISO notifies the Interconnection Customer it has received a complete Interconnection Request, the ISO, in consultation with the Connecting Transmission Owner, shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the determinations under the screens.

32.2.2.1 Screens

32.2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Connecting Transmission Owner's Distribution System.

32.2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small

Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Connecting Transmission Owner's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

32.2.2.1.3. For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW.[1]

[1] A spot network is a type of Distribution System found within modern commercial buildings to provide high reliability of service to a single customer. (Standard Handbook for Electrical Engineers, 11th edition, Donald Fink, McGraw Hill Book Company.)

32.2.2.1.4. The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

32.2.2.1.5. The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

32.2.2.1.6. Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Connecting Transmission Owner's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

32.2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

32.2.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

32.2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (*e.g.,* three or four transmission busses from the point of interconnection).

32.2.2.1.10 No construction of facilities by the Connecting Transmission Owner on its own system shall be required to accommodate the Small Generating Facility.

32.2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the ISO will provide the Interconnection Customer and the Connecting Transmission Owner a draft interconnection agreement within five Business Days after the determination.

32.2.2.3 If the proposed interconnection fails the screens, but the ISO, in consultation with the Connecting Transmission Owner, determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the ISO shall provide the Interconnection Customer and the Connecting Transmission Owner a draft interconnection agreement within five Business Days after the determination. To the extent appropriate, the ISO shall notify any Affected System or Connecting Transmission Owner prior to the determination to allow for potential input by the Affected System or Connecting Transmission Owner. For purposes of this section, Affected System may include the portions of the New York State Transmission System that may be potentially affected.

32.2.2.4 If the proposed interconnection fails the screens, but the ISO, in consultation with the Connecting Transmission Owner, does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider Minor Modifications or further study, the ISO shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

32.2.3 Customer Options Meeting

If the ISO, in consultation with the Connecting Transmission Owner, determines the Interconnection Request cannot be approved without: (1) Minor Modifications at minimal cost, (2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the ISO shall notify the Interconnection Customer of that determination within five Business Days after the determination and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the ISO's determination, the ISO shall offer to convene a customer options meeting with the Interconnection Customer and the Connecting Transmission Owner to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine, in consultation with the Connecting Transmission Owner, what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the ISO's determination, or at the customer options meeting:

32.2.3.1 The Connecting Transmission Owner shall offer to perform facility modifications or Minor Modifications to the Connecting Transmission Owner's electric system (*e.g.,* changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Connecting Transmission Owner's electric system. If the Interconnection Customer agrees to pay for the modifications to the Connecting Transmission Owner's electric system, the ISO will provide the Interconnection Customer and the Connecting Transmission Owner with a draft interconnection agreement within ten Business Days of the customer options meeting; or

32.2.3.2 The ISO shall offer to perform a supplemental review in accordance with Section 32.2.4 and provide a non-binding good faith estimate of the costs of such review; or

32.2.3.3 The ISO shall offer to continue evaluating the Interconnection Request under the Section 3 Study Process.

32.2.4 Supplemental Review

32.2.4.1 To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit to the ISO for the estimated costs of the supplemental review in the amount of the good faith estimate of the costs of such review by the ISO, in consultation with the Connecting Transmission Owner, both within 15 Business Days of the offer. If the written agreement and deposit have not been received by the ISO within that timeframe, the Interconnection Request shall continue to be evaluated under the Section 32.3 Study Process unless it is withdrawn by the Interconnection Customer.

32.2.4.2 The Interconnection Customer may specify the order in which the ISO, in consultation with the Connecting Transmission Owner, will complete the screens in Section 32.2.4.4.

32.2.4.3 The Interconnection Customer shall be responsible for the ISO's and the Connecting Transmission Owner's actual costs for the supplemental review conducted by the ISO. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the ISO will return such excess within 20 Business Days of the invoice without interest.

32.2.4.4 Within 30 Business Days following receipt of the deposit for a supplemental review, the ISO, in consultation with the Connecting Transmission Owner, shall: (1) perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the ISO's and Connecting Transmission Owner's determination under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of supplemental review, the ISO shall notify the Interconnection Customer following the failure of any of the screens, or if it is unable to perform the screen in Section 32.2.4.4.1, within two Business Days of making such determination to obtain the Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this Section 32.2.4.4; (2) terminate the supplemental review and continue evaluating the Small Generating Facility under Section 32.3; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer.

32.2.4.4.1 Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate generating facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the ISO, in consultation with the CTO, shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under Section 32.2.4.4.

32.2.4.4.1.1 The type of generation used by the proposed Small Generating Facility will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of this screen. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (*i.e.*, 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

32.2.4.4.1.2 When this screen is being applied to a Small Generating Facility that serves some station service load, only the net injection into the Connecting Transmission Owner's electric system will be considered as part of the aggregate generation.

32.2.4.4.1.3 The ISO, in consultation with the Connecting Transmission Owner will not consider as part of the aggregate generation for purposes of this screen generating facility capacity known to be already reflected in the minimum load data.

32.2.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuations is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

32.2.4.4.3 Safety and Reliability Screen: The location of the proposed Small Generating Facility and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The ISO, in consultation with the Connecting Transmission Owner, shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

32.2.4.4.3.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (*e.g.*, several large commercial customers).

32.2.4.4.3.2 Whether the loading along the line section is uniform or even.

32.2.4.4.3.3 Whether the proposed Small Generating Facility is located in close proximity to the substation (*i.e.*, less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a mainline rated for normal and emergency ampacity.

32.2.4.4.3.4 Whether the proposed Small Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

32.2.4.4.3.5 Whether operational flexibility is reduced by the proposed Small Generating Facility, such that transfer of the line section(s) of the Small Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

32.2.4.4.3.6 Whether the proposed Small Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

32.2.4.5 If the proposed interconnection passes the supplemental screens in Sections 32.2.4.4.1, 32.2.4.4.2, and 32.2.4.4.3 above, the Interconnection Request shall be approved and the ISO will provide the Interconnection Customer and the Connecting Transmission Owner with an executable interconnection agreement with the timeframes established in Sections 32.2.4.5.1 and 32.2.4.5.2 below. If the proposed interconnection fails any of the supplemental review screens and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the Section 32.3 Study Process consistent with Section 32.2.4.5.3 below.

32.2.4.5.1 If the proposed interconnection passes the supplemental screens in Sections 32.2.4.4.1, 32.2.4.4.2, and 32.2.4.4.3 above and does not require construction of facilities by the Connecting Transmission Owner on its own system, the interconnection agreement shall be provided within ten Business Days after the notification of the supplemental review results.

32.2.4.5.2 If interconnection facilities or Minor Modifications to the Connecting Transmission Owner's system are required for the proposed interconnection to pass the supplemental screens in Sections 32.2.4.4.1, 32.2.4.4.2, and 32.2.4.4.3 above, and the Interconnection Customer agrees to pay for the modifications to the Connecting Transmission Owner's electric system, the interconnection agreement, along with a non-binding good faith estimate for the interconnection facilities and/or Minor Modifications, shall be provided to the Interconnection Customer within 15 Business Days after receiving written notification of the supplemental review results.

32.2.4.5.3 If the proposed interconnection would require more than interconnection facilities or Minor Modifications to the Connecting Transmission Owner's system to pass the supplemental screens in Sections 32.2.4.4.1, 32.2.4.4.2, and 32.2.4.4.3 above, the ISO shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the Section 32.3 Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

32.3 Study Process

32.3.1 General Provisions

32.3.1.1 Except as otherwise provided in the SGIPs, the Section 32.3 Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility with the New York State Transmission System or Distribution System if the Small Generating Facility is no larger than 20 MW and does not meet the eligibility requirements of Section 32.2.1 or did not pass the Fast Track Process or the 10 kW Inverter Process.

32.3.1.2 The Interconnection Studies conducted under these procedures shall consist of analyses designed to identify the Interconnection Facilities and Upgrades required for the reliable interconnection of the Small Generating Facility to the New York State Transmission System or the Distribution System. These Interconnection Studies will be performed in accordance with Applicable Reliability Standards. The ISO will perform, or cause to be performed, the Interconnection Studies with input, as required, from the Connecting Transmission Owner.

32.3.2 Scoping Meeting

32.3.2.1 A scoping meeting will be held within ten Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The ISO, the Connecting Transmission Owner, and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting. Before a Connecting Transmission Owner participates in a scoping meeting with its Affiliates, the ISO shall post on its OASIS an advance notice of the Connecting Transmission Owner's intent to do so.

32.3.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the ISO should perform an optional feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. The Connecting Transmission Owner and Affected Transmission Owner(s), identified pursuant to Section 32.4.10 of this Attachment Z, shall be prepared to provide input regarding proposed Point(s) of Interconnection and configurations. If, within five (5) Business Days after the Scoping Meeting, the Interconnection Customer advises the ISO that it elects to proceed with an optional feasibility study, the ISO shall provide the Interconnection Customer and the Connecting Transmission Owner, as soon as possible, a non-binding good faith estimate of the cost and timeframe to perform the study. At the Interconnection Customer's option, the ISO, Connecting Transmission Owner or the Interconnection Customer may provide input regarding alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in the optional feasibility study. On the basis of the meeting, the Interconnection Customer shall designate its Point of Interconnection and one or more alternative Point(s) of Interconnection. An Interconnection Customer electing to evaluate alternative Point(s) of Interconnection must proceed through an optional feasibility study and must select the definitive Point of Interconnection for the proposed Small Generating Facility no later than the commencement of the interconnection study following the optional feasibility study.

32.3.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested an optional feasibility study must submit the study deposit pursuant to Section 32.3.3.2 of this Attachment Z and technical data requested by the ISO within fifteen (15) Business Days from the ISO's notice providing a good faith estimate of the cost and timeframe of the study. If the Interconnection Customer does not provide the required study deposit within fifteen (15) Business Days after the ISO's notice to the Interconnection Customer and the Connecting Transmission Owner of the good faith estimate of the cost and timeframe for completing the optional feasibility study, the Interconnection Customer will be subject to withdrawal. If the Interconnection Customer does not provide all required technical data, the ISO shall notify the Interconnection Customer of the deficiency and the Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such ability to cure technical deficiencies does not apply to failure to submit the required deposit. The ISO shall notify the Interconnection Customer and the Connecting Transmission Owner that the optional feasibility study has commenced following receipt of the required deposit and once the ISO deems the required technical data sufficient.

If the Interconnection Customer opts to forego the optional feasibility study, the Interconnection Customer shall, within five (5) Business Days after the Scoping Meeting advise the ISO that it elects not to proceed with an optional feasibility study, after which the ISO shall, as soon as practicable, provide the Interconnection Customer and the Connecting Transmission Owner, a non-binding good faith estimate of the cost and timeframe to perform the system impact study.

32.3.3 Optional Feasibility Study Scope and Procedures

32.3.3.1 The optional feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the Small Generating Facility.

32.3.3.2 A deposit of $10,000 or $30,000, depending upon the scope of analysis requested by the Interconnection Customer pursuant to Section 32.3.3.3 of this Attachment Z, must be submitted to the ISO within fifteen (15) Business Days of the ISO's notice of the good faith estimate of the cost and timeframe to perform the study.

32.3.3.3 The optional feasibility study may consist of any of the following technical analyses as described in the study scope:

For a $10,000 optional feasibility study deposit, Interconnection Customer may request the following limited analyses:

(1) Conceptual breaker-level one-line diagram of existing system where project proposes to interconnect (i.e., how to integrate the Small Generating Facility into the existing system); and/or

(2) Review of feasibility/constructability of conceptual breaker-level one-line diagram of the proposed interconnection (e.g., space for additional breaker

bay in existing substation; identification of cable routing concerns inside existing substation; environmental concerns inside the substation).;

For a $30,000 optional feasibility study deposit, Interconnection Customer may request the following detailed analyses:

(1) Development of conceptual breaker-level one-line diagram of existing NYS Transmission System or Distribution System where the Small Generating Facility proposes to interconnect (i.e., how to integrate the Small Generating Facility into the existing system);

(2) Review of feasibility/constructability of a conceptual breaker-level one-line diagram of the proposed interconnection (e.g., space for additional breaker bay in existing substation or identification of cable routing concerns inside existing substation);

(3) Preliminary review of local protection, communication, grounding issues associated with the proposed interconnection;

(4) Power flow, short circuit and/or bus flow analyses; and/or

(5) Identification of Connecting Transmission Owner Interconnection Facilities and Local System Upgrade Facilities with a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

The scope of the optional feasibility study will be provided to the Interconnection Customer and Connecting Transmission Owner for review and comment. After the study scope is finalized, the ISO will provide the final scope to the Connecting Transmission Owner and the Interconnection Customer. The Connecting

Transmission Owner shall indicate its agreement to the optional feasibility study scope by signing it and promptly returning it to the ISO, such agreement not to be unreasonably withheld.

32.3.3.4 The ISO may request additional information from the Interconnection Customer and Connecting Transmission Owner as may reasonably become necessary consistent with Good Utility Practice during the course of the optional feasibility study. Upon request from the ISO for additional information required for or related to the optional feasibility study, the Interconnection Customer and Connecting Transmission Owner shall provide such additional information in a prompt manner.

32.3.3.5 Connecting Transmission Owner and any Affecting Transmission Owners, together with the Interconnection Customer, will be provided with drafts of the optional feasibility study report for review. Review and comments shall be provided to the ISO within fifteen (15) Business Days of receipt.

32.3.3.6 If the optional feasibility study shows no potential for adverse system impacts and the ISO, Connecting Transmission Owner and Interconnection Customer all agree no system impact study is required, the ISO shall notify the Interconnection Customer and the Connecting Transmission Owner within five (5) Business Days of the completion of the optional feasibility study that the system impact study has been waived and shall send the Interconnection Customer and the Connecting Transmission Owner a facilities study agreement, which shall include an outline of the scope of the study and a non-binding good faith estimate of the cost and timeframe to perform the facilities study. If no additional facilities are required, the ISO shall send the Interconnection Customer and Connecting Transmission Owner a draft interconnection agreement within five (5) Business Days.

32.3.3.7 If the optional feasibility study shows the potential for adverse system impacts, the review process shall proceed to the system impact study.

32.3.4 System Impact Study

32.3.4.1 The Interconnection Customer shall advise the ISO that it elects to proceed with a system impact study within five (5) Business Days after either the delivery of the final optional feasibility study report to the Interconnection Customer or the scoping meeting, if the Interconnection Customer opts to forego the optional feasibility study. As soon as practicable after receipt of such election from the Interconnection Customer, the ISO shall provide to the Interconnection Customer and Connecting Transmission Owner a good faith estimate of the cost and timeframe for completing the system impact study.

A system impact study shall identify and detail the electric system impacts that would result if the proposed Small Generating Facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the optional feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

32.3.4.2 If the ISO, Connecting Transmission Owner and Interconnection Customer mutually agree that no system impact study is required, , the ISO shall send the Interconnection Customer and the Connecting Transmission Owner a facilities study agreement (in the form of Appendix 6) as soon as practicable after (1) transmittal of the final optional feasibility study report; or (2) confirmation that the ISO, Connecting Transmission Owner and Interconnection Customer mutually agree to waive the system impact study if the Interconnection Customer elects to skip the optional feasibility study. The ISO shall include, with the facilities study agreement tendered to the Interconnection Customer, an outline of the scope of the facilities study and a non-binding good faith estimate of the cost and timeframe to perform the study.

32.3.4.3 In order to remain under consideration for interconnection, unless the system impact study is waived upon mutual agreement of the ISO, Connecting Transmission Owner and Interconnection Customer, the Interconnection Customer must submit the required system impact study deposit set forth in Section 32.3.4.4 of this Attachment Z and the technical data requested by the ISO to the ISO within fifteen (15) Business Days of the ISO's notice of good faith estimate of the cost and timeframe to perform the system impact study.

32.3.4.4 A deposit of $50,000 for the system impact study must be submitted by the Interconnection Customer with the executed system impact study within fifteen (15) Business Days of the ISO's notice of good faith estimate of the cost and timeframe to perform the system impact study to the Interconnection Customer. If the Interconnection Customer does not provide the required study deposit within fifteen (15) Business Days after the ISO's notice to the

Interconnection Customer and the Connecting Transmission Owner of the good faith estimate of the cost and timeframe for completing the SIS, the Interconnection Customer will be subject to withdrawal. If the Interconnection Customer does not provide all required technical data, the ISO shall notify the Interconnection Customer of the deficiency and the Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such ability to cure technical deficiencies does not apply to failure to submit the required deposit. The ISO shall notify the Interconnection Customer and the Connecting Transmission Owner that the system impact study has commenced following receipt of the required deposit and once the ISO deems the required technical data sufficient.

32.3.4.5 The scope of and cost responsibilities for a system impact study shall be described in the system impact study scope. The scope of the system impact study will be provided to the Interconnection Customer and Connecting Transmission Owner for review and comment. After the study scope is finalized, the ISO will provide the final scope to the Connecting Transmission Owner and the Interconnection Customer. The Connecting Transmission Owner shall indicate its agreement to the system impact study scope by signing it and promptly returning it to the ISO, such agreement not to be unreasonably withheld. For an Interconnection Customer proposing an incremental increase in output to an existing Small Generating Facility, the total output of which does not exceed 20 MW, the system impact study scope may be narrowed upon mutual agreement among the ISO, Connecting Transmission Owner and Interconnection Customer.

32.3.4.6 The ISO may request additional information from the Interconnection Customer and Connecting Transmission Owner as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. Upon request from the ISO for additional information required for or related to the system impact study, Interconnection Customer and Connecting Transmission Owner shall provide such additional information in a prompt manner.

32.3.4.7 Affected Systems shall participate in the system impact study and provide all information necessary to prepare the study.

32.3.4.8 Connecting Transmission Owner and any Affecting Transmission Owners, together with Interconnection Customer, will be provided drafts of the system impact study report for review. Review and comments shall be provided to the ISO within fifteen (15) Business Days of receipt.

32.3.5 Facilities Study

32.3.5.1 If a system impact study(s) is required, once the required system impact study(s) is completed, a system impact study report shall be prepared by the ISO and transmitted to the Interconnection Customer and the Connecting Transmission Owner. As soon as practicable after transmittal of the final system impact study report, the ISO will tender a facilities study agreement to the Interconnection Customer and Connecting Transmission Owner . If a system impact study(s) is not required, the NYISO shall provide the Interconnection Customer and the Connecting Transmission Owner with a facilities study agreement as soon as practicable after that determination. Each facilities study agreement shall include an outline of the scope of the facilities study and a non-binding good faith estimate of the cost and timeframe to perform the facilities study.

32.3.5.2 In order to remain under consideration for interconnection, unless the ISO, Connecting Transmission Owner and Interconnection Customer mutually agree to waive the facilities study, the Interconnection Customer must return the executed facilities study agreement within 30 Calendar Days, together with the required technical data set forth in Appendix 6 and the required deposit equal to the non-binding good faith estimate of the cost and timeframe to perform the facilities study. The ISO and Connecting Transmission Owner shall execute the facilities study agreement no later than ten (10) Business Days after the ISO confirms receipt of the executed facilities study agreement, the study deposit and required technical data from the Interconnection Customer. The ISO shall provide a copy of the fully executed facilities study agreement to the Interconnection Customer and Connecting Transmission Owner.

32.3.5.3 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s), as appropriate. Connecting Transmission Owner and any Affecting Transmission Owners, together with the Interconnection Customer, will be provided with drafts of the facilities study report for review. Review and comments shall be provided to the ISO within fifteen (15) Business Days of receipt.

32.3.5.3.1 The Interconnection Customer shall be responsible for the cost of the Interconnection Facilities and Distribution Upgrades necessary to accommodate its Interconnection Request.

32.3.5.3.2 The Interconnection Customer shall be responsible for the cost of any System Upgrade Facilities determined by an Interconnection Study to be necessary to accommodate the Interconnection Request. Such Interconnection Study shall be of sufficient detail and scope to assure that this determination can be made. If any System Upgrade Facilities other than Local System Upgrade Facilities are determined to be necessary to accommodate the Interconnection Request, the Small Generating Facility shall be evaluated as a member of the next Class Year, and the Interconnection Customer's cost responsibility shall be determined in accordance with Attachment S. All other Small Generating Facilities (i.e., those for which no System Upgrade Facilities or only Local System Upgrade Facilities have been identified as necessary to accommodate the Interconnection Request) shall complete an individual Facilities Study, if required, under these Small Generator Interconnection Procedures. The standard described above in this Section regarding when a Small Generating Facility must enter a Class Year will apply to Small Generating Facilities being considered for entry into Class Year 2011 and beyond. To the extent appropriate, the ISO will notify any Affected System or transmission owner prior to the determination that System Upgrade Facilities are necessary, to allow for potential input by the Affected System or transmission owner. For purposes of this section, Affected System may include the portions of the New York State Transmission System that may be potentially affected. If the Interconnection Customer elects Capacity Resource Interconnection Service, and its Small Generating Facility is larger than 2 MW, it will be evaluated as a member of the next Class Year to determine the Interconnection Customer's responsibility for System Deliverability Upgrades in accordance with Attachment S.

32.3.5.3.3 At any time prior to the Class Year Start Date, as specified in Section 25.5.9 of Attachment S to the OATT, the Interconnection Customer may elect to proceed under this Section 32.3.5.3.3. Pending the outcome of the Class Year cost allocation process, the Interconnection Customer can elect to proceed with the interconnection of its Small Generating Facility if in the SGIA (i) it agrees in writing to accept the final cost allocation results determined in the Class Year in accordance with Attachment S, (ii) it agrees in writing to pay cash or post Security in accordance with Attachment S in that Class Year; and (iii) it agrees in writing to operate its Small Generating Facility within the limits of the current New York State Transmission System, as determined by the ISO, in consultation with the Connecting Transmission Owner; pursuant to Section 32.3.5.3.4 of the SGIP.

32.3.5.3.4 Upon the request and at the expense of the Interconnection Customer, the ISO, in consultation with the Connecting Transmission Owner, will perform operating studies on a timely basis to determine the extent to which the Interconnection Customer's Small Generating Facility can be operated prior to the installation of any System Upgrade Facilities or System Deliverability Upgrades required for that Small Generating Facility. Such tests shall be consistent with

Applicable Reliability Standards and Good Utility Practice. To the extent appropriate, the ISO will notify any Affected System or transmission owner prior to the determination to allow for potential input by the Affected System or transmission owner. For purposes of this section, Affected System may include the portions of the New York State Transmission System that may be potentially affected. The ISO and Connecting Transmission Owner shall promptly notify the Interconnection Customer of the results of these studies and shall permit the Small Generating Facility to operate consistent with the results of such studies.

32.3.5.4 Design for any required Interconnection Facilities and/or Upgrades shall be performed under the facilities study agreement, these procedures and, if applicable, Attachment S of the ISO OATT. The ISO may contract with consultants to perform activities required under the facilities study agreement. The Parties may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Connecting Transmission Owner, under the provisions of the facilities study agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the ISO and/or Connecting Transmission Owner shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

32.3.5.5 A deposit of the good faith estimated costs for the facilities study will be required from the Interconnection Customer.

32.3.5.6 The scope of and cost responsibilities for the facilities study are described in the facilities study agreement in the form of Appendix 6. ISO may request additional information from the Interconnection Customer and Connecting Transmission Owner as may reasonably become necessary consistent with Good Utility Practice during the course of the facilities study. Upon request from the ISO for additional information required for or related to the facilities study, the Interconnection Customer and Connecting Transmission Owner shall provide such additional information in a prompt manner.

32.3.5.7 As soon as practicable upon completion of the facilities study, and with the agreement of the Interconnection Customer to pay for Interconnection Facilities and Upgrades identified in the facilities study, the ISO shall provide the Interconnection Customer and the Connecting Transmission Owner a draft interconnection agreement.

32.3.5.8 Following execution of the facilities study agreement, the Interconnection Customer shall submit to the ISO an updated proposed In-Service Date, an updated proposed Initial Synchronization Date and an updated proposed Commercial Operation Date every ninety (90) Calendar Days.

32.4 Provisions that Apply to All Interconnection Requests

32.4.1 Reasonable Efforts

The ISO, in consultation with the Connecting Transmission Owner, shall make reasonable efforts to meet all time frames provided in these procedures unless the ISO, Connecting Transmission Owner and Interconnection Customer agree to a different schedule. If either the ISO or Connecting Transmission Owner cannot meet a deadline provided herein, it shall notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

32.4.2 Disputes

32.4.2.1 The ISO, Connecting Transmission Owner and Interconnection Customer agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

32.4.2.2 In the event of a dispute, the Parties will first attempt to promptly resolve it on an informal basis. If the Parties cannot promptly resolve the dispute on an informal basis, then any Party shall provide the other Parties with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

32.4.2.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, any Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

32.4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (*e.g.*, mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. The result of this dispute resolution process will be binding only if the Parties agree in advance. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

32.4.2.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-third of any costs paid to neutral third-parties.

32.4.2.6 If no Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then any Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

32.4.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Federal Energy Regulatory Commission, state, or local regulatory requirements or the Connecting Transmission Owner's specifications.

32.4.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. The ISO and Connecting Transmission Owner must be given at least five Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

32.4.5 Confidentiality

32.4.5.1 Certain information exchanged by the Parties during the administration of these procedures shall constitute confidential information ("Confidential Information") and shall be subject to this Section 32.4.5. Confidential

Information shall mean any confidential and/or proprietary information provided by one Party to another Party or Parties that is clearly marked or otherwise designated "Confidential." For purposes of these procedures, all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such. Confidential Information shall include, without limitation, information designated as such by the ISO Code of Conduct contained in Attachment F to the ISO OATT.

32.4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted to or divulged by Governmental Authorities (after notice to the other Parties and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce an interconnection agreement entered into pursuant to these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

32.4.5.2.1. Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Parties as it employs to protect its own Confidential Information.

32.4.5.2.2. Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential

Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

32.4.5.3 Notwithstanding anything in this Section 32.4.5 to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Section 32.4.5, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Each Party is prohibited from notifying the other Parties prior to the release of the Confidential Information to FERC. The Party shall notify the other Parties when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

32.4.6 Comparability

The ISO shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this document. The ISO and Connecting Transmission Owner shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all

Interconnection Customers, whether the Small Generating Facility is owned or operated by the Connecting Transmission Owner, its subsidiaries or affiliates, or others.

32.4.7 Record Retention

The ISO and Connecting Transmission Owner shall maintain for three years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

32.4.8 Interconnection Agreement

As soon as practicable upon completion of all required interconnection studies, or, if the Interconnection Customer elects to enter a Class Interconnection Facilities Study, upon completion of the decision process described in Section 25.8 of Attachment S for the Class Interconnection Facilities Study and acceptance by the Interconnection Customer of its Attachment S cost allocation, and satisfaction of the Security posting requirements described in Attachment S, the ISO shall tender to the Interconnection Customer and Connecting Transmission Owner a draft Standard Small Generator Interconnection Agreement together with draft attachments completed to the extent practicable. Upon such tender, the Interconnection Customer shall provide the ISO with an updated proposed In-Service Date, an updated proposed Initial Synchronization Date, and an updated proposed Commercial Operation Date. Such dates are subject to the limitations set forth in Section 30.4.4.5 of Attachment X to the OATT.

The draft Standard Small Generator Interconnection Agreement shall be in the form of the ISO's Commission-approved Standard Small Generator Interconnection Agreement, which is in Appendix 7 to this Attachment Z. Unless otherwise agreed by the Parties, if the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted within six (6) months after tender of the draft interconnection agreement, the Interconnection Request shall be deemed withdrawn. After the interconnection agreement is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

32.4.9 Termination of the Standard Small Generator Interconnection Agreement

The classification of a Small Generating Facility as Retired will be grounds for the termination of the Small Generator Interconnection Agreement (SGIA).   The ISO will file with the Federal Energy Regulatory Commission a notice of termination of the SGIA as soon as practicable after the Small Generating Facility is Retired. The termination of a non-conforming *pro forma* SGIA will be effective only upon acceptance by the Federal Energy Regulatory Commission of the notice of termination and proposed effective date. Upon the effective date of the termination of the SGIA, access to the Point of Interconnection of the Small Generating Facility will be available on a non-discriminatory basis pursuant to the ISO's applicable interconnection and transmission expansion processes and procedures.

32.4.10 Coordination with Affected Systems

The ISO shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators, as soon as they are identified – either by their own accord, by the Connecting Transmission Owner, or by the ISO – and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The ISO will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the ISO and Connecting Transmission Owner in all matters related to the conduct of studies and the determination of modifications to Affected Systems. Each Affected System Operator and/or Affected System shall cooperate with the ISO and Connecting Transmission Owner with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems. The Parties to this Agreement shall cooperate in good faith to provide each other, Affected System Operators and Affected Systems the information necessary to carry out the terms of the SGIP and the SGIA.

For identified Affected Transmission Owner(s) of facilities electrically adjacent to the Point of Interconnection and that have design criteria, operational criteria or other local planning criteria applicable to either (1) the substation to which the Interconnection Customer proposes to interconnect; or (2) the substation that will be required to be built to accommodate the interconnection, the ISO shall provide such Affected Transmission Owner(s) with the opportunity to review and provide comments on all study scopes, study reports and drafts thereof for the project, and will be included on communications regarding the project and meetings discussing the project or any of its studies, where such communications or meetings involve the ISO, Interconnection Customer and Connecting Transmission Owner. The ISO shall include in the appropriate interconnection study proposed studies requested by such an identified Affected Transmission Owner to the extent such studies are reasonably justified in accordance with Good Utility Practice.

32.4.11 Capacity of the Small Generating Facility

32.4.11.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total capacity of the Small Generating Facility. The reliability impact of all increases in the capacity of an existing Small Generating Facility will be evaluated by applying the NYISO Minimum Interconnection Standard. An existing Small Generating Facility interconnected with Capacity Resource Interconnection Service may, over the life of the facility, increase its capacity by a total of 2 MW above its originally established Capacity Resource Interconnection Service capacity value without having the deliverability of that 2 MW increase evaluated under the NYISO Deliverability Interconnection Standard. The deliverability impact of all increases greater than 2 MW over the life of the facility will be evaluated by applying the NYISO Deliverability Interconnection Standard in accordance with the SGIP and Attachment S to the ISO OATT.

32.4.11.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

32.4.11.3 The Interconnection Request shall be evaluated using the maximum capacity that the Small Generating Facility is capable of injecting into the Connecting Transmission Owner's electric system. However, if the maximum capacity that the Small Generating Facility is capable of injecting into the Connecting Transmission Owner's electric system is limited (*e.g.,* through the use of a control system, power relay(s), or other similar device settings or adjustments), then the Interconnection Customer must obtain the ISO's and Connecting Transmission Owner's agreement, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to implement such a limit will not adversely affect the safety and reliability of the Connecting Transmission Owner's system. If the Connecting Transmission Owner does not so agree, then the Interconnection Request must be withdrawn or revised to specify the maximum capacity that the Small Generating Facility is capable of injecting into the Connecting Transmission Owner's electric system without such limitations. Furthermore, nothing in this section shall prevent a Connecting Transmission Owner from considering an output higher than the limited output, if appropriate, when evaluating system protection impacts.

32.5 Appendices

Appendix 1 - Glossary of Terms

Terms used in the SGIP or SGIA with initial capitalization that are not defined in this Glossary shall have the meanings specified in Attachment X or Attachment S to the ISO OATT, or in Article 2 of the ISO Services Tariff.

10 kW Inverter Process – The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the Section 32.2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Appendix 5.

Affected System – An electric system other than the transmission system owned, controlled or operated by the ISO or Connecting Transmission Owner that may be affected by the proposed interconnection.

Affected System Operator – Affected System Operator shall mean the operator of any Affected System.

Affected Transmission Owner – The New York public utility or authority (or its designated agent) other than the Connecting Transmission Owner that: (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, and (ii) owns, leases or otherwise possesses an interest in a portion of the New York State Transmission System where System Deliverability Upgrades or System Upgrade Facilities are installed pursuant to Attachment Z and Attachment S to the ISO OATT.

Applicable Reliability Standards – The criteria, requirements and guidelines of the North American Electric Reliability Council, the Northeast Power Coordinating Council, the New York State Reliability Council and related and successor organizations, and the Transmission District to which the Interconnection Customer's Small Generating Facility is directly interconnected, as those criteria, requirements and guidelines are amended and modified and in effect from time to time; provided that no Party shall waive its right to challenge the applicability of or validity of any criterion, requirement or guideline as applied to it in the context of Attachment Z to the ISO OATT. For the purposes of the SGIP, this definition of Applicable Reliability Standards shall supersede the definition of Applicable Reliability Standards set out in Attachment X to the ISO OATT.

Base Case – The base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the ISO, Connecting Transmission Owner or Interconnection Customer; described in Section 30.2.3 of the Large Facility Interconnection Procedures.

Business Day – Monday through Friday, excluding federal holidays.

Capacity Resource Interconnection Service – The service provided by the ISO to Interconnection Customers that satisfy the NYISO Deliverability Interconnection Standard or that are otherwise eligible to receive CRIS in accordance with Attachment S to the ISO OATT; such service being one of the eligibility requirements for participation as an ISO Installed Capacity Supplier.

Class Year shall mean the group of generation and merchant transmission projects included in any particular Class Year Interconnection Facilities Study (Annual Transmission Reliability Assessment and/or Class Year Deliverability Study), in accordance with the criteria specified in Attachment S and in Attachment Z for including such projects.

Class Year Project shall mean an Eligible Class Year Project with an executed Class Year Interconnection Facilities Study Agreement that thereby becomes one of the group of generation and Merchant Transmission Facilities included in any particular Class Year Interconnection Facilities Study (Annual Transmission Reliability Assessment and/or Class Year Deliverability Study), in accordance with the criteria specified in Attachment S and in Attachment Z for including such projects.

Class Year Start Date shall mean the deadline for Eligible Class Year Projects to enter a Class Year Interconnection Facilities Study, determined in accordance with Section 25.5.9 of Attachment S.

Connecting Transmission Owner – The New York public utility or authority (or its designated agent) that: (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, (ii) owns, leases or otherwise possesses an interest in the portion of the New York State Transmission System or Distribution System at the Point of Interconnection, and (iii) is a Party to the Standard Small Generator Interconnection Agreement.

Distribution System – The Transmission Owner's facilities and equipment used to distribute electricity that are subject to FERC jurisdiction, and are subject to the ISO's Large Facility Interconnection Procedures in Attachment X to the ISO OATT or Small Generator Interconnection Procedures in Attachment Z to the ISO OATT under FERC Order Nos. 2003 and/or 2006. For the purpose of the SGIP, the term Distribution System shall not include LIPA's distribution facilities.

Distribution Upgrades – The modifications or additions to the Transmission Owner's existing Distribution System at or beyond the Point of Interconnection that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Minimum Interconnection Standard. Distribution Upgrades do not include Interconnection Facilities or System Upgrade Facilities or System Deliverability Upgrades.

Eligible Class Year Project: Any Developer or Interconnection Customer that: (1) satisfies the criteria for inclusion in the next Class Year Interconnection Facilities Study, as those criteria are specified in Sections 25.5.9 and 25.6.2.3.1 of Attachment S to the OATT, Section 32.1.1.7 of this Attachment Z and/or Section 32.3.5.3.2 of this Attachment Z; or (2) that seeks evaluation in a Class Year Study to obtain or increase CRIS as permitted by Attachment S to the ISO OATT and satisfies the criteria for inclusion in the next Class Year Interconnection Facilities Study specified in Section 25.5.9 of Attachment S to the OATT.

Energy Resource Interconnection Service – The service provided by the ISO to interconnect the Interconnection Customer's Small Generating Facility to the New York State Transmission System or Distribution System in accordance with the NYISO Minimum Interconnection Standard, to enable the New York State Transmission System to receive Energy and Ancillary Services from the Small Generating Facility, pursuant to the terms of the ISO OATT.

Fast Track Process – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility that meets the eligibility requirements of Section 32.2.1 of the SGIP and includes the Section 32.2 screens, customer options meeting, and optional supplemental review.

Force Majeure – Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, the absence of any necessary governmental approvals timely applied for, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. For the purposes of this Attachment Z, this definition of Force Majeure shall supersede the definitions of Force Majeure set out in Section 2.11 of the ISO OATT.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, the ISO, Affected Transmission Owner, Connecting Transmission Owner or any Affiliate thereof.

Interconnection Customer – Any entity, including the Connecting Transmission Owner or any of its affiliates or subsidiaries, that proposes to interconnect its Small Generating Facility with the New York State Transmission System or the Distribution System.

Interconnection Facilities – The Connecting Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the New York State Transmission System or the Distribution System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or System Upgrade Facilities.

Interconnection Request – The Interconnection Customer's request, in accordance with these procedures, (i) to interconnect a new Small Generating Facility to the New York State Transmission System or the Distribution System, or (ii) to materially increase the capacity of, or make a material modification to the operating characteristics of, an existing Small Generating Facility that is interconnected to the New York State Transmission System or the Distribution System. For the purposes of this Attachment Z, this definition of Interconnection Request shall supersede the definition of Interconnection Request set out in Attachment X to the ISO OATT.

Interconnection Study – Any study required to be performed under Sections 32.2 or 32.3 of the SGIP.

Local System Upgrade Facilities shall mean the System Upgrade Facilities necessary to physically interconnect a proposed project to the Connecting Transmission Owner's transmission system, consistent with applicable interconnection and system protection design standards. Local System Upgrade Facilities include any electrical facilities required to make the physical connection (*e.g.,* a new ring bus for a line connection or facilities required to create a new bay for a substation connection). Local System Upgrade Facilities also include any system protection or communication facilities that may be required for protection of the Connecting Transmission Owner's transmission facility (line or substation) involved in the interconnection. Local System Upgrade Facilities do not include System Upgrade Facilities required to mitigate any adverse reliability impact(s) of the project(s) identified through analysis such as power flow, short circuit, or stability (e.g., replacement of a circuit breaker at a nearby substation that becomes overdutied as a result of the project(s)).

Material Modification – A modification that has a material adverse impact on the cost or timing of any Interconnection Request with a later queue priority date.

Minor Modification – Modifications that will not have a material adverse impact on the cost or timing of any Interconnection Request.

New York State Transmission System - The entire New York State electric transmission system, which includes (i) the Transmission Facilities under ISO Operational Control; (ii) the Transmission Facilities Requiring ISO Notification; and (iii) all remaining transmission facilities within the New York Control Area.

NYISO Deliverability Interconnection Standard – The standard that must be met, unless otherwise provided for by Attachment S to the ISO OATT, by (i) any generation facility larger than 2MW in order for that facility to obtain CRIS; (ii) any Merchant Transmission Facility proposing to interconnect to the New York State Transmission System and receive Unforced Capacity Delivery Rights; (iii) any entity requesting External CRIS Rights, and (iv) any entity requesting a CRIS transfer pursuant to Section 25.9.5 of Attachment S to the ISO OATT. To meet the NYISO Deliverability Interconnection Standard, the Interconnection Customer must, in accordance with the rules in Attachment S to the ISO OATT, fund or commit to fund any System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

NYISO Minimum Interconnection Standard – The reliability standard that must be met by any generation facility or Merchant Transmission Facility that is subject to ISO's Large Facility

Interconnection Procedures in Attachment X to the ISO OATT or the ISO's Small Generator Interconnection Procedures in this Attachment Z, that is proposing to connect to the New York State Transmission System or Distribution System, to obtain ERIS. The Minimum Interconnection Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System or to the Distribution System. The Minimum Interconnection Standard does not impose any deliverability test or deliverability requirement on the proposed interconnection.

Open Class Year – The Class Year open for new members pursuant to the Class Start Date deadline specified in Section 25.5.9 of Attachment S to the OATT.

Party or Parties – The ISO, Connecting Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the New York State Transmission System or the Distribution System.

Queue Position – The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the ISO or by the Connecting Transmission Owner under Section 32.1.7.

Retired: A Generator that has permanently ceased operating on or after the effective date of Section 5.18 of the Services Tariff either: i) pursuant to applicable notice; or ii) as a result of the expiration of its Mothball Outage or the expiration of its ICAP Ineligible Forced Outage.

Small Generating Facility – The Interconnection Customer's device no larger than 20 MW for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Study Process – The procedure for evaluating an Interconnection Request that includes the Section 32.3 scoping meeting, feasibility study, system impact study, and facilities study.

System Deliverability Upgrades – The least costly configuration of commercially available components of electrical equipment that can be used, consistent with Good Utility Practice and Applicable Reliability Requirements, to make the modifications or additions to the existing New York State Transmission System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Deliverability Interconnection Standard for Capacity Resource Interconnection Service.

System Upgrade Facilities – The least costly configuration of commercially available components of electrical equipment that can be used, consistent with good utility practice and Applicable Reliability Requirements to make the modifications to the existing transmission system that are required to maintain system reliability due to: (i) changes in the system, including such changes as load growth and changes in load pattern, to be addressed in the form of generic generation or transmission projects; and (ii) proposed interconnections. In the case of proposed interconnection projects, System Upgrade Facilities are the modifications or additions to the existing New York State Transmission System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Minimum Interconnection Standard.

Upgrades – The required additions and modifications to the Connecting Transmission Owner's portion of the New York State Transmission System or the Distribution System at or beyond the Point of Interconnection. Upgrades may be System Upgrade Facilities or System Deliverability Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Appendix 2 - SMALL GENERATOR INTERCONNECTION REQUEST (Application Form)

An Interconnection Request is considered complete when it provides all applicable and correct information required below, together with the required application fee, submitted to the ISO . Per SGIP section 32.1.5, documentation of the site control must be submitted with the Interconnection Request.

Preamble and Instructions

An Interconnection Customer who requests an interconnection to the New York State Transmission System or the Distribution System must submit this Interconnection Request by e-mail to the ISO at NewProject@nyiso.com. The ISO will send a copy to the Connecting Transmission Owner.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is $500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the ISO a non-refundable application fee of $1,000.

Interconnection Service Options

An Interconnection Customer may interconnect its new Small Generating Facility by electing to take either Energy Resource Interconnection Service ("ERIS") or ERIS and Capacity Resource Interconnection Service ("CRIS"). The rights and obligations associated with each alternative are different. The Interconnection Customer should consult Section 32.1.1.7 of the Small Generator Interconnection Procedures for additional information, and should direct any questions about the alternatives to the ISO.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name of Interconnection Customer:____

Contact Person:____

Mailing Address:____

City:________________________ State:______________ Zip:__________________

Facility Location (if different from above):______________________________________

Telephone :________________________

E-Mail Address:____________________

Additional Contact Information

Contact Name:____

Title:____

Address:____

____

Telephone:_________________________

E-Mail Address:____________________

Application is for: _________ New Small Generating Facility
_________Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe:______________________________
____

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No___

To Supply Power to the Interconnection Customer? Yes ___ No___

To Supply Power to Others Through Wholesale Sales Over the New York State

Transmission System or Distribution System? Yes ___ No___

To Supply Power to a Host Load? Yes ___ No___

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

_________________________________ _________________________________
(Local Electric Service Provider) (Existing Account Number)

Local Electric Service Provider Contact Name:____

Title:____

Address:____

Telephone:_________________________

E-Mail Address:____________________

Project Name:____

Project Description: ____

Requested Point of Interconnection:____________________________________

Coordinates (*i.e.*, latitude and longitude) of the Proposed Point of Interconnection: __________

____

Interconnection Customer's Proposed In-Service Date:____________________________

Interconnection Customer's Proposed Initial Synchronization Date:____________________

Interconnection Customer's Proposed Commercial Operation Date:____________________

Small Generating Facility Information

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___Solar ___Wind ___Hydro ___Hydro Type (e.g. Run-of-River):________
Diesel ___Natural Gas ___Fuel Oil ___ Other (state type)________________________

Prime Mover: ___Fuel Cell ___Recip Engine ___Gas Turb ___Steam Turb
___Microturbine ___PV ___Other

Type of Generator: ____Synchronous ____Induction ____Inverter

Generator Nameplate Rating: _______kW (Typical) Generator Nameplate kVAR:_______

If solar array, fixed, 1-axis, 2-axis, 2-axis flat panel, 2-axis CPV, CSP, etc.): _________________

Interconnection Customer or Customer-Site Load:________________kW (if none, so state)

Existing load? Yes ___ No___

If existing load with metered load data, provide coincident Summer peak load: ________

If new load or existing load without metered load data, provide estimated coincident Summer peak load, together with supporting documentation for such estimated value: ________

Typical Reactive Load (if known):__________________________

Maximum Physical Export Capability Requested:___________ kW

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1.____________________________	______________________________
2.____________________________	______________________________
3.____________________________	______________________________
4.____________________________	______________________________
5.____________________________	______________________________

Is the prime mover compatible with the certified protective relay package? ____Yes ____No

Generator (or solar collector)
Manufacturer, Model Name & Number:____
Version Number:______________________________

Nameplate Output Power Rating in kW: (Summer) ______________ (Winter) ______________
Nameplate Output Power Rating in kVA: (Summer) _____________ (Winter) ______________

Individual Generator Reactive Capability in kVAR
Leading: _____________________________________ Lagging: _______________________

If wind, total number of generators in wind farm to be interconnected pursuant to this Interconnection Request: _________
Generator Height: ________________ ___Single phase ___Three Phase

Inverter Manufacturer, Model Name & Number (if used):__________________________________

Additional Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW.

- Is One-Line Diagram Enclosed? ____ Yes ____ No

Enclose copy of any Site Control documentation that indicates the precise physical location of the proposed Small Generating Facility (*e.g.*, USGS topographic map or other diagram or documentation).

- Site Control Documentation Enclosed? ____ Yes ____ No
- Site Control provided for the following number of acres: ______________________________

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer:
By (signature): ____
Name (type or print): ______________________________________
Title: ____
Company: ____
Date: ____

ATTACHMENT A TO APPENDIX 2 – SMALL GENERATOR INTERCONNECTION REQUEST– Terms and Conditions of Interconnection Study(ies)

These terms and conditions for the study of a Small Generating Facility or material modification to an existing Small Generating Facility proposed in the Interconnection Request dated __________(“the Project”)_and submitted by ____, a __________________ organized and existing under the laws of the State of _____________ (“Interconnection Customer”) sets forth the respective obligations between Interconnection Customer and the New York Independent System Operator, Inc., a not-for-profit corporation organized and existing under the laws of the State of New York (“NYISO”) (hereinafter the “Terms and Conditions”). By signing below, Interconnection Customer confirms its understanding and acceptance of the Terms and Conditions.

RECITALS

WHEREAS, the Interconnection Customer is proposing the Project; and

WHEREAS, the Interconnection Customer is already interconnected with the New York State Transmission System (or the Distribution System, as applicable) ir desires to interconnect the Small Generating Facility with the New York State Transmission System (or the Distribution System, as applicable); and

WHEREAS, the Interconnection Customer has requested NYISO to perform one or more of the following studies: Optional Feasibility Study or System Impact Study to assess the impact of the Project on the New York State Transmission System (or Distribution System, as applicable) and any Affected Systems;

Now, THEREFORE, in consideration of and subject to the terms and conditions contained herein, the Interconnection Customer and NYISO agree as follows:

1.0 When used in under these Terms and Conditions, with initial capitalization, the terms specified shall have the meanings specified in Section 32.1.1.2 of the Small Generator Interconnection Procedures (“SGIP”).

2.0 The Interconnection Customer shall elect and NYISO shall cause to be performed, in accordance with the NYISO Open Access Transmission Tariff (“OATT”), one or more of the following: Optional Feasibility Study consistent with Section 32.3.3 of the SGIP, or System Impact Study consistent Section 32.3.4 of the SGIP, collectively referred to as the “Studies.” The terms of the SGIP, as applicable, are incorporated by reference herein.

3.0 The scopes for the Studies that the Interconnection Customer elects or is required to be performed in connection with its Interconnection Request and in accordance with the SGIP shall be subject to the assumptions developed by the Interconnection Customer, NYISO, and the Connecting Transmission Owner(s) at the respective scoping meetings for each study and detailed in final written scopes in accordance with Sections 32.3.3.3 and 32.3.4.5 of the SGIP.

4.0 Each study performed in connection with the Interconnection Request and these Terms and Conditions will be based on the technical information provided by the Interconnection Customer in the Interconnection Request and shall build upon the results any study conducted under these Terms and Conditions, if applicable. NYISO reserves the right to request additional information from the Interconnection Customer as may reasonable become necessary consistent with Good Utility Practice during the course of the Studies (including dynamic modeling data). If the Interconnection Customer modifies its designated Point of Interconnection, the Interconnection Request, or the technical information provided in the Interconnection Request, the time to complete the Studies may be extended. The Interconnection Customer shall bear any increased costs to complete the Studies as a result of a modification under this Section 4.0 of these Terms and Conditions.

5.0 Optional Feasibility Study.

5.1 If elected by the Interconnection Customer, the Optional Feasibility Study shall provide, as necessary, the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

- If the Interconnection Customer elects to perform an Optional Interconnection Feasibility Study with a limited analysis (*i.e.*, $10,000 study deposit), the study shall analyze, to the extent selected by the Interconnection Customer:

    - conceptual breaker-level one-line diagram of existing system where project proposes to interconnect (*i.e.*, how to integrate the Small Generating Facility into the existing system); and/or

    - review of feasibility/constructability of conceptual breaker-level one-line diagram of the proposed interconnection (*e.g.*, space for additional breaker bay in existing substation; identification of cable routing concerns inside existing substation; environmental concerns inside the substation).

- If the Interconnection Customer elects to perform an Optional Interconnection Feasibility Study with a detailed analysis (*i.e.*, $30,000 study deposit), the study report shall provide, to the extent selected by the Interconnection Customer:

    - conceptual breaker-level one-line diagram of existing New York State Transmission System or Distribution System where the Large Facility proposes to interconnect (*i.e.*, how to integrate the Large Facility into the existing system);

    - review of the feasibility/constructability of a conceptual breaker-level one-line diagram of the proposed interconnection (*e.g.*, space for additional breaker bay in existing substation or identification of cable routing concerns inside existing substation);

- preliminary review of local protection, communication, and grounding issues associated with the proposed interconnection;

- power flow, short circuit, and/or bus flow analyses; and/or

- preliminary identification of Connecting Transmission Owner Attachment Facilities and Local System Upgrade Facilities with a non-binding good faith cost estimate of the Interconnection Customer's cost responsibility and a non-binding good faith estimated time to construct.

5.2 The Optional Feasibility Study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

5.3 The Optional Feasibility Study shall include, at the Interconnection Customer's cost, the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer.

6.0 System Impact Study.

6.1 The System Impact Study, unless otherwise waived upon the mutual agreement of the Interconnection Customer, NYISO, and the Connecting Transmission Owner(s) in accordance with Section 32.3.4 of the SGIP, shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. The System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The system impact study report shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.2 The System Impact Study shall consider all generating and merchant transmission facilities (and with respect to paragraph 6.1.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the System Impact Study commences under the SGIP,

- are directly interconnected with the New York State Transmission System or distribution facilities;

- are interconnected with Affected Systems and may have an impact on the proposed interconnection;

- have accepted their cost allocation for System Upgrade Facilities and posted security for such System Upgrade Facilities in accordance with Attachment S to the OATT; and

- have no queue position but have executed an interconnection agreement or requested that an unexecuted interconnection agreement be filed with the Federal Energy Regulatory Commission ("FERC").

6.3 Affected Systems may participate in the preparation of a System Impact Study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment on the System Impact Study to the extent the proposed interconnection potentially adversely impacts the Affected System's electric system. NYISO shall have an additional twenty (20) Business Days to complete a System Impact Study requiring review by Affected Systems.

7.0 The Interconnection Customer shall provide NYISO with a deposit for each study elected or required to be performed in connection with its proposed interconnection in accordance with Section 32.3.3.2 of the SGIP for an Optional Feasibility Study and/or Section 32.3.4.4 of the SGIP for a System Impact Study.

8.0 Any study costs incurred by NYISO shall be based on its actual costs, including applicable taxes, and will be invoiced to the Interconnection Customer after each respective study is completed and delivered to the Interconnection Customer, which will include a summary of professional time. The applicable rates that NYISO shall use to calculate its actual costs shall be provided to the Interconnection Customer at the time that NYISO provides the good faith estimate of the cost for each study elected or required to be performed in connection with the Interconnection Request and under these Terms and Conditions.

9.0 The Interconnection Customer shall pay all invoice amounts in excess of the deposit or other cash security without interest within thirty (30) calendar days after receipt of the invoice. If the deposit or other cash exceeds the invoiced fees, NYISO shall refund such excess amounts within thirty (30) calendar days of the invoice without interest. If the Interconnection Customer disputes an amount to be paid, the Interconnection customer shall pay the disputed amount to NYISO or into an interest bearing escrow account, pending resolution of the dispute in accordance with Section 32.4.2 of the SGIP. To the extent that the dispute is resolved in the Interconnection Customer's favor, that portion of the disputed amount will be returned to the Interconnection Customer with interest at rates applicable to refunds under the Commission's regulations. To the extent that the dispute is resolved in NYISO's favor, the portion of any escrowed funds and interest will be released to NYISO. NYISO and subcontractor consultants hired by NYISO shall not be obligated to perform or continue to perform any Interconnection Study work for the

Interconnection Customer unless the Interconnection Customer has paid all amounts in compliance herewith.

10.0 Miscellaneous.

10.1 Accuracy of Information. Except as the Interconnection Customer may otherwise specify in writing when it provides information to NYISO under these Terms and Conditions, the Interconnection Customer represents and warrants that the information it provides to NYISO shall be accurate and complete as of the date the information is provided. The Interconnection Customer shall promptly provide NYISO with any additional information needed to update information previously provided.

10.2 Disclaimer of Warranty. In preparing the Studies, NYISO and any subcontractor consultants hired by it shall have to rely on information provided by the Interconnection Customer, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, neither NYISO nor any subcontractor consultant hired by NYISO makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy, content, or conclusions of the Studies performed under these Terms and Conditions. The Interconnection Customer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

10.3 Limitation of Liability. In no event shall NYISO or its subcontractor consultants be liable for indirect, special, incidental, punitive, or consequential damages of any kind including loss of profits, arising under or in connection with these Terms and Conditions or the Studies performed or any reliance on the Studies by the Interconnection Customer or third parties, even if NYISO or its subcontractor consultants have been advised of the possibility of such damages. Nor shall any NYISO or its subcontractor consultants be liable for any delay in delivery or for the non-performance or delay in performance of its obligations under these Terms and Conditions.

10.4 Third-Party Beneficiaries. Without limitation of Sections 10.2 and 10.3 under these Terms and Conditions, the Interconnection Customer further agrees that subcontractor consultants hired by NYISO to conduct or review, or to assist in the conducting or reviewing, one or more of the Studies requested under the Interconnection Request shall be deemed third-party beneficiaries of these Sections 10.2 and 10.3 under these Terms and Conditions.

10.5 Term and Termination. The obligations to conduct the Studies and under these Terms and Conditions shall be effective from the date hereof and, unless earlier terminated under these Terms and Conditions, shall continue in effect until the

Studies are completed. The Interconnection Customer or NYISO may terminate their obligations under these Terms and Agreement upon the withdrawal of the Interconnection Customer's Interconnection Request under the SGIP.

10.6 Governing Law. These Terms and Conditions and any study performed thereunder shall be governed by and construed in accordance with the laws of the State of New York, without regard to any choice of laws provisions.

10.7 Severability. In the event that any part of these Terms and Conditions are deemed as a matter of law to be unenforceable or null and void, such unenforceable or void part shall be deemed severable from these Terms and Conditions and the obligations under these Terms and Conditions shall continue in full force and effect as if each part was not contained herein.

10.8 Amendment. No amendment, modification, or waiver of any term or condition hereof shall be effective unless set forth in writing and signed by the Interconnection Customer and NYISO hereto.

10.9 Survival. All warranties, limitations of liability, and confidentiality provisions provided herein shall survive the expiration or termination hereof.

10.10 Independent Contractor. Developer agrees that NYISO shall at all times be deemed to be an independent contractor and none of its employees or the employees of its subcontractors shall be considered to be employees of the Interconnection Customer as a result of performing any work under these Terms and Conditions.

10.11 No Implied Waivers. The failure of the Interconnection Customer or NYISO to insist upon or enforce strict performance of any of the provisions of these Terms and Conditions shall not be construed as a waiver or relinquishment to any extent of such party's right to insist or rely on any such provision, rights, and remedies in that or any other instances; rather, the same shall be and remain in full force and effect.

10.12 Successors and Assigns. The obligations under these Terms and Conditions, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Interconnection Customer and NYISO and their respective successors and assigns.

IN WITNESS THEREOF, the Interconnection Customer has agreed to accept and be bound by the Terms and Conditions by its duly authorized officers or agents execution on the day and year first below written.

____

[Insert name of Interconnection Customer]

By: ___________________

Title: ___________________

Date: ____________________Appendix 3 - Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.l-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-l992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Appendix 4 - Certification of Small Generator Equipment Packages

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if: (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Appendix 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

Appendix 5 - Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW ("10 kW Inverter Process")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the ISO. The ISO will send a copy to the Connecting Transmission Owner.

2.0 The ISO acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The ISO, in consultation with the Connecting Transmission Owner, evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The ISO, in consultation with the Connecting Transmission Owner, verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the SGIP. The ISO has 15 Business Days to complete this process. Unless the ISO, in consultation with the Connecting Transmission Owner, determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the ISO approves the Application and returns it to the Customer, with a copy to the Connecting Transmission Owner. Note to Customer: Please check with the ISO before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the ISO, and sends a copy to the Connecting Transmission Owner. Prior to parallel operation, the ISO, in consultation with the Connecting Transmission Owner, may inspect the Small Generating Facility for compliance with standards which may include a Connecting Transmission Owner witness test, and may schedule appropriate metering replacement, if necessary. The Customer shall cooperate with the ISO and the Connecting Transmission Owner to assure that the required inspection, witness test and/or metering replacement are completed within the timeframes outlined below.

6.0 The ISO notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Connecting Transmission Owner has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Connecting Transmission Owner is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion, unless the Connecting Transmission Owner and Customer agree otherwise. If the Connecting Transmission Owner does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

7.0 Contact Information – The Customer must provide the contact information for the legal applicant (*i.e.*, the Customer). If another entity is responsible for interfacing with the ISO and Connecting Transmission Owner, that contact information must be provided on the Application.

8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

10.0 The ISO is available to help resolve any disputes that may arise out of the proposed interconnection, in accordance with the procedures set forth in Section 32.4.2 of the SGIP in Attachment Z of the ISO OATT.

Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Per SGIP section 32.1.5, documentation of the site control must be submitted with the Interconnection Request. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of $100 must accompany this Application.

Interconnection Customer

Name of Interconnection Customer: ____

Address: ____

City: __________________________ State: ___________________ Zip:_______________

Telephone: _____________________________
E-Mail Address: _________________________

Point of Contact

Name: ____

Company: ____

Address: ____

City: __________________________ State: ___________________ Zip:_______________

Telephone: _____________________________

E-Mail Address: _________________________

Owner of the facility (include % ownership by any electric utility): ________________________

Small Generating Facility Information
Location (if different from above): ____
Electric Service Company: ____
Account Number: ____

Inverter Manufacturer: ______________________ Model__________________________________

Nameplate Rating: _____ (kW) _____ (kVA) _____ (AC Volts)

Single Phase _____ Three Phase______

System Design Capacity: __________ (kW) _________ (kVA)

Interconnection Customer or Customer-Site Load:________________kW (if none, so state)

Existing load? Yes ___ No___

If existing load with metered load data, provide coincident Summer peak load: ________

If new load or existing load without metered load data, provide estimated coincident Summer peak load: _________

Prime Mover: Photovoltaic ☐ Reciprocating Engine ☐ Fuel Cell ☐

Turbine ☐ Other ______________________

Energy Source: Solar ☐ Wind ☐ Hydro ☐ Diesel ☐ Natural Gas ☐

Fuel Oil ☐ Other (describe)__________________________________

Is the equipment UL1741 Listed? Yes____ No ____

If Yes, attach manufacturer's cut-sheet showing UL1741 listing

Estimated Installation Date:_________________ Estimated In-Service Date:_______________

The 10kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10kW that meet the codes, standards, and certification requirements of Appendices 3 and 4 of the SGIP, or the ISO, in consultation with the Connecting Transmission Owner, has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate. If the review or testing raises safety issues, the Small Generating Facility will not be allowed to commence parallel operation until the issues are resolved.

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1.__________________________	____________________________
2.__________________________	____________________________
3.__________________________	____________________________

4.___________________________ _____________________________
5.___________________________ _____________________________

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: ____

Title: ___________________________ Date: _______________________

Contingent Approval to Interconnect the Small Generating Facility

(For ISO and Connecting Transmission Owner use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Connecting Transmission Owner Signature:

Title: ____________________________________ Date: ____________________

Connecting Transmission Owner waives inspection/witness test Yes___ No___

ISO Signature: ____

Title: ____________________________________ Date: ____________________

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes_____ No ______

Interconnection Customer:____

Contact Person:____

Address:____

Location of the Small Generating Facility (if different from above):

____

City:_______________________________ State:_________________ Zip Code:_______

Telephone:__________________________

E-Mail Address:______________________

Electrician:

Name:____

Address:____

City:_______________________________ State:_________________ Zip Code:_______

Telephone:__________________________

E-Mail Address:______________________

License number:__________________________________

Date Approval to Install Facility granted by the Connecting Transmission Owner:

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local

building/electrical code of ____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

____

Print Name:____

Date:______________________

As a condition of interconnection, you are required to send a copy of this form along with a copy of the signed electrical permit to the ISO and the Connecting Transmission Owner (insert contact information below):

Name:____

NYISO:____

Address:____

____

City, State ZIP:____

E-mail:____________________

Name:____

Connecting Transmission Owner:__________________________

Address:____

____

City, State ZIP:____

E-mail:____________________

<u>Approval to Energize the Small Generating Facility (For ISO and Connecting Transmission Owner use only)</u>

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

ISO Signature:____

Title:_________________________________ Date: ____________

Connecting Transmission Owner Signature:_______________________

Title:_________________________________ Date: ____________

Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW ("Terms and Conditions")

1.0 **Construction of the Facility**
The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the ISO approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 **Interconnection and Operation**
The Customer may operate Small Generating Facility and interconnect with the Connecting Transmission Owner's Distribution System once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the ISO and the Connecting Transmission Owner, and

2.3 The Connecting Transmission Owner has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Connecting Transmission Owner, at its own expense, within ten Business Days (unless the Parties agree otherwise) after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Connecting Transmission Owner shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Connecting Transmission Owner does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise), unless the Interconnection Customer has not provided a reasonable opportunity for such inspection; or

2.3.3 The Connecting Transmission Owner waives the right to inspect the Small Generating Facility.

2.4 The Connecting Transmission Owner has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 **Safe Operations and Maintenance**
The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 **Access**
The Connecting Transmission Owner shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Connecting Transmission Owner shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 **Disconnection**
The Connecting Transmission Owner may temporarily disconnect the Small Generating Facility upon the following conditions, until the conditions no longer exist:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions, the ISO OATT and Applicable Reliability Standards.

5.4 The Connecting Transmission Owner shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 **Indemnification**
The Parties shall at all times indemnify, defend, and save the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the indemnified Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.0 **Insurance**
The Interconnection Customer and Connecting Transmission Owner shall each follow all applicable insurance requirements imposed by New York State. All insurance policies must be maintained with insurers authorized to do business in New York State, and all policies must be in place ten Business Days prior to the operation of the Inverter-Based Small Generating Facility. The Interconnection Customer and Connecting Transmission Owner shall notify each other whenever

an accident or incident recurs that is covered by such insurance, whether or not such coverage is sought. The Interconnection Customer's insurance requirements shall be specified in an attachment to these Terms and Conditions.

8.0 **Limitation of Liability**

Each Party's liability to the other Parties for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall any Party be liable to any other Parties for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 **Termination**

The agreement to operate in parallel shall become effective when executed by the Parties and shall continue in effect until ___________. The agreement may be terminated earlier under the following conditions:

9.1 **By the Customer**

By providing written notice to the NYISO and the Connecting Transmission Owner.

9.2 **By the ISO and the Connecting Transmission Owner**

If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 **Permanent Disconnection**

In the event this Agreement is terminated, the Connecting Transmission Owner shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

9.4 **Survival Rights**

This Agreement shall continue in effect after termination to the extent necessary to allow or require any Party to fulfill rights or obligations that arose under the Agreement.

10.0 **Assignment/Transfer of Ownership of the Facility**

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the NYISO and the Connecting Transmission Owner.

Interconnection Customer:	Connecting Transmission Owner:
______________________________	______________________________
By: ___________________________	By: ___________________________

Name: ______________________________ Name: ______________________________

Date: ______________________________ Date: ______________________________

New York Independent System Operator, Inc.

____

By: ______________________________

Name: ______________________________

Date: ______________________________

Appendix 6 - Facilities Study Agreement

THIS AGREEMENT is made and entered into this ____day of ________________________ 20___ by and among ____, a _________________________________ organized and existing under the laws of the State of ____ ("Interconnection Customer"), the New York Independent System Operator, Inc., a not-for-profit corporation organized and existing under the laws of the State of New York ("NYISO") and ____, a _________________ existing under the laws of the State of New York ("Connecting Transmission Owner"). Interconnection Customer, the NYISO and the Connecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on ___________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the New York State Transmission System or the Distribution System;

WHEREAS, the NYISO has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer elects to be evaluated for [ ] Interconnection Service, and has requested the NYISO to perform, or cause to be performed, a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to physically and electrically connect the Small Generating Facility with the New York State Transmission System or the Distribution System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in Section 32.1.1.2 of the SGIP.

2.0 The Interconnection Customer elects and the NYISO shall cause a facilities study to be performed in accordance with the requirements of Attachment Z of the NYISO Open Access Transmission Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement and shall be made an exhibit thereto.

4.0 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s) and to complete any additional power flow and other analysis, including deliverability analysis, that may be appropriate. The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Connecting Transmission Owner's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

5.0 The Connecting Transmission Owner may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities in accordance with the SGIP.

6.0 The Interconnection Customer shall provide to the NYISO a deposit or other commercially reasonable security in an amount equal to the good faith estimated facilities study costs.

7.0 Except to the extent required by the ISO OATT Attachment S Class Year study and cost allocation process, in cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the facilities study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Interconnection Customer may, within 30 Calendar Days after receipt of the draft report, provide written comments to the NYISO, which the NYISO shall include in the final report. The NYISO shall issue the final facilities study report within 15 Business Days of receiving Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. The NYISO may reasonably extend such fifteen-day period upon notice to Interconnection Customer if Interconnection Customer's comments require the NYISO to perform additional analyses or make other significant modifications prior to the issuance of the final facilities study report. Upon request, the NYISO shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the facilities study, subject to confidentiality arrangements consistent with Section 32.4.5 of the SGIP.

10.0 Within ten Business Days of providing a draft facilities study report to Interconnection Customer, the NYISO, the Connecting Transmission Owner, and Interconnection Customer shall meet to discuss the results of the facilities study.

11.0 Except for study costs allocated to the Interconnection Customer as a member of a Class Year, any Connecting Transmission Owner and NYISO that incurs study costs shall be based on their actual costs, including applicable taxes, and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer shall pay all invoice amounts in excess of the deposit or other security without interest within 30 calendar days after receipt of the invoice. If the deposit or other cash security exceeds the invoiced fees, the NYISO shall refund such excess within 30 calendar days of the invoice without interest. If the Interconnection Customer disputes an amount to be paid the Interconnection Customer shall pay the disputed amount to the NYISO or into an interest bearing escrow account, pending resolution of the dispute in accordance with Section 32.4.2 of the SGIP. To the extent the dispute is resolved in the Interconnection Customer's favor, that portion of the disputed amount will be returned to the Interconnection Customer with interest at rates applicable to refunds under the Commission's regulations. To the extent the dispute is resolved in the NYISO's favor, that portion of any escrowed funds and interest will be released to the NYISO. The Connecting Transmission Owner and the NYISO shall not be obligated to perform or continue to perform any Interconnection Study work for the Interconnection Customer unless the Interconnection Customer has paid all amounts in compliance herewith.

13.0 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of New York, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 Amendment. The Parties may amend this Agreement by a written instrument duly executed by the Parties.

15.0 No Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by a Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the NYISO. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

19.0 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

20.0 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the NYISO or the Connecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor’s insurance.

21.0 Reservation of Rights. Nothing in this Agreement shall alter the right of the NYISO or Connecting Transmission Owner to make unilateral filings with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder which rights are expressly reserved herein, and the existing rights of Interconnection Customer to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations are also expressly reserved herein; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Connecting Transmission Owner]

Signed_____________________________

Name (Printed):

____

Title______________________________

[Insert name of Interconnection Customer]

Signed_____________________________

Name (Printed):

____

Title______________________________

New York Independent System Operator, Inc.

Signed_____________________________

Name (Printed):

____

Title______________________________

Attachment A to Facilities Study Agreement

Data to Be Provided by the Interconnection Customer with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

> On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)
>
> On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

Specify your Interconnection Service evaluation election as either Energy Resource Interconnection Service ("ERIS") alone, or for both ERIS and some level of Capacity Resource Interconnection Service ("CRIS"); provided however that CRIS may not exceed 2 MW and may only be requested for a Small Generating Facility that is no larger than 2 MW.

Evaluation Election: ____

One set of metering is required for each generation connection to the new ring bus or existing Connecting Transmission Owner station. Number of generation connections: ____________

Will an alternate source of auxiliary power be available during CT/PT maintenance?

> Yes ____ No ____

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ____ No ____

(If Yes, indicate on the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

____

____

What protocol does the control system or PLC use?

____

____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Bus length from generation to interconnection station:

____

Physical dimensions of the proposed interconnection station:

____

Line length from interconnection station to Connecting Transmission Owner's transmission line.

____

Tower number observed in the field. (Painted on tower leg):

____

Number of third party easements required for transmission lines, if known:

____

Is the Small Generating Facility located in Connecting Transmission Owner's service area?

Yes _____ No _____ If No, please provide name of local provider:

____

Please provide the following proposed schedule dates:

Begin Construction Date:______________________

In-Service Date:______________________

Initial Synchronization Date:______________________

Generation Testing Date:______________________

Commercial Operation Date:______________________

Appendix 7 - STANDARD SMALL GENERATOR INTERCONNECTION AGREEMENT (SGIA) (Applicable To Generating Facilities No Larger Than 20 MW)

TABLE OF CONTENTS

This Standard Small Generator Interconnection Agreement ("Agreement" or "SGIA") is made and entered into this _____ day of _______________, 20__, by and among the New York Independent System Operator, Inc., a not-for-profit corporation organized and existing under the laws of the State of New York ("NYISO") and ___________________ a _____________________ organized and existing under the laws of the State of New York ("Connecting Transmission Owner"), and __________________________________, a _____________ organized and existing under the laws of the State of ___________________ ("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or referred to collectively as the "Parties."

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1 Scope and Limitations of Agreement

1.1 Applicability

This Agreement shall be used for all Interconnection Requests submitted under the Small Generator Interconnection Procedures (SGIP) except for those submitted under the 10 kW Inverter Process contained in SGIP Attachment 5.

1.2 Purpose

This Agreement governs the terms and conditions under which the Interconnection Customer's Small Generating Facility will interconnect with, and operate in parallel with, the New York State Transmission System or the Distribution System.

1.3 Scope of Interconnection Service

1.3.1 The NYISO will provide [ ] Interconnection Service to Interconnection Customer at the Point of Interconnection.

1.3.2 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any, or applicable provisions of NYISO's or Connecting Transmission Owner's tariffs. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity in accordance with the applicable provisions of the ISO OATT and Connecting Transmission Owner's tariff. The execution of this Agreement does not constitute a request for, nor agreement to, provide Energy, any Ancillary Services or Installed Capacity under the NYISO Services Tariff or any Connecting Transmission Owner's tariff. If Interconnection Customer wishes to supply or purchase Energy, Installed Capacity or Ancillary Services, then Interconnection Customer will make application to do so in accordance with the NYISO Services Tariff or Connecting Transmission Owner's tariff.

1.4 Limitations

Nothing in this Agreement is intended to affect any other agreement by and among the NYISO, Connecting Transmission Owner and the Interconnection Customer, except as otherwise expressly provided herein.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Connecting Transmission Owner shall construct, operate, and maintain its Interconnection Facilities and Upgrades covered by this Agreement in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Connecting Transmission Owner or Affected Systems.

1.5.5 The Connecting Transmission Owner and Interconnection Customer shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each of those Parties shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Connecting Transmission Owner and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Connecting Transmission Owner's electric system, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

1.5.6 The NYISO shall coordinate with all Affected Systems to support the interconnection. The Connecting Transmission Owner shall cooperate with the NYISO in these efforts.

1.5.7 The Interconnection Customer shall ensure "frequency ride through" capability and "voltage ride through" capability of its Small Generating Facility. The Interconnection Customer shall enable these capabilities such that its Small Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Connecting Transmission Owner and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to section 2.1 of this agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The

Small Generating Facility's protective equipment settings shall comply with the Transmission Owner's automatic load-shed program. The Transmission Owner shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term "ride through" as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Owner and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority on a comparable basis. The term "frequency ride through" as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Owner and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The term "voltage ride through" as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Owner and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis.

1.6 Parallel Operation Obligations

Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the applicable control area, including, but not limited to: (1) the rules and procedures concerning the operation of generation set forth in the NYISO tariffs or ISO Procedures or the Connecting Transmission Owner's tariff; (2) any requirements consistent with Good Utility Practice or that are necessary to ensure the safe and reliable operation of the Transmission System or Distribution System; and (3) the Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Connecting Transmission Owner's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power

1.8.1 Power Factor Design Criteria

1.8.1.1 Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the NYISO or the Transmission Owner in whose Transmission District the Small Generating Facility interconnects has established different requirements that apply to all similarly situated generators in the New York Control Area or Transmission District (as applicable) on a comparable basis, in accordance with Good Utility Practice.

1.8.1.2 Non-Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the NYISO or the Transmission Owner in whose Transmission District the Small Generating Facility interconnects has established a different power factor range that applies to all similarly situated non-synchronous generators in the control area or Transmission District (as applicable) on a comparable basis, in accordance with Good Utility Practice. This power factor range standard shall by dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of September 21, 2016.

1.8.2 The NYISO is required to pay the Interconnection Customer for reactive power, or voltage support service, that the Interconnection Customer provides from the Small Generating Facility in accordance with Rate Schedule 2 of the NYISO Services Tariff.

1.9 Capitalized Terms

Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement. Capitalized terms used herein that are not so defined shall have the meanings specified in Appendix 1 of Attachment Z, Section 25.1.2 of Attachment S, or Section 30.1 of Attachment X of the ISO OATT.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Small Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the NYISO and the Connecting Transmission Owner of such activities no fewer than five Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Connecting Transmission Owner may, at its own expense, send qualified personnel to the Small Generating Facility site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the NYISO and Connecting Transmission Owner a written test report when such testing and inspection is completed. The Small Generating Facility may not commence parallel operations if the NYISO, in consultation with the Connecting Transmission Owner, finds that the Small Generating Facility has not been installed as agreed upon or may not be operated in a safe and reliable manner.

2.1.2 The NYISO and Connecting Transmission Owner shall each provide the Interconnection Customer written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the NYISO or Connecting Transmission Owner of the safety, durability, suitability, or reliability of the Small Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Small Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The NYISO, in consultation with the Connecting Transmission Owner, shall use Reasonable Efforts to list applicable parallel Operating Requirements in Attachment 5 of this Agreement. Additionally, the NYISO, in consultation with the Connecting Transmission Owner, shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The NYISO and Connecting Transmission Owner shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Small Generating Facility in parallel with the New York State Transmission System or the Distribution System without prior written authorization of the NYISO. The NYISO, in consultation with the Connecting Transmission Owner, will provide such authorization once the NYISO receives notification that the Interconnection Customer has complied with all applicable parallel Operating Requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the NYISO and/or Connecting Transmission Owner may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Small Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Small Generating Facility (including any required testing), startup, and operation for a period of up to three Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the NYISO and Connecting Transmission Owner at least five Business Days prior to conducting any on-site verification testing of the Small Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the NYISO and Connecting Transmission Owner each shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on them by this Agreement or if necessary to meet their legal obligation to provide service to their customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this article.

Article 3 Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by the FERC. The NYISO and Connecting Transmission Owner shall promptly file, or cause to be filed, this Agreement with FERC upon execution, if required. If the Agreement is disputed and the Interconnection Customer requests that it be filed with FERC in an unexecuted form, the NYISO shall file, or cause to be filed, this Agreement and the NYISO shall identify the disputed language.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect for a period of ten years from the Effective Date or such other longer period as the Interconnection Customer may request and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this Agreement (if required), which notice has been accepted for filing by FERC.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the NYISO and Connecting Transmission Owner 20 Business Days written notice. The NYISO may terminate this Agreement after the Small Generating Facility is Retired.

3.3.2 Any Party may terminate this Agreement after Default pursuant to article 7.6.

3.3.3 Upon termination of this Agreement, the Small Generating Facility will be disconnected from the New York State Transmission System or the Distribution System, as applicable. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this SGIA or such non-terminating Party otherwise is responsible for these costs under this SGIA.

3.3.4 The termination of this Agreement shall not relieve any Party of its liabilities and obligations, owed or continuing at the time of the termination. The Interconnection Customer shall pay all amounts in excess of any deposit or other security without interest within 30 calendar days after receipt of the invoice for such amounts. If the deposit or other security exceeds the invoice, the Connecting Transmission Owner shall refund such excess within 30 calendar days of the invoice without interest. If the Interconnection Customer disputes an amount to be paid the Interconnection Customer shall pay the disputed amount to the Connecting Transmission Owner or into an interest bearing escrow account, pending resolution of the dispute in accordance with Article 10 of this Agreement. To the extent the dispute is resolved in the Interconnection Customer's favor, that portion of the disputed amount will be returned to the Interconnection Customer with interest at rates applicable to refunds under the Commission's regulations. To the extent the dispute is resolved in the Connecting Transmission Owner's favor, that portion of any escrowed funds and interest will be released to the Connecting Transmission Owner.

3.3.5 The limitations of liability, indemnification and confidentiality provisions of this Agreement shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions

"Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the NYISO or Connecting Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the New York State Transmission System or Distribution System, the Connecting Transmission Owner's Interconnection Facilities or the electric systems of others to which the New York State Transmission System or Distribution System is directly connected; or (3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generating Facility or the Interconnection Customer's Interconnection Facilities. Under Emergency Conditions, the NYISO or Connecting Transmission Owner may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility. The NYISO or Connecting Transmission Owner shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generating Facility. The Interconnection Customer shall notify the NYISO and Connecting Transmission Owner promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the New York State Transmission System or Distribution System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of each Party's facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The NYISO or Connecting Transmission Owner may interrupt interconnection service or curtail the output of the Small Generating Facility and temporarily disconnect the Small Generating Facility from the New York State Transmission System or Distribution System when necessary for routine maintenance, construction, and repairs on the New York State Transmission System or Distribution System. The NYISO or the Connecting Transmission Owner shall provide the Interconnection Customer with five Business Days notice prior to such interruption. The NYISO and Connecting Transmission Owner shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages

During any forced outage, the NYISO or Connecting Transmission Owner may suspend interconnection service to the Interconnection Customer to effect immediate repairs on the New York State Transmission System or the Distribution System. The NYISO shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the NYISO shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects

The NYISO or Connecting Transmission Owner shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Small Generating Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Small Generating Facility could cause damage to the New York State Transmission System, the Distribution System or Affected Systems, or if disconnection is otherwise required under Applicable Reliability Standards or the ISO OATT. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the NYISO or Connecting Transmission Owner may disconnect the Small Generating Facility. The NYISO or Connecting Transmission Owner shall provide the Interconnection Customer with five Business Day notice of such disconnection, unless the provisions of article 3.4.1 apply.

3.4.5 Modification of the Small Generating Facility

The Interconnection Customer must receive written authorization from the NYISO and Connecting Transmission Owner before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the New York State Transmission System or the Distribution System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the prior written authorization of the NYISO and Connecting Transmission Owner, the Connecting Transmission Owner shall have the right to temporarily disconnect the Small Generating Facility. If disconnected, the Small Generating Facility will not be reconnected until the unauthorized modifications are authorized or removed.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Small Generating Facility, Interconnection Facilities, and the New York State Transmission System and Distribution System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The NYISO, in consultation with the Connecting Transmission Owner, shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, the NYISO, and the Connecting Transmission Owner.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Connecting Transmission Owner's Interconnection Facilities, as set forth in Attachment 2 to this Agreement.

4.2 Distribution Upgrades

The Connecting Transmission Owner shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. If the Connecting Transmission Owner and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer. The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with owning, operating, maintaining, repairing, and replacing the Distribution Upgrades, as set forth in Attachment 6 to this Agreement.

Article 5. Cost Responsibility for System Upgrade Facilities and System Deliverability Upgrades

5.1 Applicability

No portion of this article 5 shall apply unless the interconnection of the Small Generating Facility requires System Upgrade Facilities or System Deliverability Upgrades.

5.2 System Upgrades

The Connecting Transmission Owner shall procure, construct, install, and own the System Upgrade Facilities and System Deliverability Upgrades described in Attachment 6 of this Agreement. To the extent that design work is necessary in addition to that already accomplished in the Class Year Interconnection Facilities Study for the Interconnection Customer, the Connecting Transmission Owner shall perform or cause to be performed such work. If all the Parties agree, the Interconnection Customer may construct System Upgrade Facilities and System Deliverability Upgrades that are located on land owned by the Interconnection Customer.

5.2.1 As described in Section 32.3.5.3 of the SGIP in Attachment Z of the ISO OATT, the responsibility of the Interconnection Customer for the cost of the System Upgrade Facilities and System Deliverability Upgrades described in Attachment 6 of this Agreement shall be determined in accordance with Attachment S of the ISO OATT, as required by Section 32.3.5.3.2 of Attachment Z. The Interconnection Customer shall be responsible for all System Upgrade Facility costs as required by Section 32.3.5.3.2 of Attachment Z or its share of any System Upgrade Facilities and System Deliverability Upgrades costs resulting from the final Attachment S process, as applicable, and Attachment 6 to this Agreement shall be revised accordingly.

5.2.2 Pending the outcome of the Attachment S cost allocation process, if applicable, the Interconnection Customer may elect to proceed with the interconnection of its Small Generating Facility in accordance with Section 32.3.5.3 of the SGIP.

5.3 Special Provisions for Affected Systems

For the repayment of amounts advanced to the Affected System Operator for System Upgrade Facilities or System Deliverability Upgrades, the Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment, but only if responsibility for the cost of such System Upgrade Facilities is not to be allocated in accordance with Attachment S of the ISO OATT. The agreement shall specify the terms governing payments to be made by the Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Connecting Transmission Owner shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement on a monthly basis, or as otherwise agreed by those Parties. The Interconnection Customer shall pay all invoice amounts within 30 calendar days after receipt of the invoice.

6.1.2 Within three months of completing the construction and installation of the Connecting Transmission Owner's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Connecting Transmission Owner shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Connecting Transmission Owner for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Connecting Transmission Owner shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Connecting Transmission Owner within 30 calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Connecting Transmission Owner shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

6.1.3 If the Interconnection Customer disputes an amount to be paid, the Interconnection Customer shall pay the disputed amount to the Connecting Transmission Owner or into an interest bearing escrow account, pending resolution of the dispute in accordance with Article 10 of this Agreement. To the extent the dispute is resolved in the Interconnection Customer's favor, that portion of the disputed amount will be credited or returned to the Interconnection Customer with interest at rates applicable to refunds under the Commission's regulations. To the extent the dispute is resolved in the Connecting Transmission Owner's favor, that portion of any escrowed funds and interest will be released to the Connecting Transmission Owner.

6.2 Milestones

Subject to the provisions of the SGIP, the Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement. A Party's obligations under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure event, it shall immediately notify the other Parties of the reason(s) for not meeting the milestone and: (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) requesting appropriate amendments to Attachment 4. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless: (1) it will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

At least 20 Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Connecting Transmission Owner's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Connecting Transmission Owner, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Connecting Transmission Owner and is consistent with the Uniform Commercial Code of the jurisdiction where the Point of Interconnection is located. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Connecting Transmission Owner's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Connecting Transmission Owner under this Agreement during its term. The Connecting Transmission Owner may draw on any such security to the extent that the Interconnection Customer fails to make any payments due under this Agreement. In addition:

6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Connecting Transmission Owner, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

6.3.2 The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the Connecting Transmission Owner and must specify a reasonable expiration date.

6.3.3 Notwithstanding the above, Security posted for System Upgrade Facilities for a Small Generating Facility required to enter the Class Year process, or cash or Security provided for System Deliverability Upgrades, shall meet the requirements for Security contained in Attachment S to the ISO OATT.

Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

7.1 Assignment

This Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns. This Agreement may be assigned by any Party upon 15 Business Days prior written notice and opportunity to object by the other Parties; provided that:

7.1.1 A Party may assign this Agreement without the consent of the other Parties to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the NYISO and the Connecting Transmission Owner of any such assignment. A Party may assign this Agreement without the consent of the other Parties in connection with the sale, merger, restructuring, or transfer of a substantial portion of all of its assets, including the Interconnection Facilities it owns, so long as the assignee in such a transaction directly assumes all rights, duties and obligation arising under this Agreement.

7.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the NYISO or Connecting Transmission Owner, for collateral security purposes to aid in providing financing for the Small Generating Facility.

7.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

7.2 Limitation of Liability

Each Party's liability to the other Parties for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall any Party be liable to the other Parties for any indirect, special, consequential, or punitive damages.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in article 7.2.

7.3.2 Each Party (the "Indemnifying Party") shall at all times indemnify, defend, and hold harmless the other Parties (each an " Indemnified Party") from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, the alleged violation of any Environmental Law, or the release or threatened release of any Hazardous Substance, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties (any and all of these a "Loss"), arising out of or resulting from: (i) the Indemnified Party's performance under this Agreement on behalf of the Indemnifying Party, except in cases where the Indemnifying Party can demonstrate that the Loss of the Indemnified Party was caused by the gross negligence or intentional wrongdoing by the Indemnified Party, or (ii) the violation by the Indemnifying Party of any Environmental Law or the release by the Indemnifying Party of a Hazardous Substance.

7.3.3 If a Party is entitled to indemnification under this article as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such Indemnified Party may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an Indemnifying Party is obligated to indemnify and hold any Indemnified Party harmless under this article, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, no Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a "Force Majeure Event" shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing." For the purposes of this article, this definition of Force Majeure shall supersede the definitions of Force Majeure set out in Section 32.10.1 of the ISO OATT.

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event ("Affected Party") shall promptly notify the other Parties, either in writing or via the telephone, of the existence of the Force Majeure event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Parties informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Breach and Default

7.6.1 No Breach of this Agreement shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event or the result of an act or omission of the other Parties. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the Breaching Party. Except as provided in article 7.6.2, the Breaching Party shall have 60 calendar days from receipt of the Breach notice within which to cure such Breach; provided however, if such Breach is not capable of cure within 60 calendar days, the Breaching Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Breach notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

7.6.2 If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, a Default shall exist and the non-defaulting Parties acting together shall thereafter have the right to terminate this Agreement, in accordance with article 3.3 hereof, by written notice to the defaulting Party at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not those Parties terminate this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which they are entitled at law or in equity. The provisions of this article shall survive termination of this Agreement.

7.6.3 In cases where the Interconnection Customer has elected to proceed under Section 32.3.5.3 of the SGIP, if the Interconnection Request is withdrawn or deemed withdrawn pursuant to the SGIP during the term of this Agreement, this Agreement shall terminate.

Article 8. Insurance

8.1 The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. Such insurance coverage is specified in Attachment 7 to this Agreement. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in New York State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Connecting Transmission Owner, except that the Interconnection Customer shall show proof of insurance to the Connecting Transmission Owner no later than ten Business Days prior to the anticipated commercial operation date. An Interconnection Customer of sufficient creditworthiness may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected.

8.2 The NYISO and Connecting Transmission Owner agree to maintain general liability insurance or self-insurance consistent with the existing commercial practice. Such insurance or self-insurance shall not exclude the liabilities undertaken pursuant to this Agreement.

8.3 The Parties further agree to notify one another whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 9. Confidentiality

9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such. Confidential Information shall include, without limitation, information designated as such by the NYISO Code of Conduct contained in Attachment F to the ISO OATT.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Parties as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

9.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § lb.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Each Party is prohibited from notifying the other Parties to this Agreement prior to the release of the Confidential Information to FERC. The Party shall notify the other Parties to this Agreement when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

9.4 Consistent with the provisions of this article 9, the Parties to this Agreement will cooperate in good faith to provide each other, Affected Systems, Affected System

Operators, and state and federal regulators the information necessary to carry out the terms of the SGIP and this Agreement.

Article 10. Disputes

10.1 The NYISO, Connecting Transmission Owner and Interconnection Customer agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

10.2 In the event of a dispute, the Parties will first attempt to promptly resolve it on an informal basis. The NYISO will be available to the Interconnection Customer and Connecting Transmission Owner to help resolve any dispute that arises with respect to performance under this Agreement. If the Parties cannot promptly resolve the dispute on an informal basis, then any Party shall provide the other Parties with a written Notice of Dispute. Such notice shall describe in detail the nature of the dispute.

10.3 If the dispute has not been resolved within two Business Days after receipt of the notice, any Party may contact FERC's Dispute Resolution Service ("DRS") for assistance in resolving the dispute.

10.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. The result of this dispute resolution process will be binding only if the Parties agree in advance. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

10.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-third of any costs paid to neutral third-parties.

10.6 If any Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then any Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this Agreement.

Article 11. Taxes

11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with FERC policy and Internal Revenue Service requirements.

11.2 Each Party shall cooperate with the other Parties to maintain the other Parties' tax status. Nothing in this Agreement is intended to adversely affect the tax status of any Party including the status of NYISO, or the status of any Connecting Transmission Owner with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds. Notwithstanding any other provisions of this Agreement, LIPA, NYPA and Consolidated Edison Company of New York, Inc. shall not be required to comply with any provisions of this Agreement that would result in the loss of tax-exempt status of any of their Tax-Exempt Bonds or impair their ability to issue future tax-exempt obligations. For purposes of this provision, Tax-Exempt Bonds shall include the obligations of the Long Island Power Authority, NYPA and Consolidated Edison Company of New York, Inc., the interest on which is not included in gross income under the Internal Revenue Code.

11.3 LIPA and NYPA do not waive their exemptions, pursuant to Section 201(f) of the FPA, from Commission jurisdiction with respect to the Commission's exercise of the FPA's general ratemaking authority.

11.4 Any payments due to the Connecting Transmission Owner under this Agreement shall be adjusted to include any tax liability incurred by the Connecting Transmission Owner with respect to the interconnection request which is the subject of this Agreement. Such adjustments shall be made in accordance with the provisions of Article 5.17 of the LGIA in Attachment X of the ISO OATT. Except where otherwise noted, all costs, deposits, financial obligations and the like specified in this Agreement shall be assumed not to reflect the impact of applicable taxes.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of New York, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by the Parties, or under article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns. Notwithstanding the foregoing, any subcontractor of the Connecting Transmission Owner or NYISO assisting either of those Parties with the Interconnection Request covered by this Agreement shall be entitled to the benefits of indemnification provided for under Article 7.3 of this Agreement and the limitation of liability provided for in Article 7.2 of this Agreement.

12.4 Waiver

12.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.2 Any waiver at any time by a Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer’s legal rights to obtain an interconnection from the NYISO. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

This Agreement, including all Attachments, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party’s compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. FERC expects the NYISO, the Connecting Transmission Owner, Market Participants, and Interconnection Customers interconnected to electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Parties, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Parties. The notifying Party shall: (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Parties copies of any publicly available reports filed with any governmental authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

12.11.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties to the extent provided for in Sections 32.7.2 and 32.7.3 above for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the NYISO or Connecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

Nothing in this Agreement shall alter the right of the NYISO or Connecting Transmission Owner to make unilateral filings with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder which rights are expressly reserved herein, and the existing rights of the Interconnection Customer to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations are also expressly reserved herein; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:

Interconnection Customer:
Attention:
Address:
City: State: Zip:
Phone:

If to the Connecting Transmission Owner:

Connecting Transmission Owner:
Attention:
Address:
City: State: Zip:
Phone:

If to the NYISO:

Attention:
Address:
City: State: Zip: :
Phone:

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer:
Attention:
Address:
City: State: Zip:

Connecting Transmission Owner:
Attention:

Address:
City: State: Zip:

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephoneor e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Interconnection Customer:
Attention:
Address:
City: State: Zip:
Phone:
E-mail:

If to the Connecting Transmission Owner:

Connecting Transmission Owner:
Attention:
Address:
City: State: Zip:
Phone:
E-mail:

If to the NYISO:

Attention:
Address:
City: State: Zip:
Phone:
E-mail:

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer:

Attention:
Address:
City: State: Zip:
Phone:
E-mail:

Connecting Transmission Owner's Operating Representative:

Connecting Transmission Owner:

Attention:
Address:
City: State: Zip:
Phone:
E-mail:

NYISO's Operating Representative:

Attention:
Address:
City: State: Zip:
Phone:
E-mail:

13.5 Changes to the Notice Information

Either Party may change this information by giving five Business Days written notice prior to the effective date of the change.

Article 14. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the New York Independent System Operator, Inc.

Name: ______________________________

Title: ______________________________

Date: ______________________________

For the Connecting Transmission Owner

Name: ______________________________

Title: ______________________________

Date: ______________________________

For the Interconnection Customer

Name: ______________________________

Title: ______________________________

Date: ______________________________

Attachment 1 - Glossary of Terms

Affected System – An electric system other than the transmission system owned, controlled or operated by the Connecting Transmission Owner that may be affected by the proposed interconnection.

Affected System Operator – Affected System Operator shall mean the operator of any Affected System.

Affected Transmission Owner – The New York public utility or authority (or its designated agent) other than the Connecting Transmission Owner that: (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, and (ii) owns, leases or otherwise possesses an interest in a portion of the New York State Transmission System where System Deliverability Upgrades or System Upgrade Facilities are installed pursuant to Attachment Z and Attachment S to the ISO OATT.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority, including but not limited to Environmental Law.

Applicable Reliability Standards – The criteria, requirements and guidelines of the North American Electric Reliability Council, the Northeast Power Coordinating Council, the New York State Reliability Council and related and successor organizations, or the Transmission District to which the Interconnection Customer's Small Generating Facility is directly interconnected, as those criteria, requirements and guidelines are amended and modified and in effect from time to time; provided that no Party shall waive its right to challenge the applicability of or validity of any criterion, requirement or guideline as applied to it in the context of Attachment Z to the ISO OATT and this Agreement. For the purposes of this Agreement, this definition of Applicable Reliability Standards shall supersede the definition of Applicable Reliability Standards set out in Attachment X to the ISO OATT.

Base Case – The base case power flow, short circuit, and stability data bases used for the Interconnection Studies by NYISO, Connecting Transmission Owner or Interconnection Customer; described in Section 32.2.3 of the Large Facility Interconnection Procedures.

Breach - The failure of a Party to perform or observe any material term or condition of this Agreement.

Business Day – Monday through Friday, excluding federal holidays.

Capacity Resource Interconnection Service – The service provided by NYISO to Interconnection Customers that satisfy the NYISO Deliverability Interconnection Standard or that are otherwise eligible to receive CRIS in accordance with Attachment S to the ISO OATT; such service being one of the eligibility requirements for participation as a NYISO Installed Capacity Supplier.

Connecting Transmission Owner – The New York public utility or authority (or its designated agent) that: (i) owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff, (ii) owns, leases or otherwise possesses an interest in the portion of the New York State Transmission System or Distribution System at the Point of Interconnection, and (iii) is a Party to the Standard Small Generator Interconnection Agreement.

Default – The failure of a Party in Breach of this Agreement to cure such Breach under the Small Generator Interconnection Agreement.

Distribution System – The Transmission Owner's facilities and equipment used to distribute electricity that are subject to FERC jurisdiction, and are subject to the NYISO's Large Facility Interconnection Procedures in Attachment X to the ISO OATT or Small Generator Interconnection Procedures in Attachment Z to the ISO OATT under FERC Order Nos. 2003 and/or 2006. For the purpose of this Agreement, the term Distribution System shall not include LIPA's distribution facilities.

Distribution Upgrades – The additions, modifications, and upgrades to the Connecting Transmission Owner's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities or System Upgrade Facilities or System Deliverability Upgrades.

Energy Resource Interconnection Service – The service provided by NYISO to interconnect the Interconnection Customer's Small Generating Facility to the New York State Transmission System or Distribution System in accordance with the NYISO Minimum Interconnection Standard, to enable the New York State Transmission System to receive Energy and Ancillary Services from the Small Generating Facility, pursuant to the terms of the ISO OATT.

Force Majeure – Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. For the purposes of this Agreement, this definition of Force Majeure shall supersede the definitions of Force Majeure set out in Section 32.2.11 of the NYISO Open Access Transmission Tariff.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, NYISO, Affected Transmission Owner, Connecting Transmission Owner or any Affiliate thereof.

Interconnection Customer – Any entity, including the Transmission Owner or any of the affiliates or subsidiaries, that proposes to interconnect its Small Generating Facility with the New York State Transmission System or the Distribution System.

Interconnection Facilities – The Connecting Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the New York State Transmission System or the Distribution System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or System Upgrade Facilities.

Interconnection Request – The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to materially increase the capacity of, or make a material modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the New York State Transmission System or the Distribution System. For the purposes of this Agreement, this definition of Interconnection Request shall supersede the definition of Interconnection Request set out in Attachment X to the ISO OATT.

Interconnection Study – Any study required to be performed under Sections 32.2 or 32.3 of the SGIP.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

New York State Transmission System – The entire New York State electric transmission system, which includes: (i) the Transmission Facilities under ISO Operational Control; (ii) the Transmission Facilities Requiring ISO Notification; and (iii) all remaining transmission facilities within the New York Control Area.

NYISO Deliverability Interconnection Standard – The standard that must be met, unless otherwise provided for by Attachment S to the ISO OATT, by (i) any generation facility larger than 2MW in order for that facility to obtain CRIS; (ii) any Merchant Transmission Facility proposing to interconnect to the New York State Transmission System and receive Unforced Capacity Delivery Rights; (iii) any entity requesting External CRIS Rights, and (iv) any entity requesting a CRIS transfer pursuant to Section 25.9.5 of Attachment S to the ISO OATT. To meet the NYISO Deliverability Interconnection Standard, the Interconnection Customer must, in accordance with the rules in Attachment S to the ISO OATT, fund or commit to fund any System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

NYISO Minimum Interconnection Standard – The reliability standard that must be met by any generation facility or Merchant Transmission Facility that is subject to NYISO's Large Facility Interconnection Procedures in Attachment X to the ISO OATT or the NYISO's Small Generator Interconnection Procedures in this Attachment Z, that is proposing to connect to the New York State Transmission System or Distribution System, to obtain ERIS. The Minimum Interconnection Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System or to the Distribution System. The Minimum Interconnection Standard does not impose any deliverability test or deliverability requirement on the proposed interconnection.

Operating Requirements – Any operating and technical requirements that may be applicable due to Regional Transmission Organization, Independent System Operator, control area, or the Connecting Transmission Owner's requirements, including those set forth in the Small Generator Interconnection Agreement. Operating Requirements shall include Applicable Reliability Standards.

Party or Parties – The NYISO, Connecting Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the New York State Transmission System or the Distribution System.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under this Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – The Interconnection Customer's device no larger than 20 MW for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

System Deliverability Upgrades – The least costly configuration of commercially available components of electrical equipment that can be used, consistent with Good Utility Practice and Applicable Reliability Requirements, to make the modifications or additions to the existing New York State Transmission System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Deliverability Interconnection Standard for Capacity Resource Interconnection Service.

System Upgrade Facilities – The least costly configuration of commercially available components of electrical equipment that can be used, consistent with good utility practice and Applicable Reliability Requirements to make the modifications to the existing transmission system that are required to maintain system reliability due to: (i) changes in the system, including such changes as load growth and changes in load pattern, to be addressed in the form of generic generation or transmission projects; and (ii) proposed interconnections. In the case of proposed interconnection projects, System Upgrade Facilities are the modification or additions to the existing New York State Transmission System that are required for the proposed project to connect reliably to the system in a manner that meets the NYISO Minimum Interconnection Standard.

Tariff – The NYISO's Open Access Transmission Tariff, as filed with the FERC, and as amended or supplemented from time to time, or any successor tariff.

Upgrades – The required additions and modifications to the Connecting Transmission Owner's portion of the New York State Transmission System or the Distribution System at or beyond the Point of Interconnection. Upgrades may be System Upgrade Facilities or System Deliverability Upgrades Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2 - Detailed Scope of Work, Including Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Small Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer, or the Connecting Transmission Owner. The NYISO, in consultation with the Connecting Transmission Owner, will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

Attachment 3 - One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

Attachment 4 - Milestones

In-Service Date:

Critical milestones and responsibility as agreed to by the Parties:

Milestone/Date	Responsible Party
(1)	
(2)	
(3)	
(4)	
(5)	
(6)	
(7)	
(8)	
(9)	
(10)	

Attachment 5 - Additional Operating Requirements for the New York State Transmission System, the Distribution System and Affected Systems Needed to Support the Interconnection Customer's Needs

The NYISO, in consultation with the Connecting Transmission Owner, shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the New York State Transmission System or the Distribution System.

Attachment 6 - Connecting Transmission Owner's Description of its Upgrades and Best Estimate of Upgrade Costs

The NYISO, in consultation with the Connecting Transmission Owner, shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Connecting Transmission Owner shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

The cost estimate for System Upgrade Facilities and System Deliverability Upgrades shall be taken from the ISO OATT Attachment S cost allocation process or applicable Interconnection Study, as required by Section 32.3.5.3.2 of Attachment Z. The cost estimate for Distribution Upgrades shall include the costs of Distribution Upgrades that are reasonably allocable to the Interconnection Customer at the time the estimate is made, and the costs of any Distribution Upgrades not yet constructed that were assumed in the Interconnection Studies for the Interconnection Customer but are, at the time of the estimate, an obligation of an entity other than the Interconnection Customer.

The cost estimates for Distribution Upgrades, System Upgrade Facilities, and System Deliverability Upgrades are estimates. The Interconnection Customer is ultimately responsible for the actual cost of the Distribution Upgrades, System Upgrade Facilities, and System Deliverability Upgrades needed for its Small Generating Facility, as that is determined under Attachments S, X, and Z of the ISO OATT..

Attachment 7 - Insurance Coverage

33 Attachment AA – Procedure to Protect for the Loss of Phase II Imports

NOTE: In this Attachment AA, "NYPP" refers to the ISO, "NEPEX" refers to ISO New England Inc. and "PJM" refers to PJM Interconnection, LLC.

January 1, 1991

Review Date: 10/1/2006

Reference: Procedure to Protect for the Loss of Hydro-Quebec Exports

33.1 Introduction

The Hydro-Quebec/NEPOOL Phase II tie has maximum transfer capability of 2,000 MW. Joint PJM/NYPP/NEPEX studies have concluded that the loss of the Phase II facilities at high levels of imports could have a worse effect on NYPP and PJM than the worst internal contingency that these individual systems normally protect against. Accordingly, it has been agreed that Phase II imports will be limited to the extent necessary to insure that NYPP and PJM operation reliability criteria are not violated by the loss of Phase II contingency. This procedure is designed to prevent the occurrence of a loss of Phase II contingency applicable when Phase II is operated in the isolated or synchronous mode. The absolute maximum loss of Phase II contingency allowable under this procedure will be 2,200 MW.

33.2 System Monitoring

1. NYPP and PJM will monitor their respective systems to provide NEPEX with the data required to calculate Phase II import limits.

2. NEPEX will request forecasted data from NYPP and PJM required to establish Phase II schedules.

3. NEPEX will set schedules with Hydro-Quebec which are within acceptable limits.

4. NEPEX will monitor real time system conditions in NYPP and PJM to insure that Phase II imports are within acceptable limits.

5. The calculations required to determine Phase II limitations will normally be done using a software package in the NEPEX computer. The data required to perform the calculations is received in part via the Interpool Network and by manual entry for those values not telemetered. The program fulfills the requirements of this procedure. In the event that the NEPEX computer is unavailable for use, the necessary calculations will be performed by operator use of a personal computer with data being exchanged by telephone.

33.3 Definition of Terms

The following terms apply to the three (3) NYPP voltage indicators, Rochester 345 KV, Oakdale 345 KV and Oakdale 230 KV. Each indicator will have unique values for each of these terms.

(Limit) Pre-contingency Low Voltage Limit – the lowest precontingency voltage allowed at the station based on contingencies within NYPP.

Actual Voltage – Actual voltage at the station

Voltage Margin – Actual voltage minus Pre-contingency Low Voltage Limit

Base NE/NB Contingency Limit – The maximum total loss of generation within NE/NB or loss of HQ HVDC Exports to NE/NB allowable when the station voltage is at the Pre-contingency Low Voltage Limit (for the purposes of this procedure, the Base NE/NB Contingency Limit is the maximum level of Phase II Imports allowable).

Margin Sensitivity – The number of MW of increase in the Base NE/NB Contingency Limit allowed for each one (1) KV or Voltage Margin.

The following terms apply to the fourth indicator of NYPP Reactive Conditions, the Central/East (C/E) Interface.

C/E Critical Transfer Level – Postcontingency transfer limit for the C/E interface based on NYPP reactive conditions

C/E Transfer – Actual MW transfer on the C/E interface

***** **Phase II C/E Distribution Factor –** The number of MW by which the C/E flow would be increased for each one (1) MW of the total of Phase II imports and MW armed for runback in New Brunswick which would be lost as a result of a single contingency.

The following terms apply to the PJM Eastern, Central, and Western interfaces and are used in determining limitations based on PJM reactive conditions.

PJM Transfer Limits – Precontigency transfer limits for each PJM interface based on contingencies within PJM.

PJM Transfers – Actual MW transfers on each PJM interface.

PJM Transfer Margins – Transfer limit minus actual transfer for each PJM interface.

PJM Base New England/New Brunswick (NE/NB) Contingency Limit – The maximum total loss of generation within NE/NB or loss of HQ HVDC Export to NE/NB which is allowable when any of the three (3) PJM interfaces is loaded to its precontingency transfer limit (for the purposes of this procedure, the PJM Base NE/NB Contingency Limit is the maximum level of Phase II Imports allowable).

PJM Transfer Margin Sensitivity – The number of MW of increase in the PJM Base NE/NB Contingency Limit allowed for each one (1) MW of Transfer Margin. Each PJM interface has an associated Transfer Margin Sensitivity. By exception, the PJM Operations Planning Section will notify NEPEX supervision of any required change in the Transfer Margin Sensitivities.

*THE TERMS DEFINED ABOVE ARE THE SAME TERMS USED IN THE PROCEDURE TO PROTECT FOR LOSS OF HYDRO-QUEBEC EXPORTS WITH THE EXCEPTION OF THE PHASE II C/E DISTRIBUTION FACTOR.

Loss of Phase II Contingency – The total of the MW of Phase II import and MW armed for runback in New Brunswick (Keswick Power Relays) which would be lost as a result of a single contingency (See Attachment I for Method of Calculating the Loss of Phase II Contingency). While the Keswick Power Relays will normally be disabled, they will be enabled during outages of the Chester Static VAR Compensator. MW armed during these periods must be included in the Loss of Phase II Contingency.

Phase II Import Limit (Phase II Limit) – The most restrictive Loss of Phase II Contingency allowable based on NYPP and PJM reactive conditions (See Attachment I for Method of Calculating the Phase II Import Limit.

33.4 Procedures

1. Setting Phase II Schedules – All required limitations on Phase II imports are to be recognized in the establishment of Phase II schedules for the next hour. In order to set next hour schedules for the Phase II tie, NEPEX will;

   A. Determine the total of the desired level of Phase II import plus anticipated arming in New Brunswick (if Keswick Power Relays are enabled) for the next hour.

   B. Determine the Phase II Limit with no margin for the next hour.

   C. If the Phase II Limit (no margin) is less than the desired Phase II import plus arming in New Brunswick, request that NYPP and/or PJM forecast and authorize use of any available margin for the next hour.

   D. Determine the Phase II Limit using authorized margin.

   E. Thirty minutes in advance of the hour, establish a next hour Phase II schedule with Hydro-Quebec for which the L/O Phase II Contingency (import plus arming) will be equal to or less than the Phase II Limit (which includes any authorized margin).

2. Monitoring System Conditions – At least once each hour, NEPEX will make a complete check of actual system conditions in NYPP and PJM. Whenever a condition exists such that the L/O Phase II Limit based on those conditions, NEPEX will;

   A. Contact NYPP and/or PJM to determine if the L/O Phase II Contingency must be reduced.

   B. If the L/O Phase II Contingency must be reduced, reduce imports from New Brunswick to a level at which arming (KPR) is not required and/or reduce Phase II imports so that the L/O Phase II contingency is less than the Phase II Limit.

   ACTION(S) TAKEN TO REDUCE THE L/O PHASE II CONTINGENCY MUST BE ACCOMPLISHED WITHIN TEN (10) MINUTES FROM THE TIME THE PROBLEM IS IDENTIFIED.

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ATTACHMENT I – Methods for Calculating the Loss of Phase II Contingency and the Phase II Import Limit

I. The Loss of Phase II Contingency

The loss of Phase II Contingency is made up of two components; 1) the transfer on the Phase II tie line between Hydro-Quebec and NEPOOL and 2) any MW armed for runback in New Brunswick (Keswick Power Relays). While normally disabled, the Keswick Power Relays will be enabled when the Chester Static VAR Compensator is OOS. ALL MW armed for the Keswick Power Relays must be included as part of the Loss of Phase II Contingency. The maximum Loss of Phase II Contingency allowable is 2,200 MW.

Loss of Phase II Contingency

=
Phase II transfers
+
MW armed for Keswick Power Relays

II. The Phase II Import Limit

The calculation of the Phase II Limit requires the examination of seven (7) different sets of reactive conditions, four (4) in NYPP and three (3) in PJM. Three (3) of the NYPP calculations are based on station voltages; Rochester 345, Oakdale 345, Oakdale 230.The remaining NYPP calculation is based on MW flow across the Central East Interface. The PJM calculations are based on MW flows across the Eastern, Central, and Western Interfaces.

The Phase II Limit is the most restrictive of the values calculated.

The methods for calculating the Phase II Limits are listed below.

A. Calculation of Limits for Next Hour Scheduling

1. Phase II Limit based on NYPP station voltages

   a. Limit without Voltage Margin- The Phase II Limit without Voltage Margin for each of the three stations is the Base New England/New Brunswick (NE/NB) Contingency Limit for that station.

b. Limit with Voltage Margin – The Phase II Limit with Voltage Margin for each of the three stations is the Base NE/NB Contingency Limit for that station plus the amount of Voltage Margin authorized for that station multiplied by the Margin Sensitivity for that station.

Phase II Limit
=
Station Base NW/NB Contingency Limit
+
Station Margin Sensitivity x Authorized Voltage Margin

2. <u>Phase II Limit based on NYPP Central East flow</u>

The Phase II Limit is
(the C/E Critical Transfer Level minus the forecasted C/E transfer for the next hour)
divided by
the Phase II C/E Distribution Factor

Phase II Limit
=
<u>(C/E Crit. Transfer Level- forecasted C/E Transfer)</u>
Phase II C/E Distribution Factor

3. <u>Phase II Limit based on PJM interface flows</u>

a. Limit without Transfer Margin – The Phase II Limit without Transfer Margin for each of the three (3) PJM interfaces is the PJM Base NE/NB Contingency Limit (same for all three interfaces)

b. Limit with Transfer Margin – The Phase II Limit with Transfer Margin for each of the three (3) PJM interfaces is the PJM Base NE/NB Contingency Limit
plus
the amount of Transfer Margin authorized for that interface multiplied by the Margin Sensitivity for that interface.

Phase II Limit
=
PJM Base NE/NB Contingency Limit
+
Margin Sensitivity x Authorized Transfer Margin

B. Calculation of Real Time Limits

1. Phase <u>II Limit based on NYPP station voltages</u>

The Phase II Limit for real time conditions for each of the three (3) stations is the Base NE/NB Contingency Limit for the station plus

the amount of actual Voltage Margin at the station multiplied by the Margin Sensitivity for the station

Phase II Limit
=
Station Base NE/NB Contingency Limit
+
Margin Sensitivity x actual Voltage Margin

2. <u>Phase II Limit based on NYPP Central East Flow</u>

The Phase II Limit for real time conditions is
(the C/E Critical Transfer Level minus
the C/E Transfer)

divided by

the Phase II C/E Distribution Factor

Phase II Limit
=
<u>(C/E Crit. Transfer Level- actual C/E Transfer)</u>
Phase II C/E Distribution Factor

3. <u>Phase II Limit based on PJM interface flows</u>

The Phase II Limit for real time conditions for each of the three (3) PJM interfaces is the PJM Base NE/NB Contingency Limit

plus

the amount of actual Transfer Margin on the interface multiplied by the Margin Sensitivity for the interface

Phase II Limit
=
PJM Base NE/NB Contingency Limit
+
Transfer Margin x Margin Sensitivity

34 Attachment BB – New York State Gas-Electric Coordination Protocol

For purposes of this New York State Gas-Electric Coordination Protocol ("Coordination Protocol"), the following terms shall have the meaning set forth below:

34.1 Definitions

"As Currently Required" shall mean as required by law and by the practices, protocols, and procedures reflected in the NYISO's tariffs, agreements, manuals and technical bulletins, that were in effect between and among some or all of the Parties prior to the effective date of this Coordination Protocol, and as may be amended in the future.

"Bulk Critical Generator" shall mean a Generator that is needed by the NYISO in order to prevent the shedding of firm electric load and that has been derated by reason of a GSE.

"Critical Generators" shall mean Bulk Critical Generators and Local Critical Generators, collectively.

"Department of Public Service" or "DPS" shall mean the New York State Department of Public Service.

"Energy Emergency Alert" or "EEA" shall mean a Level 2 or Level 3 Energy Emergency Alert as defined in NERC Reliability Standard EOP-002-2, Capacity and Energy Emergencies, Attachment 1.

"Feasible Critical Generator" shall mean a Critical Generator that may be able to be supplied by an LDC with natural gas.

"Feasible Natural Gas" shall mean natural gas that an LDC may be able to make available to supply a Critical Generator.

"Gas System Event" or "GSE" shall mean a situation in which gas is unavailable to a Generator that is determined to be a Critical Generator, including when the unavailability of gas is due to the issuance of an OFO or other action taken by an LDC in accordance with its tariff and/or its Gas Transportation Operating Procedures for Power Generation Customers which results in the LDC having to restrict, interrupt, impose limits on or curtail the transportation of natural gas and/or balancing services to a Generator; *provided, however,* that a GSE shall not include a situation in which a Generator has derated for economic reasons in a non-emergency situation after being scheduled to run.

"Generator" shall mean any one of the electric generation units in New York State which use natural gas as a fuel and the owners of such generation units.

"Good Utility Practice" shall mean any of the practices, methods or acts engaged in or approved by a significant portion of the electric utility industry and/or the natural gas industry during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to delineate acceptable practices, methods, or acts generally accepted in the region.

"Local Critical Generator" shall mean a Generator that is determined to be needed by a TO in order to prevent shedding of firm electric load and that has been derated by reason of a GSE.

"Local Distribution Company" or "LDC" shall mean each of the natural gas companies or their successors in New York State which supply or deliver natural gas to Generators and that are not interstate natural gas pipelines (and collectively the "LDCs").

"New York Independent System Operator" or "NYISO" is the New York not-for-profit corporation responsible for providing open access transmission service, maintaining bulk power system reliability, and administering wholesale electricity markets in New York State.

"OFO" shall mean an Operational Flow Order issued by an LDC.

"Parties" shall mean the New York Independent System Operator; the LDCs, the PPOs, the TOs and the DPS.

"PPO" shall mean any one of the entities who operate a power plant on behalf of a Generator in New York State.

"PSC" shall mean the New York State Public Service Commission.

"TO" shall mean each of the electric transmission system owners in New York State or their successors (and collectively the "TOs").

34.2 General Application

34.2.1 This Coordination Protocol shall apply to circumstances in which the NYISO has determined (for the bulk power system) or a TO has determined (for the local power system) that the loss of a Generator due to a GSE would likely lead to the loss of firm electric load. This Coordination Protocol shall also apply to communications following the declaration of an OFO or an Emergency Energy Alert.

34.2.2 The purpose of this Coordination Protocol is to be one of mutual assistance. Accordingly, nothing in this Coordination Protocol creates any obligation for an LDC to modify an OFO or to make gas supplies available to a Critical Generator(s). The decision to modify or not modify an OFO or to make available or not make available Feasible Natural Gas to a Critical Generator(s) shall be the LDC's alone, in its sole discretion. Any supply of Feasible Natural Gas shall be made pursuant to the provisions of the LDC's PSC-approved gas tariffs or other applicable sales tariff. Moreover, nothing in this Coordination Protocol creates an obligation on the part of the LDC to modify the terms and conditions of the LDC's gas tariffs and operating procedures in order to make Feasible Natural Gas available to Critical Generators.

34.2.3 This Coordination Protocol creates no additional obligations for PPOs, Generators or TOs above and beyond those that already exist in the NYISO's approved tariffs, except to follow the coordination procedures set forth in this Coordination Protocol.

34.2.4 The Parties agree that they shall follow Good Utility Practice in carrying out their obligations under this Coordination Protocol.

34.2.5 It is understood that this Coordination Protocol is intended to be used in emergency situations only and is not to be relied on to provide natural gas in a non-emergency situation to a Generator that has been derated for economic reasons after being scheduled to run.

34.3 Notifications

34.3.1 Upon the declaration of an OFO by an LDC, the LDC shall notify the DPS and the PPOs affected by the OFO, As Currently Required. In addition, the LDC shall notify the affected TOs and the NYISO. The declaration shall specify the date(s) and time(s) that the OFO will be effective and the specific service, receipt point(s) and delivery point(s) affected. The TOs shall notify the NYISO of the OFO.

34.3.2 Upon the declaration of an EEA by the NYISO due to a capacity shortage affecting the bulk power system, the NYISO shall notify the TO of such through normal communication channels, As Currently Required, and the TO shall notify the LDCs. The NYISO shall also notify the LDCs of the EEA.

34.3.3 Upon the occurrence of a GSE requiring a PPO to derate a Generator, the PPO shall notify the TO of the derating, As Currently Required. The TO shall in turn notify the NYISO, As Currently Required.

34.4 Assessment of the Electric System Following a Generator Derating

34.4.1 Upon the notification of the derating of a Generator by a PPO, the TO shall assess the reliability of the local power system, As Currently Required. The TO shall assess whether any Generator that is derated due to a GSE is a Local Critical Generator. If any Generator is determined to be a Local Critical Generator, the TO shall assess, by hour, the amount of electric energy needed to avoid the shedding of firm electric load. The TO shall then communicate its findings to the NYISO, As Currently Required.

34.4.2 Upon receiving notification from the TO that the derating of a Generator due to a GSE results in a reliability concern, the NYISO shall assess the reliability of the bulk power system, As Currently Required. The NYISO shall determine whether any Generator derated due to a GSE is a Bulk Critical Generator. If any Generator is determined to be a Bulk Critical Generator, the NYISO shall determine, for each hour, the amount of electric energy needed to avoid the shedding of firm electric load.

34.5 Assessment of Energy Requirements

34.5.1 The NYISO shall notify the TO that one or more Bulk Critical Generators has been identified and shall notify the TO of the amount of electric energy needed for each hour from each of the Bulk Critical Generators.

34.5.2 The TO shall notify the NYISO that one or more Local Critical Generators has been identified and shall notify the NYISO of the amount of electric energy needed for each hour from each of the Local Critical Generators.

34.5.3 The TO shall notify the PPO of each of the Critical Generators of the amount of electric energy needed for each hour from each of the Critical Generators.

34.5.4 The PPO of each Critical Generator shall notify each of the relevant LDCs delivering natural gas to the Critical Generators that one or more Critical Generators has been identified, and shall notify the LDCs of the amount of natural gas needed for each hour by each of the Critical Generators.

34.6 Assessment of Gas Requirements

34.6.1 The PPO of each Critical Generator or, if appropriate, its designated fuel manager, shall attempt to procure natural gas and shall notify the LDC of the amount of natural gas that it has procured, if any, and the proposed delivery point(s) it plans to use, subject to confirmation by the relevant interstate pipeline. The PPO also shall inform the LDC of the estimated amount of natural gas, if any, still needed to operate in accordance with the NYISO's schedule for each hour that the Critical Generator is required.

34.6.2 The LDC shall communicate to the PPO whether or not it is able to receive and deliver the volumes procured by the PPO or its fuel manager and, if it is not able to receive and deliver the procured gas at the identified delivery point(s), whether it is able to identify an alternative point(s) of delivery to meet the Critical Generator's natural gas requirement in whole or in part.

34.6.3 If an OFO is in effect, the LDC shall evaluate whether it is able to modify such OFO in a manner that would accommodate the delivery of all or any of the natural gas procured by the PPO or its designated fuel manager. The LDC shall notify the PPO of each Critical Generator and the DPS whether it can receive and deliver all, any or none of the gas procured by the PPO. The PPO shall notify the TO of the available gas that can be received or delivered by the LDC and the expected generation capability of the PPO with such natural gas.

34.7 Coordination of Gas Usage

34.7.1 Upon receiving notification from the TO of the Critical Generators' electric energy requirements, and from each of the PPOs of the Critical Generators of the results of its natural gas procurement efforts, and any unfilled natural gas and delivery requirements, the LDC shall assess its ability to meet the remaining natural gas needs of the Critical Generators. The LDC shall determine, for each hour, which of the Critical Generators can be feasibly supplied with natural gas and, for each hour, the quantity of natural gas that can be feasibly made available and delivered to the Critical Generators beyond the level that the Critical Generators have been able to procure for themselves.

34.7.2 The LDC shall notify the PPOs of the Critical Generators, the TO and the DPS of the amount, if any, of Feasible Natural Gas that can be made available and delivered in each hour to each of the Feasible Critical Generators. The PPO of each Feasible Critical Generator or, if appropriate, its designated fuel manager, shall notify the LDC of the portion of its Feasible Natural Gas that it expects to use.

34.7.3 The PPO of each Feasible Critical Generator shall contact the TO and modify the Generator's derating to reflect its capabilities with the Feasible Natural Gas. The TO shall notify the NYISO of changes in the derating of each Feasible Critical Generator, As Currently Required.

34.7.4 In the event that no additional natural gas can be made available or delivered to one or more Critical Generators by the LDC, the LDC shall inform the TO and the TO shall inform the NYISO.

34.7.5 An LDC providing Feasible Natural Gas shall be compensated by the Critical

Generator(s) in accordance with the provision of the LDC gas tariff determined to be applicable by the DPS.

34.8 Form of Communications

34.8.1 All communications between the Parties specified above shall use pre-existing communication channels which shall be by official telephone contact or by e-mail.

34.8.2 The Parties shall be responsible for updating each other with any changes in contact details.

35 Attachment CC – Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C.

This Joint Operating Agreement ("Agreement") dated this ___day of May 2007, is entered into among and between the following parties:

PJM Interconnection, L.L.C. ("PJM") a Delaware limited liability company having a place of business at 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403

New York Independent System Operator Inc. ("NYISO") a not-for-profit corporation established under the laws of New York State having a place of business at 10 Krey Boulevard, Rensselaer, New York 12144.

35.1 Recitals

35.1.1 PJM is the regional transmission organization that provides operating and reliability functions in portions of the mid-Atlantic and Midwest States. PJM also administers an open access tariff for transmission and related services on its grid, and independently operates markets for day-ahead, real-time energy, capacity, ancillary services and financially firm transmission rights;

35.1.2 NYISO is a not-for-profit corporation established pursuant to the ISO Agreement, responsible for providing transmission service, maintaining the reliability of the electric power system and facilitating efficient markets for capacity, energy and ancillary services in the New York Control Area in accordance with its filed Tariffs;

35.1.3 In accordance with good utility practice, the Parties seek to establish or confirm other arrangements and protocols in furtherance of the reliability of their systems and efficient market operations, as provided under the terms and conditions of this Agreement;

NOW, THEREFORE, for good and valuable consideration including the Parties' mutual reliance upon the covenants contained herein, the Parties agree as follows:

35.2 Abbreviations, Acronyms, Definitions and Rules of Construction

In this Agreement, the following words and terms shall have the meanings (such meanings to be equally applicable to both the singular and plural forms) ascribed to them in this Section 35.2. Any undefined, capitalized terms used in this Agreement shall have the meaning given under industry custom and, where applicable, in accordance with Good Utility Practices or the meaning given to those terms in the tariffs of PJM and NYISO on file at FERC.

35.2.1 Abbreviations, Acronyms and Definitions

"3500 PAR" shall mean the 3500 phase angle regulator at the Ramapo station connected to the 5018 Hopatcong-Ramapo 500 kV line.

"4500 PAR" shall mean the 4500 phase angle regulator at the Ramapo station connected to the 5018 Hopatcong-Ramapo 500 kV line.

"A PAR" shall mean the phase angle regulator located a the Goethals station connected to the A2253 Linden-Goethals 230 kV line.

"ABC Interface" shall mean the transfer path comprised of the A2253 Linden-Goethals, B3402 Hudson-Farragut and C3403 Marion-Farragut tie lines between PJM and NYISO.

"ABC PARs" shall mean the A PAR, B PAR and C PAR that control flow on the ABC Interface.

"AC" shall mean alternating current.

"Affected Party" shall mean the electric system of the Party other than the Party to which a request for interconnection or long-term firm delivery service is made and that may be affected by the proposed service.

"Agreement" shall mean this document, as amended from time to time, including all attachments, appendices, and schedules.

"Area Control Error" or **"ACE" shall** mean the instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

"Available PAR" shall mean, for purposes of Section 8.3.1 of Schedule D to this Agreement, a NY-NJ PAR that is not subject to any of the following circumstances:

(1) a PAR that is not operational and is unable to be moved;

(2) a PAR that is technically "in-service" but is being operated in an outage configuration and is only capable of feeding radial load;

(3) a PAR that is tapped-out in a particular direction is not available in the tapped-out direction;

(4) if the maximum of 400 taps/PAR/month is exceeded at an ABC PAR, Ramapo PAR or a Waldwick PAR, and the relevant asset owner restricts the RTOs from taking further taps on the affected PAR, then the affected PAR shall not be available until NYISO and PJM agree to and implement an increased bandwidth in accordance with Section 7.2 of Schedule D to this Agreement;

(5) PJM is permitted to reserve up to three taps at each end of the PAR tap range of each Waldwick PAR to secure the facilities on a post contingency basis, a Waldwick PAR shall not be considered available if a tap move would require the use of a reserved PAR tap; or

(6) NYISO is permitted to reserve up to two taps at each end of the tap range of each ABC PAR and Ramapo PAR to secure the facilities on a post contingency basis, an ABC or Ramapo PAR shall not be considered available if a tap move would require the use of a reserved PAR tap.

PJM or NYISO may choose to use PAR taps they are permitted to reserve to perform M2M coordination, but they are not required to do so.

"Available Flowgate Capability" or **"AFC"** shall mean the rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

"Available Transfer Capability" or **"ATC"** shall mean a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

"B PAR" shall mean the phase angle regulator located at the Farragut station connected to the B3402 Hudson-Farragut 345 kV line.

"Balancing Authority" or **"BA"** shall mean the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real-time.

"Balancing Authority Area" or **"BAA"** shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

"Bulk Electric System" shall have the meaning provided for in the NERC Glossary of Terms used in Reliability Standards, as it may be amended, supplemented, or restated from time to time.

"C PAR" shall mean the phase angle regulator located at the Farragut station connected to the C3403 Marion-Farragut 345 kV line.

"Capacity Benefit Margin" or **"CBM"** shall mean the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities ("LSEs"), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

"CIM" shall mean Common Infrastructure Model.

"Confidential Information" shall have the meaning stated in Section 35.8.1.

"Control Area(s)" shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied.

"Control Performance Standard" or **"CPS"** shall mean the reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.

"Coordinated Transaction Scheduling" or **"CTS"** shall mean the market rules that allow transactions to be scheduled based on a bidder's willingness to purchase energy from a source in either the NYISO or PJM Control Area and sell it at a sink in the other Control Area if the forecasted price at the sink minus the forecasted price at the corresponding source is greater than or equal to the dollar value specified in the bid.

"Coordination Committee" shall mean the jointly constituted PJM and NYISO committee established to administer the terms and provisions of this Agreement pursuant to Section 35.3.2.

"CTS Interface Bid" shall mean: (1) in PJM, a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of Schedule 1 of the Amended and Restated Operating Agreement of PJM, L.L.C.; and (2) in NYISO, a real-time bid provided by an entity engaged in an external transaction at a CTS Enabled Interface, as more fully described in NYISO Services Tariff Section 2.3.

“Delivery Point” shall mean each of the points of direct Interconnection between PJM and the NYISO Balancing Authority Areas. Such Delivery Point(s) shall include the Interconnection Facilities between the PJM and the New York Balancing Authority Areas.

“DC” shall mean direct current.

“Disclosing Party” shall have the meaning stated in Section 35.8.7.

“Dispute” shall have the meaning stated in Section 35.15.

“Disturbance Control Standard” or **“DCS”** shall mean the reliability standard that sets the time limit following a disturbance within which a balancing authority must return its Area Control Error to within a specified range.

“E PAR” shall mean the phase angle regulator located at the Waldwick station on the E-2257 Waldwick-Hawthorne 230 kV line.

“Economic Dispatch” shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

“Effective Date” shall have the meaning stated in Section 35.19.1.

“Emergency” shall mean any abnormal system condition that requires remedial action to prevent or limit loss of transmission or generation facilities that could adversely affect the reliability of the electricity system.

“Emergency Energy” shall mean energy supplied from Operating Reserve or electrical generation available for sale in New York or PJM or available from another Balancing Authority Area. Emergency Energy may be provided in cases of sudden and unforeseen outages of generating units, transmission lines or other equipment, or to meet other sudden and unforeseen circumstances such as forecast errors, or to provide sufficient Operating Reserve. Emergency Energy is provided pursuant to this Agreement and the Inter Control Area Transactions Agreement dated May 1, 2000 and priced according to Section 35.6.4 of this Agreement and said Inter Control Area Transactions Agreement.

“EMS” shall mean the respective Energy Management Systems utilized by the Parties to manage the flow of energy within their Regions.

“External Capacity Resource” shall mean: (1) for NYISO, (a) an entity (e.g., Supplier, Transmission Customer) or facility (e.g., Generator, Interface) located outside the NYCA with the capability to generate or transmit electrical power, or the ability to control demand at the direction of the NYISO, measured in megawatts or (b) a set of Resources owned or controlled by an entity within a Control Area, not the NYCA, that also is the operator of such Control Area;

and (2) for PJM, a generation resource located outside the metered boundaries of the PJM Region (as defined in the PJM Tariff) that meets the definition of Capacity Resource in the PJM Tariff or PJM's governing agreements filed with the Commission.

"F PAR" shall mean the phase angle regulator located at the Waldwick station on the F-2258 Waldwick-Hillsdale 230 kV line.

"FERC" or **"Commission"** shall mean the Federal Energy Regulatory Commission or any successor agency thereto.

"Flowgate" shall mean a representative modeling of facilities or groups of facilities that may act as potential constraint points.

"*Force Majeure*" shall mean an event of *force majeure* as described in Section 35. 20.1.

"Generator to Load Distribution Factor" or **"GLDF"** shall mean a generator's impact on a Flowgate while serving load in that generator's Balancing Authority Area.

"Good Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the North American electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted by NERC.

"Governmental Authority" shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power.

"ICCP", **"ISN"** and **"ICCP/ISN"** shall mean those common communication protocols adopted to standardize information exchange.

"IDC" shall mean the NERC Interchange Distribution Calculator used for identifying and requesting congestion management relief.

"Indemnifying Party" shall have the meaning stated in Section 35.20.3.

"Indemnitee" shall have the meaning stated in Section 35.20.3

"Intellectual Property" shall mean (i) ideas, designs, concepts, techniques, inventions, discoveries, or improvements, regardless of patentability, but including without limitation patents, patent applications, mask works, trade secrets, and know-how; (ii) works of authorship, regardless of copyright ability, including copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

"Intentional Wrongdoing" shall mean an act or omission taken or omitted by a Party with knowledge or intent that injury or damage could reasonably be expected to result.

"Interconnected Reliability Operating Limit" or **"IROL"** shall mean the value (such as MW, MVAR, Amperes, Frequency, or Volts) derived from, or a subset of, the System Operating Limits, which if exceeded, could expose a widespread area of the bulk electrical system to instability, uncontrolled separation(s) or cascading outages.

"Interconnection" shall mean a connection between two or more individual Transmission Systems that normally operate in synchronism and have interconnecting intertie(s).

"Interconnection Facilities" shall mean the Interconnection facilities described in Schedule A.

"Intermediate Term Security Constrained Economic Dispatch" shall mean PJM's algorithm that performs various functions, including but not limited to forecasting dispatch and LMP solutions based on current and projected system conditions for up to several hours into the future.

"ISO" shall mean Independent System Operator.

"JK Interface" shall mean the transfer path comprised of the JK Ramapo-South Mahwah-Waldwick tie lines between PJM and NYISO.

"kV" shall mean kilovolt of electric potential.

"LEC Adjusted Market Flow" shall mean the real-time Market Flow incorporating the observed operation of the PARs at the Michigan-Ontario border.

"Locational Marginal Price" or **"LMP"** shall mean the market clearing price for energy at a given location in a Party's RC Area, and "Locational Marginal Pricing" shall mean the processes related to the determination of the LMP.

"Losses" shall have the meaning stated in Section 35.20.3.

"M2M" shall mean the market-to-market coordination process set forth in Schedule D to this Agreement.

"**M2M Entitlement**" shall mean a Non-Monitoring RTO's share of a M2M Flowgate's total capability to be used for settlement purposes that is calculated pursuant to Section 6 of Schedule D to this Agreement.

"M2M Event" shall mean the period when both Parties are operating under M2M as defined and set forth in Schedule D to this Agreement.

"M2M Flowgate" shall mean Flowgates where constraints are jointly monitored and coordinated as defined and set forth in Schedule D to this Agreement.

"Market Flows" shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving load within an RTO's market.

"Market Participant" shall mean an entity that, for its own account, produces, transmits, sells, and/or purchases for its own consumption or resale capacity, energy, energy derivatives and ancillary services in the wholesale power markets. Market Participants include transmission service customers, power exchanges, Transmission Owners, load serving entities, loads, holders of energy derivatives, generators and other power suppliers and their designated agents.

"Metered Quantity" shall mean apparent power, reactive power, active power, with associated time tagging and any other quantity that may be measured by a Party's Metering Equipment and that is reasonably required by either Party for Security reasons or revenue requirements.

"Metering Equipment" shall mean the potential transformers, current transformers, meters, interconnecting wiring and recorders used to meter any Metered Quantity.

"Monitoring RTO" shall mean the Party that has operational control of a M2M Flowgate.

"Multiregional Modeling Working Group" or **"MMWG"** shall mean the NERC working group that is charged with multi-regional modeling.

"Mutual Benefits" shall mean the transient and steady-state support that the integrated generation and Transmission Systems in PJM and New York provide to each other inherently by virtue of being interconnected as described in Section 35.4 of this Agreement.

"MVAR" shall mean megavolt ampere of reactive power.

"MW" shall mean megawatt of capacity.

"NAESB" shall mean North American Energy Standards Board or its successor organization.

"NERC" shall mean the North American Electricity Reliability Corporation or its successor organization.

"Network Resource" shall have the meaning as provided in the NYISO OATT, for such resources located in New York, and the meaning as provided in the PJM OATT, for such resources located in PJM.

"New Year Market Flow" shall mean the Market Flow incorporating the transmission topology that includes all pre-existing Transmission Facilities and all new or upgraded Transmission Facilities whose impact on M2M Entitlements has been previously evaluated and incorporated, *and* all new or upgraded Transmission Facilities whose impact on M2M Entitlements is being evaluated in the current evaluation step.

"Non-Monitoring RTO" shall mean the Party that does not have operational control of a M2M Flowgate.

"Notice" shall have the meaning stated in Section 35. 20.22.

"NPCC" shall mean the Northeast Power Coordinating Council, Inc., including the NPCC Cross Border Regional Entity ("CBRE"), or their successor organizations.

"NY-NJ PARs" shall mean, individually and/or collectively, the ABC PARs, the Ramapo PARs, and the Waldwick PARs, all of which are components of the NYISO – PJM interface**.**

"NYISO" shall have the meaning stated in the preamble of this Agreement.

"NYISO Code of Conduct" shall mean the rules, procedures and restrictions concerning the conduct of the ISO directors and employees, contained in Attachment F to the NYISO OATT.

"NYISO Market Monitoring Plan" shall refer to Attachment O to the NYISO Services Tariff.

"NYISO Tariffs" shall mean the NYISO OATT and the NYISO Market Administration and Control Area Services Tariff ("Services Tariff"), collectively.

"NYSRC" shall mean the New York State Reliability Council.

"NYSRC Reliability Rules" shall mean the rules applicable to the operation of the New York Transmission System. These rules are based on Reliability Standards adopted by NERC and NPCC, but also include more specific and more stringent rules to reflect the particular requirements of the New York Transmission System.

"O PAR" shall mean the phase angle regulator located at the Waldwick station on the O-2267 Waldwick-Fairlawn 230kV line.

"OASIS" shall mean the Open Access Same-Time Information System required by FERC for the posting of market and transmission data on the Internet websites of PJM and NYISO.

"OATT" shall mean the applicable Open Access Transmission Tariffs on file with FERC for PJM and NYISO.

"Operating Entity" shall mean an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

"Operating Instructions" shall mean the operating procedures, steps, and instructions for the operation of the Interconnection Facilities established from time to time by the Coordination Committee or the PJM and NYISO individual procedures and processes and includes changes from time to time by the Coordination Committee to such established procedures, steps and instructions exclusive of the individual procedures.

"Operational Base Flow" or **"OBF"** shall mean an equal and opposite MW offset of power flows over the Waldwick PARs and ABC PARs to account for natural system flows over the JK Interface and the ABC Interface in order to facilitate the reliable operation of the NYISO and/or PJM transmission systems. The OBF is not a firm transmission service on either the NYISO transmission system or on the PJM transmission system. The OBF shall not result in charges from one Party to the other Party, or from one Party to the other Party's Market Participants, except for the settlements described in the Real-Time Energy Market Coordination and Settlements provisions set forth in Sections 7 and 8 of Schedule D to this Agreement. In particular, the NYISO and its Market Participants shall not be subjected to PJM Regional Transmission Expansion Plan ("RTEP") cost allocations as a result of the OBF.

"Operating Reserve" shall mean generation capacity or load reduction capacity which can be called upon on short notice by either Party to replace scheduled energy supply which is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies.

"Operational Control" shall mean Security monitoring, adjustment of generation and transmission resources, coordinating and approval of changes in transmission status for maintenance, determination of changes in transmission status for reliability, coordination with other Balancing Authority Areas and Reliability Coordinators, voltage reductions and load shedding, except that each legal owner of generation and transmission resources continues to physically operate and maintain its own facilities.

"**OTDF**" shall mean the electric PTDF with one or more system facilities removed from service (*i.e.*, outaged) in the post-contingency configuration of a system under study.

"Outages" shall mean the planned unavailability of transmission and/or generation facilities dispatched by PJM or the NYISO, as described in Section 35.9 of this Agreement.

"PAR" shall mean phase angle regulator.

"PAR Shift Factor" or **"PSF"**, shall mean the PAR's impact on a Flowgate measured as the ratio of Flowgate flow change in MW to PAR schedule change in MW.

"Party" or **"Parties"** refers to each party to this Agreement or both, as applicable.

"PJM" has the meaning stated in the preamble of this Agreement.

"PJM Code of Conduct" shall mean the code of ethical standards, guidelines and expectations for PJM's employees, officers and Board Members in their transactions and business dealings on behalf of PJM as posted on the PJM website and as may be amended from time to time.

"PJM Tariffs" shall mean the PJM OATT and the PJM Amended and Restated Operating Agreement, collectively.

"**Power Transfer Distribution Factor**" or "**PTDF**" shall mean a measure of the responsiveness or change in electrical loadings on Transmission Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer in the pre-contingency configuration of a system under study.

"Ramapo Interface" shall mean the transfer path comprised of the 5018 Hopatcong-Ramapo 500 kV tie line between PJM and NYISO.

"Ramapo PARs" shall mean the 3500 PAR and 4500 PAR that control flow on the Ramapo Interface.

"Real-Time Commitment" shall mean NYISO's multi-period security constrained unit commitment and dispatch model, as defined in the NYISO Tariffs.

"Reference Year Market Flow" shall mean the Market Flow based on a transmission topology that includes all pre-existing Transmission Facilities and all new or upgraded Transmission Facilities whose impact on M2M Entitlements has been previously evaluated and incorporated.

"Region" shall mean the Control Areas and Transmission Facilities with respect to which a Party serves as RTO or Reliability Coordinator under NERC policies and procedures.

"Regulatory Body" shall have the meaning stated in Section 35.20.21.

"Reliability Coordinator" or **"RC"** shall mean the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the wide area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

"Reliability Coordinator Area" shall mean that portion of the Bulk Electric System under the purview of the Reliability Coordinator.

"Reliability Standards" shall mean the criteria, standards, rules and requirements relating to reliability established by a Standards Authority.

"RFC" shall mean ReliabilityFirst Corporation.

"RTO" shall mean Regional Transmission Organization. For ease of reference, the New York Independent System Operator, Inc., may be referred to as an RTO in this Agreement and the NYISO and PJM may be referred to collectively as the "RTOs" or the "participating RTOs."

"Schedule" shall mean a schedule attached to this Agreement and all amendments, supplements, replacements and additions hereto.

"SDX System" shall mean the system used by NERC to exchange system data.

"Security" shall mean the ability of the electric system to withstand sudden disturbances including, without limitation, electric short circuits or unanticipated loss of system elements.

"Security Limits" shall mean operating electricity system voltage limits, stability limits and thermal ratings.

"SERC" shall mean SERC Reliability Corporation or its successor organization.

"Shadow Price" shall mean the marginal value of relieving a particular constraint which is determined by the reduction in system cost that would result from an incremental relaxation of that constraint.

"Standards Authority" shall mean NERC, and the NERC regional entities with governance over PJM and NYISO, any successor thereof, or any other agency with authority over the Parties regarding standards or criteria to either Party relating to the reliability of Transmission Systems.

"Standards Authority Standards" shall have the meaning stated in Section 35.5.2.

"State Estimator" shall mean a computer model that computes the state (voltage magnitudes and angles) of the Transmission System using the network model and real-time measurements. Line flows, transformer flows, and injections at the busses are calculated from the known state and the transmission line parameters. The State Estimator has the capability to detect and identify bad measurements.

"Storm Watch" shall mean actual or anticipated severe weather conditions under which region-specific portions of the New York State Transmission System are operated in a more conservative manner by reducing transmission transfer limits.

"Supplying Party" shall have the meaning stated in Section 35.8.2.

"System Operating Limit" or **"SOL"** shall mean the value (such as MW, MVAR, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

"**Target Value**" shall have the meaning stated in Section 7.2 of Schedule D to this Agreement.

"Third Party" refers to any entity other than a Party to this Agreement.

"TLR" shall mean the NERC Transmission Loading Relief Procedures used in the Eastern Interconnection as specified in NERC Operating Policies.

"Transmission Adjusted Market Flow" shall mean the result of applying the M2M Entitlement Transmission Adjusted Market Flow Calculation to the New Year Market Flow. The resulting Transmission Adjusted Market Flow is then used as the Reference Year Market Flow in all subsequent, iterative, evaluations.

"Transmission Operator" shall mean the entity responsible for the reliability of its "local" Transmission System, and that operates or directs the operations of the Transmission Facilities.

"Transmission Owner" shall mean an entity that owns Transmission Facilities.

"Transmission System" shall mean the facilities controlled or operated by PJM or NYISO as designated by each in their respective OATTs.

"Transmission Facility" shall mean a facility for transmitting electricity, and includes any structures, equipment or other facilities used for that purpose as defined in the Parties respective OATTs.

"Transmission Reliability Margin" or **"TRM"** shall mean the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

"Total Transfer Capability" or **"TTC"** shall mean the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected Transmission Systems by way of all transmission lines (or paths) between those areas under specified system conditions.

"Voltage and Reactive Power Coordination Procedures" are the procedures under Section 35.11 for coordination of voltage control and reactive power requirements.

"Waldwick PARs" shall mean the E PAR, F PAR and O PAR that control flow on the JK Interface.

35.2. 2 Rules of Construction.

35.2. 2.1 No Interpretation Against Drafter.

In addition to their roles as RTOs/ISOs and Reliability Coordinators, and the functions and responsibilities associated therewith, the Parties agree that each Party participated in the drafting of this Agreement and was represented therein by competent legal counsel. No rule of construction or interpretation against the drafter shall be applied to the construction or in the interpretation of this Agreement.

35.2. 2.2 Incorporation of Preamble and Recitals.

The Preamble and Recitals of this Agreement are incorporated into the terms and conditions of this Agreement and made a part thereof.

35.2. 2.3 Meanings of Certain Common Words.

The word "including" shall be understood to mean "including, but not limited to." The word "Section" refers to the applicable section of this Agreement and, unless otherwise stated, includes all subsections thereof. The word "Article" refers to articles of this Agreement.

35.2. 2.4 Standards Authority Standards, Policies, and Procedures.

All activities under this Agreement will meet or exceed the applicable Standards Authority standards, policies, or procedures as revised from time to time.

35.2. 2.5 Scope of Application.

Each Party will perform this Agreement in accordance with its terms and conditions with respect to each Control Area for which it serves as ISO or RTO and, in addition, each Control Area for which it serves as Reliability Coordinator.

35.3 Overview, Administration, and Relationship With Other Agreements

35.3.1 Purpose of This Agreement

This Agreement provides for the reliable operation of the interconnected PJM and NYISO Transmission Systems in accordance with the requirements of the Standards Authority and efficient market operations through M2M coordination. This Agreement establishes a structure and framework for the following functions related to the reliability of interconnected operations between the Parties and efficient joint market operations:

35.3.1.1 Developing and issuing Operating Instructions and Security Limits;

35.3.1.2 Coordinating operation of their respective Transmission Systems;

35.3.1.3 Developing and adopting operating criteria and standards;

35.3.1.4 Conducting operating performance reviews of the Interconnection Facilities;

35.3.1.5 Implementing each Party's respective Standards Authority requirements with regard to the PJM and NYISO Transmission Systems;

35.3.1.6 Exchanging information and coordination regarding system planning;

35.3.1.7 Providing mutual assistance in an Emergency and during system restoration;

35.3.1.9 Performance of certain other arrangements among the Parties for coordination of their systems, including, but not limited to performance consistent with the arrangements set forth in the existing agreements listed in Section 35.21 and the M2M transmission congestion coordination process that is set forth in the attached Market-to-Market Coordination Schedule and Section 35.12 below; and

35.3.1.9 Performance of certain other arrangements among the Parties for administration of this Agreement.

The Parties shall, consistent with Standards Authority requirements and the Parties' respective tariffs, rules and standards, including with respect to the NYISO, the NYSRC Reliability Rules, to the maximum extent consistent with the safe and proper operation of their respective Reliability Coordinator Area and Balancing Authority Area and necessary coordination with other interconnected systems, operate their systems in accordance with the procedures and principles set forth in this Agreement.

35.3.2 Establishment and Functions of Coordination Committee

To administer the arrangements under this Agreement, the Parties shall establish a Coordination Committee. The Coordination Committee shall undertake to jointly develop and authorize Operating Instructions to implement the intent of this Agreement with respect to reliable Transmission System operations.

35.3.2.1 The Coordination Committee shall have the following duties and responsibilities:

35.3.2.1.1 Determine the date(s) for implementing the various parts of this Agreement and undertake to jointly develop and authorize Operating Instructions to implement the intent of this Agreement;

35.3.2.1.2 Meet periodically to address any issues associated with this Agreement that a Party may raise and to determine whether any changes to this Agreement, or procedures employed under this Agreement, would enhance reliability, efficiency or economy;

35.3.2.1.3 The matters to be addressed at all meetings shall be specified in an agenda, which shall contain items specified by either Party in advance of the meeting and sent to the representatives of the other Party. All decisions of the Coordination Committee must be unanimous;

35.3.2.1.4 Conduct additional meetings upon Notice given by any Party, provided that the Notice specifies the reason(s) for requesting the meeting;

35.3.2.1.5 Initiate process reviews at the request of any Party for activities undertaken in the performance of this Agreement; and

35.3.2.1.6 In its discretion, take other actions, including the establishment of subcommittees and/or task forces, to address any issues that the Coordination Committee deems necessary consistent with this Agreement.

35.3.2.2 Coordination Committee Representatives

Within 30 days of the Effective Date, each Party shall designate a primary and alternate representative to the Coordination Committee and shall inform the other Parties of its designated representatives by Notice. A Party may change its designated Coordination Committee representatives at any time, provided that timely Notice is given to the other Parties. Each designated Coordination Committee representative shall have the authority to make decisions on issues that arise during the performance of this Agreement. The costs and expenses associated with each Party's designated Coordination Committee representatives shall be the responsibility of the designating Party.

35.3.2.3 Limitations Upon Authority of Coordination Committee

The Coordination Committee is not authorized to modify or amend any of the terms of this Agreement. The Coordination Committee is also not authorized to excuse any obligations under this Agreement or waive any rights pertaining to this Agreement. The Coordination

Committee has no authority to commit either Party to any expenditure that is beyond those expenses described in this Agreement.

35.3.3 Ongoing Review and Revisions

As set forth in Section 35.7, the Parties have agreed to the coordination and exchange of data and information under this Agreement to enhance system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. The Parties expect that these systems and the technology applicable to these systems and to the collection and exchange of data will change from time to time throughout the term of this Agreement. The Parties agree that the objectives of this Agreement can be fulfilled efficiently and economically only if the Parties, from time to time, review and, as appropriate, revise the requirements stated herein in response to such changes, including deleting, adding, or revising requirements and protocols. Each Party will negotiate in good faith in response to such revisions the other Party may propose from time to time. Nothing in this Agreement, however, shall require any Party to reach agreement with respect to any such changes, or to purchase, install, or otherwise implement new equipment, software, or devices, or functions, except as required to perform this Agreement.

35.4 Mutual Benefits

35.4.1 No Charge for Mutual Benefits of Interconnection.

The PJM Transmission System and the New York Transmission System, by virtue of being connected with a much larger Interconnection, share Mutual Benefits such as transient and steady-state support. PJM and NYISO shall not charge one another for such Mutual Benefits.

35.4.2 Maintenance of Mutual Benefits.

The Parties shall endeavor to operate or direct the operation of the Interconnection Facilities to realize the Mutual Benefits. The Parties recognize circumstances beyond their control, such as a result of operating configurations, contingencies, maintenance, or actions by third parties, may result in a reduction of Mutual Benefits.

35.5 Interconnected Operation

35.5.1 Obligation to Remain Interconnected

The Parties shall at all times during the term of this Agreement operate or direct the operation of their respective Transmission Systems so that they remain interconnected except:

35.5.1.1 During the occurrence of an event of Force Majeure which renders a Party unable to remain interconnected;

35.5.1.2 When an Interconnection is opened in accordance with the terms of an Operating Instruction or, if the Operating Instruction does not anticipate a particular circumstance where there is an imminent risk of equipment failure, or of danger to personnel or the public, or a risk to the environment, or a risk to system Security or reliability of a Transmission System, which cannot be avoided through Good Utility Practice; or

35.5.1.3 During planned maintenance where notice has been given in accordance with outage procedures as implemented by the Coordination Committee.

35.5.2 Adherence to Standards Authority Standards, Policies and Procedures

The Parties are participants in multiple Standards Authorities and are required to comply with specified standards, criteria, guides and procedures (“Standards Authority Standards”). Such Standards Authority Standards detail the many coordinating functions carried out by the parties, and this Agreement is intended to enhance those arrangements. Such Standards Authority Standards include, and the Parties agree to, the provision of “maximum reasonable assistance” to a neighboring Balancing Authority Area. Such maximum reasonable assistance will not normally require the shedding of firm load.

35.5.3 Notification of Circumstances

In the event that an Interconnection Facility is opened or if the Interconnection Facility transfer capability is changed, or if a Party plans to initiate the opening of an Interconnection Facility, or to change the transfer capability of the Interconnection Facilities, such Party shall immediately provide the other Party with notification indicating the circumstances of the opening or transfer capability change and expected restoration time, in accordance with procedures implemented by the Coordination Committee.

35.5.4 Compliance with Decisions of the Coordination Committee Direction

PJM shall direct the operation of the PJM Transmission System and the NYISO shall direct the operation of the NYISO Transmission System in accordance with the obligations of their respective tariffs, rules and standards and applicable directions of the Coordination Committee that conform with their respective tariffs, rules and standards, except where prevented by Force Majeure. The Coordination Committee's scope includes making decisions and jointly developing and approving Operating Instructions for many expected circumstances within the provisions of the Parties' respective tariffs, rules and standards. If decisions of the Coordination Committee do not anticipate a particular circumstance, the Parties shall act in accordance with Good Utility Practice.

35.5.5 Control and Monitoring

Each Party shall provide or arrange for 24-hour control and monitoring of their portion of the Interconnection Facilities.

35.5.6 Reactive Transfer and Voltage Control

The Parties agree to determine reactive transfers and control voltages in accordance with the provisions of their respective Standards Authority Standards. Real and reactive power will be transferred over the Interconnection Facilities as described in Section 35.11.

35.5.7 Inadvertent Exchanges

Inadvertent power transfers on all Interconnection Facilities shall be controlled and accounted for in accordance with the standards and procedures developed by the Standards Authorities and the system operators of each Party to this Agreement.

35.5.8 Adoption of Standards

The Parties hereby agree to adopt, enforce and comply with all applicable requirements and standards that will safeguard the reliability of the interconnected Transmission Systems. Such reliability requirements and Reliability Standards shall be:

35.5.8.1 Adopted and enforced for the purpose of providing reliable service;

35.5.8.2 Not unduly discriminatory in substance or application;

35.5.8.3 Applied consistently to both Parties with the exception of subsection 35.5.8.5 below;

35.5.8.4 Consistent with the Parties' respective obligations to applicable Standards Authorities including, without limitation, any relevant requirements or guidelines from each of NERC, or its Regional Councils' or any other Standards Authority or regional transmission group to which either of the Parties is required to adhere; and

35.5.8.5 With respect to the NYISO, consistent with the NYSRC Reliability Rules.

35.5.9 New York - PJM IROL Interface

The Parties share a joint IROL related to transfers related to the interconnecting transmission lines between their respective Reliability Coordinator Areas and Balancing Authority Areas. This IROL is adhered to in order to maintain acceptable steady-state and transient performance of the NYISO and PJM Transmission Systems. Both Parties will monitor this limit in accordance with this Agreement and independently determine the applicable import and export transfer limits. Both Parties agree to operate the interface to the most conservative limits developed in real-time and the day-ahead planning process. These operating limits shall be determined in accordance with Standards Authority Standards. Both Parties will take coordinated corrective actions to avoid a violation of the IROL. If a violation occurs, actions will be taken to clear the violation as soon as possible, and in accordance with Standards Authority Standards.

35.5.10 Coordination and Exchange of Information Regarding System Planning

The Parties shall exchange information and coordinate regarding system planning and inter-regional planning activities in a manner consistent with Standards Authority Standards and consistent with the requirements of confidentiality agreements or rules binding upon either of the Parties.

35.6 Emergency Assistance

35.6.1 Emergency Assistance

Both Parties shall exercise due diligence to avoid or mitigate an Emergency to the extent practical in accordance with applicable requirements imposed by the Standards Authority or contained in the PJM Tariffs and NYISO Tariffs. In avoiding or mitigating an Emergency, both Parties shall strive to allow for commercial remedies, but if commercial remedies are not successful or practical, the Parties agree to be the suppliers of last resort to maintain reliability on the system. For each hour during which Emergency conditions exist in a Party's Balancing Authority Area, that Party (while still ensuring operations within applicable Reliability Standards) shall determine what commercial remedies are available and make use of those that are practical and needed to avoid or mitigate the Emergency before any Emergency Energy is scheduled in that hour.

35.6.2 Emergency Operating Guides

The Parties agree to jointly develop, maintain, and share operating guides to address credible Emergency conditions.

35.6.3 Emergency Energy

Each Party shall, to the maximum extent it deems consistent with the safe and proper operation of its respective Transmission System, provide Emergency Energy to the other Party in accordance with the provisions of the Inter Control Area Transactions Agreement.

35.6.4 Costs of Compliance

Each Party shall bear its own costs of compliance with this Article except that the cost of Emergency Energy purchased by one Party at the request of the other Party shall be reimbursed in accordance with the Inter Control Area Transaction Agreement. Nothing in this Agreement shall require a Party to purchase Emergency Energy if the Party cannot recover the costs under an OATT or other agreement or lawful arrangement.

35.6.5 Emergency Conditions

If an emergency condition exists in either the NYCA or PJM, the NYISO operator or PJM dispatcher may request that the NY/PJM Interconnection Facilities be adjusted to assist directing power flows between the NYCA and PJM to alleviate the emergency condition. The taps on the ABC PARs, Ramapo PARs, and Waldwick PARs may be moved either in tandem or individually as needed to mitigate the emergency condition.

The NYISO and/or PJM shall implement the appropriate emergency procedures of either the NYISO or PJM, as appropriate, during system emergencies experienced on either the NYISO or PJM system. The NYISO and PJM shall have the authority to implement their respective emergency procedures in any order required to ensure overall system reliability.

35.7 Exchange of Information

35.7.1 Exchange of Operating Data

PJM and NYISO agree to exchange and share such information as may be required from time to time for the Parties to perform their duties and fulfill their obligations under this Agreement, subject to the requirements of existing confidentiality agreements or rules binding upon either of the Parties, including the NYISO Code of Conduct as set forth in Attachment F to the NYISO OATT, Article 6 of the NYISO Services Tariff, the PJM Code of Conduct and PJM Data Confidentiality Regional Stakeholder Group. Such information may consist of the following:

35.7.1.1 Information required to develop Operating Instructions;

35.7.1.2 Transmission System facility specifications and modeling data required to perform Security analysis;

35.7.1.2.1 The Parties will exchange their detailed EMS models in CIM format or another mutually agreed upon electronic format, and include the ICCP/ISN mapping files, identification of individual bus loads, seasonal equipment ratings and one-line drawings to expedite the model conversion process, upon request. The Parties will also exchange updates that represent the incremental changes that have occurred to the EMS model since the most recent update in an agreed upon electronic format;

35.7.1.3 Functional descriptions and schematic diagrams of Transmission System protective devices and communication facilities;

35.7.1.4 Ratings data and associated ratings methodologies for the Interconnection Facilities;

35.7.1.5 Telemetry points, equipment alarms and status points required for real-time monitoring of Security dispatch;

35.7.1.6 Data required to reconcile accounts for inadvertent energy, and for Emergency Energy transactions;

35.7.1.7 Transmission System information that is consistent with the information sharing requirements imposed by the Standards Authority;

35.7.1.8 Such other information as may be required for the Parties to maintain the reliable operation of their interconnected Transmission Systems and fulfill their obligations under this Agreement and to any Standards Authority of which either Party is a member, provided, however, that this other information will be exchanged only if that can be done in accordance with applicable restrictions on the disclosure of information to any Market Participant;

35.7.1.9 Additional information required for the Parties to administer the M2M coordination process set forth in Schedule D to this Agreement, including:

a. actual flows on M2M Flowgates;

b. actual limits for M2M Flowgates;

c. *ex ante* Shadow Prices on constrained M2M Flowgates;

d. requested relief during a M2M Event;

e. Market Flow calculation data (generator shift factors, load shift factors, interchange PTDFs, phase angle regulator OTDFs, generator output, load, net interchange);

f. Market Flows on M2M Flowgates; and

g. binding constraint thresholds (the shift factor thresholds used to identify the resource(s) available to relieve a transmission constraint).

35.7.1.10 Additional information required for the Parties to administer CTS, including:

a. interchange transaction offer attributes (frequency of scheduling, offer type, source and sink);

b. forecasted interchange schedules;

c. forecasted prices; and

d. CTS interface limits.

35.7.2 Confidentiality

The Party receiving information pursuant to this Section 35.7 shall treat such information as confidential subject to the terms and conditions of set forth in Section 35.8 of this Agreement. The obligation of each Party under this Section 35.7.2 continues and survives the termination of this Agreement by seven (7) years.

35.7.3 Data Exchange Contact

To facilitate the exchange of all such data, each Party will designate to the other Party's Vice President of Operations a contact to be available twenty-four (24) hours each day, seven (7) days per week, and an alternate contact to act in the absence or unavailability of the primary contact, to respond to any inquiries. With respect to each contact and alternate, each Party shall provide the name, telephone number, e-mail address, and fax number. Each Party may change a designee from time to time by Notice to the other Party's Vice President of Operations.

The Parties agree to exchange data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. Each Party shall provide notification to the other Party thirty (30) days prior to modifying an established data exchange format.

35.7.4 Cost of Data and Information Exchange

Each Party shall bear its own cost of providing information to the other Party.

35.7.5 Other Data

The Parties may share other data not listed in this Section 35.7 as mutually agreed upon by the Parties.

35.8 Confidential Information

35.8.1 Definition

The term "Confidential Information" shall mean: (a) all information, whether furnished before or after the mutual execution of this Agreement, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "confidential" or "proprietary" or which under all of the circumstances should be treated as confidential or proprietary; (b) any data or information deemed confidential under some other form of confidentiality agreement or tariff provided to a Party by a generator; (c) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any Confidential Information; (d) applicable material deemed Confidential Information pursuant to the PJM Data Confidentiality Regional Stakeholder Group, the PJM Code of Conduct, the NYISO Code of Conduct, or Article 6 of the NYISO's Services Tariff; (e) Protected Information under the NYISO Market Monitoring Plan; and (f) any information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC's Standards of Conduct set forth in 18 C.F.R. § 37 et. seq. and the Parties' Standards of Conduct on file with the FERC.

35.8.2 Protection

During the course of the Parties' performance under this Agreement, a Party may receive or become exposed to Confidential Information. Except as set forth herein, the Parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the Party supplying such Confidential Information ("Supplying Party"). In addition, each Party shall require that its employees, its subcontractors and its subcontractors' employees and agents to whom Confidential Information is exposed agree to be bound by the terms and conditions contained herein. Each Party shall be responsible for any breach of this section by its employees, its subcontractors and its subcontractors' employees and agents.

35.8.3 Treatment of Confidential Information

The Party receiving the Confidential Information shall treat the information in the same confidential manner as its governing documents require it to treat the confidential information of its own members and Market Participants.

35.8.4 Statute of Limitations

The receiving Party shall not release the Supplying Party's Confidential Information until expiration of the time period controlling the Supplying Party's disclosure of the same information, as such period is described in the Supplying Party's governing documents from time to time. As of the Effective Date, this period is three (3) months with respect to bid or pricing data and seven (7) calendar days for transmission data after the event ends. The obligation of each Party under this Section 35.8 continues and survives the termination of this Agreement by seven (7) years.

35.8.5 Scope

This obligation of confidentiality shall not extend to data and information that, at no fault of a recipient Party, is or was: (a) in the public domain or generally available or known to the public; (b) disclosed to a recipient by a non-Party who had a legal right to do so; (c) independently developed by a Party or known to such Party prior to its disclosure hereunder; and

(d) which is required to be disclosed by subpoena, law, or other directive of a Governmental Authority.

35.8.6 Standard of Care

Each Party shall protect Confidential Information from disclosure, dissemination, or publication. Each Party agrees to restrict access to all Confidential Information to only those persons authorized to view such information: (a) by the FERC's Standards of Conduct, (b) OASIS posting requirements in 18 C.F.R. § § 37.1-37.8 and, (c) if more restrictive, by such Party's board resolutions, tariff provisions, or other internal policies governing access to, and the sharing of, energy market or Transmission System information.

35.8.7 Required Disclosure

If a Governmental Authority requests or requires a Party to disclose any Confidential Information ("Disclosing Party"), such Disclosing Party shall provide the Supplying Party with prompt written notice of such request or requirement and will assist any efforts by the Supplying Party to contest disclosure, or seek an appropriate protective order or other appropriate remedy. The Supplying Party may also choose to waive compliance with the provisions of this Agreement. Notwithstanding the presence or absence of a protective order or a waiver, a Disclosing Party shall disclose only such Confidential Information as it is legally required to disclose. Each Party shall use reasonable efforts to obtain reliable assurances that confidential treatment will be accorded to Confidential Information required to be disclosed.

If a Disclosing Party is required to disclose any Confidential Information under this section, a Supplying Party shall have the right to immediately suspend supplying such Confidential Information to the Disclosing Party. In that event, the Parties shall meet as soon as practicable in an effort to resolve any and all issues associated with the required disclosure of such Confidential Information, and the likelihood of additional disclosures of such Confidential Information.

35.8.8 Return of Confidential Information

All Confidential Information provided by the Supplying Party shall be returned by the receiving Party to the Supplying Party promptly upon request. Upon termination or expiration of this Agreement, a Party shall use reasonable efforts to destroy, erase, delete or return to the Supplying Party any and all written or electronic Confidential Information. In no event shall a receiving Party retain copies of any Confidential Information provided by a Supplying Party.

35.8.9 Equitable Relief

Each Party acknowledges that remedies at law are inadequate to protect against breach of the covenants and agreements in this Article, and hereby in advance agrees, without prejudice to any rights to judicial relief that it may otherwise have, to the granting of equitable relief, including injunction, in the Supplying Party's favor without proof of actual damages. In addition to the equitable relief referred to in this section, a Supplying Party shall only be entitled to recover from a receiving Party any and all gains wrongfully acquired, directly or indirectly, from a receiving Party's unauthorized disclosure of Confidential Information.

35.8.10 Existing Confidential Information Obligations

Notwithstanding anything to the contrary in this Agreement, the parties shall have no obligation to disclose Confidential Information or data to the extent such disclosure of information or data would be a violation of or inconsistent with the terms and conditions of the PJM or NYISO Amended and Restated Operating Agreement, either Party's OATT, any other agreement, or applicable state or federal regulation or law. The obligation of each Party under this section continues and survives the termination of this Agreement by seven (7) years.

35.9 Coordination of Scheduled Outages

35.9.1 Coordinating Outages Operating Protocols

The Parties will jointly develop protocols for coordinating transmission and generation Outages to maintain reliability. The Parties agree to the following with respect to transmission and generation Outage coordination.

35.9.1.1 Exchange of Transmission and Generation Outage Schedule Data

Upon a Party's request, the projected status of generation and transmission availability will be communicated between the Parties, subject to data confidentiality agreements. The Parties shall exchange the most current information on proposed Outage information and provide a timely response on potential impacts of proposed Outages. The Parties shall select a mutually agreeable common format for the exchange of this information.

35.9.1.2 Evaluation and Coordination of Transmission and Generation Outages

The Parties analyze planned critical facility maintenance to determine its effects on the reliability of the Transmission System. The Parties will work together to resolve Outage conflicts and work with the facility owner(s), as necessary, to provide remedial steps.

The Parties will notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known. The Parties will evaluate the impact of emergency and forced outages on the Parties' systems to develop remedial steps as necessary.

Unforeseen changes in scheduled outages may require additional review. Each Party will consider the impact of these changes on the other Party's system reliability in addition to its own. The Parties will contact each other as soon as possible if these changes result in unacceptable system conditions to develop remedial steps as necessary.

35.10 Coordination of Transmission Planning Studies

35.10.1 Scope of Activities:

Transmission planning activities will be coordinated in accordance with the Amended and Restated Northeast ISO/RTO Planning Coordination Protocol ("Protocol"), between and among PJM Interconnection, L.L.C., the New York Independent System Operator, Inc. and ISO New England Inc., effective as of December 12, 2004 as amended on July 10, 2013.

35.10.2 Allocation of Costs of Approved Interregional Transmission Projects

The costs of Interregional Transmission Projects, as defined in the Protocol, evaluated under the Protocol and selected by PJM and NYISO (the "Regions") in their regional transmission plans for purposes of cost allocation under their respective tariffs shall, when applicable, be allocated to the PJM Region and the NYISO Region in accordance with the cost allocation principles of FERC Order No. 1000, as follows:

(a) To be eligible for interregional cost allocation pursuant to this Section 35.10.2, an Interregional Transmission Project must be selected in both the PJM and NYISO regional transmission plans for purposes of cost allocation pursuant to agreements and tariffs on file at FERC for each Region, and must be planned for construction in both the PJM region and the NYISO Region.

(b) The share of the costs of an Interregional Transmission Project allocated to a Region will be determined by the ratio of the present value of the estimated costs of such Region's displaced regional transmission project or projects to the total of the present values of the estimated costs of the displaced regional transmission projects in the Regions that have selected the Interregional Transmission Project in their regional transmission plans.

(c) The present values of the estimated costs of each Region's displaced regional transmission project shall be based on a common base date that will be the beginning of the calendar month of the cost allocation analysis for the subject Interregional Transmission Project (the "Base Date").

(d) In order to perform the analysis in Section 35.10.2(b) above, the estimated cost of the displaced regional transmission projects shall specify the year's dollars in which those estimates are provided.

(e) The present value analysis for all displaced regional transmission projects shall use a common discount rate. PJM and NYISO, in consultation with their respective transmission owners, and NYISO in consultation with other stakeholders, shall agree on the discount rate to be used for the present value analysis.

(f) PJM and NYISO, in consultation with the transmission owners in their respective regions, and NYISO in consultation with other stakeholders, shall review and determine that the cost estimates of the displaced regional transmission projects have been determined in a comparable manner prior to applying this cost allocation.

(g) No cost shall be allocated to a Region that has not selected the Interregional Transmission Project in its regional transmission plan.

(h) When a portion of an Interregional Transmission Project evaluated under the Protocol is included by a region (Region 1) in its regional transmission plan but there is no regional need or displaced regional transmission project in Region 1 and the neighboring region (Region 2) has a regional need or displaced regional project for the Interregional Transmission Project and selects the Interregional Transmission Project in its regional transmission plan, all of the costs of the Interregional Transmission Project shall be allocated to Region 2 in accordance with the methodology in this Section 35.10.2 and none of the costs shall be allocated to Region 1.

(i) The portion of the costs allocated to a region pursuant to this Section 35.10.2 shall be further allocated to the transmission customers within such Region pursuant to the applicable provisions of the region's tariffs and, if applicable, agreements on file with FERC.

(j) The following example illustrates the cost allocation for such an Interregional Transmission Project:

- A cost allocation analysis of the costs of Interregional Transmission Project Z is to be performed during a given month establishing the beginning of that month as the Base Date.
- Region A has identified a reliability need in its region and has selected a transmission project (Project X) as the preferred solution in its regional plan. The estimated cost of Project X is: Cost (X), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is: N(X).
- Region B has identified a reliability need in its region and has selected a transmission project (Project Y) as the preferred solution in its Regional Plan. The estimated cost of Project Y is: Cost (Y), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost

estimate of Project (Y) is: N(Y).

- Regions A and B, through the interregional planning process have determined that an Interregional Transmission Project (Project Z) will address the reliability needs in both regions more efficiently and cost-effectively than the separate regional projects. The estimated cost of Project Z is: Cost (Z). Regions A and B have each determined that Interregional Transmission Project Z is the preferred solution to their reliability needs and have adopted that Interregional Transmission Project in their respective regional plans in lieu of Projects X and Y, respectively. If Regions A and B have agreed to bear the costs of upgrades in other affected transmission planning regions, these costs will be considered part of Cost (Z).
- The discount rate used for all displaced regional transmission projects is: D
- Based on the foregoing assumptions, the following formulas will be used:
  - Present Value of Cost (X) = PV Cost (X) = Cost (X) / $(1+D)^{N(X)}$
  - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / $(1+D)^{N(Y)}$
  - Cost Allocation to Region A = Cost (Z) x PV Cost (X)/[PV Cost (X) + PV Cost (Y)]
  - Cost Allocation to Region B = Cost (Z) x PV Cost (Y)/[PV Cost (X) + PV Cost (Y)]
- Applying those formulas, if:

  Cost (X) = $60 Million and N(X) = 8.25 years

  Cost (Y) = $40 Million and N(Y) = 4.50 years

  Cost (Z) = $80 Million

  D = 7.5% per year

  Then:

  PV Cost (X) = $60/(1+0.075)^{8.25}$ = 33.039 Million

PV Cost (Y) = $40/(1+0.075)^{4.50}$ = 28.888 Million

Cost Allocation to Region A = \$80 x 33.039/(33.039 + 28.888) = \$42.681 Million

Cost Allocation to Region B = \$80 x 28.888/(33.039 + 28.888) = \$37.319 Million

35.10.3 Other Cost Allocation Arrangements

(a) Except as provided in this Section 35.10.3(b), the methodology in Section 35.10.2 is the exclusive means by which any costs of an Interregional Transmission Project may be allocated between or among PJM and NYISO.

(b) Subject to the filing rights described in Section 35.10.4 and any stakeholder processes required prior to the exercise of such filing rights, transmission owners and transmission developers in PJM and the NYISO and the Parties may enter into a separate agreement to allocate the cost of an Interregional Transmission Project, and other transmission projects identified pursuant to Section 6 of the Protocol in a manner other than as set forth in Section 35.10.2, provided that any such agreement is filed with and accepted by FERC in accordance with the filing rights set forth in Section 35.10.4, and such agreement shall apply only to the share of the costs of such Interregional Transmission Project or such other transmission projects allocated to the PJM Region and the NYISO Region.

35.10.4 Filing Rights with Respect to Approved Interregional Transmission Projects

Solely with respect to Interregional Transmission Projects evaluated under the Protocol and selected by PJM and NYISO in their regional transmission plans for purposes of cost allocation under their respective tariffs as set forth in Section 35.10.2, PJM and NYISO agree as follows:

(a) Nothing in Sections 35.10.2 through 35.10.6 of this Agreement or in the Protocol will convey, expand, limit or otherwise alter any rights of the Parties, transmission owners, transmission developers, other market participants, or other entities in PJM or NYISO to submit filings under Section 205 of the Federal Power Act regarding cost allocation or any other matter.

(b) As applicable, the Parties have been authorized by entities that have cost allocation rights for their respective regions, but are not parties to this Agreement, to enter into and file the cost allocation provisions set forth in Sections 35.10.2 through 35.10.6 of this Agreement. Such cost allocation provisions shall not be modified without the mutual consent of the holders of Section 205 rights and the Long Island Power Authority and the New York Power Authority with respect to interregional cost allocation in the PJM Region and the NYISO Region.

(c) With respect to PJM:

(i) The provisions in Sections 35.10.2 through 35.10.6 have been approved by the PJM Transmission Owners acting through the Consolidated Transmission Owners Agreement (“CTOA”) pursuant to Section 9.1 of the PJM Open Access Transmission Tariff (“PJM Tariff”) and Article 7 of the CTOA, and any amendment to the provisions of Sections 35.10.2 through 35.10.6 or any other provision of this Agreement allocating the costs of Interregional Transmission Projects, shall require approval by the PJM Transmission Owners acting through the CTOA pursuant to Section 9.1 of the PJM Tariff and Article 7 of the CTOA and shall be filed pursuant Section 205 of the Federal Power Act in accordance with the PJM Tariff and Article 7 of the CTOA.

(ii) Nothing in Sections 35.10.2 through 35.10.6 of this Agreement shall limit or alter the rights of the PJM Transmission Owners set forth in the PJM Tariff and CTOA to submit filings under Section 205 of the Federal Power Act.

35.10.5 Merchant Transmission and Individual Transmission Owner Projects

Nothing in this Agreement shall preclude the development of Interregional Transmission Projects that are funded solely by merchant transmission developers or by individual transmission owners.

35.10.6 Consequences to Other Regions from Regional or Interregional Transmission Projects

Except as provided herein in sections 35.10.2 and 35.10.3 of this Agreement, or where cost responsibility is expressly assumed by NYISO or PJM in other documents, agreements or tariffs on file with FERC, neither the NYISO Region nor the PJM Region shall be responsible for compensating another region or each other for required upgrades or for any other consequences in another planning region associated with regional or interregional transmission facilities, including but not limited to, transmission projects identified pursuant to Section 6 of the Protocol and Interregional Transmission Projects identified pursuant to Section 7 of the Protocol.

35.10.7 Coordination of Transmission Planning Studies Regarding Reliability Transmission Projects Located Entirely Within One Region

This section addresses the process through which PJM and NYISO will coordinate the study of reliability transmission projects located entirely within one Region. The Regions agree to share information and data that arise in the performance of each Region’s respective planning activities as necessary or appropriate for effective coordination between the Regions, including the timely identification and notification of proposed reliability transmission projects to meet the

Region's reliability needs, according to the process set forth herein. For purposes of this section 35.10.7, the Region proposing a reliability transmission project to meet such Region's regional reliability needs is referred to as the "proposing Region" and the Region adjacent to the "proposing Region" that may potentially be impacted by such proposal is referred to as the "potentially impacted Region."

35.10.7.1 The Regions shall share their respective baseline reliability analysis undertaken as part of their regional reliability planning process no later than the time it is initially provided to the proposing Region's stakeholders through the appropriate committee.

35.10.7.2 Based on its review of the proposing Region's proposed reliability transmission project, the potentially impacted Region shall identify the potential violations, based upon planning or reliability criteria, including applicable transmission owner criteria then in effect, that, depending on how solved, including through the use of proposed regional transmission projects, could negatively impact reliability on the potentially impacted Region's system.

35.10.7.3 The Regions shall discuss identified impacts and coordinate any special studies that need to be undertaken to analyze such impacts.

(a) Each Region shall be responsible for performing studies of potential impacts on its system. The Regions may agree on the most efficient way to perform the special studies on a case-specific basis, including which Region will conduct which study(ies).

(b) The Regions will provide to each other all of the technical information on their respective systems that is needed for each to perform the necessary studies.

(c) The Regions will coordinate the timing and conduct of such studies.

(d) Each Region will be responsible for all of its respective study costs related to the studies conducted under this coordinated study process.

35.10.7.4 Results of studies of impacts on the potentially impacted Region's system will be submitted to the proposing Region no later than at the time the proposed reliability transmission project(s) are presented to the proposing Region's stakeholders for final review and prior to submitting to the Board. The Regions shall discuss with each other potential alternative solutions, including changes to operating protocols, and the mitigation of impacts on the potentially impacted Region's system. The Regions' agreed-to mitigation shall be presented to the proposing Region's stakeholders as part of the overall solution to the identified reliability need.

35.10.7.5 Other than agreed-to mitigation or operational alternatives, each Region is responsible for the costs of addressing impacts to its own system.

35.11 Voltage Control and Reactive Power Coordination

35.11.1 Specific Voltage and Reactive Power Coordination Procedures

The Parties will utilize the following procedures to coordinate the use of voltage control equipment to maintain a reliable bulk power Transmission System voltage profile on their respective systems.

35.11.1.1 Under normal conditions, each Party shall provide for the supply and control of the reactive regulation requirements in its own area, including reactive reserve, so that applicable emergency voltage levels can be maintained following any of the set of contingencies that are observed under normal conditions.

35.11.1.2 Under normal conditions, each Party will anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light loads.

35.11.1.3 Under an abnormal condition, either Party experiencing rapid voltage decay will immediately implement all possible actions, including the shedding of firm load, to correct the problem until such time that the decay has been corrected.

35.12 M2M Coordination Process and Coordinated Transaction Scheduling

35.12.1 M2M Coordination Process

The fundamental philosophy of the M2M transmission congestion coordination process that is set forth in the attached Market-to-Market Coordination Schedule is to allow any transmission constraints that are significantly impacted by generation dispatch changes in both the NYISO and PJM markets or by the operation of the NY-NJ PARs to be jointly managed in the real-time security-constrained economic dispatch models of both Parties. This joint real-time management of transmission constraints near the market borders will provide a more efficient and lower cost transmission congestion management solution and coordinated pricing at the market boundaries.

Under normal system operating conditions, the Parties utilize the M2M coordination process on defined M2M Flowgates that experience congestion. The Party that is responsible for monitoring a M2M Flowgate will initiate and terminate the redispatch component of the M2M coordination process. The Party that is responsible for monitoring a M2M Flowgate is expected to bind that Flowgate when it becomes congested, and to initiate market-to-market redispatch to utilize the more cost effective generation between the two markets to manage the congestion in accordance with Section 7.1.2 of the attached Market-to-Market Coordination Schedule. NY-NJ PAR coordination need not be formally invoked by either Party. It is ordinarily in effect.

The M2M coordination process includes a settlement process that applies when M2M coordination is occurring.

35.12.2 Coordinated Transaction Scheduling

Coordinated Transaction Scheduling or “CTS” are real time market rules implemented by NYISO and PJM that allow transactions to be scheduled based on a bidder’s willingness to purchase energy at a source (in the PJM Control Area or the NYISO Control Area) and sell it at a sink (in the other Control Area) if the forecasted price at the sink minus the forecasted price at the corresponding source is greater than or equal to the dollar value specified in the bid.

CTS transactions are ordinarily evaluated on a 15-minute basis consistent with forecasted real-time prices from NYISO's Real-Time Commitment run and the forecasted price information from PJM's Intermediate Term Security Constrained Economic Dispatch solution. Coordinated optimization with CTS improves interregional scheduling efficiency by: (i) better ensuring that scheduling decisions take into account relative price differences between the regions; and (ii) moving the evaluation of bids and offers closer to the time scheduling decisions are implemented.

NYISO and PJM may suspend the scheduling of CTS transactions when NYISO or PJM are not able to adequately implement schedules as expected due to: (1) a failure or outage of the data link between NYISO and PJM prevents the exchange of accurate or timely data necessary to implement the CTS transactions; (2) a failure or outage of any computational or data systems preventing the actual or accurate calculation of data necessary to implement the CTS transactions; or (3) when necessary to ensure or preserve system reliability.

35.13 Joint Checkout Procedures

35.13.1 Scheduling Checkout Protocols

35.13.1.1 Both Parties shall require all transaction schedules to be tagged in accord with the NERC tagging standard. For reserve sharing and other emergency schedules that are not tagged, the Parties will enter manual schedules after the fact into their respective scheduling systems.

35.13.1.2 When there is a transaction scheduling conflict, the Parties will work to modify the schedule as soon as practical.

35.13.1.3 The Parties will perform the following types of checkouts. Checkouts will be consistent with 35.13.1.1 and 35.13.1.2.

(a) Day-ahead checkout shall be performed daily on the day before the transaction is to flow. Day-ahead checkout includes the verification of import and export totals and individual transaction schedules.

(b) Real-time checkout shall be performed hourly during the hour before the transaction is to flow. Real-time checkout includes the verification of import and export totals and individual transaction schedules.

(c) After-the-fact checkout of transactions shall be performed the next business day following the day of the transactions.

(d) After-the-fact reporting of hourly scheduled energy interchanged and hourly actual energy interchanged shall be updated by each Party each day and exchanged with the other Party. Each day, month to date data shall be exchanged. Parties shall resolve discrepancies within ten (10) business days of the end of each month.

35.14 TTC/ATC/AFC Calculations

35.14.1 TTC/ATC/AFC Protocols

In accordance with Section 35.9, the Parties will exchange scheduled Outages of all interconnections and other Transmission Facilities.

35.14.1.1 Scheduled Outages of Transmission Resources

Each Party will provide the projected status of scheduled Outages of Transmission Facilities for a minimum of eighteen (18) months or more if available.

35.14.1.2 Transmission Interchange Schedules

Each Party will make available its interchange schedules to permit accurate calculation of TTC and ATC/AFC values.

35.14.2 Configuration/Facility Changes

Transmission configuration changes and generation additions (or retirements) shall be communicated via the NERC MMWG process.

35.14. 3 Transmission System Impacts

35.14.3.1 The Parties shall coordinate with each other as needed and with other Reliability Coordinators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations.

35.14.3.2 Each Party shall operate to prevent the likelihood that a disturbance, action, or non-action in its area will result in a SOL or IROL violation for the other Party. In instances where there is a difference in derived limits, Parties shall respect the most limiting parameter.

35.14.3.3 A Party who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) that impacts the other Party shall issue an alert to the other Party without unreasonable delay.

35.14.3.4 Each Party shall confirm reliability assessment results and determine the effects within its own and the other Party's areas. The Parties shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

35.15 Dispute Resolution Procedures

35.15.1 Good Faith Negotiation

The Parties shall attempt in good faith to achieve consensus with respect to all matters arising under this Agreement and to use reasonable efforts through good faith discussion and negotiation to avoid and resolve disputes that could delay or impede a Party from receiving the benefits of this Agreement. These dispute resolution procedures apply to any dispute that arises from either Party's performance of, or failure to perform, in compliance with this Agreement and which the Parties are unable to resolve prior to invocation of these procedures.

35.15.2 Dispute Resolution

In the event of a Dispute arising out of or relating to this Agreement that is not resolved by the representatives of the Parties who have been designated under Section 35.3.2.2 of this Agreement within 7 days of the reference to such representatives of such Dispute, each Party shall, within 14 days' written notice by either Party to the other, designate a senior officer with authority and responsibility to resolve the Dispute and refer the Dispute to them. The senior officer designated by each Party shall have authority to make decisions on its behalf with respect to that Party's rights and obligations under this Agreement. The senior officers, once designated, shall promptly begin discussions in a good faith effort to agree upon a resolution of the Dispute. If the senior officers do not agree upon a resolution of the Dispute within 14 days of its referral to them, or within such longer period as the senior officers mutually agree to in writing, or do not within the same 14 day period agree to refer the matter to some individual or organization for alternate Dispute resolution, then the Parties shall request that FERC's Dispute Resolution Service mediate their efforts to resolve the Dispute. Upon a Party's determination, at any point in the mediation process, that mediation has failed to resolve the Dispute, either Party may seek formal resolution by initiating a proceeding before the FERC. If the FERC is not willing or able to consider or resolve a Dispute, then either Party shall have the right to pursue any and all remedies available to it at law or in equity.

Neither the giving of notice of a Dispute, nor the pendency of any Dispute resolution process as described in this section shall relieve a Party of its obligations under this Agreement, extend any notice period described in this Agreement or extend any period in which a Party must act as described in this Agreement. Notwithstanding the requirements of this section, either Party may terminate this Agreement in accordance with its provisions, or pursuant to an action at equity. The issue of whether such a termination is proper shall not be considered a Dispute hereunder.

35.16 Interconnection Revenue Metering

35.16.1 Obligation to Provide Inadvertent Energy Accounting Metering

The Parties shall require appropriate electric metering devices to be installed as required to measure electric power quantities for determining Interconnection Facilities inadvertent energy accounting.

35.16.2 Standards for Metering Equipment

The parties shall cause any Metering Equipment used to meter Metered Quantities for inadvertent energy accounting to be designed, verified, sealed and maintained in accordance with the Party’s respective metering standards or as otherwise agreed upon by the Coordination Committee.

35.16.3 Meter Compensation to the Point of Interconnection

The metering compensation for transmission line losses to the Interconnection Facilities Delivery Point shall be determined by the Party’s respective standards or otherwise agreed to by the Coordination Committee.

35.16.4 Metering Readings

The Parties shall require that integrated meter readings are provided at least once each hour for Interconnection Facilities accounting purposes and meter registers are read at least monthly, as close as practical to the last hour of the month. An appropriate adjustment shall be made to register readings not taken on the last hour of the month.

35.17 Retained Rights of Parties

35.17.1 Parties Entitled to Act Separately

This Agreement does not create or establish, and shall not be construed to create or establish, any partnership or joint venture between or among any of the Parties. This Agreement establishes terms and conditions solely of a contractual relationship, among independent entities, to facilitate the achievement of the joint objectives described in the Agreement. The contractual relationship established hereunder implies no duties or obligations among the Parties except as specified expressly herein.

35.18 Representations

35.18.1 Good Standing

Each Party represents and warrants that it is duly organized, validly existing and in good standing under the laws of the state or province in which it is organized, formed, or incorporated, as applicable.

35.18.2 Authority to enter Into Agreement

Each Party represents and warrants that it has the right, power, and authority to enter into this Agreement, to become a Party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms.

35.18.3 Organizational Formation Documents

Each Party represents and warrants that the execution, delivery and performance of this Agreement does not violate or conflict with its organizational or formation documents.

35.18.4 Regulatory Authorizations

Each Party represents and warrants that it has, or applied for, all regulatory authorizations necessary for it to perform its obligations under this Agreement.

35.19 Effective Date, Implementation, Term and Termination

35.19.1 Effective Date; Implementation

This Agreement shall become effective as of the date that all of the following have occurred: (i) upon the execution hereof by both Parties, and (ii) acceptance or approval by the Federal Energy Regulatory Commission. Commencing with the Effective Date, the Parties shall commence and continue efforts to implement other provisions of this Agreement on dates determined by the Coordination Committee, which dates shall be the earliest dates reasonably feasible for both Parties.

35.19.2 Term

This Agreement shall continue in full force and effect unless terminated in accordance with the provisions of this Agreement.

35.19.3 Right of a Party to Terminate

35.19.3.1 NYISO may terminate this Agreement at any time upon not less than twelve (12) months' Notice to PJM.

35.19.3.2 PJM may terminate this Agreement at any time upon not less than twelve (12) months' Notice to NYISO.

35.19.3.3 This Agreement may be terminated at anytime by mutual agreement in writing.

35.19.4 Survival

The applicable provisions of this Agreement shall continue in effect after any termination of this Agreement to provide for adjustments and payments under Section 35.15, dispute resolution, determination and enforcement of liability, and indemnification, arising from acts or events that occurred during the period this Agreement was in effect. In addition, Sections 35.8.4 and 35.8.10 of this Agreement provides that the obligation to safeguard Confidential Information continues in effect for a period of seven years after any termination of this Agreement.

35.19.5 Post-Termination Cooperation

Following any termination of this Agreement, all Parties shall thereafter cooperate fully and work diligently in good faith to achieve an orderly resolution of all matters resulting from such termination.

35.20 Additional Provisions

35.20.1 Force Majeure

A Party shall not be considered to be in default or breach of this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, arising out of or from any act, omission, or circumstance by or in consequence of any act of God, labor disturbance, sabotage, failure of suppliers of materials, act of the public enemy, war, invasion, insurrection, riot, fire, storm, flood, ice, earthquake, explosion, epidemic, breakage or accident to machinery or equipment or any other cause or causes beyond such Party's reasonable control, including any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities, or by making of repairs necessitated by an emergency circumstance not limited to those listed above upon the property or equipment of the Party or property or equipment of others which is deemed under the Operational Control of the Party. A Force Majeure event does not include an act of negligence or Intentional Wrongdoing by a Party. Any Party claiming a Force Majeure event shall use reasonable diligence to remove the condition that prevents performance and shall not be entitled to suspend performance of its obligations in any greater scope or for any longer duration than is required by the Force Majeure event. Each Party shall use its best efforts to mitigate the effects of such Force Majeure event, remedy its inability to perform, and resume full performance of its obligations hereunder.

35.20.2 Force Majeure Notification

A Party suffering a Force Majeure event ("Affected Party") shall notify the other Party ("Non-Affected Party") in writing ("Notice of Force Majeure Event") as soon as reasonably practicable specifying the cause of the event, the scope of commitments under the Agreement affected by the event, and a good faith estimate of the time required to restore full performance. Except for those commitments identified in the Notice of Force Majeure Event, the Affected Party shall not be relieved of its responsibility to fully perform as to all other commitments in the Agreement. If the Force Majeure Event continues for a period of more than 90 days from the date of the Notice of Force Majeure Event, the Non-Affected Party shall be entitled, at its sole discretion, to terminate the Agreement.

35.20.3 Indemnification

"Indemnifying Party" means a Party who holds an indemnification obligation hereunder. An "Indemnitee" means a Party entitled to receive indemnification under this Agreement as to any Third Party claim. Each Party will defend, indemnify, and hold the other Party harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively, "Losses"), brought or obtained by any Third Party against such other Party, only to the extent that such Losses arise directly from:

(a) Gross negligence, recklessness, or willful misconduct of the Indemnifying Party or any of its agents or employees, in the performance of this Agreement, except to the extent the Losses arise (i) from gross negligence, recklessness, willful misconduct or breach of contract or law by the Indemnitee or such Indemnitee's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon the Indemnitee, or such Indemnitee's agents or employees;

(b) Any claim arising from the transfer of Intellectual Property in violation of Section 35.20.8; or

(c) Any claim that such Indemnitee caused bodily injury to an employee of Third Party due to gross negligence, recklessness, or willful conduct of the Indemnifying Party.

(d) The Indemnitee shall give Notice to the Indemnifying Party as soon as reasonably practicable after the Indemnitee becomes aware of the Indemnifiable Loss or any claim, action or proceeding that may give rise to an indemnification. Such notice shall describe the nature of the loss or proceeding in reasonable detail and shall indicate, if practicable, the estimated amount of the loss that has been sustained by the Indemnitee. A delay or failure of the Indeminitee to provide the required notice shall release the Indemnifying Party (a) from any indemnification obligation to the extent that such delay or failure materially and adversely affects the Indemnifying Party's ability to defend such claim or materially and adversely increases the amount of the Indemnifiable Loss, and (b) from any responsibility for any costs or expenses of the Indemnitee in the defense of the claim during such period of delay or failure.

(e) The indemnification by either Party shall be limited to the extent that the liability of a Party seeking indemnification would be limited by any applicable law and arises from a claim by a Party acting within the scope of this Agreement as to obligations of the other Party under this Agreement.

35.20.4 Headings

The headings used for the Articles and Sections of this Agreement are for convenience and reference purposes only, and shall not be construed to modify, expand, limit, or restrict the provisions of this Agreement.

35.20.5 Liability to Non-Parties

Nothing in this Agreement, whether express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person or entity that is not a Party or a permitted successor or assign.

35.20.6 Liability Between Parties

The Parties' duties and standard of care with respect to each other, and the benefits and rights conferred on each other shall be no greater than as expressly stated herein. Neither Party, its directors, officers, trustees, employees or agents, shall be liable to the other Party for any loss, damage, claim, cost, charge or expense, whether direct, indirect, incidental, punitive, special, exemplary or consequential, arising from the other Party's performance or nonperformance under this Agreement, except to the extent that a Party, is found liable for gross negligence or willful misconduct, in which case the Party responsible shall be liable only for direct and ordinary damages and not for any lost goodwill, incidental, consequential, punitive, special, exemplary or indirect damage.

This section shall not limit amounts required to be paid under this Agreement, including any of the appendices, schedules or attachments to this Agreement. This section shall not apply to adjustments or corrections for errors in invoiced amounts due under this Agreement, including any of the appendices, schedules or attachments to this Agreement.

35.20.7 Limitation on Claims

No claim seeking an adjustment in the billing for any service, transaction, or charge under this Agreement, including any of the appendices, schedules or attachments to this Agreement, may be asserted with respect to a week or month, if more than one year has elapsed (a) since the first date upon which an invoice was rendered for that week or month, or (b) since the date upon which a changed or modified invoice was rendered for that week or month. The Party responsible for issuing an invoice may not, of its own initiative, issue a changed or modified invoice if more than one year has elapsed since the first date upon which an invoice was rendered for a week or month. A changed or modified invoice may be issued more than one year after the first date upon which an invoice was rendered for a week or month in order to correct for or address a timely-raised claim seeking an adjustment in the billing for any service, transaction, or charge under this Agreement.

35.20.8 Unauthorized Transfer of Third-Party Intellectual Property

In the performance of this Agreement, no party shall transfer to another party any Intellectual Property, the use of which by another Party would constitute an infringement of the rights of any Third Party. In the event such transfer occurs, whether or not inadvertent, the transferring Party shall, promptly upon learning of the transfer, provide Notice to the receiving Party and upon receipt of such Notice the receiving Party shall take reasonable steps to avoid claims and mitigate losses.

35.20.9 Intellectual Property Developed Under This Agreement

If during the term of this Agreement, the Parties mutually develop any new Intellectual Property that is reduced to writing or any tangible form, the Parties shall negotiate in good faith concerning the ownership and licensing of such Intellectual Property.

35.20.10 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware without giving effect to the State of Delaware’s conflict of law principles.

35.20.11 License and Authorization

The agreements and obligations expressed herein are subject to such initial and continuing governmental permission and authorization as may be required. Each Party shall be responsible for securing and paying for any approvals required by it from any regulatory agency of competent jurisdiction relating to its participation in this Agreement and will reasonably cooperate with the other Party in seeking such approvals.

35.20.12 Assignment

This Agreement shall inure to the benefit of, and be binding upon and may be performed by, the successors and assigns of the Parties hereto respectively, but shall not be assignable by either Party without the written consent of the other.

35.20.13 Amendment

35.20.13.1 Authorized Representatives

No amendment of this Agreement shall be effective unless by written instrument duly executed by the Parties' authorized representatives. For the purposes of this section, an authorized person refers to individuals designated as such by Parties in their respective corporate by-laws.

35.20.13.2 Review of Agreement

The terms of this Agreement are subject to review for potential amendment at the request of either Party. If, after such review, the Parties agree that any of the provisions hereof, or the practices or conduct of either Party impose an inequity, hardship or undue burden upon the other Party, or if the Parties agree that any of the provisions of this Agreement have become obsolete or inconsistent with changes related to the Interconnection Facilities, the Parties shall endeavor in good faith to amend or supplement this Agreement in such a manner as will remove such inequity, hardship or undue burden, or otherwise appropriately address the cause for such change.

35.20.13.3 Mutual Agreement

The Parties may amend this Agreement at any time by mutual agreement in accordance with Section 35.20.13.1 above.

35.20.14 Performance

The failure of a Party to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any right held by such Party. Any waiver on any specific occasion by either Party shall not be deemed a continuing waiver of such right, nor shall it be deemed a waiver of any other right under this Agreement.

35.20.15 Rights, Remedies or Benefits

This Agreement is not intended to and does not create any rights, remedies, or benefits of any kind whatsoever in favor of any entities other than the Parties, their principals and, where permitted, their assigns.

35.20.16 Agreement

This Agreement, including all Attachments attached hereto, is the entire agreement between the Parties with respect to the subject matter hereof, and supersedes all prior or contemporaneous understandings or agreements, oral or written, with respect to the subject matter of this Agreement.

35.20.17 Governmental Authorizations

This Agreement, including its future amendments is subject to the initial and continuing governmental authorizations, including approval of the FERC, required to establish, operate and maintain the Interconnection Facilities as herein specified. Each Party shall take all actions necessary and reasonably within its control to maintain all governmental rights and approvals required to perform its respective obligations under this Agreement.

35.20.18 Unenforceable Provisions

If any provision of this Agreement is deemed unenforceable, the rest of the Agreement shall remain in effect and the Parties shall negotiate in good faith and seek to agree upon a substitute provision that will achieve the original intent of the Parties.

35.20.19 Execution

This Agreement may be executed in multiple counterparts, each of which shall be considered an original instrument, but all of which shall be considered one and the same Agreement, and shall become binding when all counterparts have been signed by each of the Parties and delivered to each Party hereto. Delivery of an executed signature page counterpart by telecopier or e-mail shall be as effective as delivery of a manually executed counterpart.

35.20.20 Billing and Payment

35.20.20.1 General Billing and Payment Rules

This Section 35.20.20.1 of the Agreement sets forth the billing and payment rules that apply to all charges arising under this Agreement except for charges resulting from the M2M coordination process set forth in Schedule D to this Agreement.

35.20.20.1.1 Invoicing. When charges arise under this Agreement, the billing RTO shall submit an invoice to the other RTO within five (5) business days after the first day of the month indicating the net amount owed by that RTO for the previous month.

35.20.20.1.2 Payments. Payments under this Agreement will be effected in immediately available funds of the United States of America.

The RTO owing payments on net in the invoice shall make those payments within five (5) business days after the receipt of the invoice.

In the event of a billing and payment dispute between the Parties, the dispute resolution procedures and limitation of the claims section contained in this Agreement shall apply to the review, challenge, and correction of invoices.

35.20.20.1.3 Interest on Unpaid Balances. Interest on any unpaid amount (including amounts placed in escrow) shall be calculated in accordance with the method specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a (a)(2)(iii). Interest on unpaid amounts shall be calculated from the due date of the bill to the date of payment. Invoices shall be considered as having been paid on the date of receipt of payment.

35.20.20.1.4 RTO Bills and Payments to their Respective Customers. Bills or payments that either RTO is authorized to issue directly to its customer shall be invoiced, paid and/or processed in accordance with the relevant RTO's billing and payment tariff rules.

35.20.20.2 Billing and Payment for the M2M Coordination Process set forth in Schedule D to this Agreement

For the limited purposes of these billing and payment rules that apply to the M2M coordination process, PJM shall be considered a "Customer" as that term is used in Section 7 of the NYISO Services Tariff where the NYISO Services Tariff applies and NYISO shall be considered a "Transmission Customer" as that term is used in Section 7 of the PJM OATT where the PJM OATT applies.

35.20.20.2.1 Invoicing and Settlement Information. NYISO shall provide invoice and settlement information to PJM consistent with Section 7.2.1 (*Invoices and Settlement Information*), 7.2.3.1 (*Weekly Invoice*), and 7.2.3.2 (*Monthly Invoice*) of the NYISO Services Tariff or any successor NYISO Services Tariff provision(s).

NYISO may use estimates for invoicing consistent with Section 7.2.4 (*Use of Estimated Data and Meter Data*) of the NYISO Services Tariff or any successor NYISO Services Tariff provision(s).

35.20.20.2.2 Payments. Unless otherwise indicated in writing by the Parties, all payments due under this Agreement will be effected in immediately available funds of the United States of America.

Payments shall be due and payable in accordance with the terms and conditions set herein and notwithstanding any invoicing disputes. In the event of a billing and payment dispute between the Parties under this Agreement, the dispute resolution procedures and limitation of the claims section contained in this Agreement shall apply to the review, challenge, and correction of invoices.

PJM shall make payments to the NYISO's Clearing Account consistent with Sections 7.2.3.3 (*Payment by the Customer*) and 7.2.5 (*Method of Payment*) of the NYISO Services Tariff or any successor NYISO Services Tariff provision(s). NYISO shall make payments, from the NYISO's Clearing Account, to PJM consistent with Section 7.1A(a) (*Payments*: *Monthly Bills*), 7.1A(b) (*Payments*: *Weekly Bills*), 7.1A(c) (*Payments*: *Form of Payments*), and 7.1A(e) (*Payments*: *Payment Calendar*) of the PJM OATT or any successor PJM OATT provision(s).

35.20.20.2.3 Interest on Unpaid Balances. Interest on any unpaid amount whether owed to PJM or to NYISO (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a (a)(2)(iii). Interest on unpaid amounts shall be calculated from the due date of the bill to the date of payment. Invoices shall be considered as having been paid on the date of receipt of payment.

35.20.20.2.4 Payment Obligation. The RTOs each assume responsibility for ensuring that their respective payment obligations resulting from the M2M coordination process set forth in Schedule D to this Agreement are satisfied without regard for their ability to collect such payments from their respective customers.

35.20.21 Regulatory Authority

If any regulatory authority having jurisdiction (or any successor boards or agencies), a court of competent jurisdiction or other Governmental Authority with the appropriate jurisdiction (collectively, the "Regulatory Body") issues a rule, regulation, law or order that has the effect of cancelling, changing or superseding any term or provision of this Agreement (the "Regulatory

Requirement"), then this Agreement will be deemed modified to the extent necessary to comply with the Regulatory Requirement. Notwithstanding the foregoing, if a Regulatory Body materially modifies the terms and conditions of this Agreement and such modification(s) materially affect the benefits flowing to one or both of the Parties, as determined by either of the Parties within twenty (20) business days of the receipt of the Agreement as materially modified, the Parties agree to attempt in good faith to negotiate an amendment or amendments to this Agreement or take other appropriate action(s) so as to put each Party in effectively the same position in which the Parties would have been had such modification not been made. In the event that, within sixty (60) days or some other time period mutually agreed upon by the Parties after such modification has been made, the Parties are unable to reach agreement as to what, if any, amendments are necessary and fail to take other appropriate action to put each Party in effectively the same position in which the Parties would have been had such modification not been made, then either Party shall have the right to unilaterally terminate this Agreement forthwith.

35.20.22 Notices

Except as otherwise agreed from time to time, any Notice, invoice or other communication which is required by this Agreement to be given in writing, shall be sufficiently given at the earlier of the time of receipt or deemed time of receipt if delivered personally to a senior official of the Party for whom it is intended or electronically transferred or sent by registered mail, addressed as follows:

PJM:

PJM Interconnection L.L.C.
2750 Monroe BoulevardAudubon, PA 19403
Attn: President & CEO

NYISO: New York Independent System Operator
10 Krey Boulevard
Rensselaer, New York 12144
Attn: President & CEO

or delivered to such other person or electronically transferred or sent by registered mail to such other address as either Party may designate for itself by Notice given in accordance with this section or delivered by any other means agreed to by the Parties hereto.

Any Notice, or communication so mailed shall be deemed to have been received on the third business day following the day of mailing, or if electronically transferred shall be deemed to have been received on the same business day as the date of the electronic transfer, or if delivered personally shall be deemed to have been received on the date of delivery or if delivered by some other means shall be deemed to have been received as agreed to by the Parties hereto.

The use of a signed facsimile of future Notices and correspondence between the Parties related to this Agreement shall be accepted as proof of the matters therein set out. Follow-up with hard copy by mail will not be required unless agreed to by the Coordination Committee.

A Party may change its designated recipient of Notices, or its address, from time to time by giving Notice of such change.

IN WITNESS WHEREOF, the signatories hereto have caused this Agreement to be executed by their duly authorized officers.

PJM INTERCONNECTION, L.L.C.

By: Michael E. Bryson, Vice President – Operations

____

Date: ____________________________

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

By: Wesley J. Yeomans, Vice President – Operations

____

Date:_____________________________

35.21 Schedules A and B

Schedule A - Description Of Interconnection Facilities

The NYISO – PJM Joint Operating Agreement covers the PJM – NYISO *Interconnection Facilities* under the *Operational Control* of the NYISO and PJM. For *Operational Control* purposes, the point of demarcation for each of the *Interconnection Facilities* listed below is the point at which each *Interconnection Facility* crosses the PJM-New York State boundary, except as noted below.

The PJM-NYISO *Interconnection* contains twenty-five (25) alternating current ("AC") *Interconnection Facilities*, seven (7) of which form one (1) AC pseudo-tie[20]; and further contains two (2) HVDC *Interconnection Facilities* as well as one (1) *Variable Frequency Transformer (VFT).* These are tabulated below:

NY/PJM *Interconnection Facilities*:

PJM	NYISO	Designated	(kV)	Common Meter Point(s)
Hopatcong	Ramapo	5018	500	Ramapo
Cresskill	Sparkill	751	69	Cresskill
E. Sayre	N. Waverly	956	115	E. Sayre
E. Towanda	Hillside	70	230	Hillside
Erie East	South Ripley	69	230	South Ripley
Harings Corners	Corporate Drive	703	138	Harings
Harings Corners	Pearl River	45	34	Harings
Harings Corners	W. Nyack	701	69	Harings
Mainesburg	Watercure	30	345	Mainesburg
Homer City	Mainesburg	47	345	Homer &Mainesburg
Pierce Brook	Five Mile Rd.	37	345	Pierce Brook
Homer City	Pierce Brook	48	345	Homer & Pierce Brook
Marion	Farragut	C3403	345	Farragut
Hudson	Farragut	B3402	345	Farragut
Linden	Goethals	A2253	230	Goethals
Linden VFT	Linden Cogen	VFT	345	Linden VFT
Montvale	Pearl River	491	69	Montvale
Montvale	Blue Hill	44	69	Montvale
Montvale	Blue Hill	43	69	Montvale
S. Mahwah	Hilburn	65	69	S. Mahwah
S. Mahwah	S. Mahwah	BK 258	138/345	S. Mahwah
S. Mahwah	Ramapo	51	138	S. Mahwah
Waldwick	S. Mahwah	J3410	345	Waldwick
Waldwick	S. Mahwah	K3411	345	Waldwick
Tiffany	Goudey	952	115	Goudey
Warren	Falconer	171	115	Warren

[20] WEQ-007 "Inadvertent Interchange Payback Standards," North American Energy Standards Board (NAESB), on-line at www.naesb.org.

RECO	NYISO	AC Pseudo-Tie	Various	O&R EMS
Sayerville	Newbridge	HVDC-Tie	500	Newbridge
Bergen	West 49th	HVDC-Tie Y56	345	Bergen

<u>NY/PJM Interfaces at which NYISO and PJM are Authorized to Consider CTS Interface Bids:</u>

PJM Interface Name	PNODE ID	Corresponding NYISO Proxy Generator Buses[21]	PTID
NYIS	5413134	PJM_GEN_KEYSTONE	24065
NYIS	5413134	PJM_LOAD_KEYSTONE	55857
LindenVFT	81436855	PJM_GEN_VFT_PROXY	323633
LindenVFT	81436855	PJM_LOAD_VFT_PROXY	355723
Neptune	56958967	PJM_GEN_NEPTUNE_PROXY	323594
Neptune	56958967	PJM_LOAD_NEPTUNE_PROXY	355615
HudsonTP	1124361945	PJM_HTP_GEN	323702
HudsonTP	1124361945	HUDSONTP_345KV_HTP_LOAD	355839

Schedule B - Other Existing Agreements:

1.0 Lake Erie Emergency Redispatch (LEER)

2.0 RAMAPO PHASE ANGLE REGULATOR OPERATING PROCEDURE prepared by the NYPP/PJM Circulation Study Operating Committee.

3.0 Northeastern ISO/RTO Coordination of Planning Protocol

4.0 Inter Control Area Transaction Agreement.

5.0 Procedures to Protect for Loss of Phase II Imports (effective January 16, 2007, pursuant to Order issued January 12, 2007, in FERC Docket No. ER07-231-000).

[21] *See* NYISO Market Administration and Control Area Services Tariff Section 4.4.4 for additional information.

6.0 Joint Emergency Operating Protocol dated September 10, 2009, among PJM Interconnection, L.L.C., New York Independent System Operator, Inc., and Linden VFT, LLC (Filed by PJM on October 1, 2009, in FERC Docket No. ER09-996-000).

35.22 Reserved for future use.

35.23 Schedule D – Market-to-Market Coordination Process – Version 1.0

NYISO & PJM
Market-to-Market Coordination Schedule
Table of Contents

1 Overview of the Market-to-Market Coordination Process

The purpose of the M2M coordination process is to set forth the rules that apply to M2M coordination between PJM and NYISO and the associated settlements processes.

The fundamental philosophy of the PJM/NYISO M2M coordination process is to set up procedures to allow any transmission constraints that are significantly impacted by generation dispatch changes and/or Phase Angle Regulator ("PAR") control actions in both markets to be jointly managed in the security-constrained economic dispatch models of both RTOs. This joint management of transmission constraints near the market borders will provide the more efficient and lower cost transmission congestion management solution, while providing coordinated pricing at the market boundaries.

The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM will include not only joint redispatch, but will also incorporate coordinated operation of the NY-NJ PARs that are located at the NYISO – PJM interface. This real-time coordination will result in a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real-time to manage constraints. Under this approach, the flow entitlements on the M2M Flowgates do not impact the physical dispatch; the flow entitlements are used in market settlements to ensure appropriate compensation based on comparison of the actual Market Flows to the flow entitlements.

2 M2M Flowgates

Only a subset of all transmission constraints that exist in either market will require coordinated congestion management. This subset of transmission constraints will be identified as M2M Flowgates. Flowgates eligible for the M2M coordination process are called M2M Flowgates. For the purposes of the M2M coordination process (in addition to the studies described in Section 3 of this Schedule D) the following will be used in determining M2M Flowgates.

2.1 NYISO and PJM will only be performing the M2M coordination process on M2M Flowgates that are under the operational control of NYISO or PJM. NYISO and PJM will not be performing the M2M coordination process on Flowgates that are owned and controlled by third party entities.

2.2 The Parties will make reasonable efforts to lower their generator binding threshold to match the lower generator binding threshold utilized by the other Party. The generator and NY-NJ PAR binding thresholds (the shift factor thresholds used to identify the resource(s) available to relieve a transmission constraint), will not be set below 3%, except by mutual consent. This requirement applies to M2M Flowgates. It is not an additional criterion for determination of M2M Flowgates.

2.3 For the purpose of determining whether a monitored element Flowgate is eligible for the M2M coordination process, a threshold for determining a significant GLDF or NY-NJ PARs PSF will take into account the number of monitored elements. Implementation of M2M Flowgates will ordinarily occur through mutual agreement.

2.4 All Flowgates eligible for M2M coordination will be included in the coordinated operations of the NY-NJ PARs. Flowgates with significant GLDF will also be included in joint redispatch.

2.5 M2M Flowgates that are eligible for redispatch coordination are also eligible for coordinated operation of the NY-NJ PARs. M2M Flowgates that are eligible for coordinated operation of the NY-NJ PARs are not necessarily also eligible for redispatch coordination.

2.6 The NYISO shall post a list of all of the M2M Flowgates located in theNew York Control Area ("NYCA") on its web site. PJM shall post a list of all of the M2M Flowgates located in its Control Area on its web site.

3 M2M Flowgate Studies

To identify M2M Flowgates the Parties will perform an off-line study to determine if the significant GLDF for at least one generator within the Non-Monitoring RTO, or significant PSF for at least one NY-NJ PAR, on a potential M2M Flowgate within the Monitoring RTO is greater than or equal to the thresholds as described below. The study shall be based on an up-to-date power flow model representation of the Eastern Interconnection, with all normally closed Transmission Facilities in-service. The transmission modeling assumptions used in the M2M Flowgate studies will be based on the same assumptions used for determining M2M Entitlements in Section 6 of this Schedule D.

3.1 Either Party may propose that a new M2M Flowgate be added at any time. The Parties will work together to perform the necessary studies within a reasonable timeframe.

3.2 The GLDF or NY-NJ PARs PSF thresholds for M2M Flowgates with one or more monitored elements are defined as:

i. Single monitored element, 5% GLDF/NY-NJ PARs PSF;

ii. Two monitored elements, 7.5% GLDF/NY-NJ PARs PSF; and

iii. Three or more monitored elements, 10% GLDF/NY-NJ PARs PSF.

3.3 For potential M2M Flowgates that pass the above NY-NJ PARs PSF criteria, the Parties must still mutually agree to add each Flowgate as an M2M Flowgate for coordinated operation of the NY-NJ PARs.

3.4 For potential M2M Flowgates that pass the above GLDF criteria, the Parties must still mutually agree to add each Flowgate as an M2M Flowgate for redispatch coordination.

3.5 The Parties can also mutually agree to add a M2M Flowgate that does not satisfy the above criteria.

4 <u>Removal of M2M Flowgates</u>

Removal of M2M Flowgates from the systems may be necessary under certain conditions including the following:

4.1 A M2M Flowgate is no longer valid when (a) a change is implemented that affects either Party's generation impacts causing the Flowgate to no longer pass the M2M Flowgate Studies, or (b) a change is implemented that affects the impacts from coordinated operation of the NY-NJ PARs causing the Flowgate to no longer pass the M2M Flowgate Studies. The Parties must still mutually agree to remove a M2M Flowgate, such agreement not to be unreasonably withheld. Once a M2M Flowgate has been removed, it will no longer be eligible for M2M settlement.

4.2 A M2M Flowgate that does not satisfy the criteria set forth in Section 3.2 above, but that is created based on the mutual agreement of the Parties pursuant to Section 3.5 above, shall be removed two weeks after either Party provides a formal notice to the other Party that it withdraws its agreement to the M2M Flowgate, or at a later or earlier date that the Parties mutually agree upon. The formal notice must include an explanation of the reason(s) why the agreement to the M2M Flowgate was withdrawn.

4.3 The Parties can mutually agree to remove a M2M Flowgate from the M2M coordination process whether or not it passes the coordination tests. A M2M Flowgate should be removed when the Parties agree that the M2M coordination process is not, or will not be, an effective mechanism to manage congestion on that Flowgate.

5 <u>Market Flow Determination</u>

Each RTO will independently calculate its Market Flow for all M2M Flowgates using the equations set forth in this Section. The Market Flow calculation is broken down into the following steps:

- Determine Shift Factors for M2M Flowgates
- Compute RTO Load and Losses (less imports)
- Compute RTO Generation (less exports)
- Compute RTO Generation to Load impacts on the Market Flow
- Compute RTO interchange scheduling impacts on the Market Flow
- Compute PAR impacts on the Market Flow
- Compute Market Flow

5.1 Determine Shift Factors for M2M Flowgates

The first step to determining the Market Flow on a M2M Flowgate is to calculate generator, load and PAR shift factors for the each of the M2M Flowgates. For real-time M2M coordination, the shift factors will be based on the real-time transmission system topology.

5.2 Compute RTO Load Served by RTO Generation

Using area load and losses for each load zone, compute the RTO Load, in MWs, by summing the load and losses for each load zone to determine the total zonal load for each RTO load zone. Twenty percent of RECo load shall be included in the Market Flow calculation as PJM load. *See* Section 6.2, of this Schedule D.

$Zonal\_Total\_Load_{zone} = Load_{zone} + Losses_{zone}$, for each RTO load zone

Where:

zone =	the relevant RTO load zone;
$\text{Zonal\_Total\_Load}_{\text{zone}}$ =	the sum of the RTO's load and transmission losses for the zone;
$\text{Load}_{\text{zone}}$ =	the load within the zone; and
$\text{Losses}_{\text{zone}}$ =	the transmission losses for transfers through the zone.

Next, reduce the Zonal Loads by the scheduled line real-time import transaction schedules that sink in that particular load zone:

$$Zonal\_Reduced\_Load_{zone} = Zonal\_Total\_Load_{zone} - \sum_{scheduled\_lines=1}^{all} Import\_Schedules_{scheduled\_line,zone}$$

Where:

zone =	the relevant RTO load zone;
scheduled_line =	each of the Transmission Facilities identified in Table 1 below;
$Zonal\_Reduced\_Load_{zone}$ =	the sum of the RTO's load and transmission losses in a zone reduced by the sum of import schedules over scheduled lines to the zone;
$Zonal\_Total\_Load_{zone}$ =	the sum of the RTO's load and transmission losses for the zone; and
$Import\_Schedules_{scheduled\_line,zone}$ =	import schedules over a scheduled line to a zone.

The real-time import schedules over scheduled lines will only reduce the load in the sink load zones identified in Table 1 below:

Table 1. List of Scheduled Lines

Scheduled Line	NYISO Load Zone	PJM Load Zone
Dennison Scheduled Line	North	Not Applicable
Cross-Sound Scheduled Line	Long Island	Not Applicable
HTP Scheduled Line	New York City	Mid-Atlantic Control Zone
Linden VFT Scheduled Line	New York City	Mid-Atlantic Control Zone
Neptune Scheduled Line	Long Island	Mid-Atlantic Control Zone
Northport – Norwalk Scheduled Line	Long Island	Not Applicable

Once import schedules over scheduled lines have been accounted for, it is then appropriate to reduce the net RTO Load by the remaining real-time import schedules at the proxies identified in Table 2 below:

Table 2. List of Proxies*

Proxy	Balancing Authorities Responsible
PJM shall post and maintain a list of its proxies on its OASIS website. PJM shall provide to NYISO notice of any new or deleted proxies prior to implementing such changes in its M2M software.	PJM
NYISO proxies are the Proxy Generator Buses that are not identified as Scheduled Lines in the table that is set forth in Section 4.4.4 of the NYISO's Market Services Tariff. The NYISO shall provide to PJM notice of any new of deleted proxies prior to implementing such changes in its M2M software.	NYISO

*Scheduled lines and proxies are mutually exclusive. Transmission Facilities that are components of a scheduled line are not also components of a proxy (and vice-versa).

$$RTO\_Net\_Load = \sum_{zone=1}^{all} Zonal\_Reduced\_Load_{zone}$$

Where:

zone = the relevant RTO load zone;

RTO_Net_Load = the sum of load and transmission losses for the entire RTO footprint reduced by the sum of import schedules over all scheduled lines; and

$Zonal\_Reduced\_Load_{zone}$ = the sum of the RTO's load and transmission losses in a zone reduced by the sum of import schedules over scheduled lines to the zone.

$$RTO\_Final\_Load = RTO\_Net\_Load - \sum_{proxy=1}^{all} Import\_Schedules_{proxy}$$

Where:

proxy = representations of defined sets of Transmission Facilities that (i) interconnect neighboring Balancing Authorities, (ii) are collectively scheduled, and (iii) are identified in Table 2 above;

RTO_Final_Load = the sum of the RTO's load and transmission losses for the entire RTO footprint, sequentially reduced by (i) the sum of import schedules over all scheduled lines, and (ii) the sum of all proxy import schedules;

RTO_Net_Load = the sum of load and transmission losses for the entire RTO footprint reduced by the sum of import schedules over all scheduled lines; and

$Import\_Schedules_{proxy}$ = the sum of import schedules at a given proxy.

Next, calculate the Zonal Load weighting factor for each RTO load zone:

$$Zonal\_Weighting_{zone} = \left(\frac{Zonal\_Reduced\_Load_{zone}}{RTO\_Net\_Load}\right)$$

Where:

zone = the relevant RTO load zone;

$Zonal\_Weighting_{zone}$ = the percentage of the RTO's load contained within the zone;

RTO_Net_Load = the sum of load and transmission losses for the entire RTO footprint reduced by the sum of import schedules over all scheduled lines; and

$Zonal\_Reduced\_Load_{zone}$ = the sum of the RTO's load and transmission losses in a zone reduced by the sum of import schedules over scheduled lines to the zone.

Using the Zonal Weighting Factor compute the zonal load reduced by RTO imports for each load zone:

$$Zonal\_Final\_Load_{zone} = Zonal\_Weighting_{zone} \times RTO\_Final\_Load$$

Where:

zone = the relevant RTO load zone;

$Zonal\_Final\_Load_{zone}$ = the final RTO load served by internal RTO generation in the zone;

$Zonal\_Weighting_{zone}$ = the percentage of the RTO's load contained within the zone; and

RTO_Final_Load = the sum of the RTO's load and transmission losses for the entire RTO footprint, sequentially reduced by (i) the sum of import schedules over all scheduled lines, and (ii) the sum of all proxy import schedules.

Using the Load Shift Factors ("LSFs") calculated above, compute the weighted RTOLSF for each M2M Flowgate as:

$$RTO\_LSF_{M2M\_Flowgate-m} = \sum_{zone=1}^{all}\left(LSF_{(zone,M2M\_Flowgate-m)} \times \left(\frac{Zonal\_Final\_Load_{zone}}{RTO\_Final\_Load}\right)\right)$$

Where:

M2M_Flowgate-m = the relevant flowgate;

zone = the relevant RTO load zone;

$RTO\_LSF_{M2M\_Flowgate-m}$ = the load shift factor for the entire RTO footprint on M2M Flowgate m;

$LSF_{(zone,M2M\_Flowgate-m)}$ = the load shift factor for the RTO zone on M2M Flowgate m;

$Zonal\_Final\_Load_{zone}$ = the final RTO load served by internal RTO generation in the zone; and

RTO_Final_Load = the sum of the RTO's load and transmission losses for the entire RTO footprint, sequentially reduced by (i) the sum of import schedules over all scheduled lines, and (ii) the sum of all proxy import schedules.

5.3 Compute RTO Generation Serving RTO Load

Using the real-time generation output in MWs, compute the Generation serving RTO Load. Sum the output of RTO generation within each load zone:

$RTO\_Gen_{zone} = \sum_{unit=1}^{all} Gen_{unit,zone}$, for each RTO load zone

Where:

zone = the relevant RTO load zone;

unit = the relevant generator;

RTO_Gen_{zone} = the sum of the RTO's generation in a zone; and

$Gen_{unit,zone}$ = the real-time output of the unit in a given zone.

Next, reduce the RTO generation located within a load zone by the scheduled line real-time export transaction schedules that source from that particular load zone:

$$RTO\_Reduced\_Gen_{zone} = RTO\_Gen_{zone} - \sum_{scheduled\_line=1}^{all} Export\_Schedules_{scheduled\_line,zone}$$

Where:

zone = the relevant RTO load zone;

scheduled_line = each of the Transmission Facilities identified in Table 1 above;

$RTO\_Reduced\_Gen_{zone}$ = the sum of the RTO's generation in a zone reduced by the sum of export schedules over scheduled lines from the zone;

RTO_Gen_{zone} = the sum of the RTO's generation in a zone; and

$Export\_Schedules_{scheduled\_line,zone}$ = export schedules from a zone over a scheduled line.

The real-time export schedules over scheduled lines will only reduce the generation in the source zones identified in Table 1 above. The resulting generator output based on this reduction is defined below.

$$Reduced\ Gen_{unit} = Gen_{unit,zone}\left(\frac{RTO\_Reduced\_Gen_{zone}}{RTO\_Gen_{zone}}\right)$$

Where:

unit = the relevant generator;

zone = the relevant RTO load zone;

$Gen_{unit,zone}$ = the real-time output of the unit in a given zone;

Reduced Gen_{unit} = each unit's real-time output after reducing the RTO_Net_Gen by the real-time export schedules over scheduled lines;

$RTO\_Reduced\_Gen_{zone}$ =	the sum of the RTO's generation in a zone reduced by the sum of export schedules over scheduled lines from the zone; and
RTO_Gen_{zone} =	the sum of the RTO's generation in a zone.

Once export schedules over scheduled lines are accounted for, it is then appropriate to reduce the net RTO generation by the remaining real-time export schedules at the proxies identified in Table 2 above.

$$RTO\_Net\_Gen = \sum_{zone=1}^{all} RTO\_Reduced\_Gen_{zone}$$

Where:

zone =	the relevant RTO load zone;
RTO_Net_Gen =	the sum of the RTO's generation reduced by the sum of export schedules over all scheduled lines; and
$RTO\_Reduced\_Gen_{zone}$ =	the sum of the RTO's generation in a zone reduced by the sum of export schedules over scheduled lines from the zone.

$$RTO\_Final\_Gen = RTO\_Net\_Gen - \sum_{proxy=1}^{all} Export\_Schedules_{proxy}$$

Where:

proxy =	representation of defined sets of Transmission Facilities that (i) interconnect neighboring Balancing Authorities, (ii) are collectively scheduled, and (iii) are identified in Table 2 above;
RTO_Final_Gen =	the sum of the RTO's generation output for the entire RTO footprint, sequentially reduced by (i) the sum of export schedules over all scheduled lines, and (ii) the sum of all proxy export schedules;
RTO_Net_Gen =	the sum of the RTO's generation reduced by the sum of export schedules over all scheduled lines; and

$Export\_Schedules_{proxy}$ = the sum of export schedules at a given proxy.

Finally, weight each generator's output by the reduced RTO generation:

$$Gen\_Final_{unit} = Reduced\ Gen_{unit} \times \frac{RTO\_Final\_Gen}{RTO\_Net\_Gen}$$

Where:

unit = the relevant generator;

Gen_Final_{unit} = the portion of each unit's output that is serving the RTO Net Load;

$Reduced\ Gen_{unit}$ = each unit's real-time output after reducing the RTO_Net_Gen by the real-time export schedules over scheduled lines;

RTO_Final_Gen = the sum of the RTO's generation output for the entire RTO footprint, sequentially reduced by (i) the sum of export schedules over all scheduled lines, and (ii) the sum of all proxy export schedules; and

RTO_Net_Gen = the sum of the RTO's generation reduced by the sum of export schedules over all scheduled lines.

5.4 <u>Compute the RTO GTL for all M2M Flowgates</u>

The generation-to-load flow for a particular M2M Flowgate, in MWs, will be determined as:

$$RTO\_GTL_{M2M\_Flowgate-m} = \sum_{unit=1}^{all} \begin{matrix} Gen\_Final_{unit} \times \\ \left(GSF_{(unit,M2M\_Flowgate-m)} - RTO\_LSF_{M2M\_Flowgate-m}\right) \end{matrix}$$

Where:

M2M_Flowgate-m = the relevant flowgate;

unit = the relevant generator;

$RTO\_GTL_{M2M\_Flowgate-m}$ = the generation to load flow for the entire RTO footprint on M2M Flowgate m;

Gen_Final_{unit} = the portion of each unit's output that is serving RTO Net Load;

$GSF_{(unit,M2M\_Flowgate-m)}$ = the generator shift factor for each unit on M2M Flowgate m; and

$RTO\_LSF_{M2M\_Flowgate-m}$ = the load shift factor for the entire RTO footprint on M2M Flowgate m.

5.5 Compute the RTO Interchange Scheduling Impacts for all M2M Flowgates

For each scheduling point that the participating RTO is responsible for, determine the net interchange schedule in MWs. Table 3 below identifies both the participating RTO that is responsible for each listed scheduling point, and the "type" assigned to each listed scheduling point.

Table 3. List of Scheduling Points

Scheduling Point	**Scheduling Point Type**	**Participating RTO(s) Responsible**
NYISO-PJM	common	NYISO and PJM
HTP Scheduled Line	common	NYISO and PJM
Linden VFT Scheduled Line	common	NYISO and PJM
Neptune Scheduled Line	common	NYISO and PJM
PJM shall post and maintain a list of its non-common scheduling points on its OASIS website. PJM shall provide to NYISO notice of any new or deleted non-common scheduling points prior to implementing such changes in its M2M software.	non-common	PJM
NYISO non-common scheduling points include all Proxy Generator Buses and Scheduled Lines listed in the table that is set forth in Section 4.4.4 of the NYISO's Market Services Tariff that are not identified in this Table 3 as common scheduling points. The NYISO shall provide to PJM notice of any new or deleted non-common scheduling points prior to implementing such changes in its M2M software.	non-common	NYISO

$$RTO\_Transfers_{sched\_pt} = Imports_{sched\_pt} + WheelsIn_{sched\_pt} - Exports_{sched\_pt} - WheelsOut_{sched\_pt}$$

Where:

sched_pt = the relevant scheduling point. A scheduling point can be either a proxy or a scheduled line;

$RTO\_Transfers_{sched\_pt}$ = the net interchange schedule at a scheduling point;

$Imports_{sched\_pt}$ = the import component of the interchange schedule at a scheduling point;

$WheelsIn_{sched\_pt}$ = the injection of wheels-through component of the interchange schedule at a scheduling point;

$Exports_{sched\_pt}$ = the export component of the interchange schedule at a scheduling point; and

$WheelsOut_{sched\_pt}$ = the withdrawal of wheels-through component of the interchange schedule at a scheduling point.

The equation below applies to all non-common scheduling points that only one of the participating RTOs is responsible for. *Parallel_Transfers* are applied to the Market Flow of the responsible participating RTO. For example, the *Parallel_Transfers* computed for the IESO-NYISO non-common scheduling point are applied to the NYISO Market Flow.

$$Parallel\_Transfers_{\text{M2M\_Flowgate-m}} = \sum_{\text{nc\_sched\_pt}=1}^{all} RTO\_Transfers_{\text{nc\_sched\_pt}} \times PTDF_{(\text{nc\_sched\_pt,M2M\_Flowgate}-\text{m})}$$

Where:

M2M_Flowgate-m = the relevant flowgate;

nc_sched_pt = the relevant non-common scheduling point. A non-common scheduling point can be either a proxy or a scheduled line. Non-common scheduling points are identified in Table 3, above;

$Parallel\_Transfers_{\text{M2M\_Flowgate-m}}$ = the flow on M2M Flowgate m due to the net interchange schedule at the non-common scheduling point;

$RTO\_Transfers_{nc\_sched\_pt}$ = the net interchange schedule at the non-common scheduling point, where a positive number indicates the import direction; and

$PTDF_{(nc\_sched\_pt,\ M2M\_Flowgate\text{-}m)}$ = the power transfer distribution factor of the non-common scheduling point on M2M Flowgate m. For NYISO, the PTDF will equal the generator shift factor of the non-common scheduling point.

The equation below applies to common scheduling points that directly interconnect the participating RTOs. *Shared_Transfers* are applied to the Monitoring RTO's Market Flow only. NYISO to PJM transfers would be considered part of NYISO's Market Flow for NYISO-monitored Flowgates and part of PJM's Market Flow for PJM-monitored Flowgates.

$$Shared\_Transfers_{\text{M2M\_Flowgate-m}} = \sum_{\text{cmn\_sched\_pt}=1}^{all} RTO\_Transfers_{\text{cmn\_sched\_pt}} \times PTDF_{(\text{cmn\_sched\_pt,M2M\_Flowgate}-\text{m})}$$

Where:

M2M_Flowgate-m = the relevant flowgate;

cmn_sched_pt = the relevant common scheduling point. A common scheduling point can be either a proxy or a scheduled line. Common scheduling points are identified in Table 3, above;

$Shared\_Transfers_{M2M\_Flowgate\text{-}m}$ = the flow on M2M Flowgate m due to interchange schedules on the common scheduling point;

$RTO\_Transfers_{cmn\_sched\_pt}$ = the net interchange schedule at a common scheduling point, where a positive number indicates the import direction; and

$PTDF_{(cmn\_sched\_pt,\ M2M\_Flowgate\text{-}m)}$ = the generation shift factor of the common scheduling point on M2M Flowgate m. For NYISO, the PTDF will equal the generator shift factor of the common scheduling point.

5.6 Compute the PAR Effects for all M2M Flowgates

For the PARs listed in Table 4 below, the RTOs will determine the generation-to-load flows and interchange schedules, in MWs, that each PAR is impacting.

Table 4. List of Phase Angle Regulators

PAR	Description	PAR Type	Actual Schedule	Target Schedule	Responsible Participating RTO(s)
1	RAMAPO PAR3500	common	From telemetry	From telemetry*	NYISO and PJM
2	RAMAPO PAR4500	common	From telemetry	From telemetry*	NYISO and PJM
3	FARRAGUT TR11	common	From telemetry	From telemetry*	NYISO and PJM
4	FARRAGUT TR12	common	From telemetry	From telemetry*	NYISO and PJM
5	GOETHSLN BK_1N	common	From telemetry	From telemetry*	NYISO and PJM
6	WALDWICK O2267	common	From telemetry	From telemetry*	NYISO and PJM
7	WALDWICK F2258	common	From telemetry	From telemetry*	NYISO and PJM
8	WALDWICK E2257	common	From telemetry	From telemetry*	NYISO and PJM
9	STLAWRNC PS_33	non-common	From telemetry	0	NYISO
10	STLAWRNC PS_34	non-common	From telemetry	0	NYISO

*****Pursuant to the rules for implementing the M2M coordination process over the NY-NJ PARs that are set forth in this M2M Schedule.

Compute the PAR control as the actual flow less the target flow across each PAR:

$$PAR\_Control_{par} = Actual\_MW_{par} - Target\_MW_{par}$$

Where:

par = each of the phase angle regulators listed in Table 4, above;

$PAR\_Control_{par}$ = the flow deviation on each of the PARs;

$Actual\_MW_{par}$ = the actual flow on each of the PARs, determined consistent with Table 4 above; and

$Target\_MW_{par}$ = the target flow that each of the PARs should be achieving, determined in accordance with Table 4 above.

When the Actual_MW and Target_MW are both set to "From telemetry" in Table 4 above, the *PAR_Control* will equal zero.

Common PARs

In the equations below, the Non-Monitoring RTO is credited for or responsible for *PAR_Impact* resulting from the common PAR effect on the Monitoring RTO's M2M Flowgates. The common PAR impact calculation only applies to the common PARs identified in Table 4 above.

Compute control deviation for all common PARs on M2M Flowgate m based on the PAR_Control_{par} MWs calculated above:

$$Cmn\_PAR\_Control_{M2M\_Flowgate-m} = \sum_{cmn\_par=1}^{all} \left(PSF_{(cmn\_par,M2M\_Flowgate-m)} \times PAR\_Control_{cmn\_par}\right)$$

Where:

M2M_Flowgate-m = the relevant flowgate;

cmn_par = each of the common phase angle regulators, modeled as Flowgates, identified in Table 4, above;

$\text{Cmn\_PAR\_Control}_{\text{M2M\_Flowgate-m}}$ = the sum of flow on M2M Flowgate m after accounting for the operation of common PARs;

$\text{PSF}_{(\text{cmn\_par,M2M\_Flowgate-m})}$ = the PSF of each of the common PARs on M2M Flowgate m; and

$\text{PAR\_Control}_{\text{cmn\_par}}$ = the flow deviation on each of the common PARs.

Compute the impact of generation-to-load and interchange schedules across all common PARs on M2M Flowgate m as the Market Flow across each common PAR multiplied by that PAR's shift factor on M2M Flowgate m:

$$Cmn\_PAR\_MF_{M2M\_Flowgate-m} = \sum_{cmn\_par=1}^{all} \left(\begin{array}{c} \left(PSF_{(cmn\_par,M2M\_Flowgate-m)}\right) \times \\ \left(RTO\_GTL_{cmn\_par} + Parallel\_Transfers_{cmn\_par}\right) \end{array} \right)$$

Where:

M2M_Flowgate-m = the relevant flowgate;

cmn_par = the set of common phase angle regulators, modeled as Flowgates, identified in Table 4 above;

$Cmn\_PAR\_MF_{M2M\_Flowgate-m}$ = the sum of flow on M2M Flowgate m due to the generation to load flows and interchange schedules on the common PARs;

$PSF_{(cmn\_par,M2M\_Flowgate-m)}$ = the PSF of each of the common PARs on M2M Flowgate m;

$RTO\_GTL_{cmn\_par}$ = the generation to load flow for each common par, computed in the same manner as the generation to load flow is computed for M2M Flowgates in Section 5.4 above; and

$Parallel\_Transfers_{cmn\_par}$ = the flow on each of the common PARs caused by interchange schedules at non-common scheduling points.

Next, compute the impact of the common PAR effect for M2M Flowgate m as:

$$Cmn\_PAR\_Impact_{M2M\_Flowgate-m} = Cmn\_PAR\_MF_{M2M\_Flowgate-m} - Cmn\_PAR\_Control_{M2M\_Flowgate-m}$$

Where:

$M2M\_Flowgate\text{-}m$ = the relevant flowgate;

$Cmn\_PAR\_Impact_{M2M\_Flowgate-m}$ = potential flow on M2M Flowgate m that is affected by the operation of the common PARs;

$Cmn\_PAR\_MF_{M2M\_Flowgate-m}$ = the sum of flow on M2M Flowgate m due to the generation to load and interchange schedules on the common PARs; and

$Cmn\_PAR\_Control_{M2M\_Flowgate-m}$ = the flow deviation on each of the common PARs.

Non-Common PARs

For the equations below, the NYISO will be credited or responsible for *PAR_Impact* on all M2M Flowgates because the NYISO is the participating RTO that has input into the operation of these devices. The non-common PAR impact calculation only applies to the non-common PARs identified in Table 4 above.

Compute control deviation for all non-common PARs on M2M Flowgate m based on the PAR control MW above:

$$NC\_PAR\_Control_{M2M\_Flowgate-m} = \sum_{nc\_par=1}^{all} PSF_{(nc\_par,M2M\_Flowgate-m)} \times PAR\_Control_{nc\_par}$$

Where:

M2M_Flowgate-m = the relevant flowgate;

nc_par = each of the non-common phase angle regulators, modeled as Flowgates, identified in Table 4 above;

$NC\_PAR\_Control_{M2M\_Flowgate-m}$ = the sum of flow on M2M Flowgate m after accounting for the operation of non-common PARs;

$PSF_{(nc\_par,M2M\_Flowgate-m)}$ = the PSF of each of the non-common PARs on M2M Flowgate m; and

$PAR\_Control_{nc\_par}$ = the flow deviation on each of the non-common PARs.

Compute the impact of generation-to-load and interchange schedules across all non-common PARs on M2M Flowgate m as the Market Flow across each PAR multiplied by that PAR's shift factor on M2M Flowgate m:

$$NC\_PAR\_MF_{M2M\_Flowgate-m} = \sum_{nc\_par=1}^{all} \left(\begin{array}{c} (PSF_{nc\_par,M2M\_Flowgate-m}) \times \\ (RTO\_GTL_{nc\_par} + Parallel\_Transfers_{nc\_par}) \end{array} \right)$$

Where:

M2M_Flowgate-m = the relevant flowgate;

nc_par = the set of non-common phase angle regulators, modeled as Flowgates, identified in Table 4 above;

$NC\_PAR\_MF_{M2M\_Flowgate-m}$ = the sum of flow on M2M Flowgate m due to the generation to load flows and interchange schedules on the non-common PARs;

$PSF_{(nc\_par,M2M\_Flowgate-m)}$ = the outage transfer distribution factor of each of the non-common PARs on M2M Flowgate m;

$RTO\_GTL_{nc\_par}$ = the generation to load flow for each non-common par, computed in the same manner as the generation to load flow is computed for M2M Flowgates in Section 5.4 above; and

$Parallel\_Transfers_{nc\_par}$ = the flow, as computed above where the M2M Flowgate m is one of the non-common PARs, on each of the non-common PARs caused by interchange schedules at non-common scheduling points.

Next, compute the non-common PAR impact for M2M Flowgate m as:

$$NC\_PAR\_Impact_{M2M\_Flowgate-m} = NC\_PAR\_MF_{M2M\_Flowgate-m} - NC\_PAR\_Control_{M2M\_Flowgate-m}$$

Where:

M2M_Flowgate-m = the relevant flowgate;

$NC\_PAR\_Impact_{M2M\_Flowgate\text{-}m}$ = the potential flow on M2M Flowgate m that is affected by the operation of non-common PARs;

$NC\_PAR\_MF_{M2M\_Flowgate\text{-}m}$ = the sum of flow on M2M Flowgate m due to the generation to load and interchange schedules on the non-common PARs; and

$NC\_PAR\_Control_{M2M\_Flowgate\text{-}m}$ = the sum of flow on M2M Flowgate m after accounting for the operation of non-common PARs.

<u>Aggregate all PAR Effects for Each M2M Flowgate</u>

The total impacts from the PAR effects for M2M Flowgate m is:

$$PAR\_Impact_{M2M\_Flowgate-m} = Cmn\_PAR\_Impact_{M2M\_Flowgate-m} + NC\_PAR\_Impact_{M2M\_Flowgate-m}$$

Where:

M2M_Flowgate-m = the relevant flowgate;

$PAR\_Impact_{M2M\_Flowgate\text{-}m}$ = the flow on M2M Flowgate m that is affected after accounting for the operation of both common and non-common PARs;

$Cmn\_PAR\_Impact_{M2M\_Flowgate\text{-}m}$ = potential flow on M2M Flowgate m that is affected by the operation of the common PARs; and

$NC\_PAR\_Impact_{M2M\_Flowgate\text{-}m}$ = the potential flow on M2M Flowgate m that is affected by the operation of non-common PARs.

5.7 Compute the RTO Aggregate Market Flow for all M2M Flowgates

With the *RTO_GTL* and *PAR_IMPACT* known, we can now compute the *RTO_MF* for all M2M Flowgates as:

$$RTO\_MF_{M2M\_Flowgate-m} = RTO\_GTL_{M2M\_Flowgate-m} + Parallel\_Transfers_{M2M\_Flowgate-m} + Shared\_Transfers_{M2M\_Flowgate-m} - PAR\_Impact_{M2M\_Flowgate-m}$$

Where:

M2M_Flowgate-m = the relevant flowgate;

$RTO\_MF_{M2M\_Flowgate-m}$ = the Market Flow caused by RTO generation dispatch and transaction scheduling on M2M Flowgate m after accounting for the operation of both the common and non-common PARs;

$RTO\_GTL_{M2M\_Flowgate-m}$ = the generation to load flow for the entire RTO footprint on M2M Flowgate m;

$Parallel\_Transfers_{M2M\_Flowgate-m}$ = the flow on M2M Flowgate m caused by interchange schedules that are not jointly scheduled by the participating RTOs;

$Shared\_Transfers_{M2M\_Flowgate-m}$ = the flow on M2M Flowgate m caused by interchange schedules that are jointly scheduled by the participating RTOs; and

$PAR\_Impact_{M2M\_Flowgate-m}$ = the flow on M2M Flowgate m that is affected after accounting for the operation of both the common and non-common PARs.

6 M2M Entitlement Determination Method

M2M Entitlements are the equivalent of financial rights for the Non-Monitoring RTO to use the Monitoring RTO’s transmission system within the confines of the M2M redispatch process. The Parties worked together to develop the M2M Entitlement determination method set forth below.

Each Party shall calculate a M2M Entitlement on each M2M Flowgate and compare the results on a mutually agreed upon schedule.

6.1 M2M Entitlement Topology Model and Impact Calculation

The M2M Entitlement calculation shall use both RTOs' static topological models to determine the Non-Monitoring RTO's mutually agreed upon share of a M2M Flowgate's total capacity based on historic dispatch patterns. Both RTOs' models must include the following items:

1. a static transmission and generation model;
2. generator, load, and PAR shift factors;
3. generator output, load, and interchange schedules from 2009 through 2011 or any subsequent three year period mutually agreed to by the Parties;
4. a PAR impact assumption that the PAR control is perfect for all PARs within the transmission models except the PARs at the Michigan-Ontario border;
5. new or upgraded Transmission Facilities; and
6. Transmission Facility retirements.

Each Party shall calculate the GLDFs using a transmission model that contains a mutually agreed upon set of: (1) transmission lines that are modeled as in-service; (2) generators; and (3) loads. Using these GLDFs, generator output data from the three year period agreed to by the Parties, and load data from the three year period agreed to by the Parties, the Parties shall calculate each Party's MW impact on each M2M Flowgate for each hour in the three year period agreed to by the Parties.

Using these impacts, the Parties shall create a reference year consisting of four periods ("M2M Entitlement Periods") for each M2M Flowgate. The M2M Entitlement Periods are as follows:

1. M2M Entitlement Period 1: December, January, and February;
2. M2M Entitlement Period 2: March, April, and May;
3. M2M Entitlement Period 3: June, July, and August; and
4. M2M Entitlement Period 4: September, October, and November.

For each of the M2M Entitlement Periods listed above the Non-Monitoring RTO will calculate its M2M Entitlement on each M2M Flowgate for each hour of each day of a week that will serve as the representative week for that M2M Entitlement Period. The M2M Entitlement for each day/hour, for each M2M Flowgate will be calculated by averaging the Non-Monitoring RTO's Market Flow on an M2M Flowgate for each particular day/hour of the week. The Non-Monitoring RTO shall use the Market Flow data for all of the like day/hours, that occurred in that day of the week and hour in the M2M Entitlement Period, in each year contained within the three year period agreed to by the Parties to calculate the Non-Monitoring RTO's average Market Flow on each M2M Flowgate. When determining M2M settlements each Party will use the M2M Entitlement that corresponds to the hour of the week and to the M2M Entitlement Period for which the real-time Market Flow is being calculated.

The Parties will use the M2M Entitlements that are calculated based on data from the 2009 through 2011 three year period for at least their first year of implementing the M2M coordination process.

6.2 M2M Entitlement Calculation

Each Party shall independently calculate the Non-Monitoring RTO's M2M Entitlement for all M2M Flowgates using the equations set forth in this Section. The Parties shall mutually agree upon M2M Entitlement calculations. Any disputes that arise in the M2M Entitlement calculations will be resolved in accordance with the dispute resolution procedures set forth in Section 35.15 of this Agreement.

Eighty percent of the RECo load shall be excluded from the calculation of Market Flows and M2M Entitlements, and shall instead be reflected as a PJM obligation over the Ramapo PARs in accordance with Sections 7.2.1 and 8.3 of this Schedule D. The remaining twenty percent of RECo load shall be included in the M2M Entitlement and Market Flow calculations as PJM load.

The following assumptions apply to the M2M Entitlement calculation:

1. the Parties shall calculate the values in this Section using the M2M Entitlement Topology Model discussed in Section 6.1 above, unless otherwise stated;
2. the impacts from the *Parallel_Transfers* and *Shared_Transfers* terms of the Market Flow calculation (*see* Section 5.5) are excluded from the Market Flow that is used to calculate M2M Entitlements;
3. perfect PAR Control exists for all PARs within the transmission models except the PARs at the Ontario/Michigan border; and
4. External Capacity Resources may be included in the calculation of M2M Entitlements consistent with Section 6.2.1.1 of this Schedule D.

Once the Reference Year Market Flows have been calculated for each interval to determine the integrated hourly Market Flow for each hour of the relevant three year period agreed to by the Parties, the new M2M Entitlement will be determined for a representative week in each M2M Entitlement Period using the method established in Section 6.1 above. In the event of new or upgraded Transmission Facilities, Section 6.3 of this Schedule D sets forth the rules that will be used to adjust M2M Entitlements.

6.2.1 Treatment of Out-of-Area Capacity Resources and Representation of Ontario/Michigan PARs in the M2M Entitlement Calculation Process

6.2.1.1 Modeling of External Capacity Resources

External Capacity Resources may be included in the M2M Entitlement calculation to the extent the Parties mutually agree to their inclusion.

For the initial implementation of this M2M coordination process that will use 2009 through 2011 data to develop M2M Entitlements, PJM will be permitted to include its External Capacity Resources in the M2M Entitlement calculation. NYISO has not requested inclusion of any External Capacity Resources in the M2M Entitlement calculation for the initial implementation of M2M. When the Parties decide to update the data used to determine M2M Entitlements:

a. PJM will be permitted to include External Capacity Resources that have an equivalent net M2M Entitlement impact to the net M2M Entitlement impact of the PJM External Capacity Resources that were used for the initial implementation of the M2M coordination process. Inclusion of PJM External Capacity Resources that exceed the net M2M Entitlement impact of the PJM External Capacity Resources that were used for the initial implementation of the M2M coordination process must be mutually agreed to by the Parties.

b. The Parties may mutually agree to permit the NYISO to include External Capacity Resources in the M2M Entitlement calculation.

6.2.1.2 Modeling of the Ontario/Michigan PARs

The Ontario/Michigan PARs will be modeled as not controlling power flows in the M2M Entitlement calculation process. The Parties agree that this modeling treatment is only appropriate when it is paired with the rules for calculating Market Flows and M2M settlements that are set forth in Sections 5 and 8 of this Agreement. Section 7.1 specifies how the RTOs will adjust Market Flows to account for the impact of the operation of the Ontario/Michigan PARs when the PARs are in service. The referenced Market Flow and M2M settlement rules are necessary because they are designed to ensure that M2M settlement obligations based on M2M Entitlements and Market Flows will not result in compensation for M2M redispatch when no actual M2M redispatch occurs.

6.3 <u>M2M Entitlement Adjustment for New Transmission Facilities, Upgraded Transmission Facilities or Retired Transmission Facilities</u>

This Section sets forth the rules for incorporating new or upgraded Transmission Facilities, and Transmission Facility retirements, into the M2M Entitlement calculation. For all M2M Entitlement adjustments, the non-building RTO is the non-funding market, and the building RTO is the funding market.

If the cost of a new or upgraded Transmission Facility is borne solely by the Market Participants of the building RTO for the new or upgraded Transmission Facility, the Market Participants of the building RTO will exclusively benefit from the increase in transfer capability on the building RTO's Transmission Facilities. Therefore, the non-building RTO's M2M Entitlements shall not increase as result of such new or upgraded Transmission Facilities. Reciprocally, a building RTO's M2M Entitlements on the non-building RTO's M2M Flowgates shall not increase as a result of such new or upgraded Transmission Facilities.

To the extent a building RTO's new or upgraded Transmission Facility, or Transmission Facility retirement, reduces the non-building RTO's impacts on one or more of the building RTO's M2M Flowgates by redistributing the non-building RTO's modeled flows, the non-building RTO's M2M Entitlement will be redistributed to ensure that the non-building RTO's aggregate M2M Entitlements on the building RTOs transmission system, including both existing M2M Flowgates and upgraded or new Transmission Facilities that are not yet M2M Flowgates, is not decreased.

In assessing the impact of new or upgraded Transmission Facilities, or Transmission Facility retirements, the non-building RTO's revised total circulation through the building RTO shall not result in a net increase in M2M Entitlements for the non-building RTO on the building RTO's transmission system. The formulas below shall be used to determine the *pro-rata* adjustment that will be applied to determine the redistributed interval level and hourly integrated Market Flow (*i.e.*, the Transmission Adjusted Market Flow). Once a Transmission Adjusted Market Flow that incorporates the topology adjustment and reallocation of flows has been calculated for each hour of the three year period agreed to by the Parties, the new M2M Entitlement will be determined for each hour and day of the week in each M2M Entitlement Period using the method established in Section 6.1 above.

The Parties will mutually perform an analysis to determine if new or upgraded Transmission Facilities, or Transmission Facility retirements, will have an impact on any of the non-building RTO's M2M Flowgates. If the new or upgraded Transmission Facilities, or Transmission Facility retirements, are determined to have a 5% or less impact on each of the non-building RTO's M2M Flowgates, calculated individually for each M2M Flowgate, then the non-building RTO is not required to update its operational models to incorporate the new, upgraded or retired Transmission Facilities. If the new or upgraded Transmission Facilities, or Transmission Facility retirements, are determined to have greater than a 5% impact, but less than a 10% impact on each of the non-building RTO's M2M Flowgates, calculating the impact individually for each M2M Flowgate, then the Parties may mutually agree not to require the non-building RTO to update its operational models.

If Transmission Facilities outside the Balancing Authority Areas of the Parties are added or upgraded and the new or upgraded Transmission Facilities would, individually or in aggregate, cause a change in either Party's aggregate M2M Entitlements of at least 10%, then the Parties may mutually agree to incorporate those Transmission Facilities into the static transmission models used to perform the M2M Entitlement calculations.

M2M Entitlement Transmission Adjusted Market Flow Calculation:

This process determines the Transmission Adjusted Market Flow for existing and new or retired Transmission Facilities when new Transmission Facilities are built or existing Transmission Facilities are upgraded or retired. This process does not apply to the addition of new M2M Flowgates that are associated with existing Transmission Facilities.

First, determine the reference set of Market Flows, called Reference Year Market Flows, for all M2M Flowgates using a static transmission model before adding any new or upgraded Transmission Facilities, or removing retired Transmission Facilities.

Second, account for new or upgraded Transmission Facilities or Transmission Facility retirements in order from the first completed new/upgraded/retired facility to the last (most recently completed) new/upgraded/retired facility. Reflect the new/upgraded/retired facilities, grouped by building RTO, in the reference year model to determine the new set of Market Flows called New Year Market Flows.

Third, compare the New Year Market Flows to the Reference Year Market Flows, in net across all M2M Flowgates (after adding new or upgraded Transmission Facilities and/or removing retired Transmission Facilities), to determine whether the New Year Market Flows have increased or decreased relative to the Reference Year Market Flows. If the comparison indicates that New Year Market Flows have increased or decreased relative to the Reference Year Market Flows, apply the formulas below to determine new Transmission Adjusted Market Flows.

The comparison process is performed on a step-by-step basis. In some cases it will be appropriate to aggregate the impacts of more than one new or upgraded Transmission Facility into a single “step” of the evaluation.

Transmission Adjusted Market Flow Formula:

$$TotPost = \sum_{f \in F} Post_f$$
$$TotPre = \sum_{f \in E} Pre_f$$
$$NewPost = \sum_{f \in N} Post_f$$
$$ExistPost = \sum_{f \in E} Post_f$$
$$ExistPre = \sum_{f \in E} Pre_f$$

The non-building RTO’s Transmission Adjusted Market Flow (*Ent_f*) is calculated as follows for each Transmission Facility in the building RTO’s set of monitored M2M Flowgates $f \in F$:

$$Ent_f = \begin{cases} Post_f \cdot \dfrac{TotPre}{TotPost}, & \text{if } ExistPost > ExistPre \\ Post_f, & \text{if } ExistPost \leq ExistPre \text{ and } f \in E \\ \Big(Max\big((ExistPre - ExistPost), 0\big)\Big) \cdot \dfrac{Post_f}{NewPost}, & \text{if } ExistPost \leq ExistPre \text{ and } f \in N. \end{cases}$$

The building RTO's Transmission Adjusted Market Flow (Ent_f) is calculated as follows for each Transmission Facility in the non-building RTO's set of monitored M2M Flowgates $f \in F$:

$$Ent_f = \begin{cases} Post_f \cdot \dfrac{TotPre}{TotPost}, & \text{if } ExistPost > ExistPre \text{ and } f \in E \\ Post_f, & \text{if } ExistPost \leq ExistPre \text{ and } f \in E \\ 0, & \text{otherwise.} \end{cases}$$

Where:

f represents the relevant Transmission Facility within the building or non-building RTO.

E represents the existing facilities: the set of M2M Flowgates and previously accounted for new, upgraded or retired Transmission Facilities (which may not be M2M Flowgates) in the relevant (building or non-building) RTO.

N represents the new, upgraded or retired facilities: the set of Transmission Facilities in the relevant (building or non-building) RTO whose impact on M2M Entitlements is being evaluated.

F represents the set of all Transmission Facilities in the relevant (building or non-building) RTO, including all elements of sets *E* and *N*.

Pre_f is pre-upgrade/retirement market flow on *f*: the market flow on facility *f* calculated using the M2M Entitlement assumptions and based on a transmission topology that includes all pre-existing Transmission Facilities and all new, upgraded or retired Transmission Facilities whose impact on M2M Entitlements has been previously evaluated and incorporated.

$Post_f$ is the post-upgrade/retirement market flow on *f*: the market flow on facility *f* calculated using the M2M Entitlement assumptions and based on a transmission topology that includes all pre-existing Transmission Facilities and all new, upgraded or retired Transmission Facilities whose impact on M2M Entitlements has been previously evaluated and incorporated, *and* all new, upgraded or retired Transmission Facilities whose impact on M2M Entitlements is being evaluated in the current evaluation step. For Transmission Facility retirements, $Post_f$ shall equal zero.

6.4 M2M Entitlement Adjustment for a New Set of Generation, Load and Interchange Data

Section 6.3 above addresses how new or upgraded Transmission Facilities and Transmission Facility retirements will be reflected in the determination of M2M Entitlements.

This Section explains how the Parties will update the model used to determine M2M Entitlements to reflect new/updated generation, load and interchange information.

When moving the initial 2009-2011 period generation, interchange and load data forward, the RTOs will need to gather the data specified in Sections 6.1, 6.2 and (where appropriate) 6.3, above for the agreed upon three year period. External Capacity Resources will be included consistent with Section 6.2.1.1, above.

In accordance with the rules specified in Sections 6.1, 6.2 and (where appropriate) 6.3, above, the new set of data will be used to establish a new Reference Year Market Flow. When new or upgraded Transmission Facility or Transmission Facility retirement adjustments are necessary, the new Reference Year Market Flows will be used to determine the New Year and Transmission Adjusted Market Flows based on the rules set forth above. When no new or upgraded Transmission Facility or Transmission Facility retirement adjustments need to be applied, the new Reference Year Market Flows are the basis for the new M2M Entitlements.

7 Real-Time Energy Market Coordination

Operation of the NY-NJ PARs and redispatch are used by the Parties in real-time operations to effectuate this M2M coordination process. Operation of the NY-NJ PARs will permit the Parties to redirect energy to reduce the overall cost of managing transmission congestion and to converge the participating RTOs' cost of managing transmission congestion. Operation of the NY-NJ PARs to manage transmission congestion requires cooperation between the NYISO and PJM. Operation of the NY-NJ PARs shall be coordinated by the RTOs.

When a M2M Flowgate that is under the operational control of either NYISO or PJM and that is eligible for redispatch coordination, becomes binding in the Monitoring RTOs real-time security constrained economic dispatch, the Monitoring RTO will notify the Non-Monitoring RTO of the transmission constraint and will identify the appropriate M2M Flowgate that requires redispatch assistance. The Monitoring and Non-Monitoring RTOs will provide the economic value of the M2M Flowgate constraint (i.e., the Shadow Price) as calculated by their respective dispatch models. Using this information, the security-constrained economic dispatch of the Non-Monitoring RTO will include the M2M Flowgate constraint; the Monitoring RTO will evaluate the actual loading of the M2M Flowgate constraint and request that the Non-Monitoring RTO modify its Market Flow via redispatch if it can do so more efficiently than the Monitoring RTO (i.e., if the Non-Monitoring RTO has a lower Shadow Price for that M2M Flowgate than the Monitoring RTO).

An iterative coordination process will be supported by automated data exchanges in order to ensure the process is manageable in a real-time environment. The process of evaluating the Shadow Prices between the RTOs will continue until the Shadow Prices converge and an efficient redispatch solution is achieved. The continual interactive process over the following dispatch cycles will allow the transmission congestion to be managed in a coordinated, cost-effective manner by the RTOs. A more detailed description of this iterative procedure is discussed in Section 7.1 and the appropriate use of this iterative procedure is described in Section 10.

7.1 Real-Time Redispatch Coordination Procedures

The following procedure will apply for managing redispatch for M2M Flowgates in the real-time Energy market:

7.1.1 M2M Flowgates shall be monitored per each RTO's internal procedures.

a. When (i) an M2M Flowgate is constrained to a defined limit (actual or contingency flow) by a non-transient constraint, and (ii) Market Flows are such that the Non-Monitoring RTO may be able to provide an appreciable amount of redispatch relief to the Monitoring RTO, then the Monitoring RTO shall reflect the monitored M2M Flowgate as constrained.

b. M2M Flowgate limits shall be periodically verified and updated.

7.1.2 Testing for an Appreciable Amount of Redispatch Relief and Determining the Settlement Market Flow:

When the PARs at the Michigan-Ontario border are not in-service, the ability of the Non-Monitoring RTO to provide an appreciable amount of redispatch relief will be determined by comparing the Non-Monitoring RTO's Market Flow to the Non-Monitoring RTO M2M Entitlement for the constrained M2M Flowgate. When the Non-Monitoring RTO Market Flow (also the Market Flow used for settlement) is greater than the Non-Monitoring RTO M2M Entitlement for the constrained M2M Flowgate, the Monitoring RTO will assume that an appreciable amount of redispatch relief is available from the Non-Monitoring RTO and will engage the M2M coordination process for the constrained M2M Flowgate.

When any of the PARs at the Michigan-Ontario border are in-service, the ability of the Non-Monitoring RTO to provide an appreciable amount of redispatch relief will be determined by comparing either (i) the Non-Monitoring RTO's unadjusted Market Flow, or (ii) the Non-Monitoring RTO Market Flow adjusted to reflect the expected impact of the PARs at the Michigan-Ontario border ("LEC Adjusted Market Flow"), to the Non-Monitoring RTO M2M Entitlement for the constrained M2M Flowgate. The rules for determining which Market Flow (unadjusted or adjusted) to compare to the Non-Monitoring RTO M2M Entitlement when any of the PARs at the Michigan-Ontario border are in-service are set forth below.

a. Calculating the Expected Impact of the PARs at the Michigan-Ontario Border on Market Flows

The Non-Monitoring RTO's unadjusted Market Flow is determined as *RTO_MF* in accordance with the calculation set forth in Section 5 above. The expected impact of the PARs at the Michigan-Ontario border is determined as follows:

$$MICH - OH\_PAR\_Impact_{M2M\_Flowgate-m} = \sum_{MICH-OH\ Path=1}^{4} \begin{pmatrix} (PSF_{(MICH-OH\ Path, M2M\_Flowgate-m)}) \times \\ (RTO\_MF_{MICH-OH\ Path} - LEC/4) \end{pmatrix}$$

Where:

M2M_Flowgate-m = the relevant M2M Flowgate;

MICH-OH Path = each of the four PAR paths connecting Michigan to Ontario, Canada;

$MICH\text{-}OH\_PAR\_Impact_{M2M\_Flowgate\text{-}m}$ = the expected impact of the operation of the PARs at the Michigan-Ontario border on the flow on M2M Flowgate m;

$PSF_{(MICH\text{-}OH\ Path, M2M\_Flowgate\text{-}m)}$ = the PSF of each of the four Michigan-Ontario PAR paths on M2M Flowgate m;

$RTO\_MF_{MICH\text{-}OH\ Path}$ = the Market Flow for each of the four Michigan-Ontario PAR paths, computed in the same manner as the Market Flow is computed for M2M Flowgates in Section 5 above; and

LEC = Actual circulation around Lake Erie as measured by each RTO.

The Non-Monitoring RTO's LEC Adjusted Market Flow, reflecting the expected impact of the PARs on the Michigan-Ontario border, can be determined by adjusting the *RTO_MF* from Section 5 to incorporate the *MICH-OH_PAR_Impact* calculated above.

$$LEC\ Adjusted\ Market\ Flow_{M2M\_Flowgate-m} = RTO\_MF_{M2M\_Flowgate-m} - MICH - OH\_PAR\_Impact_{M2M\_Flowgate-m}$$

Where:

M2M_Flowgate-m = the relevant flowgate;

MICH-OH Path = each of the four PAR paths connecting Michigan to Ontario, Canada;

$\text{MICH-OH\_PAR\_Impact}_{\text{M2M\_Flowgate-m}}$ = the expected impact of the operation of the PARs at the Michigan-Ontario border on the flow on M2M Flowgate m;

$\text{RTO\_MF}_{\text{M2M\_Flowgate-m}}$ = the Market Flow caused by RTO generation dispatch and transaction scheduling on M2M Flowgate m after accounting for the operation of both the common and non-common PARs; and

LEC Adjusted Market $\text{Flow}_{\text{M2M\_Flowgate-m}}$ = the Market Flow caused by RTO generation dispatch and transaction scheduling on M2M Flowgate m after accounting for the operation of the common PARs, the non-common PARs, and the PARs at the Michigan-Ontario border.

b. Determining Whether to Use Unadjusted Market Flow or LEC Adjusted Market Flow; Determining if Appreciable Redispatch Relief is Available

1) When the Non-Monitoring RTO’s LEC Adjusted Market Flow equals the Non-Monitoring RTO’s unadjusted Market Flow and the Non-Monitoring RTO’s Market Flow (also the Market Flow used for settlement) is greater than the Non-Monitoring RTO M2M Entitlement for the constrained M2M Flowgate, the Monitoring RTO will assume that an appreciable amount of redispatch relief is available from the Non-Monitoring RTO and will engage the M2M coordination process for the constrained M2M Flowgate.

2) When the Non-Monitoring RTO’s unadjusted Market Flow is greater than the Non-Monitoring RTO’s LEC Adjusted Market Flow, then the following calculation shall be performed to determine if an appreciable amount of redispatch relief is expected to be available:

   A. Determine the minimum of (a) the Non-Monitoring RTO’s unadjusted Market Flow, and (b) the Non-Monitoring RTO’s M2M Entitlement, for the constrained M2M Flowgate; and

   B. Determine the maximum of (x) the value from step A above, and (y) the Non-Monitoring RTO’s LEC Adjusted Market Flow

When the value from B above (the Market Flow used for settlement), is greater than the Non-Monitoring RTO's M2M Entitlement for the constrained M2M Flowgate, the Monitoring RTO will assume that an appreciable amount of redispatch relief is available from the Non-Monitoring RTO and will engage the M2M coordination process for the constrained M2M Flowgate.

3) When the Non-Monitoring RTO's unadjusted Market Flow is less than the Non-Monitoring RTO LEC Adjusted Market Flow, the following calculation shall be performed to determine if an appreciable amount of redispatch relief is expected to be available:

A. Determine the maximum of (a) the Non-Monitoring RTO's unadjusted Market Flow, and (b) the Non-Monitoring RTO M2M Entitlement, for the constrained M2M Flowgate; and

B. Determine the minimum of (x) the value from A above, and (y) the Non-Monitoring RTO's LEC Adjusted Market Flow

When the value from B above (the Market Flow used for settlement), is greater than the Non-Monitoring RTO's M2M Entitlement for the constrained M2M Flowgate, the Monitoring RTO will assume that an appreciable amount of redispatch relief is available from the Non-Monitoring RTO and will engage the M2M coordination process for the constrained M2M Flowgate.

7.1.3 The Monitoring RTO initiates M2M, notifies the Non-Monitoring RTO of the M2M Flowgate that is subject to coordination and updates required information.

7.1.4 The Non-Monitoring RTO shall acknowledge receipt of the notification and one of the following shall occur:

a. The Non-Monitoring RTO refuses to activate M2M:
    i. The Non-Monitoring RTO notifies the Monitoring RTO of the reason for refusal; and
    ii. The M2M State is set to "Refused"; or
b. The Non-Monitoring RTO agrees to activate M2M:
    i. Such an agreement shall be considered an initiation of the M2M redispatch process for operational and settlement purposes; and
    ii. The M2M State is set to "Activated".

7.1.5 The Parties have agreed to transmit information required for the administration of this procedure, as per Section 35.7.1 of this Agreement.

7.1.6 As Shadow Prices converge and approach zero or the Non-Monitoring RTO's Market Flows and Shadow Prices are such that an appreciable amount of redispatch relief can no longer be provided to the Monitoring RTO, the Monitoring RTO shall be responsible for the continuation or termination of the M2M redispatch process. Current and forecasted future system conditions shall be considered.[22]

When the Monitoring RTO's Shadow Price is not approaching zero the Monitoring RTO can (1) use the procedure called *Testing for an Appreciable Amount of Relief and Determining the Settlement Market Flow* from step 2b above, and (2) compare the Non-Monitoring RTO's Shadow Price to the Monitoring RTO's Shadow Price, to determine whether there is an appreciable amount of market flow relief being provided.

When the *Testing for an Appreciable Amount of Relief and Determining the Settlement Market Flow* procedure indicates there is not an appreciable amount of relief being provided, and the Non-Monitoring RTO Shadow Price is not less than the Monitoring RTO Shadow Price, then the Monitoring RTO may terminate the M2M coordination process.

7.1.7 Upon termination of M2M, the Monitoring RTO shall

a. Notify the Non-Monitoring RTO; and

b. Transmit M2M data to the Non-Monitoring RTO with the M2M State set to "Closed". The timestamp with this transmission shall be considered termination of the M2M redispatch process for operational and settlement purposes.

7.2 <u>Real-Time NY-NJ PAR Coordination</u>

The NY-NJ PARs will be operated to facilitate interchange schedules while minimizing regional congestion costs. When congestion is not present, the NY-NJ PARs will be operated to achieve the target flows as established below in Section 7.2.1.

PJM and the NYISO have operational control of the NY-NJ PARs and direct the operation of the NY-NJ PARs, while Public Service Electric and Gas Company ("PSE&G") and

[22] Termination of M2M redispatch may be requested by either RTO in the event of a system emergency.

Consolidated Edison Company of New York ("Con Edison") have physical control of the NY-NJ PARs. The Con Edison dispatcher sets the PAR taps for the ABC PARs and Ramapo PARs at the direction of the NYISO. The PSE&G dispatchers set the PAR taps for the Waldwick PARs at the direction of PJM.

PJM and the NYISO have the responsibility to direct the operation of the NY-NJ PARs to maintain compliance with the requirements of this Agreement. PJM and the NYISO shall make reasonable efforts to minimize movement of the NY-NJ PARs while implementing the NY-NJ PAR target flows and the NY-NJ PAR coordination process. PJM and the NYISO will employ a +/- 50 MW operational bandwidth around each NY-NJ PAR's target flow to limit tap movements and to maintain actual flows at acceptable levels. This operational bandwidth shall not impact or change the NY-NJ PAR Settlement rules in Section 8.3 of this Agreement. The operational bandwidth provides a guideline to assist the RTOs' efforts to avoid unnecessary NY-NJ PAR tap movements.

In order to preserve the long-term availability of the NY-NJ PARs, a maximum number of 20 PAR tap changes per NY-NJ PAR per day, and a maximum number of 400 PAR tap changes per NY_NJ PAR per calendar month will normally be observed. If the number of PAR tap changes exceed these limits, then the operational bandwidth shall be increased in 50 MW increments until the total number of PAR tap changes no longer exceed 400 PAR tap changes per NY-NJ PAR per month, unless PJM and the NYISO mutually agree otherwise.

In order to implement the NY-NJ PAR coordination process, including the establishment and continuation of the initial and any future OBF as defined in this Section and Section 35.2 of this Agreement, on the ABC PARs and the Waldwick PARs, the facilities comprising the ABC Interface and JK Interface shall be functional and operational at all times, consistent with Good Utility Practice, except when they are taken out-of-service to perform maintenance or are subject to a forced outage.

7.2.1 NY-NJ PAR Target Values

A Target Value for flow between the NYISO and PJM shall be determined for each NY-NJ PAR based on the net interchange schedule between the Parties. These Target Values shall be used for settlement purposes as:

$$Target_{PARx} = (InterchangeFactor_{PARx}) + (Operational\ Base\ Flow_{PARx}) + (RECo\_Load_{PARx})$$

Where:

$Target_{PARx} =$ Calculated Target Value for the flow on each NY-NJ PAR For purposes of this equation, a positive value* indicates a flow from PJM to the NYISO.

* The sign conventions apply to the formulas used in this Agreement. The Parties may utilize different sign conventions in their market software so long as the software produces results that are consistent with the rules set forth in this Agreement.

$InterchangeFactor_{PARx} =$ The MW value of the net interchange schedule between PJM and NYISO over the AC tie lines distributed across each in-service NY-NJ PAR calculated as net interchange schedule times the interchange percentage. The interchange percentage for each NY-NJ PAR is listed in Table 5.

If a NY-NJ PAR is out-of-service or is bypassed, or if the RTOs mutually agree that a NY-NJ PAR is incapable of facilitating interchange, the percentage of net interchange normally assigned to that NY-NJ PAR will be transferred over the western AC tie lines between the NYISO and PJM. The remaining in-service NY-NJ PARs will continue to be assigned the interchange percentages specified in Table 5.

$\mathrm{OperationalBaseFlow}_{\mathrm{PARx}} =$ The MW value of OBF distributed across each of the in-service ABC PARs and Waldwick PARs.

Either Party may establish a temporary OBF to address a reliability issue until a long-term solution to the identified reliability issue can be implemented. Any temporary OBF that is established shall be at a level that both Parties can reliably support. The Party that establishes the OBF shall: (1) explain the reliability need to the other Party; (2) describe how the OBF addresses the identified reliability need; and (3) identify the expected long-term solution to address the reliability need.

The initial 400 MW OBF, effective on May 1, 2017, is expected to be reduced to zero MW by June 1, 2021.

The Parties may mutually agree to modify an established OBF value that normally applies when all of the ABC PARs and Waldwick PARs are in service. Modification of the normally applied OBF value will be implemented no sooner than two years after mutual agreement on such modification has been reached, unless NYISO and PJM mutually agree to an earlier implementation date.

The NYISO and PJM shall post the OBF values, in MW, normally applied to each ABC PAR and Waldwick PAR when all of the ABC PARs and Waldwick PARs are in service, on their respective websites. The NYISO and PJM shall also post the methodology used to reduce the OBF under certain outage conditions on their respective websites. The NYISO and PJM shall review the OBF MW value at least annually.

$RECo\_Load_{PARx} =$ The MW value of the telemetered real-time Rockland Electric Company Load to be delivered over a NY-NJ PAR shall be calculated as real-time RECo Load times the RECo Load percentage listed in Table 5. RECo Load is the portion of Orange and Rockland load that is part of PJM. The primary objective of the NY-NJ PARs is the delivery of scheduled interchange. Deliveries to serve RECo Load over the Ramapo PARs will only be permitted to the extent there is unused transfer capability on the Ramapo PARs after accounting for interchange. Subject to the foregoing limitation, when one of the Ramapo PARs is out of service the full RECo Load percentage (80%) will be applied to the in-service Ramapo PAR. The RECo Load percentage ordinarily used for each NY-NJ PAR is listed in Table 5:

Table 5

PAR Name	Description	Interchange Percentage	RECo Load Percentage
3500	RAMAPO PAR3500	16%	40%^
4500	RAMAPO PAR4500	16%	40%^
E	WALDWICK E2257	5%	0%
F	WALDWICK F2258	5%	0%
O	WALDWICK O2267	5%	0%
A	GOETHSLN BK_1N	7%	0%
B	FARRAGUT TR11	7%	0%
C	FARRAGUT TR12	7%	0%

^ Subject to the foregoing limitation, when one of the Ramapo PARs is out of service the full RECo Load Percentage (80%) will be applied to the in-service Ramapo PAR.

7.2.2 Determination of the Cost of Congestion at each NY-NJ PAR

The incremental cost of congestion relief provided by each NY-NJ PAR shall be determined by each of the Parties. These costs shall be determined by multiplying each Party's Shadow Price on each of its M2M Flowgates by the PSF for each NY-NJ PAR for the relevant M2M Flowgates.

The incremental cost of congestion relief provided by each NY-NJ PAR shall be determined by the following formula:

$$Congestion\$_{(PARx,RTO)} =$$

$$\sum_{M2M\ Flowgates-m\ \in M2M\ Flowgates_{RTO}} \left(PSF_{(M2M\ Flowgate-m,PARx)} \times Shadow\$_{M2M\ Flowgate-m}\right)$$

Where:

$Congestion\$_{(PARx,RTO)} =$	Cost of congestion at each NY-NJ PAR for the relevant participating RTO, where a negative cost of congestion indicates taps in the direction of the relevant participating RTO would alleviate that RTO's congestion;
$M2M\ Flowgates_{RTO} =$	Set of M2M Flowgates for the relevant participating RTO;
$PSF_{(M2M\ Flowgate-m,PARx)} =$	The PSF for each NY-NJ PAR on M2M Flowgate–m; and
$Shadow\$_{M2M\ Flowgate-m} =$	The Shadow Price on the relevant participating RTO's M2M Flowgate m.

7.2.3 Desired PAR Changes

Consistent with the congestion cost calculation established in Section 7.2.2 above, if the NYISO congestion costs associated with a NY-NJ PAR are less than the PJM congestion costs associated with the same NY-NJ PAR, then hold or take taps into NYISO.

Similarly, if the PJM congestion costs associated with a NY-NJ PAR are less than NYISO congestion costs associated with the same NY-NJ PAR, then hold or take taps into PJM.

Any action on the NY-NJ PARs will be coordinated between the Parties and taken into consideration other PAR actions.

8 Real-Time Energy Market Settlements

8.1 Information Used to Calculate M2M Settlements

For each M2M Flowgate there are two components of the M2M settlement, a redispatch component and a NY-NJ PAR coordination component. Both M2M settlement components are defined below.

For the redispatch component, market settlements under this M2M Schedule will be calculated based on the following:

1. the Non-Monitoring RTO's real-time Market Flow, determined in accordance with Section 7.1 above, on each M2M Flowgate compared to its M2M Entitlement for M2M Flowgates eligible for redispatch on each M2M Flowgate; and
2. the *ex-ante* Shadow Price at each M2M Flowgate.

For the NY-NJ PARs coordination component, Market settlements under this M2M Schedule will be calculated based on the following:

1. actual real-time flow on each of the NY-NJ PARs compared to its target flow ($Target_{PARx}$);
2. PSF for each NY-NJ PAR onto each M2M Flowgate; and
3. the *ex-ante* Shadow Price at each M2M Flowgate.

Either or both of the Parties shall be excused from paying an *M2MPARSettlement* (described in *S*ection 8.3 of this Schedule D) to the other Party at times when a Storm Watch is in effect in New York and the operating requirements and other criteria set forth in Section 8.3.1 below are satisfied.

8.2 Real-Time Redispatch Settlement

If the M2M Flowgate is eligible for redispatch, then compute the real-time redispatch settlement for each interval as specified below.

When $RT\_MktFlow_{M2M\ Flowgate-m_i} > M2M\_Ent_{M2M\ Flowgate-m_i}$,

$$MonRTO\_Payment_{M2M\ Flowgate-m_i} = Mon\_Shadow\$_{M2M\ Flowgate-m_i} \times \left(RT\_MktFlow_{M2M\ Flowgate-m_i} - M2M\_Ent_{M2M\ Flowgate-m_i}\right) \times {}^{s_i}/_{3600sec}$$

When $RT\_MktFlow_{M2M\ Flowgate-m_i} < M2M\_Ent_{M2M\ Flowgate-m_i}$,

$$Non\_MonRTO\_Payment_{M2M\ Flowgate-m_i} = Non\_Mon\_Shadow\$_{M2M\ Flowgate-m_i} \times \left(M2M\_Ent_{M2M\ Flowgate-m_i} - RT\_MktFlow_{M2M\ Flowgate-m_i}\right) \times {}^{s_i}/_{3600sec}$$

Where:

$Non\_MonRTO\_Payment_{M2M\ Flowgate-m_i}$ = M2M redispatch settlement, in the form of a payment to the Non-Monitoring RTO from the Monitoring RTO, for M2M Flowgate m and interval *i*;

$MonRTO\_Payment_{M2M\ Flowgate-m_i}$ = M2M redispatch settlement, in the form of a payment to the Monitoring RTO from the Non-Monitoring RTO, for M2M Flowgate m and interval *i*;

$RT\_MktFlow_{M2M\ Flowgate-m_i}$ = real-time RTO_MF, determined for settlement in accordance with Section 7.1 above, for M2M Flowgate m and interval *i*;

$M2M\_Ent_{M2M\ Flowgate-m_i}$ = Non-Monitoring RTO M2M Entitlement for M2M Flowgate m and interval *i*;

$Mon\_Shadow\$_{M2M\ Flowgate-m_i}$ = Monitoring RTO's Shadow Price for M2M Flowgate m and interval *i*;

$Non\_Mon\_Shadow\$_{M2M\ Flowgate-m_i}$ = Non-Monitoring RTO's Shadow Price for M2M Flowgate m and interval *i*; and

s_i = number of seconds in interval *i*.

8.3 <u>NY-NJ PARs Settlements</u>

Compute the real-time NY-NJ PARs settlement for each interval as specified below.

When

$Actual_{PARx_i} > Target_{PARx_i}$,

$$NYImpact_{PARx_i} = Max(\left(Congestion\$_{(PARx,NY)_i} \times \left(Target_{PARx_i} - Actual_{PARx_i}\right)\right), 0) \times {}^{s_i}/_{3600sec}$$

$$PJMImpact_{PARx_i} = \left(Congestion\$_{(PARx,PJM)_i} \times \left(Actual_{PARx_i} - Target_{PARx_i}\right)\right) \times {}^{s_i}/_{3600sec}$$

When

$Actual_{PARx_i} < Target_{PARx_i}$,

$$NYImpact_{PARx_i} = \left(Congestion\$_{(PARx,NY)_i} \times \left(Target_{PARx_i} - Actual_{PARx_i}\right)\right) \times {}^{s_i}/_{3600sec}$$

$$PJMImpact_{PARx_i} = Max(\left(Congestion\$_{(PARx,PJM)_i} \times \left(Actual_{PARx_i} - Target_{PARx_i}\right)\right), 0) \times {}^{s_i}/_{3600sec}$$

$$M2MPARSettlement_i = \left(Min\left(\sum^{All\ NY-NJ\ PARs} NYImpact_{PARx_i}, 0\right) - Min\left(\sum^{All\ NY-NJ\ PARs} PJMImpact_{PARx_i}, 0\right)\right) \times {}^{s_i}/_{3600sec}$$

Where:

$Actual_{PARx_i} =$ Measured real-time actual flow on each of the NY-NJ PARs for interval *i*. For purposes of this equation, a positive value indicates a flow from PJM to the NYISO;

$Target_{PARx_i} =$ Calculated Target Value for the flow on each NY-NJ PAR as described in Section 7.2.1 above for interval i. For purposes of this equation, a positive value indicates a flow from PJM to the NYISO;

$PJMImpact_{\,PARx_i} =$ PJM Impact, defined as the impact that the current NY-NJ PAR flow relative to target flow is having on PJM's system congestion for interval *i*. For purposes of this equation, a positive value indicates that the PAR flow relative to target flow is reducing PJM's system congestion, whereas a negative value indicates that the PAR flow relative to target flow is increasing PJM's system congestion.

$NYImpact_{PARx_i} =$ NYISO Impact, defined as the impact that the current NY-NJ PAR flow relative to target flow is having on NYISO's system congestion for interval *i*. For purposes of this equation, a positive value indicates that the PAR flow relative to target flow is reducing NYISO's system congestion, whereas a negative value indicates that the PAR flow relative to the target flow is increasing NYISO's system congestion system.

$Congestion\$_{(PARx,PJM)_i} =$ Cost of congestion at each NY-NJ PAR for PJM, calculated in accordance with Section 7.2.2 above for interval *i*;

$Congestion\$_{(PARx,NY)_i} =$ Cost of congestion at each NY-NJ PAR for NYISO, calculated in accordance with Section 7.2.2 above for interval *i*, and

$M2MPARSettlement_i =$ M2M PAR Settlement across all NY-NJ PARs, defined as a payment from NYISO to PJM when the value is positive, and a payment from PJM to NYISO when the value is negative for interval *i*.

$s_i =$ number of seconds in interval *i*.

8.3.1 NY-NJ PAR Settlements During Storm Watch Events

PJM shall not be required to pay a M2MPARSettlement (calculated in accordance with Section 8.3 of this Schedule D) to NYISO when a Storm Watch is in effect and PJM has taken the actions required below to assist the NYISO, or when NYISO has not taken the actions required below to address power flows resulting from the redispatch of generation to address the Storm Watch.

NYISO shall not be required to pay a M2MPARSettlement to PJM when a Storm Watch is in effect and NYISO has taken the actions required of it below to address power flows resulting from the redispatch of generation to address the Storm Watch.

When a Storm Watch is in effect, the RTOs will determine whether PJM and/or NYISO are required to pay a M2MPARSettlement to the other RTO based on three Storm Watch compliance requirements that address the operation of (a) the JK transmission lines and associated Waldwick PARs, (b) the ABC transmission lines and associated ABC PARs, and (c) the 5018 transmission line and associated Ramapo PARs. Compliance shall be determined as follows:

a. *JK Storm Watch compliance*: Subject to the exceptions that follow, PJM will be "Compliant" at the JK interface when either of the following two conditions are satisfied, otherwise it will be "Non-compliant":

   i. Flow on the JK interface was at or above the sum of the Target flows for each Available Waldwick PAR at any point in the trailing (rolling) 15-minutes[23]; or

   ii. PJM took at least two taps on each Available Waldwick PAR in the direction to reduce flow into PJM at any point in the trailing (rolling) 15-minutes.

   If NYISO denies PJM's request to take one or more taps at a Waldwick PAR to reduce flow into PJM and achieve compliance at the JK interface, then PJM shall be considered "Compliant" at the JK interface.

   If PJM cannot take a required tap at a Waldwick PAR because the change will result in an overload on PJM's system unless NYISO first takes a tap at an ABC PAR increasing flow into New York, and flow on the ABC interface is not at or above the sum of the Target flows for each Available ABC PAR, then PJM may request that NYISO take a tap at an ABC PAR increasing flow into New York. PJM will be "Compliant" at the JK interface if NYISO does not take the requested tap within five minutes of receiving PJM's request. "Compliant" status achieved pursuant to this paragraph shall continue until NYISO takes the requested PAR tap, or the Parties agree that NYISO not taking the requested PAR tap is no longer preventing PJM from taking the PAR tap(s) (if any) PJM needs to achieve compliance at the JK interface.

   If PJM cannot take a required tap at a Waldwick PAR because the change will result in an overload on PJM's system unless NYISO first takes a tap at a Ramapo PAR increasing flow into New York, and flow on the 5018 interface is not at or above the sum of the Target flows for each Available Ramapo

[23] For example, if the sum of the Target flows for Available Waldwick PARs is +200 MW, then PJM will be "Compliant" if flow into PJM on JK was at or above +200 MW during any six second measurement interval over the trailing (rolling) 15 minutes.

PAR, then PJM may request that NYISO take a tap at a Ramapo PAR increasing flow into New York. PJM will be "Compliant" at the JK interface if NYISO does not either (i) take the requested tap within five minutes of receiving PJM's request, or (ii) inform PJM that NYISO is unable to take the requested tap at Ramapo because the change would result in an actual or post-contingency overload on the 5018 lines, or on either of the Ramapo PARs (NYISO will be responsible for demonstrating both the occurrence and duration of the condition). "Compliant" status achieved pursuant to this paragraph shall continue until NYISO takes the requested PAR tap, or the Parties agree that NYISO not taking the requested PAR tap is no longer preventing PJM from taking the PAR tap(s) (if any) PJM needs to achieve compliance at the JK interface.

If PJM cannot take a required tap at a Waldwick PAR because the change would result in an actual or post-contingency overload on either or both of the JK lines, or on any of the Waldwick PARs, and the overload cannot be addressed through NYISO taking taps at ABC or Ramapo, then PJM will be considered "Compliant" at the JK interface until the condition is resolved. PJM will be responsible for demonstrating both the occurrence and duration of the condition.

b. _ABC Storm Watch compliance_: Subject to the exceptions that follow, NYISO will be "Compliant" at the ABC interface when either of the following two conditions are satisfied, otherwise it will be "Non-compliant":

   i. Flow on the ABC interface was at or above the sum of the Target values for each Available ABC PAR at any point in the trailing (rolling) 15-minutes[24]; or

   ii. NYISO took at least two taps on each Available ABC PAR in the direction to increase flow into New York at any point in the trailing (rolling) 15-minutes.

If PJM denies NYISO's request to take one or more taps at an ABC PAR to increase flow into New York and achieve compliance at the ABC interface, then NYISO shall be considered "Compliant" at the ABC interface.

If NYISO cannot take a required tap at an ABC PAR because the change will result in an overload on NYISO's system unless PJM first takes a tap at a Waldwick PAR reducing flow into PJM, and flow on the JK interface is not at or below the sum of the Target values for each Available Waldwick PAR, then NYISO may request that PJM take a tap at a Waldwick PAR reducing flow into PJM. NYISO will be "Compliant" at the ABC interface if PJM does

[24] For example, if the sum of the Target values for each Available ABC PAR is +200 MW, then NYISO will be "Compliant" if flow into New York on ABC was at or above +200 MW during any six second measurement interval over the trailing (rolling) 15 minutes.

not take the requested tap within five minutes of receiving NYISO's request. "Compliant" status achieved pursuant to this paragraph shall continue until PJM takes the requested PAR tap, or the Parties agree that PJM not taking the requested PAR tap is no longer preventing NYISO from taking the PAR tap(s) (if any) NYISO needs to achieve compliance at the ABC interface.

If NYISO cannot take a required tap at an ABC PAR because the change would result in an actual or post-contingency overload on one or more of the ABC lines, or on any of the ABC PARs, and the overload cannot be addressed through NYISO taking taps at Ramapo or PJM taking taps at Waldwick, then NYISO will be considered "Compliant" at the ABC interface until the condition is resolved. NYISO will be responsible for demonstrating both the occurrence and duration of the condition.

c. *5018 Storm Watch compliance*: Subject to the exceptions that follow, NYISO will be "Compliant" at the 5018 interface when either of the following two conditions are satisfied, otherwise it will be "Non-compliant":

   i. Flow on the 5018 interface was at or above the sum of the Target values for each Available Ramapo PAR described in Section 7.2.1 of this Schedule D at any point in the trailing (rolling) 15-minutes; or

   ii. NYISO took at least two taps on each Available Ramapo PAR in the direction to increase flow into New York at any point in the trailing (rolling) 15-minutes.

If PJM denies NYISO's request to take one or more taps at a Ramapo PAR to increase flow into New York and achieve compliance at the 5018 interface, then NYISO shall be considered "Compliant" at the 5018 interface.

If NYISO cannot take a required tap at a Ramapo PAR because it will result in an overload on NYISO's system unless PJM first takes a tap at a Waldwick PAR reducing flow into PJM, and flow on the JK interface is not at or below the sum of the Target values for each Available Waldwick PAR, then NYISO may request that PJM take a tap at a Waldwick PAR reducing flow into PJM. NYISO will be "Compliant" at the 5018 interface if PJM does not take the requested tap within five minutes of receiving NYISO's request. "Compliant" status achieved pursuant to this paragraph shall continue until PJM takes the requested PAR tap, or the Parties agree that PJM not taking the requested PAR tap is no longer preventing NYISO from taking the PAR tap(s) (if any) NYISO needs to achieve compliance at the Ramapo interface.

If NYISO cannot take a required tap at a Ramapo PAR because the change would result in an actual or post-contingency overload on the 5018 line, or on either of the Ramapo PARs, and the overload cannot be addressed through NYISO taking taps at ABC or PJM taking taps at Waldwick, then NYISO will be considered "Compliant" at the 5018 interface until the condition is resolved. NYISO will be responsible for demonstrating both the occurrence and duration of the condition.

When a Storm Watch is in effect in New York, PJM shall only be required to pay a M2MPARSettlement to NYISO when PJM is "Non-compliant" at the JK interface, while NYISO is "Compliant" at both the ABC and 5018 interfaces. Otherwise, PJM shall not be required to pay a M2MPARSettlement to NYISO at times when a Storm Watch is in effect in New York.

When a Storm Watch is in effect in New York, NYISO shall only be required to pay a M2MPARSettlement to PJM when NYISO is "Non-compliant" at the ABC interface or the 5018 interface, or both of those interfaces. When NYISO is "Compliant" at both the ABC and 5018 interfaces, NYISO shall not be required to pay a M2MPARSettlement to PJM at times when a Storm Watch is in effect in New York.

When all three interfaces (JK, ABC, 5018) are "Compliant," or during the first 15-minutes in which a Storm Watch is in effect, this Section 8.3.1 excuses the Parties from paying a M2MPARSettlement to each other at times when a Storm Watch is in effect in New York.

Compliance and Non-compliance shall be determined for each interval of the NYISO settlement cycle (normally, every 5-minutes) that a Storm Watch is in effect.

8.4 Calculating a Combined M2M Settlement

The M2M settlement shall be the sum of the real-time redispatch settlement for each M2M Flowgate and M2MPARSettlement for each interval

$$Redispatch\ NY\ Settlement_i = \left(\sum_{M2M\ Flowgate\ m}^{all\ NY\ M2M\ Flowgates} \left(MonRTO\ Payment_{M2M\ Flowgate\ m_i} - Non\ MonRTO\ Payment_{M2M\ Flowgate\ m_i}\right)\right)$$

$$Redispatch\ PJM\ Settlement = \left(\sum_{M2M\ Flowgate\ m}^{all\ PJM\ M2M\ Flowgates} \left(MonRTO\ Payment_{M2M\ Flowgate\ m_i} - Non\ MonRTO\ Payment_{M2M\ Flowgate\ m_i}\right)\right)$$

Where:

$Redispatch\ NY\ Settlement_i =$ M2M NYISO settlement, defined as a payment from PJM to NYISO when the value is positive, and a payment from the NYISO to PJM when the value is negative for interval *i*;

$Redispatch\ PJM\ Settlement_i =$ M2M PJM settlement, defined as a payment from NYISO to PJM when the value is positive, and a payment from the PJM to NYISO when the value is negative for interval *i*;

$Non\ MonRTO\ Payment_{M2M\ Flowgate\ m_i} =$ Monitoring RTO payment to Non-Monitoring RTO for congestion on M2M Flowgate m for interval *i*; and

$MonRTO\ Payment_{M2M\ Flowgate\ m_i} =$ Non-Monitoring RTO payment to Monitoring RTO for congestion on M2M Flowgate m for interval *i*.

$$M2M\ Settlement_i = Redispatch\ PJM\ Settlement_i - Redispatch\ NY\ Settlement_i + M2MPARSettlement_i$$

Where:

$M2M\ Settlement_i =$ M2M settlement, defined as a payment from the NYISO to PJM when the value is positive, and a payment from PJM to the NYISO when the value is negative for interval *i*;

$Redispatch\ NY\ Settlement_i =$ M2M NYISO settlement, defined as a payment from PJM to NYISO when the value is positive, and a payment from the NYISO to PJM when the value is negative for interval *i*;

$Redispatch\ PJM\ Settlement_i =$ M2M PJM settlement, defined as a payment from NYISO to PJM when the value is positive, and a payment from the PJM to NYISO when the value is negative for interval *i*;

$M2MPARSettlement_i =$ M2M PAR Settlement across all NY-NJ PARs, defined as a payment from NYISO to PJM when the value is positive, and a payment from PJM to NYISO when the value is negative for interval *i*.

For the purpose of settlements calculations, each interval will be calculated separately and then integrated to an hourly value:

$$M2M\_Settlement_h = \sum_{i=1}^{n} M2M\_Settlement_i$$

Where:

$M2M\_Settlement_h =$ M2M settlement for hour *h*; and

n = Number of intervals in hour *h*.

Section 10.1 of this Schedule D sets forth circumstances under which the M2M coordination process and M2M settlements may be temporarily suspended.

9 <u>When One of the RTOs Does Not Have Sufficient Redispatch</u>

Under the normal M2M coordination process, sufficient redispatch for a M2M Flowgate may be available in one RTO but not the other. When this condition occurs, in order to ensure an operationally efficient dispatch solution is achieved, the RTO without sufficient redispatch will redispatch all effective generation to control the M2M Flowgate to a “relaxed” Shadow Price limit. Then this RTO calculates the Shadow Price for the M2M Flowgate using the available redispatch which is limited by the maximum physical control action inside the RTO. Because the magnitude of the Shadow Price in this RTO cannot reach that of the other RTO with sufficient redispatch, unless further action is taken, there will be a divergence in Shadow Prices and the LMPs at the RTO border.

Subject to Section 10.1.2 of this Schedule D, a special process is designed to enhance the price convergence under this condition. If the Non-Monitoring RTO cannot provide sufficient relief to reach the Shadow Price of the Monitoring RTO, the constraint relaxation logic will be deactivated. The Non-Monitoring RTO will then be able to use the Monitoring RTO’s Shadow Price without limiting the Shadow Price to the maximum Shadow Price associated with a physical control action inside the Non-Monitoring RTO. With the M2M Flowgate Shadow Prices being the same in both RTOs, their resulting bus LMPs will converge in a consistent price profile.

10 <u>Appropriate Use of the M2M Coordination Process</u>

Under normal operating conditions, the Parties will model all M2M Flowgates in their respective real-time EMSs. M2M Flowgates will be controlled using M2M tools for coordinated redispatch and coordinated operation of the NY-NJ PARs, and will be eligible for M2M settlements.

10.1 <u>Qualifying Conditions for M2M Settlement</u>

10.1.1 **Purpose of M2M**. M2M was established to address regional, not local issues. The intent is to implement the M2M coordination process and settle on such coordination where both Parties have significant impact.

10.1.2 Minimizing Less than Optimal Dispatch. The Parties agree that, as a general matter, they should minimize financial harm to one RTO that results from the M2M coordination process initiated by the other RTO that produces less than optimal dispatch.

10.1.3 Use M2M Whenever Binding a M2M Flowgate. During normal operating conditions, the M2M redispatch process will be initiated by the Monitoring RTO whenever an M2M Flowgate that is eligible for redispatch is constrained and therefore binding in its dispatch. Coordinated operation of the NY-NJ PARs is the default condition and does not require initiation by either Party to occur.

10.1.4 Most Limiting Flowgate. Generally, controlling to the most limiting Flowgate provides the preferable operational and financial outcome. In principle and as much as practicable, the M2M coordination process will take place on the most limiting Flowgate, and to that Flowgate's actual limit (thermal, reactive, stability).

10.1.5 Abnormal Operating Conditions.

a. A Party that is experiencing system conditions that require the system operators' immediate attention may temporarily delay implementation of the M2M redispatch process or cease an active M2M redispatch event until a reasonable time after the system condition that required the system operators' immediate attention is resolved.

b. Either Party may temporarily suspend an active M2M coordination process or delay implementation of the M2M coordination process if a Party is experiencing, or acting in good faith suspects it may be experiencing, (1) a failure or outage of the data link between the Parties prevents the exchange of accurate or timely real-time data necessary to implement the M2M coordination process; or (2) a failure or outage of any computational or data systems preventing the actual or accurate calculation of data necessary to implement the M2M coordination process. The Parties shall resolve the issue causing the failure or outage of the data link, computational systems, or data systems as soon as possible in accordance with Good Utility Practice. The Parties shall resume implementation of the M2M coordination process following the successful testing of the data link or relevant system(s) after the failure or outage condition is resolved.

10.1.6 Transient System Conditions. A Party that is experiencing intermittent congestion due to transient system conditions including, but not limited to, interchange ramping or transmission switching, is not required to implement the M2M redispatch process unless the congestion continues after the transient condition(s) have concluded.

10.1.7 Temporary Cessation of M2M Coordination Process Pending Review. If the net charges to a Party resulting from implementation of the M2M coordination process for a market-day exceed five hundred thousand dollars, then the Party that is responsible for paying the charges may (but is not required to) suspend implementation of this M2M coordination process (for a particular M2M Flowgate, or of the entire M2M coordination process) until the Parties are able to complete a review to ensure that both the process and the calculation of settlements resulting from the M2M coordination process are occurring in a manner that is both (a) consistent with this M2M Coordination Schedule, and (b) producing a just and reasonable result. The Party requesting suspension must identify specific concerns that require investigation within one business day of requesting suspension of the M2M coordination process. If, following their investigation, the Parties mutually agree that the M2M coordination process is (i) being implemented in a manner that is consistent with this M2M Coordination Schedule and (ii) producing a just and reasonable result, then the M2M coordination process shall be re-initiated as quickly as practicable. If the Parties are unable to mutually agree that the M2M coordination process was being implemented appropriately, or of the Parties are unable to mutually agree that the M2M coordination process was producing a just and reasonable result, the suspension (for a particular M2M Flowgate, or of the entire M2M coordination process) shall continue while the Parties engage in dispute resolution in accordance with Section 35.15 of this Agreement.

10.1.8 Suspension of M2M Settlement when a Request for Taps on NY-NJ PARs to Prevent Overuse is Refused. If a Party requests that taps be taken on any NY-NJ PAR to reduce the requesting Party's overuse of the other Party's transmission system, refusal by the other Party or its Transmission Owner(s) to permit taps to be taken to reduce overuse shall result in the NY-NJ PAR settlement component of M2M (*see* Section 8.3 above) being suspended until the tap request is granted.

10.1.9 Suspension of NY-NJ PAR Settlement due to Transmission Facility Outage(s). The Parties shall suspend PAR settlements for a NY-NJ PAR when that NY-NJ PAR is out of service, is bypassed, or the RTOs mutually agree that a NY-NJ PAR is incapable of facilitating interchange.

No other Transmission Facility outage(s) will trigger suspension ofNY-NJ PAR settlements under this Section 10.1.9.

10.2 <u>After-the-Fact Review to Determine M2M Settlement</u>

Based on the communication and data exchange that has occurred in real-time between the Parties, there will be an opportunity to review the use of the M2M coordination process to verify it was an appropriate use of the M2M coordination process and subject to M2M settlement. The Parties will initiate the review as necessary to apply these conditions and settlements adjustments. The Parties will cooperate to review the data exchanged and used to determine M2M settlements and will mutually identify and resolve errors and anomalies in the calculations that determine the M2M settlements.

If the data exchanged for the M2M redispatch process was relied on by the Non-Monitoring RTO's dispatch to determine the shadow cost the Non-Monitoring RTO was dispatching to when providing relief at an M2M Flowgate, the data transmitted by the Monitoring RTO that was used to determine the Non-Monitoring RTO's shadow cost shall not be modified except by mutual agreement prior to calculating M2M settlements. Any necessary corrections to the data exchange shall be made for future M2M coordination.

10.3 Access to Data to Verify Market Flow Calculations

Each Party shall provide the other Party with data to enable the other Party independently to verify the results of the calculations that determine the M2M settlements under this M2M Coordination Schedule. A Party supplying data shall retain that data for two years from the date of the settlement invoice to which the data relates, unless there is a legal or regulatory requirement for a longer retention period. The method of exchange and the type of information to be exchanged pursuant to Section 35.7.1 of this Agreement shall be specified in writing. The Parties will cooperate to review the data and mutually identify or resolve errors and anomalies in the calculations that determine the M2M settlements. If one Party determines that it is required to self report a potential violation to the Commission's Office of Enforcement regarding its compliance with this M2M Coordination Schedule, the reporting Party shall inform, and provide a copy of the self report to, the other Party. Any such report provided by one Party to the other shall be Confidential Information.

11 M2M Change Management Process

11.1 Notice

Prior to changing any process that implements this M2M Schedule, the Party desiring the change shall notify the other Party in writing or via email of the proposed change. The notice shall include a complete and detailed description of the proposed change, the reason for the proposed change, and the impacts the proposed change is expected to have on the implementation of the M2M coordination process, including M2M settlements under this M2M Schedule.

11.2 Opportunity to Request Additional Information

Following receipt of the Notice described in Section 11.1, the receiving Party may make reasonable requests for additional information/documentation from the other Party. Absent mutual agreement of the Parties, the submission of a request for additional information under this Section shall not delay the obligation to timely note any objection pursuant to Section 11.3, below.

11.3 Objection to Change

Within ten business days after receipt of the Notice described in Section 11.1 (or within such longer period of time as the Parties mutually agree), the receiving Party may notify in writing or via email the other Party of its disagreement with the proposed change. Any such notice must specifically identify and describe the concern(s) that required the receiving Party to object to the described change.

11.4 Implementation of Change

The Party proposing a change to its implementation of the M2M coordination process shall not implement such change until (a) it receives written or email notification from the other Party that the other Party concurs with the change, or (b) the ten business day notice period specified in Section 11.3 expires, or (c) completion of any dispute resolution process initiated pursuant to this Agreement.

36 Attachment DD - Rules to Allocate the Cost of NY Transco LLC Transmission Facilities and Formula Rates

36.1 Overview

36.1.1 Cost Allocation

The purpose of Section 36.2 is to provide for the allocation of costs to be recovered through the Transco Facilities Charge ("TFC") described in Section 6.13 of Schedule 13 of the ISO OATT for the following New York Transco, LLC ("NY Transco") projects, each of which has been approved by the New York Public Service Commission on November 4, 2013, in Case No. 12-E-0503 (the "Transmission Owner Transmission Solutions" or "TOTS" projects): (1) the Second Ramapo-to-Rock Tavern 345-kV Line Project; (2) the Marcy South Series Compensation and Fraser-to-Coopers Corners Reconductoring Project; and (3) the Staten Island Unbottling Project.[1]

36.1.2 Formula Rates

Section 36.3 provides NY Transco's formula rate and implementation rules for the formula rate to recover costs related to its projects through the TFC.

[1] Any costs incurred on the forced cooling portion of the Staten Island Unbottling Project after the date of the Commission's order approving the offer of partial settlement in Docket No. ER15-572-000, issued on March 17, 2016, shall not be recovered through the TFC without further order of the Commission.

36.2 Attachment 1 to Attachment DD

36.2.1 Allocation Tables

36.2.1.1 TOTS Projects

COST ALLOCATION TABLE

Transmission District	Allocation of Project Costs (%)
Consolidated Edison Co. of NY, Inc. Orange and Rockland Utilities, Inc.	63.18
Long Island Power Authority	8.55
Niagara Mohawk Power Corp.	12.16
New York Gas & Electric Corp. Rochester Gas and Electric Corp.	10.12
Central Hudson Gas & Electric Corp.	5.99
New York Power Authority	Load is treated the same as all other load serving entities ("LSE") and NYPA as an LSE will pay the same rate as the LSEs in each transmission district.

36.3 Attachment 2 to Attachment DD

36.3.1 Formula Rates

36.3.1.1 Rate Formula Template

Index

Rate Formula Template
Utilizing FERC Form 1 Data

Projected Annual Transmission Revenue Requirement
For the 12 months ended 12/31/

New York Transco LLC

Appendix A	Main body of the Formula Rate
Attachment 1	Detail of the Revenue Credits
Attachment 2	Monthly Plant and Accumulated Depreciation balances
Attachment 3	Cost Support Detail
Attachment 4	Calculations showing the revenue requirement by Investment, including any Incentives,
Attachment 5	Cost of Debt should Construction Financing be Obtained
Attachment 6a and 6b	Detail of the Accumulated Deferred Income Tax Balances
Attachment 7 and 7a	True-Up calculations
Attachment 8	True-Up for the Construction Financing calculations in Attachment 5
Attachment 9	Depreciation Rates
Attachment 10	W orkpapers

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

New York Transco LLC

Projected Annual Transmission Revenue Requirement
For the 12 months ended 12/31/

Line No.			(1)		(2)	(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 74)			12 months	$ -
	REVENUE CREDITS		Total		Allocator	
2	Total Revenue Credits	Attachment 1, line 6	-	TP	1.0000	-
3	Net Revenue Requirement	(line 1 minus line 2)				-
4	True-up Adjustment	Attachment 7	-	DA	1.00000	-
5	NET ADJUSTED REVENUE REQUIREMENT	(line 3 plus line 4)				$ -

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/

New York Transco LLC

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE (Note M)					
6	Production	(Attach 2, line 75)	-	NA	-	-
7	Transmission	(Attach 2, line 15)	-	TP	1.0000	-
8	Distribution	(Attach 2, line 30)	-	NA	-	-
9	General & Intangible	(Attach 2, lines 45 & 60)	-	W/S	-	-
10	TOTAL GROSS PLANT (sum lines 6-9)	(GP=1 if plant =0)	-	GP=	-	-
11	ACCUMULATED DEPRECIATION & AMORTIZATION (Note M)					
12	Production	(Attach 2, line 151)	-	NA	-	-
13	Transmission	(Attach 2, line 91)	-	TP	1.0000	-
14	Distribution	(Attach 2, line 106)	-	NA	-	-
15	General & Intangible	(Attach 2, lines 121 & 136	-	W/S	-	-
16	TOTAL ACCUM. DEPRECIATION (sum lines 12-15)		-			-
17	NET PLANT IN SERVICE					
18	Production	(line 6- line 12)	-			-
19	Transmission	(line 7- line 13)	-			-
20	Distribution	(line 8- line 14)	-			-
21	General & Intangible	(line 9- line 15)	-			-
22	TOTAL NET PLANT (sum lines 18-21)	(NP=1 if plant =0)	-	NP=	-	-
23	ADJUSTMENTS TO RATE BASE (Note A)					
24	ADIT	(Attach 6a, line 9)	-	TP	1.0000	-
25	Account No. 255 (enter negative) (Note F)	(Attach 3, line 153)	-	NP	-	-
26	CWIP	(Attach 10)	-	DA		-
27	Unfunded Reserves (enter negative)	(Attach 3, line 170a)	-	DA	1.0000	-
28	Unamortized Regulatory Assets	(Attach 10) (Note L)	-	DA	1.0000	-
29	Unamortized Abandoned Plant	(Attach 10) (Note K)	-	DA	1.0000	-
30	TOTAL ADJUSTMENTS (sum lines 24-29)		-			-
31	LAND HELD FOR FUTURE USE	Attachment 10	-	TP	1.0000	-

32	W ORKING CAPITAL (Note C)					
33	CW C	calculated (1/8 * Line 45)	-			-
34	Materials & Supplies (Note B)	(Attach 3, line 189)	-	TP	1.0000	-
35	Prepayments (Account 165 - Note C)	(Attach 3, line 170)	-	GP	-	-
36	TOTAL WORKING CAPITAL (sum lines 33-35)		-			-
37	RATE BASE (sum lines 22, 30, 31, & 36)		-			-

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

New York Transco LLC

For the 12 months ended 12/31/

	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
38	O&M					
39	Transmission	321.112.b	-	TP=	1.0000	-
40	Less Accounts 565, 561 and 561.1 to 561.8	321.96.b & 84.b to 92.b	-	TP=	1.0000	-
41	A&G	323.197.b	-	W/S	-	-
42	Less EPRI & Reg. Comm. Exp. & Other Ad.	(Note D & Attach 3, line 171)	-	DA	-	-
43	Plus Transmission Related Reg. Comm. Exp.	(Note D & Attach 3, line 172)	-	TP=	1.0000	-
44	PBOP expense adjustment	(Attach 3, line 243)	-	TP=	1.0000	-
44a	~~Less Account 566~~	~~321.97.b~~	-	~~DA~~	-	-
44b	Amortization of Regulatory Assets	(Attach 10, line 2)	-	DA	-	-
44c	Account 566 excluding amort. of Reg Assets	(line 44a less line 44b)	-	DA	-	-
45	TOTAL O&M (sum lines 39, 41, 43, 44, 44b, 44c	less lines 40 & 42, 44a) (Note D)	-			-
46	DEPRECIATION EXPENSE					
47	Transmission	336.7.f (Note M)	-	TP	1.0000	-
48	General and Intangible	336.1.f + 336.10.f (Note M)	-	W/S	- -	
49	Amortization of Abandoned Plant	(Attach 3, line 155) (Note K)	-	DA	1.0000	-
50	TOTAL DEPRECIATION (Sum lines 47-49)		-			-
51	TAXES OTHER THAN INCOME TAXES (Note E)					
52	LABOR RELATED					
53	Payroll	263._.i (enter FN1 line #)	-	W/S	-	-
54	Highway and vehicle	263._.i (enter FN1 line #)	-	W/S	-	-
55	PLANT RELATED					
56	Property	263._.i (enter FN1 line #)	-	GP	-	-
57	Gross Receipts	263._.i (enter FN1 line #)	-	NA	-	-
58	Other	263._.i (enter FN1 line #)	-	GP	-	-
59	TOTAL OTHER TAXES (sum lines 53-58)		-			-
60	INCOME TAXES	(Note F)				
61	~~T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)}} *(1-n) =~~		-			
62	CIT=(T/1-T) * (1-(W CLTD/R)) =		-			
63	where W CLTD=(line 91) and R= (line 94)					
64	and FIT, SIT, p, & n are as given in footnote F.					
65	1 / (1 - T) = (T from line 61)		-			
66	Amortized Investment Tax Credit (Atttachment 4, line 14)		-			
67	Income Tax Calculation = line 62 * line 71 * (1-n)		-			-
68	ITC adjustment (line 65 * line 66 * (1- n))		-	NP	-	-
69	Total Income Taxes	(line 67 plus line 68)	-			-
70	RETURN					
71	[Rate Base (line 37) * Rate of Return (line 94)]		-	NA		-
72	Rev Requirement before Incentive Projects (sum lines 45, 50, 59, 69, 71)		-			-
73	Incentive Return and Income Tax on Authorized Projects (Attach 4, line 67, col h & j)		-	DA	100%	-
74	Total Revenue Requirement (sum lines 72 & 73)		-			-

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/

New York Transco LLC SUPPORTING CALCULATIONS AND NOTES

75	TRANSMISSION PLANT INCLUDED IN RTO RATES			
76	Total transmission plant (line 7, column 3)			-
77	Less transmission plant excluded from RTO rates	(Note H)	(Attachment 3, line 175)	-

78	Less transmission plant included in OATT Ancillary Services (Note H)	(Attachment 3, line 175)				-
79	Transmission plant included in RTO rates (line 76 less lines 77 & 78)					-
80	Percentage of transmission plant included in RTO Rates (line 79 divided by line 76) [If line 76 equal zero, enter 1)				TP=	1.0000

81	W AGES & SALARY ALLOCATOR (W &S) (Note I)									
82		Form 1 Reference	$	TP	Allocation					
83	Production	354.20.b	-	0.00	-					
84	Transmission	354.21.b	-	1.00	-					
85	Distribution	354.23.b	-	0.00	-		W &S Allocator			
86	Other	354.24,25,26.b	-	0.00	-		($ / Allocation)			
87	Total (sum lines 83-86) [TP equals 1 if there are no wages & salaries]		-		-	=	-	=	WS	

88	RETURN (R) (Note J)						
89							
90			$	%	Cost	Weighted	
91	Long Term Debt	(Attach 3, lines 249 & 270 or Attach 5) (Note G)	-	-	-	-	=W CLTD
92	Preferred Stock	(Attachment 3, lines 251 & 273)	-	-	-	-	
93	Common Stock	(Attachment 3, line 257)	-	-	9.50%	-	
94	Total (sum lines 91-93)		-			-	=R

Development of Base Carrying charge and Summary of Incentive and Non-Incentive Investments

			(a)		(b)		(c)
		Source of Total Column	Non-incentive Investments from Attachment 4 (Note N)	Row Numbers	Incentive Investments from Attachment 4 (Note N)	Row Numbers	Total
95	Net Transmission Plant in Service	(Attachment 4, lines 66, 66a…, column b)	-	-	-	-	-
96	CW IP in Rate Base	(Line 26)	-		-		-
97	Unamortized Abandoned Plant	(Line 29)	-				-
98	Regulatory Assets	(Line 28)	-				-
99	Development of Base Carrying charge and Summary of Incentive and Non-Incentive Investments (Sum of lines 95 to 98)		-				-
100	Return and Taxes	(Sum lines 69 & 71)					-
101	Total Revenue Credits	(Line 2)					-
102	Base Carrying Charge (used in Attach 4, Line 65)	(Line 100 - Line 101)/ Line 99					-

SUPPORTING CALCULATIONS AND NOTES

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/

New York Transco LLC

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note
Letter

A The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. The formula uses the stated average of the beginning and end of year balances to prorate ADIT to comply with IRS normalization rules. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated.

B Identified in Form 1 as being only transmission related.

C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 line 57 in the Form 1. D Line 42 removes EPRI Annual Membership Dues listed in Form 1 at 353._.f (enter FN1 line #),
any EPRI Lobbying expenses included in line 42 of the template and all Regulatory Commission Expenses itemized at 351.h
Line 42 removes all advertising included in Account 930.1, except safety, education or out-reach related advertising
Line 42 removes all EEI and EPRI research, development and demonstration expenses and NY Transco will not participate in EEI or EPRI.
Line 43 reflects all Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized at 351.h
Line 38 or Line 41 and thus Line 45 shall include any NYISO charges other than penalties, including but not limited to administrative costs. E Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.
Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

F The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base.
multiplied by (1/1-T) .

Inputs Required:			
	FIT =	-	
	SIT=	-	(State Income Tax Rate or Composite SIT from Attach 3)
	p =	-	(percent of federal income tax deductible for state purposes)
	n=	-	(not for profit entity ownership percentage)

For each Rate Year (including both Annual Projections and True-Up Adjustments) the statutory income tax rates utilized in the Formula Rate shall reflect the weighted average rates actually in effect during the Rate Year. For example, if the statutory tax rate is 10% from January 1 through June 30, and 5% from July 1 through December 31, such rates would be weighted 181/365 and 184/365, respectively, for a non-leap year.

G The cost of debt is determined using the internal rate of return methodology shown on Attachment 5 once project financing is obtained. Prior to obtaining project financing, an interest rate of 3.85% from Table 4 of Attachment 5 will be used and will not be trued up. Attachment 5 contains an estimate of the internal rate of return methodology; the methodology will be applied to actual amounts for use in Appendix A.
After the completion of construction, the cost of debt will be calculated pursuant to Attachment 3

H Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

I Enter dollar amounts

J ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC under FPA Section 205 or 206.
The capital structure will be the actual capital structure up to 53% equity. Lines 93 will be capped at 53% equity. If the actual equity ratio exceeds 53% , the common stock ratio will be reset to 53% and the debt ratio will be equal to 1 minus sum of the preferred stock ratio and common stock ratio.

K Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Company must submit a Section 205 filing to recover the cost of abandoned plant. Any such filing to recover the cost of an abandoned plant item shall be made no later than 180 days after the date that Company formally declares such plant item abandoned.

L Unamortized Regulatory Assets, consisting of all expenses incurred but not included in CWIP prior to the date the rate is charged to customers, is included at line 28
Carrying costs equal to the weighted cost of capital on the balance of the regulatory asset will accrue until the rate is charged to customers

M Balances exclude Asset Retirement Costs

N Non-incentive investments are investments without ROE incentives and incentive investments are investments with ROE incentives

Attachment 1 - Revenue Credit Workpaper*
New York Transco LLC

	Account 454 - Rent from Electric Property (300.19.b)	Notes 1 & 3	
1	Rent from FERC Form No. 1		-
	Account 456 (including 456.1) (300.21.b and 300.22.b)	Notes 1 & 3	
2	Other Electric Revenues (Note 2)		-
3	Professional Services		-
4	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
5	Rent or Attachment Fees associated with Transmission Facilities		-
6	Total Revenue Credits	Sum lines 2-5 + line 1	-

Note 1 All revenues booked to Account 454 that are derived from cost items classified as transmission-related will be included as a revenue credit. All revenues booked to Account 456 (includes 456.1) that are derived from cost items classified as transmission-related, and are not derived from rates under this transmission formula rate will be included as a revenue credit. Work papers will be included to properly classify revenues booked to these accounts to the transmission function. A breakdown of all Account 454 revenues by subaccount will be provided below, and will be used to derive the proper calculation of revenue credits. A breakdown of all Account 456 revenues by subaccount and customer will be provided and tabulated below, and will be used to develop the proper calculation of revenue credits.

Note 2 If the facilities associated with the revenues are not included in the formula, the revenue is shown below, but not included in the total above and explained in the Attachment 3.

Note 3 All Account 454 and 456 Revenues must be itemized below

Line No.		TOTAL	NY-ISO	Other 1	Other 2
1	Account 456				
1a	Transmission Service	-	-	-	-
…		-	-	-	-
1x					
2	Trans. Fac. Charge	-	-	-	-
	Trans Studies	-	-	-	-
3	Total	-	-	-	-
4	Less:				
5	Revenue for Demands in Divisor	-	-	-	-
6	**Sub Total Revenue Credit**	-	-	-	-
7	Prior Period Adjustments	-	-	-	-
8	Total	-	-	-	-
9	Account 454	$			
9a	Joint pole attachments - telephone	-			
9b	Joint pole attachments - cable	-			
9c	Underground rentals	-			
9d	Transmission tower wireless rentals	-			
9e	Misc non-transmission rentals	-			
9f		-			
9g		-			
…					
9x		-			
10	Total	-			

Attachment 2 - Cost Support

New York Transco LLC

Plant in Service Worksheet

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Calculation of Transmission Plant In Service

December

January

February

Mar

ch

April

May

June

July

August

September

O

ctober

November

December

Transmission Plant In Service

Calculation of Distribution Plant In Service

Decembe

r J a n u a r y F e b r u a r y M a r c h A p r i l M a y J u n e J u

	Source (Less ARO, see Note M)	Year	Balance
ly			
August			
September	p206.58.b	2016	-
October	company records	2016	-
November	company records	2016	-
December	company records	2016	-
Distribution Plant In Service	company records	2016	-
	company records	2016	-
	company records	2015	-
Calculation of Intangible Plant In Service	company records	2016	-
	company records	2016	-
	company records	2016	-
	company records	2016	-
	company records	2016	-
	p207.58.g	2016	-
	(sum lines 2-14) /13		-

Source (Less ARO, see Note M)	Year	Balance
p206.75.b	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
company records	2016	-
p207.75.g	2016	-
(sum lines 17-29) /13		-

Source (Less ARO, see Note M)	Enter Amount of Transmission CIACs	Docket Nos. for Transmission CIACs

32	December	p204.5.b	2016	-	-
33	January	company records	2016	-	-
34	February	company records	2016	-	-
35	March	company records	2016	-	-
36	April	company records	2016	-	-
37	May	company records	2016	-	-
38	June	company records	2016	-	-
39	July	company records	2016	-	-
40	August	company records	2016	-	-
41	September	company records	2016	-	-
42	October	company records	2016	-	-
43	November	company records	2016	-	-
44	December	p205.5.g	2016	-	-
45	**Intangible Plant In Service**	(sum lines 32-44) /13		-	-
46	**Calculation of General Plant In Service**	Source (Less ARO, see Note M)			
47	December	p206.99.b	2016	-	
48	January	company records	2016	-	
49	February	company records	2016	-	
50	March	company records	2016	-	
51	April	company records	2016	-	
52	May	company records	2016	-	
53	June	company records	2016	-	
54	July	company records	2016	-	
55	August	company records	2016	-	
56	September	company records	2016	-	
57	October	company records	2016	-	
58	November	company records	2016	-	
59	December	p207.99.g	2016	-	
60	**General Plant In Service**	(sum lines 47-59) /13		-	
61	**Calculation of Production Plant In Service**	Source (Less ARO, see Note M)			
62	December	p204.46b	2016	-	
63	January	company records	2016	-	
64	February	company records	2016	-	
65	March	company records	2016	-	
66	April	company records	2016	-	

67	May	company records	2016	-
68	June	company records	2016	-
69	July	company records	2016	-

70	August	company records	2016	-
71	September	company records	2016	-
72	October	company records	2016	-
73	November	company records	2016	-
74	December	p205.46.g	2016	-
75	**Production Plant In Service**	(sum lines 62-74) /13		-
76	**Total Plant In Service**	(sum lines 15, 30, 45, 60, & 75)		-

Accumulated Depreciation Worksheet

77	**Calculation of Transmission Accumulated Depreciation**	Source (Less ARO, see Note M)	Year	Balance
78	December	Prior year p219.25.b	2016	-
79	January	company records	2016	-
80	February	company records	2016	-
81	March	company records	2016	-
82	April	company records	2016	-
83	May	company records	2016	-
84	June	company records	2016	-
85	July	company records	2016	-
86	August	company records	2016	-
87	September	company records	2016	-
88	October	company records	2016	-
89	November	company records	2016	-
90	December	p219.25.b	2016	-
91	**Transmission Accumulated Depreciation**	(sum lines 78-90) /13		-
92	**Calculation of Distribution Accumulated Depreciation**	Source (Less ARO, see Note M)		
93	December	Prior year p219.26.b	2016	-
94	January	company records	2016	-
95	February	company records	2016	-
96	March	company records	2016	-
97	April	company records	2016	-
98	May	company records	2016	-
99	June	company records	2016	-

100	July	company records	2016	-
101	August	company records	2016	-
102	September	company records	2016	-

103	October	company records	2016	-	
104	November	company records	2016	-	
105	December	p219.26.b	2016	-	
106	**Distribution Accumulated Depreciation**	(sum lines 93-105) /13		-	
					Amount of
107	**Calculation of Intangible Accumulated Amortization**	Source (Less ARO, see Note M)			Transmission CIACs
108	December	Prior year p200.21.c	2016	-	-
109	January	company records	2016	-	-
110	February	company records	2016	-	-
111	March	company records	2016	-	-
112	April	company records	2016	-	-
113	May	company records	2016	-	-
114	June	company records	2016	-	-
115	July	company records	2016	-	-
116	August	company records	2016	-	-
117	September	company records	2016	-	-
118	October	company records	2016	-	-
119	November	company records	2016	-	-
120	December	p200.21.c	2016	-	-
121	**Accumulated Intangible Amortization**	(sum lines 108-120) /13		-	-
122	**Calculation of General Accumulated Depreciation**	Source (Less ARO, see Note M)			
123	December	Prior year p219.28.b	2016	-	
124	January	company records	2016	-	
125	February	company records	2016	-	
126	March	company records	2016	-	
127	April	company records	2016	-	
128	May	company records	2016	-	
129	June	company records	2016	-	
130	July	company records	2016	-	
131	August	company records	2016	-	
132	September	company records	2016	-	
133	October	company records	2016	-	
134	November	company records	2016	-	
135	December	p219.28.b	2016	-	
136	**Accumulated General Depreciation**	(sum lines 123-135) /13		-	

137	**Calculation of Production Accumulated Depreciation**	Source (Less ARO, see Note M)		
138	December	p219.20:24.b (prior year)	2016	-
139	January	company records	2016	-

140	February	company records	2016	-
141	March	company records	2016	-
142	April	company records	2016	-
143	May	company records	2016	-
144	June	company records	2016	-
145	July	company records	2016	-
146	August	company records	2016	-
147	~~September~~	~~company records~~	~~2016~~	-
148	October	company records	2016	-
149	November	company records	2016	-
150	December	p219.20 thru 219.24.b	2016	-
151	**Production Accumulated Depreciation**	(sum lines 138-150) /13		-
152	**Total Accumulated Depreciation and Amortization**	(sum lines 91, 106, 121, 136, & 151)		-

Attachment 3 - Cost Support
New York Transco LLC

Details

Numbering continues from Attachment 2			Beginning of Year	End of Year	Average Balance	Amortization Expense
153	Account No. 255 (enter negative from FERC Form No. 1)	266.8 and 267.8	-	-	-	
154	Unamortized Abandoned Plant	Attachment 10, line 4, col. (y)			-	
	(recovery of abandoned plant requires a FERC order approving the amount and recovery period)					
155	Amortization of Abandoned Plant	Attachment 10, line 4, col. (h)				-

			Year	Balance
156	Prepayments (Account 165)			
	(Prepayments exclude Prepaid Pension Assets)			
157	December	111.57.d	-	-
158	January	company records	-	-
159	February	company records	-	-
160	March	company records	-	-
161	April	company records	-	-
162	May	company records	-	-
163	June	company records	-	-
164	July	company records	-	-
165	August	company records	-	-
166	September	company records	-	-
167	October	company records	-	-
168	November	company records	-	-
169	December	111.57.c	-	-
			-	-
170	**Prepayments**	(sum lines 157-169) /13		-

Reserves

170a	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Amount	Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account	Enter 1 if the accrual account is included in the formula rate, enter (0) if O if the accrual account is NOT included in the formula rate	Enter the percentage paid for by customers, 1 less the percent associated with an offsetting liability on the balance sheet	Allocation (Plant or Labor Allocator)	Amount Allocated, col. c x col. d x col. e x col. f x col. g
	Reserve 1	-	-	-	-	-	-
	Reserve 2	-	-	-	-	-	-
	Reserve 3	-	-	-	-	-	-
	Reserve 4	-	-	-	-	-	-
	…	-	--	-		--	
	…	-	-	-	-	-	-
	Total						-

All unfunded reserves will be listed above, specifically including (but not limited to) all subaccounts for FERC Account Nos. 228.1 through 228.4. "Unfunded reserve" is defined as an accrued balance (1) created and increased by debiting an expense which is included in this formula rate (column (e), using the same allocator in column (g) as used in the formula to allocate the amounts in the corresponding expense account) (2) in advance of an anticipated expenditure related to that expense (3) that is not deposited in a restricted account (e.g., set aside in an escrow account, see column (d)) with the earnings thereon retained within that account. Where a given reserve is only partially funded through accruals collected from customers, only the balance funded by customer collections shall serve as a rate base credit, see column (f). The source of monthly balance data is company records.

EPRI Dues Cost Support

Allocated General & Common Expenses

171	EPRI and EEI Dues to be excluded from the formula rate	EPRI Dues p353._.f (enter FN1 line #)	-

Regulatory Expense Related to Transmission Cost Support

Directly Assigned A&G

			Form 1 Amount	Transmission Related	Other	Details*
172	Regulatory Commission Exp Account 928	p323.189.b	-	-	-	

* insert case specific detail and associated assignments here

Multi-state Workpaper

Income Tax Rates
Weighting

New York

1

State 2

State 3

State 4

State 5

Weighed Average

173 SIT=State Income Tax Rate or Composite 0.0710 0.07

Multiple state rates are weighted based on the state apportionment factors on the state income tax returns and the number of days in the year that the rates are effective (see Note F)

Safety Related and Education and Out Reach Cost Support

			Form 1 Amount	Safety Related, Education, Siting & Outreach Related	Other	Details
	Directly Assigned A&G					
174	General Advertising Exp Account 930.1	company records			-	

Safety advertising consists of any advertising whose primary purpose is to educate the recipient as to what is safe or is not safe.
Education advertising consists of any advertising whose primary purpose is to educate the recipient as about transmission related facts or issues
Outreach advertising consists of advertising whose primary purpose is to attract the attention of the recipient about a transmission related issue Siting advertising consists of advertising whose primary purpose is to inform the recipient about locating transmission facilities
Lobbying expenses are not allowed to be included in account 930.1

Excluded Plant Cost Support

		Excluded Transmission Facilities	Transmission plant included in OATT Ancillary Services and not otherwise excluded	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
175	Excluded Transmission Facilities	-	-	**General Description of the Facilities**

A worksheet will be provided if there are ever any excluded transmission plant or transmission plant in OATT Ancillary Services

Add more lines if necessary

Materials & Supplies

	Note: for the projection, the prior year's actual balances will be used Form No.1 page		Stores Expense Undistributed p227.16	Transmission Materials & Supplies p227.8	Construction Materials & Supplies p227.5	Total
176	December	Column b	-	-	-	-
177	January	Company Records	-	-	-	-
178	February	Company Records	-	-	-	-
179	March	Company Records	-	-	-	-
180	April	Company Records	-	-	-	-
181	May	Company Records	-	-	-	-

182 June Company Records - - - -

183	July	Company Records	-	-	-	-
184	August	Company Records	-	-	-	-
185	September	Company Records	-	-	-	-
186	October	Company Records	-	-	-	-
187	November	Company Records	-	-	-	-
188	December	Column c	-	-	-	-
189	Average					-

PBOPs

Details

190	**ConEd**			
191	Total PBOP expenses		$	(8,800,000)
192	Labor dollars		$	1,444,841,000
193	Cost per labor dollar		$	(0.0061)
194	labor (labor not capitalized) current year	Company Records		-
195	PBOP Expense for current year			-
196	PBOP Expense in Account 926 for current year	Company Records		-
197	PBOP Adjustment for Appendix A, Line 44			-
198	Lines 191-193 cannot change absent approval or acceptance by FERC in a separate proceeding.			
198	**NiMo**			
199	Total PBOP expenses		$	70,883,643
200	Labor dollars		$	313,713,746
201	Cost per labor dollar		$	0.2260
202	labor (labor not capitalized) current year	Company Records		-
203	PBOP Expense for current year			-
204	PBOP Expense in Account 926 for current year	Company Records		-
205	PBOP Adjustment for Appendix A, Line 44			-
206	Lines 199-201 cannot change absent approval or acceptance by FERC in a separate proceeding.			
207	**NYSEG**			
208	Total PBOP expenses		$	2,057,829
209	Labor dollars		$	187,586,000
210	Cost per labor dollar		$	0.0110
211	labor (labor not capitalized) current year	Company Records		-
212	PBOP Expense for current year			-
213	PBOP Expense in Account 926 for current year	Company Records		-
214	PBOP Adjustment for Appendix A, Line 44			-
215	Lines 208-210 cannot change absent approval or acceptance by FERC in a separate proceeding.			
216	**RGE**			
217	Total PBOP expenses		$	3,561,081
218	Labor dollars		$	79,625,000
219	Cost per labor dollar		$	0.0447
220	labor (labor not capitalized) current year	Company Records		-
221	PBOP Expense for current year			-
222	PBOP Expense in Account 926 for current year	Company Records		-
223	PBOP Adjustment for Appendix A, Line 44			-

224 Lines 217-219 cannot change absent approval or acceptance by FERC in a separate proceeding.

225	**CHG&E**			
226	Total PBOP expenses		$	(3,863,900)
227	Labor dollars			108,206,368
228	Cost per labor dollar		$	(0.0357)
229	labor (labor not capitalized) current year	Company Records		-
230	PBOP Expense for current year			-
231	PBOP Expense in Account 926 for current year	Company Records		-
232	PBOP Adjustment for Appendix A, Line 44			-
233	Lines 226-228 cannot change absent approval or acceptance by FERC in a separate proceeding.			
234	**New York Transco LLC**			
235	Total PBOP expenses		$	-
236	Labor dollars		$	-
237	Cost per labor dollar			$0.000
238	labor (labor not capitalized) current year	Company Records		-
239	PBOP Expense for current year			-
240	PBOP Expense in Account 926 for current year	Company Records		-
241	PBOP Adjustment for Appendix A, Line 44			-
242	Lines 235-237 cannot change absent approval or acceptance by FERC in a separate proceeding.			
243	PBOP expense adjustment	(sum lines 197, 214, 205, 223, 232, & 241)		-

Attachment 3 - Cost Support

New York Transco LLC

COST OF CAPITAL

Line No.	Description	Form No.1 Reference	December Col. (a)	January Col. (b)	February Col. (c)	March Col. (d)	April Col. (e)	May Col. (f)	June Col. (g)	July Col. (h)	August Col. (i)	September Col. (j)	October Col. (k)	November Col. (l)	December Col. (m)	13 Month Avg. Col. (n)
244	Long Term Debt:															
245	Acct 221 Bonds	112.18.c,d	-	-	-	-	-	-	-	-	-	-	-	-	-	-
246	Acct 223 Advances from Assoc. Companies	112.20.c,d	-	-	-	-	-	-	-	-	-	-	-	-	-	-
247	Acct 224 Other Long Term Debt	112.21.c,d	-	-	-	-	-	-	-	-	-	-	-	-	-	-
248	Less Acct 222 Reacquired Debt	112.19 c, d enter negative	-	-	-	-	-	-	-	-	-	-	-	-	-	-
249	Total Long Term Debt	Sum Lines 244 - 248	-	-	-	-	-	-	-	-	-	-	-	-	-	-
250 251	Preferred Stock (1)	112.3.c,d	-	-	-	-	-	-	-	-	-	-	-	-	-	-
252																
253	Common Equity- Per Books	112.16.c,d	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254	Less Acct 204 Preferred Stock	112.3.c,d	-	-	-	-	-	-	-	-	-	-	-	-	-	-
255	Less Acct 219 Accum Other Compre. Income	112.15.c,d	-	-	-	-	-	-	-	-	-	-	-	-	-	-
256	Less Acct 216.1 Unappropriated Undistributed Subsidiary Earnings	112.12.c,d														-
257	Adjusted Common Equity	Ln 253 - 254 - 255 - 256	-	-	-	-	-	-	-	-	-	-	-	-	-	-
258 259																
	Total (Line 249 plus Line 251 plus Line 257)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
260 261																
	Cost of Debt															
262	Acct 427 Interest on Long Term Debt	117.62.c													-	
263	Acct 428 Amortization of Debt Discount and Expense	117.63.c													-	
264	Acct 428.1 Amortization of Loss on Reacquired Debt	117.64.c													-	
265	Acct 430 Interest on Debt to Assoc. Companies (LTD portion only) (2)	117.67.c													-	
266	Less: Acct 429 Amort of Premium on Debt	117.65.c enter negative													-	
267	Less: Acct 429.1 Amort of Gain on	117.66.c enter negative													-	
	Total Interest Expense	Sum Lines 262 - 267													-	
268 269																
270	Average Cost of Debt (Line 268 / Line 249)														-	
271 272																
	Cost of Preferred Stock															
273 274	Preferred Stock Dividends	118.29.c														
275	Average Cost of Preferred Stock (Line 273 / Line 251)														-	

Note 1. If and when the Company issues preferred stock, footnote will indicate the authorizing regulatory agency, the docket/case number, and the date of the Note
2. Interest on Debt to Associated Companies (FERC 430) will be populated with interest related to Long-Term Debt only.

Project Worksheet
Attachment 4

Rate Formula Template
Utilizing Appendix A Data

For the 12 months ended 12/31/

The calcuations below calcuate that additional revenue requirement for 100 basis points of ROE and 1 percent change in the equity component of the capital structure.
These amounts are then used to caluate the actual increase in revenue in the table below (starting on line 66) associated with the actual incentive authortized by the Commisison The use of the 100 basis point calulations do not presume any particular incentive (i.e., 100 basis points) being granted by the Commisison.

New York Transco LLC

Base ROE and Income Taxes Carrying Charge

1 Rate Base

2 BASE RETURN CALCULATION:

3 Long Term Debt (Appendix A, Line 91)
4 Preferred Stock (Appendix A, Line 92)
5 Common Stock (Appendix A, Line 93)
6 Total (sum lines 3-5)
7 Return multiplied by Rate Base (line 1 * line 6)

8 INCOME TAXES
9 T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = (Appendix A, line 61)
10 CIT=(T/1-T) * (1-(W CLTD/R)) =
11 where W CLTD=(line 3) and R= (line 6)
12 and FIT, SIT & p are as given in footnote F on Appendix A.
13 1 / (1 - T) = (T from line 9)
14 Amortized Investment Tax Credit (266.8f) (enter negative)

15 Income Tax Calculation = line 10 * line 7 * (1-n)
16 ITC adjustment (line 13 * line 14) * (1-n)
17 Total Income Taxes (line 15 plus line 16)

18 Base Return and Income Taxes
19 Rate Base
20 Return and Income Taxes at Base ROE

100 Basis Point Incentive ROE and Income Taxes Carrying Charge

21 Rate Base

22 100 Basis Point Incentive Return impact on

23 Long Term Debt (line 3)
24 Preferred Stock (line 4)
25 Common Stock (line 5 plus 100 basis points)
26 Total (sum lines 24-26)
27 100 Basis Point Incentive Return multiplied by Rate Base (line 21 * line 26)

28 INCOME TAXES
29 T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = (Appendix A, line 61)
30 CIT=(T/1-T) * (1-(W CLTD/R)) =
31 where W CLTD=(line 23) and R= (line 26)
32 and FIT, SIT & p are as given in footnote F on Appendix A.
33 1 / (1 - T) = (T from line 29)
34 Amortized Investment Tax Credit (line 14)

35 Income Tax Calculation = line 30 * line 27 * (1-n)
36 ITC adjustment (line 33 * line 34) * (1-n)
37 Total Income Taxes (line 35 plus line 36)

38 Return and Income Taxes with 100 basis point increase in ROE
39 Rate Base
40 Return and Income Taxes with 100 basis point increase in ROE
41 Difference in Return and Income Taxes between Base ROE and 100 Basis Point Incentive

Effect of 1% Increase in the Equity Ratio

42 Rate Base

43 100 Basis Point Incentive Return

44 Long Term Debt (line 3 minus 1% in equity ratio)
45 Preferred Stock (line 4)
46 Common Stock (line 5 plus 1% in equity ratio))
47 Total (sum lines 44-46)
48 Line 47 x line 42

49 INCOME TAXES
50 T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = (Appendix A, line 61)
51 CIT=(T/1-T) * (1-(W CLTD/R)) =

		Allocator			Result
					-
$	%	Cost	Weighted		
-	0%	0.00%	0.00%		
-	0%	0.00%	0.00%		
-	0%	9.50%	0.00%		
-			0.00%		
					-
-					
-					
-					
-					
-					-
-	NP	-			-
-					-
	Sum lines 7 and 17				-
	Line 1				-
	Line 18 / line 19				-

Attachment 4

				Result
				-
$	%	Cost	Weighted	
-	0%	0.00%	-	
-	0%	0.00%	-	
-	0%	10.50%	-	
-			-	
				-
-				
-				
-				
-				
-				-
-	NP	-		-
-				-
	Sum lines 27 and 37			-
	Line 21			-
	Line 38 / line 39			-
	Line 40- Line 20			-

Results

				-
$	%	Cost	Weighted	
-	-1%	0.00%	0.00%	
-	0%	0.00%	0.00%	
-	1%	9.50%	0.10%	
-			0.10%	
				-
-				
-				

52 where W CLTD=(line 44) and R= (line 47)
53 and FIT, SIT & p are as given in footnote F on Appendix A.
54 1 / (1 - T) = (T from line 50) -
55 Amortized Investment Tax Credit (line 14) -

56 Income Tax Calculation = line 51 * line 48 * (1-n) - -
57 ITC adjustment (line 54 * line 55) * (1-n) - NP - -
58 Total Income Taxes (line 56 plus line 57) - -

59 Return and Income Taxes with 1% Increase in the Equity Ratio — Sum lines 48 and 58 — -
60 Rate Base — Line 42 — -
61 Return and Income Taxes with 1% Increase in the Equity Ratio — Line 59 / line 60 — -
62 Difference between Base ROE and 1% Increase in the Equity Ratio — Line 61 - Line 20 — -

Attachment 4

63 Revenue Requirement per project including incentives

64 Expense Allocator [Appendix A, lines 45 and 59, less Appendix A, line 44b / Gross Transmission Plant In Service Column (l) including Transmission CIACs] times TP on Appendix A, line 80 (Note B) -
65 Base Carrying Charge (used in Line 102 Appendix A) -

The table below breaks out the total revenue requirement on Appendix A separately for each investment. The total of Column (p) must equal the amount shown on Appendix A, Line 3.

Line	(a) Description	(b) Net Investment (Note A)	(c) ROE Authorized by FERC (Note C)	(d) ROE Base (From Appendix A, line 93)	(e) Incentive Authorized by FERC (Note D)	(f) % Line 41	(g) Col (e) / .01 x Col (f)	(h) Incentive $ (Col (b) x Col (g)	(i) Equity % in Capital Structure (% above base %, -% below base %)(1 equals 1%) (Note D)	(j) Impact of Equity Component of Capital Structure(Col (b) x (i) x Line 62	(k) Base Return and Tax (Line 65 x Col (b)	(l) Gross Plant In Service (Note B)	(m) Expense Allocator (line 64)	(n) O&M (exc Amort. Of Reg. Assets), Taxes Other than Income (Col. (l) x Col. (m)	(o) Depreciation/Amortization Expense	(p) Total Revenues (Col. (h) + (j) + (k) +(n) +(o))
66	-	-	-	9.50%	-	-	-	-	-	-	-	-	-	-	-	-
66a	-	-	-	9.50%	-	-	-	-	-	-	-	-	-	-	-	-
66b	-	-	-	9.50%	-	-	-	-	-	-	-	-	-	-	-	-
66c	-	-	-	9.50%	-				-				-	-	-	
…			-	9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
…				9.50%									-	-		
				9.50%									-	-		
67	Total			9.50%									-	-		
	Check Sum Appendix A Line 3	$0.00						-		-	-	$0		-	-	-
	Difference (must be zero)															-
Note:																-

A Column (b), Net Investment includes the Net Plant In Service, unamortized regulatory assets, unamortized abandoned plant and CWIP
B Column (l), Gross Plant in Service excludes Regulatory Assets, CWIP, and Abandoned Plant.
C Column (e), for each project with an incentive in column (e), note the docket No. in which FERC granted the incentive
D No incentive or change in the equity percentage in Columns (e) and (i) can be made absent Commisison authorization

Project	Docket No.	Note
TOTs 1 - Ramapo to Rock Tavern	ER15-572	Up to $228 million for the 3 TOTS projects in aggregate
TOTs 2 - Staten Island Unbottling Feeder Split	ER15-572	Up to $228 million for the 3 TOTS projects in aggregate
TOTs 3 - NYSEG's Marcy South Series Comp Fraser to Coopers Corner	ER15-572	Up to $228 million for the 3 TOTS projects in aggregate

Attachment 5 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology (Note 13)

New York Transco LLC
HYPOTHETICAL EXAMPLE

Assumes financing will be a 5 year loan with Origination Fees of $2.1 million and a Commitments Fee of 0.3% on the undrawn principal.
Consistent with GAAP, the Origination Fees and Commitments Fees will be amortized using the standard Internal Rate of Return formula below.
Each year, the amounts wit [redacted] mitments Fees, and total loan amount will be updated on this attachment.

Table 1

1 **Total Loan Amount** **$ 125,000,000**

Table 2

2 **Internal Rate of Return**[1] **4.892%**

3 **Based on following Financial Formula**[2]**:**

4 **NPV = 0 =**

Table 3

	Origination Fees	
5	Underwriting Discount	-
6	Arrangement Fee Upfront Fee	250,000
7	Rating Agency Fee	437,500
8	Legal Fees	-
9	Total Issuance Expense	1,000,000
10		**1,687,500**
11		
12		
13		

Table 4

		2014	2015	2016	2017	2018	2019	2020
14	LIBOR Rate	0.64%	1.03%	1.60%	2.13%	2.13%	2.13%	2.13%
15	Spread	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%	2.25%
16	**Interest Rate**	2.89%	3.28%	3.85%	4.38%	4.38%	4.38%	4.38%

Table 5

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
17	**Year**		**Capital Expenditures ($000's)**	**Principal Drawn In Quarter ($000's)**	**Principal Drawn To Date ($000's)**	**Interest & Principal ($000's)**	**Origination Fees ($000's)**	**Commitment & Utilization Fee ($000's)**	**Net Cash Flows ($000's)**
					Cumulative Col. D	1/4 * Interest Rate from Line 16 x Col. E prior quarter and Principal repayment	Input in first Qtr of Loan	(line 1/1000 less Col. E prior quarter)*line 13/4 +line 12/4000+line 11/4000	(D-F-G-H)
18									
19									
20	3/31/2014	Q3	19,350	9,675	9,675		2,100		7,575
21	6/30/2014	Q4	19,350	9,675	19,350	70		124	9,481
22	9/30/2014	Q1	19,350	9,675	29,025	141		117	9,418
23	12/31/2014	Q2	19,350	9,675	38,700	211		109	9,354
24	3/31/2015	Q3	24,775	12,388	51,088	275		102	12,010
2526	6/30/2015	Q4	24,775	12,388	63,475	418		93	11,876
2728	9/30/2015	Q1	24,775	12,388	75,863	525		84	11,778
	12/31/2015	Q2	24,775	12,388	88,250	628		74	11,685
	3/31/2016	Q3	23,950	11,975	100,225	723		65	11,187
29	6/30/2016	Q4	23,950	11,975	112,200	962		56	10,957
30	9/30/2016	Q1	23,950	11,975	124,175	1,089		47	10,839
31	12/31/2016	Q2	23,950	11,975	136,150	1,205		38	10,732
32	3/31/2017	Q3	23,575	11,788	147,938	1,292		29	10,466
33	6/30/2017	Q4	23,575	11,788	159,725	1,615		20	10,152
34	9/30/2017	Q1	23,575	11,788	171,513	1,763		11	10,013
35	12/31/2017	Q2	23,575	11,788	183,300	1,893		3	9,891
3637	3/31/2018	Q3	-	-	183,300	185,280			(185,280)
38									
39									
40									
41									
42									

Notes 1 The IRR is the input to Debt Cost shown on Appendix A, Page 4, Line 91 during the construction period, after obtaining project financing, in accordance with Note G of Appendix A.

2. The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation is shown on line 4.

N is the last quarter the loan would be outstanding

t is each quarter

Ct is the cash flow (Table 5, Col. I in each quarter)

Alternatively the equation can be written as 0 = C0 + C1/(1+IRR) + C2/(1+IRR)2 + C3/(1+IRR)3 + . . . +Cn/(1+IRR)n and solved for IRR

The Excel ™ formula on line 2 is : (round(XIRR(first quarter of loan Col A of Table 5:last quarter of loan Col A of Table 5, first quarter of loan Col I of Table 5: last quarter of loan Col I of Table 5, 8%),4)) The 8% in the above formula is a seed number to ensure the formula produces a positive number.

3. Line 1 reflects the loan amount, the maximum amount that can be drawn on

4. Lines 5 through 13 include the fees associated with the loan. They are estimated based on current bank condition and are updated with the actual fees once the actual fees are known.

5. The estimate of the average 3 month Libor forward rate for the year on line 14 is that published by Bloomberg Finance L.P. during August of the prior year and is trued-up to actual average 3 month Libor rate for the year under the loan.

6. Table 5, Col. C reflect the capital expenditures in each quarter

7. Table 5, Col. D reflect the amount of the loan that is drawn down in the quarter

8. Table 5, Col. E is the amount of principle drawn down

9. Table 5, Col F calculates the interest on the principle drawn down to date based on the applicable interest on line 16

10. Table 5, Col. G is the total origination fees in line 10 and is input in the first quarter that a portion of the loan in drawn

11. Table 5, Col. H is calculated as follows:

(line 1/1000 less Col. E prior quarter)*line 13/4 +line 12/4000+line 11/4000

Where A = Loan amount in line 1 less the amount drawn down (Table 5, Col. (E)) in the prior quarter

12. The inputs shall be estimated based on the current market conditions and is subject to true up for all inputs , e.g., fees, interest rates, spread, and Table 3 once the amounts are known

13. Prior to obtaining long term debt, the cost of debt, will be 3.28%. If NY Transco obtains project financing, the long term debt rate will be determined using the methodology in Attachment 5 and Attachment 5 contains a hypothetical example of the internal rate of return methodology; the methodology will be applied to actual amounts for use in Attachment A. After the first project is placed into service, NY Transco will use the its actual cost of long term debt determined in Attachment 3.   The capital structure will be the actual capital structure up to 53% equity.

New York Transco LLC
Attachment 6a - Accumulated Deferred Income Taxes (ADIT) Worksheet (Beginning of Year)
Beginning of Year

	Item		Transmission Related	Plant Related	Labor Related	Total	
1		ADIT-282	-	-	-		From Acct. 282 total, below
2		ADIT-283	-	-	-		From Acct. 283 total, below
3		ADIT-190	-	-	-		From Acct. 190 total, below
4		Subtotal	-	-	-		
5		Wages & Salary Allocator			-		
6		NP		-			
7		Beginning of Year	-	-	-	-	
8		End of year from Attachment 6b, line 7	-	-	-	-	
9		Average of Beginning of Year and End of Year ((7 +8)/2)	-	-	-	-	Enter as negative Appendix A, line 24.

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately. For ADIT directly related to project depreciation or CWIP, the balance must shown in a separate row for each project.

	A	B	C	D	E	F	G
		Total	Gas, Prod Or Other Related	Transmission Related	Plant Related	Labor Related	Justification
10	ADIT-190						
11a							
11b							
11c							
…							
12	Subtotal - p234	-	-	-	-	-	
13	Less FASB 109 Above if not separately removed						
14	Less FASB 106 Above if not separately removed						
15	Total	-	-	-	-	-	

Instructions for Account 190:

16 1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
17 2. ADIT items related only to Transmission are directly assigned to Column D
18 3. ADIT items related to Plant and not in Columns C & D are included in Column E
19 4. ADIT items related to labor and not in Columns C & D are included in Column F
20 5. If the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

New York Transco LLC
Attachment 6a - Accumulated Deferred Income Taxes (ADIT) Worksheet (Beginning of Year)
Beginning of Year

	A	B	C	D	E	F	G
		Total	Gas, Prod Or Other Related	Transmission Related	Plant Related	Labor Related	Justification
21	ADIT- 282						

22a

22b

22c							
…							
…							
…							
…							
…							
…							
23	Subtotal - p275	-	-	-	-	-	
24	Less FASB 109 Above if not separately removed						
25	Less FASB 106 Above if not separately removed						
26	Total	-	-	-	-	-	

Instructions for Account 282:

27 1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

28 2. ADIT items related only to Transmission are directly assigned to Column D

29 3. ADIT items related to Plant and not in Columns C & D are included in Column E

30 4. ADIT items related to labor and not in Columns C & D are included in Column F

31 5. If the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

New York Transco LLC

Attachment 6a - Accumulated Deferred Income Taxes (ADIT) Worksheet (Beginning of Year)

				Beginning of Year			
	A	B	C	D	E	F	G
32	ADIT- 283	Total	Gas, Prod Or Other Related	Transmission Related	Plant Related	Labor Related	
33a							
33b							
33c							
…							
…							
…							
…							
…							
…							
…							
34	Subtotal - p277	-	-	-	-	-	
35	Less FASB 109 Above if not separately removed						
36	Less FASB 106 Above if not separately removed						
37	Total	-	-	-	-	-	

Instructions for Account 283:

38 1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

39 2. ADIT items related only to Transmission are directly assigned to Column D

40 3. ADIT items related to Plant and not in Columns C & D are included in Column E

41 4. ADIT items related to labor and not in Columns C & D are included in Column F

42 5. If the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

New York Transco LLC
Attachment 6b - Accumulated Deferred Income Taxes (ADIT) Worksheet (End of Year)
End of Year

Line		Transmission Related	Plant Related	Labor Related	Total	
1	ADIT-282	-	-	-		From Acct. 282 total, below
2	ADIT-283	-	-	-		From Acct. 283 total, below
3	ADIT-190	-	-	-		From Acct. 190 total, below
4	Subtotal	-	-	-		
5	Wages & Salary Allocator			-		
6	NP		-			
7	End of Year ADIT	-	-	-	-	

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately. For ADIT directly related to project depreciation or CWIP, the balance must be shown in a separate row for each project.

	A	B	C	D	E	F	G
		Total	Gas, Prod Or Other Related	Transmission Related	Plant Related	Labor Related	Justification
8	ADIT-190						
9a							
9b							
9c							
…							
…							
…							
…							
…							
…							
…							
10	Subtotal - p234	-	-	-	-	-	
11	Less FASB 109 Above if not separately removed						
12	Less FASB 106 Above if not separately removed						
13	Total	-	-	-	-	-	

Instructions for Account 190:
14 1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
15 2. ADIT items related only to Transmission are directly assigned to Column D
16 3. ADIT items related to Plant and not in Columns C & D are included in Column E
17 4. ADIT items related to labor and not in Columns C & D are included in Column F
18 5. If the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

New York Transco LLC
Attachment 6b - Accumulated Deferred Income Taxes (ADIT) Worksheet (End of Year)
End of Year

A	B	C	D	E	F	G
	Total	Gas, Prod				

19 ADIT- 282

	Or Other Related	Transmission Related	Plant Related	Labor Related	Justification

20a

-

20b							
20c							
…							
…							
…							
…							
…							
…							
21	Subtotal - p275	-	-	-	-	-	
22	Less FASB 109 Above if not separately removed						
23	Less FASB 106 Above if not separately removed						
24	Total	-	-	-	-	-	

Instructions for Account 282:

25 1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

26 2. ADIT items related only to Transmission are directly assigned to Column D

27 3. ADIT items related to Plant and not in Columns C & D are included in Column E

28 4. ADIT items related to labor and not in Columns C & D are included in Column F

29 5. If the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

New York Transco LLC

Attachment 6b - Accumulated Deferred Income Taxes (ADIT) Worksheet (End of Year)

End of Year

	A	B	C	D	E	F	G
		Total	Gas, Prod				
30	ADIT- 283		Or Other	Transmission	Plant	Labor	
			Related	Related	Related	Related	
31a							
31b							
31c							
…							
…							
…							
…							
…							
…							
…							
32	Subtotal - p277	-	-	-	-	-	
33	Less FASB 109 Above if not separately removed						

34 Less FASB 106 Above if not separately removed

35 Total

Instructions for Account 283:

36 1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
37 2. ADIT items related only to Transmission are directly assigned to Column D
38 3. ADIT items related to Plant and not in Columns C & D are included in Column E
39 4. ADIT items related to labor and not in Columns C & D are included in Column F
40 5. If the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Attachment 7 - Example of True-Up Calculation (Note 3)
New York Transco LLC

2014 Revenue Requirement Billed (Note 1)		2014 Actual Revenue Requirement (Note 2)		Over (Under) Recovery
$0	**Less**	$0	**Equals**	$0

Interest Rate on Amount of Refunds or Surcharges		Over (Under) Recovery Plus Interest	Monthly Interest Rate on Attachment 7a	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
			0.2708%				

An over or under collection will be recovered prorata over year collected, held for one year and returned prorata over next year. If the first year is a partial year, the true-up (over or under recovery per month and interest calculation) will reflect only the number of months for which the rate was charged.

Calculation of Interest					Monthly		
January	Year 2014	-	0.2708%	12	-		-
February	Year 2014	-	0.2708%	11	-		-
March	Year 2014	-	0.2708%	10	-		-
April	Year 2014	-	0.2708%	9	-		-
May	Year 2014	-	0.2708%	8	-		-
June	Year 2014	-	0.2708%	7	-		-
July	Year 2014	-	0.2708%	6	-		-
August	Year 2014	-	0.2708%	5	-		-
September	Year 2014	-	0.2708%	4	-		-
October	Year 2014	-	0.2708%	3	-		-
November	Year 2014	-	0.2708%	2	-		-
December	Year 2014	-	0.2708%	1	-		-
					-		-
					Annual		
January through December	Year 2014	-	0.2708%	12	-		-

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2016	-	0.2708%		-	-	-
February	Year 2016	-	0.2708%		-	-	-
March	Year 2016	-	0.2708%		-	-	-
April	Year 2016	-	0.2708%		-	-	-
May	Year 2016	-	0.2708%		-	-	-
June	Year 2016	-	0.2708%		-	-	-
July	Year 2016	-	0.2708%		-	-	-
August	Year 2016	-	0.2708%		-	-	-
September	Year 2016	-	0.2708%		-	-	-
October	Year 2016	-	0.2708%		-	-	-
November	Year 2016	-	0.2708%		-	-	-
December	Year 2016	-	0.2708%		-	-	-
					-		

Total Amount of True-Up Adjustment	$ -
Less Over (Under) Recovery	$ -
Total Interest	$ -

Note 1: Revenue requirements billed is input, source data are the invoices from NYISO. The amounts exclude any true ups or prior period adjustments. Note 2: The actual revenue requirement is input from Attachment 4, line 66, column p. The amounts exclude any true-ups or prior period adjustments. Note 3: This "Example" sheet will be populated with actuals and used in each year's annual true-up calculation.

True-Up Interest Calculation

			Pursuant to 18 C.F.R. Section 35.19 (a)
	FERC Quarterly Interest Rate		
1	Qtr 3 (Previous Year)		3.25%
2	Qtr 4 (Previous Year)		3.25%
3	Qtr 1 (Current Year)		3.25%
4	Qtr 2 (Current Year)		3.25%
5	Average of the last 4 quarters	(Lines 1-4 / 4)	3.25%
6	Interest Rate Used for True-up adjustment (Note B)		0.0325
7	Monthly Interest Rate for Attachment 7	(Line 6 / 12)	0.0027

Attachment 8 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan (Note 1)
New York Transco LLC

SUMMARY

YEAR		Estimated Effective cost of debt used in true up	Final Effective cost of debt for the construction loan:	Revenue Requirement: Based on cost of debt used in prior year true-ups (Note 2)	Revenue Requirement: Based on Actual Final Cost of Debt (Note 3)	Over (Under) Recovery	Monthly FERC Refund Interest Rate applicable over the ATRR period	Total Amount of Construction Loan Related True-Up to be included in rates (Refund)/Owed
2014		7.18%	6.50%	$ 2,500,000.00	$ 2,400,000.00	$ 100,000.00	0.550%	$ (148,288.33)
2015		6.8%	6.50%	$5,000,000.00	$5,150,000.00	$ (150,000.00)	0.560%	$ 209,670.43
2016		7.2%	6.50%	$8,300,000.00	$8,200,000.00	$ 100,000.00	0.540%	$ (131,109.09)
2017		7.3%	6.50%	$12,300,000.00	$12,000,000.00	$ 300,000.00	0.580%	$ (368,656.73)
2018	*	7.1%	6.50%	$18,000,000.00	$17,900,000.00	$ 100,000.00	0.570%	$ (114,946.28)
2018	**	6.50%	6.50%	$25,000,000.00	$25,000,000.00	$ -		
								$ (553,329.99)

The Hypothetical Example:

** Assumes that the construction loan is retired on December 31, 2018*

*** Assumes that the construction loan IRR on Attachment 5 has an effective rate of 6.5%*

Calculation of Applicable Interest Expense for each ATRR period

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Hypothetical Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Calculation of Interest for 2014 True-Up Period							
An over or under collection will be recovered prorata over 2014, held for 2015, 2016, 2017, 2018, and 2019 and returned prorate over 2020					**Monthly**		
January	Year 2014	-	0.5500%	12.00	-		-
February	Year 2014	-	0.5500%	11.00	-		-
March	Year 2014	10,000	0.5500%	10.00	(550)		(10,550)
April	Year 2014	10,000	0.5500%	9.00	(495)		(10,495)
May	Year 2014	10,000	0.5500%	8.00	(440)		(10,440)
June	Year 2014	10,000	0.5500%	7.00	(385)		(10,385)
July	Year 2014	10,000	0.5500%	6.00	(330)		(10,330)
August	Year 2014	10,000	0.5500%	5.00	(275)		(10,275)
September	Year 2014	10,000	0.5500%	4.00	(220)		(10,220)
October	Year 2014	10,000	0.5500%	3.00	(165)		(10,165)
November	Year 2014	10,000	0.5500%	2.00	(110)		(10,110)
December	Year 2014	10,000	0.5500%	1.00	(55)		(10,055)
					(3,025)		**(103,025)**
					Annual		
January through December	Year 2015	(103,025)	0.5600%	12.00	(6,923)		**(109,948)**
January through December	Year 2016	(109,948)	0.5400%	12.00	(7,125)		**(117,073)**
January through December	Year 2017	(117,073)	0.5800%	12.00	(8,148)		**(125,221)**
January through December	Year 2018	(125,221)	0.5700%	12.00	(8,565)		**(133,786)**
January through December	Year 2019	(133,786)	0.5700%	12.00	(9,151)		**(142,937)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2020	**142,937**	0.5700%		(815)	(12,357)	(131,395)
February	Year 2020	131,395	0.5700%		(749)	(12,357)	(119,786)
March	Year 2020	119,786	0.5700%		(683)	(12,357)	(108,112)
April	Year 2020	108,112	0.5700%		(616)	(12,357)	(96,371)
May	Year 2020	96,371	0.5700%		(549)	(12,357)	(84,563)
June	Year 2020	84,563	0.5700%		(482)	(12,357)	(72,687)
July	Year 2020	72,687	0.5700%		(414)	(12,357)	(60,744)
August	Year 2020	60,744	0.5700%		(346)	(12,357)	(48,733)
September	Year 2020	48,733	0.5700%		(278)	(12,357)	(36,653)
October	Year 2020	36,653	0.5700%		(209)	(12,357)	(24,505)
November	Year 2020	24,505	0.5700%		(140)	(12,357)	(12,287)
December	Year 2020	12,287	0.5700%		(70)	(12,357)	0
					(5,351)		
Total Amount of True-Up Adjustment for 2014 ATRR						$ (148,288)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (48,288)	

Attachment 8 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
New York Transco LLC

Calculation of Interest for 2015 True-Up Period							
An over or under collection will be recovered prorata over 2015, held for 2016, 2017, 2018, and 2019 and returned prorate over 2020					**Monthly**		
January	Year 2015	(12,500)	0.5600%	12.00	840		13,340
February							
March							

April	Year 2015	(12,500)	0.5600%	11.00	770	13,270
May	Year 2015	(12,500)	0.5600%	10.00	700	13,200
June	Year 2015	(12,500)	0.5600%	9.00	630	13,130
	Year 2015	(12,500)	0.5600%	8.00	560	13,060
	Year 2015	(12,500)	0.5600%	7.00	490	12,990

July	Year 2015	(12,500)	0.5600%	6.00	420		12,920
August	Year 2015	(12,500)	0.5600%	5.00	350		12,850
September	Year 2015	(12,500)	0.5600%	4.00	280		12,780
October	Year 2015	(12,500)	0.5600%	3.00	210		12,710
November	Year 2015	(12,500)	0.5600%	2.00	140		12,640
December	Year 2015	(12,500)	0.5600%	1.00	70		12,570
					5,460		**155,460**
					Annual		
January through December	Year 2016	155,460	0.5400%	12.00	10,074		**165,534**
January through December	Year 2017	165,534	0.5800%	12.00	11,521		**177,055**
January through December	Year 2018	177,055	0.5700%	12.00	12,111		**189,166**
January through December	Year 2019	189,166	0.5700%	12.00	12,939		**202,104**

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2020	**(202,104)**	0.5700%		1,152	17,473	185,784
February	Year 2020	(185,784)	0.5700%		1,059	17,473	169,370
March	Year 2020	(169,370)	0.5700%		965	17,473	152,863
April	Year 2020	(152,863)	0.5700%		871	17,473	136,262
May	Year 2020	(136,262)	0.5700%		777	17,473	119,566
June	Year 2020	(119,566)	0.5700%		682	17,473	102,775
July	Year 2020	(102,775)	0.5700%		586	17,473	85,888
August	Year 2020	(85,888)	0.5700%		490	17,473	68,905
September	Year 2020	(68,905)	0.5700%		393	17,473	51,826
October	Year 2020	(51,826)	0.5700%		295	17,473	34,649
November	Year 2020	(34,649)	0.5700%		197	17,473	17,374
December	Year 2020	(17,374)	0.5700%		99	17,473	(0)
					7,566		

Total Amount of True-Up Adjustment for 2015 ATRR	$	209,670
Less Over (Under) Recovery	$	(150,000)
Total Interest	$	59,670

Calculation of Interest for 2016 True-Up Period

An over or under collection will be recovered prorata over 2016, held for 2017, 2018 and 2019 and returned prorate over 2020 **Monthly**

January	Year 2016	8,333	0.5400%	12.00	(540)		(8,873)
February	Year 2016	8,333	0.5400%	11.00	(495)		(8,828)
March	Year 2016	8,333	0.5400%	10.00	(450)		(8,783)
April	Year 2016	8,333	0.5400%	9.00	(405)		(8,738)
May	Year 2016	8,333	0.5400%	8.00	(360)		(8,693)
June	Year 2016	8,333	0.5400%	7.00	(315)		(8,648)
July	Year 2016	8,333	0.5400%	6.00	(270)		(8,603)
August	Year 2016	8,333	0.5400%	5.00	(225)		(8,558)
September	Year 2016	8,333	0.5400%	4.00	(180)		(8,513)
October	Year 2016	8,333	0.5400%	3.00	(135)		(8,468)
November	Year 2016	8,333	0.5400%	2.00	(90)		(8,423)
December	Year 2016	8,333	0.5400%	1.00	(45)		(8,378)
					(3,510)		**(103,510)**
					Annual		
January through December	Year 2017	(103,510)	0.5800%	12.00	(7,204)		**(110,714)**
January through December	Year 2018	(110,714)	0.5700%	12.00	(7,573)		**(118,287)**
January through December	Year 2019	(118,287)	0.5700%	12.00	(8,091)		**(126,378)**

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2020	**126,378**	0.5700%		(720)	(10,926)	(116,173)
February	Year 2020	116,173	0.5700%		(662)	(10,926)	(105,909)
March	Year 2020	105,909	0.5700%		(604)	(10,926)	(95,587)
April	Year 2020	95,587	0.5700%		(545)	(10,926)	(85,206)
May	Year 2020	85,206	0.5700%		(486)	(10,926)	(74,766)
June	Year 2020	74,766	0.5700%		(426)	(10,926)	(64,266)
July	Year 2020	64,266	0.5700%		(366)	(10,926)	(53,707)
August	Year 2020	53,707	0.5700%		(306)	(10,926)	(43,087)
September	Year 2020	43,087	0.5700%		(246)	(10,926)	(32,407)
October	Year 2020	32,407	0.5700%		(185)	(10,926)	(21,666)
November	Year 2020	21,666	0.5700%		(123)	(10,926)	(10,864)
December	Year 2020	10,864	0.5700%		(62)	(10,926)	0
					(4,731)		

Total Amount of True-Up Adjustment for 2016 ATRR	$	(131,109)
Less Over (Under) Recovery	$	100,000
Total Interest	$	(31,109)

Attachment 8 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
New York Transco LLC

Calculation of Interest for 2017 True-Up Period

An over or under collection will be recovered prorata over 2017, held for 2018 and 2019, and returned prorate over 2020 **Monthly**

January	Year 2017		25,000	0.5800%	12.00	(1,740)		(26,740)
February		June		Year 2017			25,000	
March		July		Year 2017			25,000	
April		August		Year 2017			25,000	
May				Year 2017			25,000	

Year 2017	0.5800%	25,000	11.00	(1,595)	(26,595)
Year 2017	0.5800%	25,000	10.00	(1,450)	(26,450)
Year 2017	0.5800%	25,000	9.00	(1,305)	(26,305)
	0.5800%		8.00	(1,160)	(26,160)
	0.5800%		7.00	(1,015)	(26,015)
	0.5800%		6.00	(870)	(25,870)
	0.5800%		5.00	(725)	(25,725)

September	Year 2017	25,000	0.5800%	4.00	(580)		(25,580
October	Year 2017	25,000	0.5800%	3.00	(435)		(25,435
November	Year 2017	25,000	0.5800%	2.00	(290)		(25,290
December	Year 2017	25,000	0.5800%	1.00	(145)		(25,145
					(11,310)		**(311,310**
					Annual		
January through December	Year 2018	(311,310)	0.5700%	12.00	(21,294)		**(332,604**
January through December	Year 2019	(332,604)	0.5700%	12.00	(22,750)		**(355,354**

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2020	**355,354**	0.5700%				
February	Year 2020	326,658	0.5700%		(2,026)	(30,721)	(326,658
March	Year 2020	297,798	0.5700%		(1,862)	(30,721)	(297,798
April	Year 2020	268,774	0.5700%		(1,697)	(30,721)	(268,774
May	Year 2020	239,585	0.5700%		(1,532)	(30,721)	(239,585
June	Year 2020	210,229	0.5700%		(1,366)	(30,721)	(210,229
July	Year 2020	180,706	0.5700%		(1,198)	(30,721)	(180,706
August	Year 2020	151,015	0.5700%		(1,030)	(30,721)	(151,015
September	Year 2020	121,154	0.5700%		(861)	(30,721)	(121,154
October	Year 2020	91,123	0.5700%		(691)	(30,721)	(91,123
November	Year 2020	60,921	0.5700%		(519)	(30,721)	(60,921)
December	Year 2020	30,547	0.5700%		(347)	(30,721)	(30,547
					(174)	(30,721)	0
					(13,303)		

Total Amount of True-Up Adjustment for 2017 ATRR	$	(368,657)
Less Over (Under) Recovery	$	300,000
Total Interest	$	(68,657)

Calculation of Interest for 2018 True-Up Period

An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020					**Monthly**		
January	Year 2018	8,333	0.5700%	12.00	(570)		(8,903
February	Year 2018	8,333	0.5700%	11.00	(523)		(8,856
March	Year 2018	8,333	0.5700%	10.00	(475)		(8,808
April	Year 2018	8,333	0.5700%	9.00	(428)		(8,761
May	Year 2018	8,333	0.5700%	8.00	(380)		(8,713
June	Year 2018	8,333	0.5700%	7.00	(333)		(8,666
July	Year 2018	8,333	0.5700%	6.00	(285)		(8,618
August	Year 2018	8,333	0.5700%	5.00	(238)		(8,571
September	Year 2018	8,333	0.5700%	4.00	(190)		(8,523
October	Year 2018	8,333	0.5700%	3.00	(143)		(8,476
November	Year 2018	8,333	0.5700%	2.00	(95)		(8,428
December	Year 2018	8,333	0.5700%	1.00	(48)		(8,381
					(3,705)		**(103,705**
					Annual		
January through December	Year 2019	(103,705)	0.5700%	12.00	(7,093)		**(110,798**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2020	**110,798**			(632)	(9,579)	(101,851
February	Year 2020	101,851	0.5700%		(581)	(9,579)	(92,853
March	Year 2020	92,853	0.5700%		(529)	(9,579)	(83,803
April	Year 2020	83,803	0.5700%		(478)	(9,579)	(74,702
May	Year 2020	74,702	0.5700%		(426)	(9,579)	(65,549
June	Year 2020	65,549	0.5700%		(374)	(9,579)	(56,344
July	Year 2020	56,344	0.5700%		(321)	(9,579)	(47,086
August	Year 2020	47,086	0.5700%		(268)	(9,579)	(37,776
September	Year 2020	37,776	0.5700%		(215)	(9,579)	(28,412
October	Year 2020	28,412	0.5700%		(162)	(9,579)	(18,995)
November	Year 2020	18,995	0.5700%		(108)	(9,579)	(9,525)
December	Year 2020	9,525	0.5700%		(54)	(9,579)	0
					(4,148)		

Total Amount of True-Up Adjustment for 2018 ATRR	$	(114,946)
Less Over (Under) Recovery	$	100,000
Total Interest	$	(14,946)

Note 1: This 'Hypothetical Example' sheet will be populated with actuals and used in each year's annual true-up calculation.
Note 2: Enter the revenue requirement from the true-up for that year (Note 2)
Note 3: Enter the revenue requirement from re-running the prior year true-ups with the final cost of debt once all inputs to Attachment 5 are based on actual data.

Attachment 9 - Depreciation and Amortization Rates

New York Transco LLC

Account Number	FERC Account	Rate (Annual) Percent

TRANSMISSION PLANT		
1 350.1	Land Rights	1.02
2 352	Structures and Improvements	2.05
3 353	Station Equipment	2.26
4 354	Towers and Fixtures	2.04
5 355	Poles and Fixtures	2.24
6 356	Overhead Conductor and Devices	2.22
7 357	Underground Conduit	2.05
8 358	Underground Conductor and Devices	2.39
9 359	Roads & Trails	1.17
10 **PRODUCTION PLANT**	All Accounts	0.00
11 **DISTRIBUTION PLANT**	All Accounts	0.00
GENERAL PLANT		
12 390	Structures & Improvements	3.36
13 391	Office Furniture & Equipment	5.24
14 392	Transportation Equipment	9.78
15 393	Stores Equipment	3.91
16 394	Tools, Shop & Garage Equipment	4.68
17 395	Laboratory Equipment	3.75
18 396	Power Operated Equipment	7.62
19 397	Communication Equipment	3.82
20 398	Miscellaneous Equipment	4.55
INTANGIBLE PLANT		
21 303	Miscellaneous Intangible Plant	
	5 Yr	20.00
	7 Yr	14.29
	10 Year	10.00
	15 year	6.67
	Transmission facility Contributions in Aid of Construction	Note 1

These depreciation and amortization rates will not change absent the appropriate filing at FERC.

Note 1: In the event a Contribution in Aid of Construction (CIAC) is made for a transmission facility, the transmission depreciation rates above will be weighted based on the relative amount of underlying plant booked to the accounts shown in lines 1-7 above and the weighted average depreciation rate will be used to amortize the CIAC. Once determined for a particular CIAC, the rate will not change for that CIAC absent Commission approval.

Attachment 10 - Workpapers
New York Transco LLC

Regulatory Assets

No.	(a) Project Name	(b) Recovery Amnt Approved *	(c) Recovery Period Months *	(d) Monthly Amort Exp (b) / (c)	(e) Amort Periods this year	(f) Current Amort Expense (d) x (e)	(g) % Allocated to Formula Rate *	(h) Amort Exp in Formula Rate** (f) x (g)	(i) Dec. 31 2015	(j) Jan. 31 2016	(k) Feb. 28/29 2016	(l) Mar. 31 2016	(m) Apr. 30 2016	(n) May 31 2016	(o) Jun. 30 2016	(p) Jul. 31 2016	(q) Aug. 31 2016	(r) Sept. 30 2016	(s) Oct. 31 2016	(t) Nov. 30 2016	(u) Dec. 31 2016	(v) Avg Unamortized Balance Sum (i) through (u) / 13	(w) % Approved for Rate Base *	(x) Allocated to Formula Rate (from (g))	(y) Rate Base Balance (v) x (w) x (x)	(z) Project Code	(aa) Docket No
1a	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
1b				-		-		-														-		-	-		
1c				-		-		-														-		-	-		
				-		-		-														-		-	-		
...				-		-		-														-		-	-		
				-		-		-														-		-	-		
...				-		-		-														-		-	-		
				-		-		-														-		-	-		
...				-		-		-														-		-	-		
																						-		-	-		
2	Total Regulatory Asset in Rate Base (sum lines 1a-1...):			-		-		-																			

* Non-zero values in these columns may only be established per FERC order
**All amortizations of the Regulatory Asset are to be booked to Account 566

Abandoned Plant

No.	(a) Project Name	(b) Recovery Amnt Approved *	(c) Recovery Period Months *	(d) Monthly Amort Exp (b) / (c)	(e) Amort Periods this year	(f) Current Amort Expense (d) x (e)	(g) % Allocated to Formula Rate *	(h) Amort Exp in Formula Rate (f) x (g)	(i) Dec. 31 2014	(j) Jan. 31 2015	(k) Feb. 28/29 2015	(l) Mar. 31 2015	(m) Apr. 30 2015	(n) May 31 2015	(o) Jun. 30 2015	(p) Jul. 31 2015	(q) Aug. 31 2015	(r) Sept. 30 2015	(s) Oct. 31 2015	(t) Nov. 30 2015	(u) (v) Dec. 31 2015	(w) Avg Unamortized Balance Sum (i) through (u) / 13	(x) % Approved for Rate Base *	(y) Allocated to Formula Rate (from (g))	(z) Rate Base Balance (v) x (w) x (x)	(aa) Project Code	Docket No
3a				-		-		-														-		-	-		
3b				-		-		-														-		-	-		
3c				-		-		-														-		-	-		
				-		-		-														-		-	-		
...				-		-		-														-		-	-		
				-		-		-														-		-	-		
				-		-		-														-		-	-		
				-		-		-														-		-	-		
...				-		-		-														-		-	-		
4	Total Abandoned Plant in Rate Base (sum lines 3a-3...):							-																	-		

* Non-zero values in these columns may only be established per FERC order

Land Held for Future Use (LHFU)

No.	(a) Subaccount No.	(b) Item Name	(c) Land Held for Future Use and Estimated Date	(d) Dec. 31 2014	(e) Jan. 31 2015	(f) (g) Feb. 28/29 2015	(h) (i) Mar. 31 2015	Apr. 30 2015	May 31 2015	(j) Jun. 30 2015	(k) Jul. 31 2015	(l) (m) Aug. 31 2015	(n) Sept. 30 2015	Oct. 31 2015	(o) Nov. 30 2015	(p) Dec. 31 2015	(q) Average of Columns (d) Through (p)
5a																	-
5b																	-
5c																	-
...																	-
...																	-
...																	-
...																	-
...																	-
6	Total LHFU in rate base (sum lines 5a-5...):																-

CWIP in Rate Base

No.	(a) Project Name	(b) job ID	(c) Construction Start Date	(d) Estimated in-service date	(e) Approval Doc. No.	(f) Dec. 31 2015	(g) Jan. 31 2016	(h) Feb. 28/29 2016	(i) Mar. 31 2016	(j) Apr. 30 2106	(k) May 31 2016	(l) (m) Jun. 30 2016	(n) Jul. 31 2016	Aug. 31 2016	(o) Sept. 30 2016	(p) Oct. 31 2016	(q) Nov. 30 2016	(r) Dec. 31 2016	(s) Avg (f) through (r)	(t) % approved for recovery	(u) Rate Base Amnt (s) x (t)
7a											219,600,000	0	0	0	0	0	0	0	16,892,308	0.0%	-
7b																			-	0.0%	-
7c																			-	0.0%	-
...																			-	0.0%	-
...																			-	0.0%	-
...																			-	0.0%	-
																			-	0.0%	-

...		-	-
...		-	-
...		-	-
...		-	-
...		-	-
8	Total (sum lines 7a-7...)	Total CWIP in Rate Base	-

Change to recovery percent in Column (t) requires FERC order

Actual Additions by FERC Account

The total of these additions should total the additions reported in the FERC Form No.1 on page 206, lines 48 to 56

	Project	350	352	352	353	354	355	356	357	358	359	
		Land Rights	Structures and Improvements	Structures and Improvements - Equipment	Station Equipment	Towers and Fixtures	Poles and Fixtures	Overhead Conductor and Devices	Underground Conduit	Underground Conductor and Devices	Roads and Trails	Total
9a	Project 1											-
9b	Project 2											-
9c												-
...												-
...												-
...												-
...												-
...												-
...												-
...												-
...												-
...												-
...												-
...												
10	Total(sum lines 9a-9...)											-

Intangible Plant Detail

The total

	Item	Description	Source	Service Life	Amount
11a			Company Records		
11b			Company Records		
11c			Company Records		
...			Company Records		
...			Company Records		
...			Company Records		
...			Company Records		
...			Company Records		
...			Company Records		
...			Company Records		
...			Company Records		
...			Company Records		
...			Company Records		
...			Company Records		
12	Total (sum lines 11a-11...) ties to 205.5.g				-

Detail of Affiliate Charges Included in NY Transco's Books as Requested by Certain Parties to the Filing

Transactions between NY Transco and any entity that is associated (affiliated) with NY Transco must be reported on page 429 of the Form No. 1. The chart below is to include all charges to the NYTransco by an affiliate, by Affilate and by FERC account number

	FERC Account	Central Hudson G&E	Consolidated Edison	Niagara Mohawk	NY State E&G	Rochester G&E	Total
13a	101						-
13b	....						-
13c	....						-
....	....						-
...	....						-
...	350						-
...	....						-
...	....						-
...	....						-
...	....						-
...	....						-
...	....						-
...	920						

	-								
...	....							-	
...	....							-	
...		935						-	
14	Total		-	-	-	-	-	-	(sum lines 13a-13...)

36.3.1.2 Formula Rate Implementation Protocols

The formula rate template ("Template") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of NY Transco for transmission revenue requirement determinations under the ISO OATT. NY Transco shall follow the instructions specified in the Formula Rate to calculate annually its Net Adjusted Revenue Requirement, as set forth at page 1, line 5 of the Template ("Net Adjusted Revenue Requirement"). The Net Adjusted Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of NY Transco's Net Adjusted Revenue Requirement upon the effective date for incorporation into the ISO OATT through an appropriate filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA").

Section 1. Annual Projection

a. No later than September 30 preceding the first Rate Year, and each subsequent Rate Year, NY Transco shall determine its projected Net Adjusted Revenue Requirement for the upcoming Rate Year in accordance with NY Transco's Formula Rate ("Annual Projection"). The Annual Projection shall include the True-up Adjustment described and defined in Section 2 below, if applicable. NY Transco shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format and fully-functioning Excel file fully populated with formulas intact at a publicly accessible location on ISO's internet website.

Such posting shall include (i) all inputs in sufficient detail to identify the components of NY Transco's projected Net Adjusted Revenue Requirement, and

(ii) explanations of the bases for the projections and input data to demonstrate that each input to the formula rate is consistent with the requirements of the formula rate. If the date for making such posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day. NY Transco shall electronically serve each Annual Projection upon the Service List.[2]

b. If NY Transco makes changes in the Annual Projection for a given Rate Year, NY Transco shall cause such revised Annual Projection to be promptly posted at a publicly accessible location on the ISO internet website and shall electronically serve a link to the website upon the Service List. Changes posted prior to October 31 of the preceding Rate Year, or the next business day if October 31 is not a business day (or such later date as can be accommodated under the ISO's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-up Adjustment for the Rate Year.

c. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

[2] As used in these protocols, "Service List" shall include but not be limited to (i) the email list of ISO OATT Transmission Customers maintained by the ISO; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the ISO footprint; and (iii) any consumer advocate agency authorized by state law to review and

contest the rates for any such public utility, provided such consumer advocate agency requests to be placed on the Service List and provides an e-mail address to NY Transco.

Section 2. True-up Adjustment

NY Transco will calculate the amount of under- or over-collection of its actual Net Revenue Requirement, as set forth at page 1, line 3 of the Template during the preceding Rate Year ("True-up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-up Adjustment shall be the sum of components a and b, determined in the following manner:

a. NY Transco's projected Net Revenue Requirement collected during the previous Rate Year[3] will be compared to NY Transco's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with NY Transco's Formula Rate and based upon (i) NY Transco's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to NY Transco's calculation of its annual revenue requirement, (iii) the books and records of NY Transco (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the ISO OATT and other governing documents that apply to the calculation of annual revenue requirements under individual transmission owner formula rates, to determine any over- or under-recovery ("True-up Adjustment Over/Under Recovery"). NY Transco will include a variance analysis of, at minimum, actual revenue requirement components of rate base, operating and

[3] If the initial year of this rate schedule is a partial year, the initial projected Net Revenue Requirement will be divided by the number of months the Formula Rate is in effect to calculate the monthly projected cost of service to be collected each month of the first year. Similarly, the actual Net Revenue Requirement will be divided by the number of months the rate is in effect to calculate the actual cost of service to be collected each month of the first

year. The first True-up Adjustment will compare the projected Net Revenue Requirement billed and the actual Net Revenue Requirement for that initial Rate Year.

maintenance expenses, depreciation and amortization expense, taxes, return on rate base, and revenue credits as compared to the corresponding components in the projected revenue requirement that was calculated for the prior Rate Year with an explanation of all changes.

b. Interest on any True-up Adjustment Over/Under Recovery of the actual Net Revenue Requirement shall be calculated in accordance with the Formula Rate Attachment 7a.

Section 3. Annual Update

a. On or before June 30 following each Rate Year, NY Transco shall calculate its actual Net Adjusted Revenue Requirement, including the True-up Adjustment as described in Section 2 ("Annual Update") for such Rate Year, and shall cause such Annual Update to be posted, in both a Portable Document Format and fullyfunctioning Excel format containing the populated template with formula intact for that year's update, at a publicly accessible location on the ISO internet website, and electronically serve a link to the website upon the Service List. In addition, the Annual Update shall be contemporaneously submitted as an informational filing with the FERC.

b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

c. The date on which the last of the events listed in Section 3.a or 3.b occurs shall be that year's "Publication Date." Any delay past the date on which the last of the events listed in Section 3.a or 3.b occurs shall result in an equivalent extension of time for the submission of information requests and challenges, as described in Sections 4 and 5 below.

d. Together with the posting of the Annual Update, NY Transco shall cause to be posted on the ISO website the time, date and location for a stakeholder meeting including but not limited to (i) any Eligible Customer under the ISO OATT; (ii) any regulatory agency with rate jurisdiction over a public utility located within the ISO footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility, or (iv) any party with standing under FPA Section 205 or 206 (collectively, "Interested Persons") in order for NY Transco to explain its Annual Update and to provide Interested Persons an opportunity to seek information and clarifications regarding the Annual Update ("Stakeholder Meeting"). NY Transco shall accommodate interested parties that wish to participate in the Stakeholder Meeting via teleconference or webinar. The Stakeholder Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after June 30.

e. The Annual Update for the Rate Year:

(i) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1 to enable any interested party to replicate the calculation of the Formula Rate.[4]

[4] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Adjusted Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced from is superseded, the successor

form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinue form shall be utilized.

(ii) Shall provide supporting documentation and workpapers for the data used in the Annual Update that are not otherwise available in the FERC Form No. 1, including all adjustments made to the FERC Form No. 1 data in determining formula inputs.

(iii) Shall include a variance analysis of, at minimum, actual revenue requirement components of rate base, operating and maintenance expenses, depreciation and amortization expense, taxes, return on rate base, and revenue credits as compared to the corresponding components in the projected revenue requirement that was calculated for the prior Annual Update with an explanation of changes.

(iv) Shall provide notice and a narrative summary of all changes in NY Transco's accounting policies and practices from those in effect for the calendar year upon which the immediately preceding Annual Update was based that affect the Formula Rate or calculation of the Annual Update ("Accounting Change(s)"). Accounting Changes may, among other things, include: (1) the initial implementation of an accounting standard or policy, (2) the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction, (3) corrections of mistakes and prior period adjustments,[5] (4) the implementation of new estimation methods or policies that change prior estimates, and (5) changes to income tax elections. Such notice shall also include (1) those changes that could impact the Formula Rate or the calculations under the Formula Rate within the next three years; and

[5] For purposes of these Protocols, "mistakes" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as, but not limited to, arithmetic and other inadvertent computational errors, erroneous Form No. 1 references, or the like. Mistakes shall not include matters involving exercise of judgment or substantive

differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

(2) any changes in the ISO OATT from the provisions of the ISO OATT in effect during the calendar year upon which the most recent Net Revenue Requirement was based and that could impact the Formula Rate or the calculations under the Formula Rate within the next three years.

(v) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.

(vi) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and

(vii) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Person seeking to modify the Formula Rate (*i.e.,* any modifications to the Formula Rate will require, as applicable, an FPA Section 205 or Section 206 filing or initiation of a Section 206 investigation).

(viii) Shall provide support for any deferred income tax account balances, including any Statement of Financial Accounting Standard Nos. 106 and 109 Adjustments.

(ix) Shall identify and provide support for any costs and expenses related to any merger or acquisition of a jurisdictional facility (including, but not limited to, acquisition premiums and goodwill) that have been included in the Annual

Update, including a citation to the FERC order approving the recovery of such costs and expenses; otherwise, any such costs that have been reported in the

FERC Form No. 1 must be deducted from the costs to be recovered in the Annual Update.

(x) Shall identify any asset retirement obligations ("ARO") included in the Annual Update, including a citation to the FERC order approving recovery of the ARO; otherwise, any such items reported in the FERC Form No. 1 must be deducted from the costs to be recovered in the Annual Update.

(xi) Shall identify the specific amounts included in the annual Update related to each transmission incentive project, a citation to the proceeding in which FERC granted the incentive, and provide a derivation of the value for each project. (xii) Shall include a worksheet listing all the errors and corrections agreed to by NY Transco and any interested parties, or ordered by FERC, related to the previous Rate Year that have been incorporated into the current Annual Update.

f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA Section 205 or 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) "Post-Employment Benefits other than Pensions" pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions ("PBOP") charges; and (iii) the depreciation and/or amortization rates as set forth in Attachment 9 to the Formula Rate template. No changes may be made to the ROE, capital structure, PBOP expenses, or depreciation and/or amortization rates absent a filing under Sections 205 or 206 of the Federal Power Act.

g. Example - Timeline for 2015 Annual Update:

On or before September 30 of the first year, NY Transco will determine the projected Net Adjusted Revenue Requirement for the second year, which is expected to be the first year that costs are recovered from ISO customers under the Formula Rate. NY Transco will post the Annual Projection for the second Rate Year in accordance with Section 1 above. NY Transco will not determine a True-up Adjustment or post an Annual Update on August 1 of the second year if no costs have been recovered under the Formula Rate during the first year. On or before September 30 of the second year, NY Transco will post the Annual Projection for the third Rate Year. On or before August 1 of the third year, NY Transco will post its first Annual Update, consisting of the True-up Adjustment for the second Rate Year determined pursuant to Section 2 above. Such True-up Adjustment will be reflected in the Annual Projection of the Net Adjusted Revenue Requirement for the fourth Rate Year posted on or before September 30 of the third year. The Annual Update posted August 1 of the third year will be subject to the customer review and challenge procedures described in Sections 4, 5, and 6 of these Protocols.

Section 4. Annual Review Procedures

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Persons shall have up to the latest of one hundred fifty (150) calendar days after the Publication Date, thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of NY Transco), or thirty (30) calendar days after resolution of a dispute that does not result in the production of additional information ("Review Period"), to review the calculations and to notify NY Transco in writing of any specific challenges, including but not limited to challenges related to Accounting Changes and to the Annual Update ("Preliminary Challenge"). Interested persons may challenge through a Preliminary Challenge or a Formal Challenge: (1) whether NY Transco has properly calculated the Annual Update under review (including any corrections pursuant to Section 6); (ii) whether the costs included in the Annual Update are properly recordable and recorded, prudent, reasonable, and incurred according to appropriate procurement methods and cost control methodologies and otherwise consistent with NY Transco's accounting policies, practices and procedures consistent with the USofA; (iii) whether the input data used in the Annual Update are accurate and correctly used in the Formula Rate; (iv) the effect of Accounting Changes; and (v) whether the Formula Rate has been applied according to its terms, including the procedures in these Protocols. NY Transco shall promptly cause to be posted all Preliminary Challenges at a publicly accessible location on the ISO internet website and a link to the website will be electronically served upon the Service List. Any Formal Challenges are to be filed in the NY Transco's informational filing dockets.

NY Transco shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which NY Transco agrees or disagrees with the challenge. If NY Transco disagrees with the Preliminary Challenge, its response shall include supporting documentation. NY Transco shall promptly cause to be posted responses to all Preliminary Challenges at a publicly accessible location on the ISO internet website and a link to the website will be electronically served upon the Service List.

b. Interested Persons shall have up to one hundred twenty (120) calendar days after each annual Publication Date (unless such period is extended with the written consent of NY Transco) to serve reasonable information requests on NY Transco. Information requests shall be limited to what is necessary to determine if: (i) NY Transco has properly calculated the Annual Update under review (including any corrections pursuant to Section 6); (ii) the costs included in the Annual Update are properly recordable and recorded, reasonable, prudent, and incurred according to appropriate procurement methods and cost control methodologies and otherwise consistent with NY Transco's accounting policies, practices and procedures consistent with the USofA; (iii) the input data used in the Annual Update are accurate and correctly used in the Formula Rate; (iv) the effect of Accounting Changes; (v) the Formula Rate has been applied according to its terms, including the procedures in these Protocols; and (vi) any other information that may reasonably have substantive effect on the calculation of the revenue requirement pursuant to the Formula Rate. NY Transco shall cause any information requests received to be posted at a publicly accessible location on the ISO internet website and shall electronically serve a link to the website upon the Service List. The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

c. NY Transco shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) business days of receipt of such requests. In the event an information request is not provided within 10 business days, the parties will mutually agree on an extension of the Review Period.

To the extent NY Transco and any Interested Person(s) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, NY Transco or any Interested Person may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules. NY Transco shall not clam that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing NY Transco's Annual True-Up or Projected Net Revenue Requirement.

d. Failure to pursue an issue through a Preliminary Challenges or to otherwise lodge a Formal Challenge regarding any issue as to a given Annual Update only bars pursuit of such issue with respect to that Annual Update, and in no event shall bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

e. If a change made by NY Transco to its accounting policies, practices or procedures, or their application to the Formula Rate, pursuant to Section 3(e)(iv) of these Protocols is found by the FERC to be unjust, unreasonable, and/or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any lawful remedy that may be prescribed by FERC to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 5. Resolution of Challenges

a. NY Transco shall appoint a senior representative to attempt to resolve any Preliminary Challenge. If NY Transco and any Interested Person have not resolved any Preliminary Challenge to the Annual Update within sixty (60) calendar days after the end of the Review Period (unless such period is extended with the written consent of NY Transco to continue efforts to resolve the Preliminary Challenge), such Interested Person may, within thirty (30) calendar days thereafter, file a challenge with the FERC ("Formal Challenge"), which shall be served on NY Transco by electronic service on the date of such filing. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by NY Transco pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Person from raising that issue in a Formal Challenge.

b. Any response by NY Transco to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal

Challenge, and NY Transco shall serve on the filing party(ies) and the Service List by electronic service on the date of such filing.

c. In any proceeding concerning a given year's Annual Update (including corrections) or Accounting Change(s), NY Transco shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

d. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of NY Transco to file unilaterally, pursuant to Section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a Section 205 filing under these Protocols (including, but not limited to, ROE, depreciation and amortization rates, and PBOPs), or the right of any other party or the Commission to seek such changes pursuant to Section 206 of the FPA and the regulations thereunder.

e. NY Transco may, at its discretion and at a time of its choosing, make a limited filing pursuant to Section 205 to modify stated values in the Formula Rate for amortization and depreciation rates, or PBOP rates. The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

Section 6. Changes to Annual Updates

If NY Transco determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, NY Transco shall promptly notify the Service List, file a correction to the Annual Update with the FERC as an amended informational filing, and cause such information to be posted at a publicly accessible location on the ISO internet website. Such corrections shall be subject to review at the time they are made and shall be reflected in the next Annual Update, with interest. A corrected posting shall reset the deadlines under Section 4 and 5 of the Protocols for Interested Person review and the revised dates shall run from the posting date(s) for each of the corrections. The scope of review shall be limited to the aspects of the Formula Rate affected by the corrections. Interest on any over- or under-recovery due to corrections for preceding True-up Adjustments shall be calculated monthly on such over- or under-recovery from January 1 of the corrected Rate Year through December 31 of the Rate Year in which such over- or under-recovery is reflected ("Correction Period"). The applicable monthly interest rates for the Correction Period for an over-recovery shall be determined in accordance with the Formula Rate true-up worksheet divided by twelve (12) for each month from the beginning of the Correction Period through December 31 of the Rate Year immediately preceding the Rate Year in which such over-recovery is reflected. The applicable monthly interest rates for the Correction Period for an under-recovery shall be the annual interest rate determined in accordance 18 C.F.R § 35.19a divided by twelve (12) for each month from the beginning of the Correction Period through December 31 of the Rate Year immediately preceding the Rate Year in which such under-recovery is reflected.

Section 7. Construction Work in Progress

a. *Accounting.* For each transmission project for which NY Transco has been authorized by a Commission order to include Construction Work in Progress ("CWIP") in transmission rate base ("CWIP Project"), NY Transco shall use the following accounting procedures to ensure that it does not recover an Allowance for Funds Used During Construction ("AFUDC") for such project.

(i) NY Transco shall assign each CWIP Project a unique Funding Project Number ("FPN") for internal cost tracking purposes. For a CWIP Project for which the NY Transco is recovering less than 100% of CWIP in rate base, two FPNs will be assigned, one reflecting the CWIP balance in rate base and the other reflecting the balancing accruing AFUDC. NY Transco will assign FPNs in such a way that an Interested Person can identify that the balances are associated with the same project.

(ii) NY Transco shall record actual construction costs to each FPN through work orders that are coded to correspond to the FPN for each CWIP Project. Such work orders shall be segregated from work orders for transmission projects for which the Commission has not authorized NY Transco to include CWIP in rate base.

(iii) For each CWIP Project for which NY Transco is allowed to include 100% of CWIP in rate base, NY Transco shall ensure that no AFUDC will be accrued under the associated FPN.

(iv) For each CWIP Project, NY Transco shall prepare monthly work order summaries of costs incurred under the associated FPN. These summaries shall show monthly additions to CWIP and plant in service and shall correspond to amounts recorded in NY Transco's FERC Form No. 1. NY Transco shall use these summaries as data inputs into the Annual Update calculated pursuant to Section 3 and shall make such work order summaries available upon request pursuant to the review procedures of Section 4.

(v) When a CWIP Project is, or portion thereof, is placed into service, NY Transco shall deduct from total CWIP the accumulated charges for work orders under the FPN for that project, or portion thereof. The purpose of this control process is to ensure that expenditures are not double counted as both CWIP and as additions to plant.

(vi) For transmission projects for which the Commission has not authorized NY Transco to include CWIP in rate base, NY Transco shall record AFUDC to be applied to CWIP and capitalized when the project is placed into service.

b. *Annual Reporting.* For each CWIP Project, NY Transco shall file a report with the Commission at the time of NY Transco's Annual Update that shall include the following information concerning each such project:

(i) the actual amount of CWIP recorded for each project;

(ii) any amounts recorded in related FERC accounts or subaccounts, such as AFUDC and regulatory liability;

(iii) the resulting effect of CWIP on the revenue requirement;

(iv) a statement of the current status of each project; and the estimated in-service date for each project.

37 Attachment EE – Coordination Agreement Between ISO New England Inc. and The New York Independent System Operator, Inc.

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THIS AGREEMENT was made the 1st day of January 2006 and is hereby restated on the 1st day of August 2017

BETWEEN:

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC., a not-for-profit corporation established under the laws of New York State, hereinafter called the "NYISO".

and

ISO NEW ENGLAND INC., a not-for-profit, private corporation established under the laws of the State of Delaware, hereinafter called "ISO-NE".

RECITALS

WHEREAS, capitalized terms not otherwise defined herein shall have the meanings ascribed to them in Section 1.0 hereof;

WHEREAS, ISO-NE and the NYISO are sometimes hereinafter referred to, collectively, as the "Parties" and, individually, as a "Party";

WHEREAS, the NYISO is an independent, not-for-profit corporation established pursuant to the ISO Agreement, responsible for providing transmission service, maintaining the Reliability of the electric power system and facilitating efficient markets for capacity, energy and ancillary services in the New York Balancing Authority Area in accordance with its filed NYISO Tariffs;

WHEREAS, ISO-NE is a not-for-profit, independent corporation that serves as the RTO for New England, in which capacity it operates New England's wholesale electricity markets, manages a comprehensive regional bulk power system planning process and is responsible for the day-to-day reliable operation of New England's bulk power system;

WHEREAS, ISO-NE, as RTO for the New England Transmission System and administrator of the New England markets, and the NYISO as the ISO for the New York Transmission System, enter into coordination agreements and operating arrangements with the operators of neighboring Reliability Coordinator Areas and Balancing Authority Areas, and coordinate system operation and Emergency procedures with neighboring Reliability Coordinator Areas and Balancing Authority Areas;

WHEREAS, the NYISO and ISO-NE desire to coordinate interconnected operation to maintain Reliability for both of the power systems of New York State and the New England States, recognizing the Parties' desire to maximize interconnected capability under the terms and conditions contained in this Agreement; and

WHEREAS, related to the Interconnection Facilities:

A. ISO-NE is the Reliability Coordinator, Balancing Authority, Transmission Operator, market operator, and Planning Authority for the six New England States and operates and is responsible for the secure operation of the New England Transmission System in accordance with its Transmission Operating Agreements with New England Transmission Owners and in compliance with the FERC-accepted ISO-NE Tariff , and the requirements and criteria set forth by NERC or NPCC and, as such, has the power and authority to enter into this Agreement and perform its obligations under it;

B. NYISO is the Reliability Coordinator, Balancing Authority, Transmission Operator, market operator, and Planning Authority for New York State and operates and is responsible for the secure operation of the New York Transmission System in accordance with its Transmission Operating Agreements with New York Transmission Owners and in compliance with the FERC-accepted New York Independent System Operator Agreement ("ISO Agreement"), the Agreement Between New York Independent System Operator and Transmission Owners ("ISO/TO Agreement"), the Agreement Between New York Independent System Operator and the New York State Reliability Council ("ISO/NYSRC Agreement"), NYISO Tariffs, and the requirements and criteria set forth by NERC, NPCC and the NYSRC and, as such, has the power and authority to enter into this Agreement and perform its obligations under it; and

C. The New England Transmission System and the New York Transmission System interconnect by way of the Interconnection Facilities, which are described in Schedule A of this Agreement; and

D. The Parties wish to record their agreement as to the operational and other matters addressed herein and pertaining to the Interconnection Facilities; and

WHEREAS the Parties desire to manage the operational aspects of their interconnected operations by developing, administering and implementing practices, procedures and sharing information relating to Reliability coordination and power system operation that will be managed and approved by a committee formed under this Agreement;

NOW, THEREFORE, THIS AGREEMENT WITNESSES THAT in consideration of the mutual agreements and obligations between the Parties and for other good and valuable consideration ISO-NE and the NYISO agree as follows:

ARTICLE 1.0: DEFINITIONS

In this Agreement, the following words and terms shall have the meanings (such meanings to be equally applicable to both the singular and the plural forms) ascribed to them in this Article 1.0.

"Adequacy" means the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

"Agreement" means this Agreement and the Schedule(s) attached hereto and incorporated herein.

"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

"Balancing Authority Area" means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

"Confidential Information" has the meaning stated in Section 6.5 of this Agreement.

"Confirmed Trust Relationship" means that one Responsible Settlement Party has granted another Responsible Settlement Party permission to confirm, modify or withdraw its CTS Interface Bids.

"Control Area" means an electric system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (1) match, at all times, the power output of the Generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the Load within the electric power system(s); (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and (4) provide sufficient capacity to maintain Operating Reserves in accordance with Good Utility Practice.

"Coordination Committee" means the jointly constituted ISO-NE and NYISO committee established to administer the terms and provisions of this Agreement pursuant to Article 7.0 of this Agreement.

"Coordinated Transaction Scheduling" or "CTS" means an external transaction scheduling process between the NYCA and NECA in which Market Participants' bids, to buy energy in one region and sell in another region, are economically and simultaneously cleared by ISO-NE and NYISO. This process takes place pursuant to market rules in the Parties' respective tariffs that allow transactions to be scheduled over a CTS Enabled Interface based on a bidder's willingness to purchase energy from the NYCA or NECA (the source) and sell it to the other Control Area (the sink) if the bid price is less than or equal to the expected LMP difference across the interface in the requested direction, as of the time the interface is scheduled.

"CTS Enabled External Proxy Bus" shall mean an External Proxy Bus at which the Parties accept CTS Interface Bids to schedule external transactions in the real-time energy market.

"CTS Enabled Interface" means an Interconnection at which the Parties accept CTS Interface Bids for all import offers, for all export bids, and for wheels through the NECA. The CTS Enabled Interfaces are specified in Section 4.4.4 of the NYISO's Market Administration and Control Area Services Tariff and in Section III.1.10.7.A of the ISO-NE Tariff.

"CTS Interface Bid" means: (1) in ISO-NE, an Interface Bid as defined in the ISO-NE Tariff, and an hourly spread bid associated with the wheeling of energy through the NECA, and (2) in NYISO, a CTS Interface Bid as defined in the NYISO Tariff.

"Delivery Point" means a point on each of the three Interconnections between the New England Balancing Authority Area and the NYISO Balancing Authority Area and such other points of Interconnection as may be established. Such Delivery Point(s) shall include the Interconnection Facilities between ISO-NE and the NYISO.

"Dispute" has the meaning attributed thereto in Article 19.0 of this Agreement.

"Effective Date" means the reference date of this Agreement as shown on the first page of this Agreement.

"Emergency" means any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the Reliability of the Bulk Electric System (as defined by NERC).

"Emergency Energy" means energy supplied from Operating Reserve or electrical generation available for sale in New York or New England or available from another Balancing Authority Area. Emergency Energy may be provided in cases of sudden and unforeseen outages of generating units, transmission lines or other equipment, or to meet other sudden and unforeseen circumstances such as forecast errors, or to provide sufficient Operating Reserve. Emergency Energy is provided pursuant to this Agreement and priced according to Attachment A of Schedule C of this Agreement.

"External Interface Congestion" means the portion of the congestion component of the LMP at an External Proxy Bus that is associated with an External Proxy Bus Constraint.

"External Proxy Bus" means a location that is selected to represent an Interconnection with a Party's Control Area for which LMPs are calculated. In NYISO, this is a Proxy Generator Bus as defined in the NYISO Services Tariff. In ISO-NE, this is an External Node as defined in the ISO-NE Tariff.

"External Proxy Bus Constraint" has the meaning set forth in Section 4.2 of Schedule D to this Agreement.

"FERC" means the Federal Energy Regulatory Commission.

"Force Majeure" means an event of force majeure as described in Section 13.1 of this Agreement.

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the North American electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with good business practices, Reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted by NERC and the FERC.

"Intentional Wrongdoing" means an act or omission taken or omitted by a Party with knowledge or intent that injury or damage could reasonably be expected to result.

"Interconnection" means a connection(s) between two or more individual Transmission Systems that have interconnecting Intertie(s).

"Interconnection Facilities" means the Interconnections described in Schedule A.

"Interconnection Reliability Operating Limit" or "IROL" means a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages (as defined by NERC) that adversely impact the reliability of the Bulk Electric System.

"Intertie" means a transmission line that forms part of an Interconnection.

"ISO" means independent system operator, as designated by FERC.

"ISO Agreement" means the agreement that establishes the NYISO.

"ISO-NE Supply Price Points" means a set of increasing MW and price pairs, as described in Section 3 of Schedule D.

"ISO-NE Tariff" means the ISO New England Inc. Transmission, Markets and Services Tariff, which includes the ISO-NE Open Access Transmission Tariff and ISO-NE market rules.

"Locational Marginal Price" or "LMP" shall mean the market price for energy at a given location in a Party's Control Area, calculated in accordance with the requirements of the Party's tariff, and "Locational Marginal Pricing" shall mean the processes related to the determination of the LMP.

"Market Participant" means a participant in either the ISO-NE- or NYISO-administered wholesale power markets. Market Participants include transmission service customers, power exchanges, Transmission Owners, load serving entities, loads, holders of energy derivatives, generators and other power suppliers and their designated agents.

“Metered Quantity” means apparent power, reactive power, active power, with associated time tagging and any other quantity that may be measured by a Party’s Metering Equipment and that is reasonably required by either Party for Security reasons or revenue requirements.

“Metering Equipment” means the potential transformers, current transformers, meters, interconnecting wiring and recorders used to meter any Metered Quantity.

“Mutual Benefits” as described in Article 3.0 of this Agreement, means the transient and steady-state support that the integrated generation and transmission facilities in the New England and New York Transmission Systems provide to each other inherently by virtue of being interconnected.

“NERC” means the North American Electric Reliability Corporation or the successor organization.

“New England Control Area” or “NECA” is the Control Area for New England as defined in the ISO-NE Tariff.

“New England Transmission System” for the purpose of this Agreement means the entire system of transmission facilities, within the New England Reliability Coordinator Area and Balancing Authority Area that are under ISO-NE’s operational jurisdiction, as defined in Transmission Operating Agreements and the ISO-NE Tariff.

“New York Control Area” or “NYCA” means the Control Area that is under the operational control of the NYISO, as defined in the NYISO Tariffs.

“New York State Reliability Council” or “NYSRC” means the organization that promotes and preserves the Reliability of electric service on the New York Transmission System by developing and maintaining NYSRC Reliability Rules which are complied with by the NYISO, and for monitoring and assuring compliance with such rules.

“New York Transmission System” for the purpose of this Agreement means the “NYS Transmission System” as that term is defined in the NYISO OATT.

"NPCC" means the Northeast Power Coordinating Council Inc. or its successor organization.

“NPCC Criteria, Guides and Procedures” are documents, or the successor of these documents, that contain the Reliability Standards of the NPCC and which detail the principles of interconnected planning and operations that define and direct the efforts of the NPCC and its members. These documents are essential to maintaining the Security, Adequacy, Reliability and efficient operation of the interconnected bulk power supply system of NPCC members.

“NYISO Open Access Transmission Tariff” or “NYISO OATT” means the NYISO Open Access Transmission Tariff accepted by FERC.

"NYISO Services Tariff" means the NYISO Market Administration and Control Area Services Tariff accepted by FERC.

"NYISO Tariffs" means the NYISO OATT and the NYISO Services Tariff, collectively.

"NYSRC Reliability Rules" means the rules applicable to the operation of the New York Transmission System by the NYISO. These rules are based on Reliability Standards adopted by NERC and NPCC, but also include more specific and more stringent rules to reflect the particular requirements of the New York Transmission System.

"Operating Instructions" means the joint operating procedures, steps, and instructions that are to be utilized by both Parties for the operation of the Interconnection Facilities established and modified from time to time by the Coordination Committee in accordance with (a) the ISO-NE Tariff and the NYISO Tariffs, (b) Schedule B of this Agreement and (c) the ISO-NE and NYISO individual procedures and processes. Operating Instructions are separate from the ISO-NE and NYISO individual procedures and processes.

"Operating Reserve" means: (1) in ISO-NE, an Operating Reserve as defined in Section I.2.2 of the ISO-NE Tariff, and (2) in NYISO, an Operating Reserve as defined in Section 2.2 of the NYISO Services Tariff. For purposes of Schedule D to this Agreement, 10-minute Operating Reserve is considered a higher quality product than 30-minute Operating Reserve.

"Operational Control" for the purpose of this Agreement, means Security monitoring, adjustment of generation and transmission resources, coordinating and approval of changes in transmission status for maintenance, determination of changes in transmission status for Reliability, coordination with other Balancing Authority Areas and Reliability Coordinators, voltage reductions and load shedding, except that each legal owner of generation and transmission resources continues to physically operate and maintain its own facilities.

"Parties" means ISO-NE and NYISO, and "Party" means either one of them.

"Planning Authority" means the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

"Ramp Limit" means, for purposes of Schedule D to this Agreement, either: (1) the maximum allowable amount of change in net interchange at a CTS Enabled Interface over a defined period of time, established in accordance with Section 5.1 of Schedule D; or (2) the maximum allowable amount of change in net interchange across all NYISO Proxy Generator Buses over a defined period of time, established in accordance with the NYISO Tariffs.

"Real-Time Commitment" or "RTC" means the NYISO's multi-period security constrained unit commitment and dispatch model, as defined in the NYISO Tariffs.

"Reliability" means the degree of performance of the bulk electric system that results in electricity being delivered within Reliability Standards and in the amount desired. Electric system Reliability can be addressed by considering two basic and functional aspects of electric systems, which are Adequacy and Security.

"Reliability Coordinator" means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area (as defined by NERC) view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

"Reliability Coordinator Area" means the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

"Reliability Standards" means the criteria, standards and requirements relating to Reliability established by a Standards Authority.

"Responsible Settlement Party" or "RSP" means a Market Participant that is responsible for the financial settlement of one or more transactions at a CTS Enabled Interface, as determined in accordance with the requirements of the Parties' respective tariffs that address the settlement of external transactions at CTS Enabled Interfaces.

"RTO" means a regional transmission organization, as designated by FERC.

"Schedule" means a schedule attached to this Agreement and all amendments, attachments, supplements, replacements and/or additions thereto.

"Security" means the ability of the electric system to withstand sudden disturbances including, without limitation, electric short circuits or unanticipated loss of system elements.

"Standards Authority" means NERC, NPCC, NYSRC or any other agency with authority over either Party regarding standards or criteria relating to the Reliability of Transmission Systems.

"System Operating Limit" means the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable Reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to the following NERC-defined ratings or limits: Facility Ratings (applicable pre- and post-Contingency equipment or facility ratings); Transient Stability Ratings (applicable pre- and post-Contingency Stability Limits); Voltage Stability Ratings (applicable pre- and post-Contingency Voltage Stability); and System Voltage Limits (applicable pre- and post-Contingency Voltage Limits).

"Third Party" means a person or entity that is not a Party to this Agreement.

"Transfer Limit" means the minimum or maximum net interchange that can be scheduled on a CTS Enabled Interface and is established in accordance with Section 5.0 of Schedule D.

"Transmission Operating Agreement(s)" means the respective agreements that establish the terms and conditions under which the Transmission Owners transferred to the NYISO and ISO-

NE Operational Control over the Interconnection Facilities. For the NYISO, these agreements are the ISO Agreement, the ISO/TO Agreement, and the ISO/NYSRC Agreement. For ISO-NE, this is the Transmission Operating Agreement, which provides operating authority over certain Interconnection Facilities (i.e., the NY/NE Northern AC Interconnection and the NNC Interconnection), and Attachment K to Section II of the ISO-NE Tariff, which provides operating authority over other Interconnection Facilities (i.e., the CSC Interconnection).

"Transmission Operator" means the entity responsible for the Reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities in accordance with applicable Transmission Operating Agreements.

"Transmission Owner" means the entity that owns and maintains transmission facilities.

"Transmission System" means a system for transmitting electricity, and includes any structures, equipment or other facilities used for that purpose.

ARTICLE 2.0: SCOPE OF AGREEMENT

2.1 Restatement of Prior Agreement

The terms of the prior agreement made between the Parties dated January 1, 2006, are hereby amended, restated and superseded by the terms of this Agreement, to be effective on the Effective Date of this Agreement.

2.2 Purpose of This Agreement

This Agreement provides for the reliable operation of the interconnected New England and New York Transmission Systems in accordance with the requirements of the Standards Authority.

This Agreement establishes a structure and framework for the following functions related to the Reliability of interconnected operations between the Parties:

(a) developing and issuing Operating Instructions and System Operating Limits;

(b) coordinating operation of their respective Transmission Systems;

(c) developing and adopting operating criteria and standards;

(d) conducting operating performance reviews of the Interconnection Facilities;

(e) considering matters related to transmission service and access;

(f) implementing each Party's respective NERC and NPCC requirements with regard to the New England Transmission System and New York Transmission System;

(g) exchanging operations information regarding the Interconnection;

(h) exchanging information and coordinating regarding system planning;

(i) providing mutual assistance in an Emergency and during system restoration;

(j) administering Coordinated Transaction Scheduling; and

(k) implementing other arrangements between the Parties for the coordination of their systems.

The Parties shall, consistent with NPCC Criteria, Guides and Procedures and the Parties' respective tariffs, rules and standards, including with respect to the NYISO, the NYSRC Reliability Rules, to the maximum extent they deem consistent with the safe and proper operation of their respective Reliability Coordinator Area and Balancing Authority Area and necessary coordination with other interconnected systems, and with the furnishing of dependable and satisfactory service to their own customers, operate their systems in accordance with the following procedures and principles.

ARTICLE 3.0: MUTUAL BENEFITS

3.1 No Charge for Mutual Benefits of Interconnection

Both the New England Transmission System and New York Transmission System, by virtue of being connected to each other and with a much larger Interconnection, share Mutual Benefits such as transient and steady-state support. NYISO and ISO-NE shall not charge one another for such Mutual Benefits.

3.2 Maintenance of Mutual Benefits

The Parties shall endeavor to operate or direct the operation of the Interconnection Facilities to realize the Mutual Benefits. The Parties recognize circumstances beyond their control, such as a result of operating configurations, contingencies, maintenance, or actions by Third Parties, may result in a reduction of Mutual Benefits.

ARTICLE 4.0: INTERCONNECTED OPERATION

4.1 Obligation to Remain Interconnected

The Parties shall at all times during the term of this Agreement operate or direct the operation of their respective Transmission Systems so that they remain interconnected except:

(a) during the occurrence of an event of Force Majeure which renders a Party unable to remain interconnected;

(b) when an Interconnection is opened in accordance with the terms of an Operating Instruction;

(c) when an Interconnection is opened in accordance with Good Utility Practice in a particular circumstance where there is an imminent risk of equipment failure, or of danger to personnel or the public, or a risk to the environment, or risk to the Reliability of a Transmission System that is not anticipated and addressed within an Operating Instruction; or

(d) during planned maintenance where notice has been given in accordance with outage procedures as implemented by the Coordination Committee.

4.2 Adherence to NPCC Criteria, Guides and Procedures

The Parties are participants in the NPCC and are required to comply with NPCC Criteria, Guides and Procedures. Such NPCC Criteria, Guides and Procedures detail the many coordinating functions carried out by the Parties and this Agreement is intended to enhance this arrangement.

Such NPCC Criteria include, and the Parties agree to comply with, “Emergency Operation Criteria” (Document A-3), which describes the basic factors to be considered by a Reliability Coordinator and Balancing Authority in formulating plans and procedures to be followed in an Emergency. A principle of operation in this NPCC Criterion is that upon receiving a request for assistance to avoid or mitigate an Emergency, a Balancing Authority Area would provide “maximum reasonable assistance” to a neighboring Balancing Authority Area. Such reasonable assistance would not normally require the shedding of firm load.

4.3 Notification of Circumstances

In the event that a component of the Interconnection Facilities is opened or if the transfer capability of a component of the Interconnection Facilities is changed, or if a Party plans to initiate the opening of any component of the Interconnection Facilities, or to change the transfer capability of any component of the Interconnection Facilities, such Party shall immediately provide the other Party with notification indicating the circumstances of the opening or transfer capability change and expected restoration time, in accordance with procedures implemented by the Coordination Committee or applicable NPCC Criteria, Guides and Procedures.

4.4 Compliance with Coordination Committee Direction

ISO-NE shall direct the operation of the New England Transmission System and the NYISO shall direct the operation of the New York Transmission System in accordance with the obligations of their respective tariffs, rules and standards and applicable directions of the Coordination Committee that conform with their respective tariffs, rules and standards, including with respect to the NYISO, the NYSRC Reliability Rules, except where prevented by Force Majeure. The Coordination Committee direction includes decisions and jointly developed and approved Operating Instructions. If decisions or Operating Instructions of the Coordination Committee do not anticipate a particular circumstance, the Parties shall act in accordance with Good Utility Practice.

4.5 Control and Monitoring

Each Party shall provide or arrange for 24-hour control and monitoring of their portion of the Interconnection Facilities.

4.6 Reactive Transfer and Voltage Control

The Parties agree to determine reactive transfers and control voltages in accordance with the provisions of NPCC "Guidelines for Inter-Area Voltage Control" (Document B-03). Real and reactive power will be transferred over the Interconnection Facilities, which are described in Schedule A of this Agreement.

4.7 Inadvertent

Inadvertent power transfers on all Interconnection Facilities shall be controlled and accounted for in accordance with the standards and procedures developed by NERC and NPCC and implemented by the Coordination Committee and the system operators of each Party to this Agreement.

4.8 Adoption of Standards

The Parties hereby agree to adopt, enforce and comply with requirements and standards that will safeguard Reliability of the interconnected Transmission Systems. Such Reliability requirements and Reliability Standards shall be:

(a) adopted and enforced for the purpose of providing reliable service;

(b) not unduly discriminatory in substance or application;

(c) applied consistently to both Parties (with the exception of subsection (e) below);

(d) consistent with the Parties' respective obligations to applicable Standards Authorities including, without limitation, any relevant requirements or guidelines from each of NERC, NPCC or any other Standards Authority to which the Parties are required to adhere; and

(e) with respect to the NYISO, consistent with the NYSRC Reliability Rules.

4.9 New York - New England IROL Interface

The Parties share a joint Interconnection Reliability Operating Limit ("IROL") related to transfers on the interconnecting transmission lines between their respective Reliability Coordinator Areas and Balancing Authority Areas. This IROL is adhered to in order to ensure acceptable steady-state and transient performance of the New York and New England Transmission Systems. Both Parties will monitor this limit in accordance with this Agreement and independently determine the applicable import and export transfer limits. Both Parties agree to operate the interface to the most conservative limits developed in real-time and the day-ahead planning process. These operating limits shall be determined in accordance with NERC Reliability Standards and NPCC Criteria, Guides and Procedures. Both Parties will take coordinated corrective actions to avoid a violation of the IROL. If a violation occurs, coordinated corrective actions shall be taken to ensure that the violation is cleared as soon as possible, and in accordance with NERC Reliability Standards.

4.10 Coordination and Exchange of Information Regarding System Operations and Planning

Each Party shall have operating procedures, processes or plans in place for activities that require notification, exchange of information or coordination of actions with the other Party to support Interconnection reliability. Each Party shall have communications capabilities with the other Party, for both voice and data exchange as required to meet reliability needs of the Interconnection.

The Parties shall exchange information and coordinate regarding system operations and planning and inter-regional planning activities in a manner consistent with NERC and NPCC requirements, and consistent with the requirements of Section 6 of this Coordination Agreement.

ARTICLE 5.0: EMERGENCY ASSISTANCE

5.1 Emergency Assistance

Both Parties shall exercise due diligence to avoid or mitigate an Emergency to the extent practicable as per each Party's requirements related to the mitigation of an Emergency, in applicable policies and procedures imposed by NERC, NPCC, or (for the NYISO) the NYSRC, or contained in the ISO-NE Tariff and NYISO Tariffs. In avoiding or mitigating an Emergency, both Parties shall strive to allow for commercial remedies, but if commercial remedies are not successful, the Parties agree to be the suppliers of last resort to ensure Reliability on the system. For each hour during which Emergency conditions exist in a Party's Balancing Authority Area, that Party (while still ensuring operations within applicable Reliability Standards) shall determine what commercial remedies are available and make use of those that are available and needed to avoid or mitigate the Emergency before any Emergency Energy is scheduled in that hour.

5.2 Emergency Energy Transactions

Each Party shall, to the maximum extent it deems consistent with the safe and proper operation of its respective Transmission System, provide Emergency Energy to the other Party in accordance with the provisions of Schedule C of this Agreement.

ARTICLE 6.0: EXCHANGE OF INFORMATION AND CONFIDENTIALITY

ISO-NE and NYISO are authorized and agree to exchange and share such information as is required for the Coordination Committee to perform its duties and for the Parties to fulfill their obligations under this Agreement.

Any Party that receives Confidential Information or Critical Energy Infrastructure Information ("CEII") pursuant to this Article 6 (the "Receiving Party") shall treat such information as confidential subject to the terms and conditions set forth in Section 6.5 of this Agreement.

6.1 Information

The Parties are authorized and agree to share the following information:

(a) Information required to develop Operating Instructions;

(b) Transmission System facility specifications and modeling data required to perform Security analysis;

(c) Functional descriptions and schematic diagrams of Transmission System protective devices and communication facilities;

(d) Ratings data and associated ratings methodologies for the Interconnection Facilities;

(e) Telemetry points, equipment alarms and status points required for real-time monitoring of Security dispatch;

(f) Data required to reconcile accounts for inadvertent energy, and for Emergency Energy transactions;

(g) Transmission System information that is consistent with the information sharing requirements imposed by the NERC and NPCC;

(h) Such other information as may be required for the Parties to maintain the reliable operation of their interconnected Transmission Systems and fulfill their obligations under this Agreement and to any Standards Authority of which either Party is a member, provided, however, that this other information will be exchanged only if it can be done in accordance with applicable restrictions on the disclosure of information to any Market Participant; and

(i) Information related to the administration of CTS including:

- ISO-NE Market Participant user and organization information;

- ISO-NE Supply Price Points for each CTS Enabled Interface;
- ISO-NE Transfer Limits for each CTS Enabled Interface;
- NYISO and ISO-NE Operating Reserves and reserve requirements;
- Day-ahead schedules, and real-time actual output and limits for NYCA generators that have capacity obligations in the ISO-NE market and for NECA generators that have capacity obligations in the NYISO market;
- Real-time bids, including real-time bids to wheel energy, submitted at a CTS Enabled Interface between the NYCA and the NECA (to be provided by NYISO);
- NYISO Day Ahead Operating Plan; and
- NYISO RTC results, including cleared MWs for all bids at a CTS Enabled Interface between the NYCA and the NECA, as well as LMPs, Transfer Limits and constraint information related to the scheduling of real-time energy transactions between the NYCA and the NECA.

6.2 Data Exchange Contact

To facilitate the exchange of all such data, each Party will designate to the other Party's Vice President in charge of operations a contact(s), plus one or more alternate contacts, to be available twenty-four (24) hours each day, seven (7) days per week to respond to data inquiries. An alternate contact of each Party shall be its Operations Control Room. Each Party shall provide the name, telephone number, e-mail address, and fax number of each contact and alternate. Each Party may change the designated contact by notifying the other Party's Vice President in charge of operations in advance of the change.

The Parties agree to exchange data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. Each Party shall provide notification to the other Party thirty (30) days prior to modifying an established data exchange format.

6.3 Cost of Data and Information Exchange

Each Party shall bear its own cost of providing information to the other Party.

6.4 Other Data

The Parties may share Confidential Information not listed in this Article 6 that is necessary for the coordinated operation of their systems, subject to the protections set forth in Section 6.5, below.

6.5 Treatment of Confidential Information and Critical Energy Infrastructure Information

(a) Definitions. For purposes of addressing information shared or exchanged pursuant to this Agreement, the term "Confidential Information" shall mean: (i) all information, whether furnished before or after the mutual execution of this Agreement, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "confidential" or "proprietary" or which under all of the circumstances should be treated as confidential or proprietary; (ii) information that is Confidential Information or Strategic Information under the ISO New England Information Policy or the NYISO Code of Conduct; (iii) information that is Protected Information under the NYISO Market Monitoring Plan; (iv) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any Confidential Information; or (v) any information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC's Standards of Conduct set forth in 18 C.F.R. § 37 *et. seq*. and the Parties' Standards of Conduct on file with the FERC.

(b) Labeling of Confidential Information. In circumstances where it may not be clear that information that is provided or exchanged between the Parties pursuant to the authority provided in this Agreement is Confidential Information, the information being provided should be clearly marked "confidential" or "proprietary." Such labeling is not required for the regular, automated exchange of Confidential Information that occurs, for example, to permit the Parties to administer CTS.

(c) Protection. Except as set forth herein, the Receiving Party shall not, at any time during or after the term of this Agreement, in any manner, either directly or indirectly, divulge, disclose, or communicate to any person, firm, corporation or other entity, or use for any purposes other than those set forth herein, any Confidential Information acquired from the party disclosing the information (the "Disclosing Party"), without the express prior written consent of the Disclosing Party. The Receiving Party shall not disclose any Confidential Information to anyone except to officers and employees of the Receiving Party and to its outside consultants, advisers and/or attorneys, in each case who have a need to know to further the purposes set forth herein and who have been advised of the confidential nature of the Confidential Information and who have agreed to abide by the terms of this Agreement or are bound by equally restrictive covenants (collectively, "Authorized Representatives"). The Receiving Party agrees that it shall be liable for any breach of this Agreement by its Authorized Representatives.

(d) Survival. The obligation of each Party and each Authorized Representative under this Article 6 continues and survives the termination of this Agreement.

(e) Scope. This obligation of confidentiality shall not extend to data and information that, at no fault of the Receiving Party, is or becomes: (a) in the public domain or generally available or known to the public; (b) disclosed to a recipient by a non-Party who had a legal right to do so; or (c) independently developed by the Receiving Party or known to such Party prior to its disclosure hereunder.

(f) Required Disclosure or Submission on a Confidential Basis. If a governmental authority requests or requires the Receiving Party to publicly disclose any of the Disclosing Party's Confidential Information, or if a request from another person or entity is made in writing pursuant to a legal discovery process, the Receiving Party shall provide the Disclosing Party with prompt notice of such request or requirement. The Disclosing Party shall in turn, to the extent required by the terms of its tariff, provide any Market Participant whose Confidential Information is the subject of possible disclosure with prompt written notice of the circumstances that may require such disclosure so that the Market Participant has a reasonable opportunity to seek a protective order or other appropriate remedy to prevent disclosure.

If a Receiving Party is required to publicly disclose any Confidential Information under this Section, the Parties shall meet as soon as practicable in an effort to resolve any and all issues associated with the required disclosure, and the possibility of further requested or required disclosures of the Disclosing Party's Confidential Information.

The process described above shall also be followed if a governmental authority requests or requires the Receiving Party to submit any of the Disclosing Party's Confidential Information on a confidential basis (with the exception of requests for Confidential Information from FERC or the Commodity Futures Trading Commission ("CFTC") to the NYISO). The Receiving Party shall notify the governmental authority that the requested or required information contains NYISO or ISO-NE Market Participant specific Confidential Information, if applicable, and shall use reasonable efforts to protect the Confidential Information from public disclosure.

If FERC or the CFTC request or require the NYISO to submit any Confidential Information it received from ISO-NE on a confidential basis, the NYISO will seek permission to inform ISO-NE of the requirement or request and, if granted, will follow the procedures outlined above. In the event FERC or the CFTC does not permit the NYISO to notify ISO-NE of the request, NYISO shall inform FERC or the CFTC in writing that the disclosed information includes Confidential Information, and shall request that FERC or the CFTC inform NYISO before releasing to a third party any of the Confidential Information.

If a governmental authority (including FERC and the CFTC) that requested or required the submission, on a confidential basis, of Confidential Information by a Receiving Party issues a notice indicating that it is considering disclosing, or intends to disclose any Confidential Information provided by the Disclosing Party, or if the governmental authority (including FERC and the CFTC) receives a public records demand or other legal discovery request seeking disclosure of any

Confidential Information provided by the Disclosing Party, the Receiving Party shall notify the Disclosing Party so that the Disclosing Party may seek an appropriate protective order or other appropriate remedy. The Disclosing Party shall in turn, to the extent required by the terms of its tariff, provide any Market Participant whose Confidential Information is the subject of possible disclosure under this provision with prompt written notice of the circumstances that may require such disclosure so that the Market Participant has a reasonable opportunity to seek a protective order or other appropriate remedy to prevent disclosure.

(g) Return of Confidential Information. Information provided pursuant to this Section 6 is deemed to be on loan, and remains the property of the Disclosing Party notwithstanding the disclosure of such Confidential Information to the Receiving Party hereunder. All Confidential Information provided by the Disclosing Party shall be returned by the Receiving Party to the Disclosing Party or destroyed, erased or deleted by the Receiving Party, with written confirmation provided to the Disclosing Party, promptly upon request. Upon termination of this Agreement, a Party shall use reasonable efforts to destroy, erase, delete or return to the Disclosing Party any and all written or electronic Confidential Information. Unless otherwise expressly agreed in a separate license agreement, the disclosure of Confidential Information to the Receiving Party will not be deemed to constitute a grant, by implication or otherwise, of a right or license to the Confidential Information or in any patents or patent applications of the Disclosing Party.

(h) Relief. Each Party acknowledges that remedies at law are inadequate to protect against breach of the covenants and agreements in this Article, and hereby in advance agrees, without prejudice to any rights to judicial relief that it may otherwise have, to the granting of equitable relief, including injunction, in the Disclosing Party's favor without proof of actual damages. In addition to the equitable relief referred to in this Section, a Disclosing Party shall only be entitled to recover from a Receiving Party any and all gains wrongfully acquired, directly or indirectly, from a Receiving Party's unauthorized disclosure of Confidential Information.

(i) Existing Confidential Information Obligations**.** Notwithstanding anything to the contrary in this Agreement, the Parties shall have no obligation to disclose Confidential Information or data to the extent such disclosure of information or data would be a violation of or inconsistent with applicable state or federal regulation or law. This Agreement requires the Parties to exchange Confidential Information that is necessary for the Coordination Committee to perform its duties, or for the Parties to fulfill their obligations under this Agreement. The Parties are not obligated to share Confidential Information for other purposes.

(j) The term "CEII" or "Critical Energy Infrastructure Information" shall mean all information, whether furnished before or after the mutual execution of this Agreement, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "CEII" or "Critical Energy Infrastructure Information" or which under all of the circumstances should be treated as such in accordance with the definition of CEII in 18 C.F.R. § 388.13(c)(1). The Receiving Party shall maintain all CEII in a secure place. The Receiving Party shall treat CEII received under this agreement in accordance with its own procedures for protecting CEII and shall not disclose CEII to anyone except its Authorized Representatives.

6.6 Unauthorized Transfer of Third-Party Intellectual Property

In the performance of this Agreement, no Party shall transfer to the other Party any Intellectual Property, the use of which by the other Party would constitute an infringement of the rights of another entity (including the Parties). In the event such transfer occurs, whether or not inadvertent, the transferring Party shall, promptly upon learning of the transfer, provide Notice to the receiving Party and upon receipt of such Notice the receiving Party shall take reasonable steps to avoid claims and mitigate losses.

ARTICLE 7.0: COORDINATION COMMITTEE

7.1 Coordination Committee Inauguration and Authorization

The Parties shall form a Coordination Committee under this Agreement. Within 30 days of the Effective Date, each of the Parties shall appoint two representatives, a principal and an alternate, to serve as members of the Coordination Committee with the authority to act on their behalf with respect to actions or decisions taken by the Coordination Committee. A Party may, at any time upon providing prior notice to the other Party, designate a replacement principal member or alternate member to the Coordination Committee.

7.2 Coordination Committee Duties and Responsibilities

The Coordination Committee exists to administer or assist the Parties' implementation of the provisions of this Agreement. The Coordination Committee shall develop and adopt policies, instructions, and recommendations relating to the Parties' performance of their obligations under this Agreement, attempt to resolve Disputes between the Parties pursuant to Article 17.0 of this Agreement, and shall undertake any other actions specifically delegated to it pursuant to this Agreement.

The Coordination Committee shall undertake to assist the Parties' efforts to jointly develop Operating Instructions to implement the intent of this Agreement in accordance with Schedule B of this Agreement, 'Procedures for Development and Authorization of Operating Instructions'. The Coordination Committee shall authorize such Operating Instructions once developed. To the extent that the Operating Instructions require participation by local control centers and Transmission Owners in the New England or the New York Reliability Coordinator Areas, those entities will be involved in the development process.

Should the terms and conditions contained in this Agreement be found to conflict with or fail to recognize obligations of a Standards Authority of which either Party is a member or other regulatory requirements, the Parties agree to amend this Agreement accordingly.

Any recommendations on revisions to this Agreement shall be provided to each Party's appropriate corporate officers for approval.

7.3 Limitations of Coordination Committee Authority

The Coordination Committee is not authorized to modify or amend any of the terms of this Agreement. The Coordination Committee is also not authorized to excuse any obligations under this Agreement or waive any rights pertaining to this Agreement. The Coordination Committee has no authority to commit either Party to any expenditure that is beyond those expenses described herein.

7.4 Exercise of Coordination Committee Duties

The Coordination Committee shall hold meetings no less frequently than once each calendar year. The matters to be addressed at all meetings shall be specified in an agenda, which shall contain items specified by either Party in advance of the meeting and sent to the representatives of the other Party. All decisions of the Coordination Committee must be unanimous. Special meetings may be called at any time if the Coordination Committee deems such meetings to be necessary or appropriate.

Subject to the limitations on its authority as described in Section 7.3 of this Agreement, the Coordination Committee has the responsibility and authority to take action on all aspects of this Agreement, including, but not limited to the following:

(a) amending, adding or canceling Operating Instructions and providing written notice in accordance with Article 18.0 of this Agreement;

(b) assessment of non-compliance with this Agreement and, subject to Article 19.0 of this Agreement, the taking of appropriate action in respect thereof;

(c) documentation of decisions related to the initial resolution of Disputes as set out in Article 19.0 of this Agreement, or in cases of unresolved Disputes, the circumstances relevant to the Dispute in question as contemplated by the requirements of Article 19.0 of this Agreement; and

(d) preparation, documentation, retention and distribution of Coordination Committee meeting minutes and agendas.

ARTICLE 8.0: RELIABILITY COORDINATION AND RELIABILITY ASSESSMENT OF OUTAGES

Both Parties agree to provide each other with updates on planned outage schedules and other activities in accordance with NPCC Criteria, Guides and Procedures that may impact on the Reliability or availability of the interconnected New York Transmission System and New England Transmission System. As Reliability Coordinators and Balancing Authorities, the NYISO and ISO-NE, shall interact with each other as required, and with other Balancing Authorities and Reliability Coordinators, to establish System Operating Limits and to perform Reliability coordination and Reliability assessments of outages.

ARTICLE 9.0: OPERATIONAL INFORMATION

9.1 Obligation to Provide Operational Data and Status Points

The Parties shall ensure that appropriate monitoring facilities are installed as required to provide for electric power quantities or equipment loading to enable monitoring of System Operating Limits, meet requirements of each of NERC and NPCC, and for determining Interconnection Facilities inadvertent energy accounting.

ARTICLE 10.0: INTERCONNECTION REVENUE METERING

10.1 Obligation to Provide Inadvertent Energy Accounting Metering

The Parties shall ensure appropriate electric metering devices are installed as required to measure electric power quantities for determining Interconnection Facilities inadvertent energy accounting.

10.2 Standards for Metering Equipment

Any Metering Equipment used to meter Metered Quantities for inadvertent energy accounting shall be designed, verified, sealed and maintained in accordance with the Party's respective metering standards or as otherwise agreed to by the Coordination Committee.

10.3 Meter Compensation to the Point of Interconnection

The metering compensation for transmission line losses to the Interconnection Facilities Delivery Point shall be determined by the Party's respective standards or otherwise agreed to by the Coordination Committee.

10.4 Metering Readings

The Parties shall ensure that integrated meter readings are provided at least once each hour for Interconnection Facilities accounting purposes and meter registers are read at least monthly, as close as practicable to the last hour of the month. An appropriate adjustment shall be made to register readings not taken on the last hour of the month.

ARTICLE 11.0: JOINT CHECKOUT PROCEDURES

11.1 Scheduling Checkout Protocols

Both Parties shall require all real-time energy market transaction schedules over Interconnections to be tagged in accord with the NERC tagging standard. For Simultaneous Activation of Reserves ("SAR") and other emergency schedules that are not tagged, the Parties will enter manual schedules into their respective operating systems.

When there is a real-time energy market transaction scheduling conflict, the Parties will work to modify the schedule as soon as practical.

Consistent with the foregoing requirements, the Parties will perform the following types of checkouts:

(a) Day-ahead checkout shall be performed daily on the day before the transaction is to flow. Day-ahead checkout includes the verification of net interchange totals and individual transaction schedules;

(b) Real-time checkout shall be performed during the period before the transaction is to flow. Real-time checkout includes the verification of net interchange totals and individual transaction schedules;

(c) After-the-fact checkout of real-time transactions shall be performed the next business day following the day of the transactions;

(d) After-the-fact reporting of scheduled energy interchange and actual energy interchange shall be updated by each Party each day and exchanged with the other Party. Within ten (10) business days of the end of each month, the previous month's data shall be reconciled.

ARTICLE 12.0: COORDINATED TRANSACTION SCHEDULING

CTS is addressed in Schedule D to this Agreement and in the ISO-NE and NYISO Tariffs.

ARTICLE 13.0: LIABILITY

13.1 Force Majeure

A Party shall not be considered to be in default or breach of this Agreement, and shall be excused from performance or liability for damages to the other Party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, arising out of or from any act, omission, or circumstance by or in consequence of any act of God, labor disturbance, sabotage, failure of contractors or suppliers of materials, act of the public enemy, war, invasion, insurrection, riot, fire, storm, flood, ice, earthquake, explosion, epidemic, breakage or accident to machinery or equipment or any other cause or causes beyond such Party's reasonable control, including any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities, or by making of repairs necessitated by an emergency circumstance not limited to those listed above upon the property or equipment of the Party or property or equipment of others which is deemed under the Operational Control of the Party. A Force Majeure event does not include an act of negligence or Intentional Wrongdoing by a Party. Any Party claiming a Force Majeure event shall use reasonable diligence to remove the condition that prevents performance and shall not be entitled to suspend performance of its obligations in any greater scope or for any longer duration than is required by the Force Majeure event. Each Party shall use its best efforts to mitigate the effects of such Force Majeure event, remedy its inability to perform, and resume full performance of its obligations hereunder.

A Party suffering a Force Majeure event ("Affected Party") shall notify the other Party ("Non-Affected Party") in writing ("Notice of Force Majeure Event") as soon as reasonably practicable specifying the cause of the event, the scope of commitments under the Agreement affected by the event, and a good faith estimate of the time required to restore full performance. Except for those commitments identified in the Notice of Force Majeure Event, the Affected Party shall not be relieved of its responsibility to fully perform as to all other commitments in the Agreement. If the Force Majeure event continues for a period of more than 90 days from the date of the Notice of Force Majeure Event, the Non-Affected Party shall be entitled, at its sole discretion, to terminate the Agreement.

13.2 Liability to Third Parties

Nothing in this Agreement, whether express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person or entity that is not a Party or a permitted successor or assign.

13.3 Indemnification

(a) Definitions. An "Indemnifying Party" means a Party who holds an indemnification obligation hereunder. An "Indemnitee" means a Party entitled to receive indemnification under this Agreement.

(b) Third Party Losses. Each Party will defend, indemnify, and hold the other Party harmless from all losses, damages, liabilities, obligations, claims, demands, suits, proceedings, recoveries, settlements, costs and expenses, court costs, attorney fees, causes of action, judgments and other obligations (collectively, "Losses") brought or obtained by any Third Party against such other Party, only to the extent that such Losses arise directly from the:

(i) Gross negligence, recklessness, or willful misconduct of the Indemnifying Party or any of its agents or employees, in the performance of this Agreement; except to the extent such Losses arise (i) from gross negligence, recklessness, willful misconduct or breach of contract or law by the Indemnitee or such Indemnitee's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon the Indemnitee, or such Indemnitee's agents or employees; or

(ii) Breach of the Parties' obligations in Article 6 hereof.

(c) Process. The Indemnitee shall give Notice to the Indemnifying Party as soon as reasonably practicable after the Indemnitee becomes aware of the indemnifiable Losses or any claim, action or proceeding that may give rise to an indemnification. Such notice shall describe the nature of the Losses or proceeding in reasonable detail, explain how the Losses relate to the performance of this Agreement, and shall indicate, if practicable, the estimated amount of the Losses that has been sustained by the Indemnitee. A delay or failure of the Indemnitee to provide the required notice shall release the Indemnifying Party (i) from any indemnification obligation to the extent that such delay or failure materially and adversely affects the Indemnifying Party's ability to defend such claim or materially and adversely increases the amount of the indemnifiable Losses, and (ii) from any responsibility for any costs or expenses of the Indemnitee in the defense of the claim during such period of delay or failure.

(d) Indemnification shall be limited to the extent that the liability of the Indemnitee would be limited by any applicable law.

13.4 Liability Between the Parties

The Parties' duties and standard of care with respect to each other, and the benefits and rights conferred on each other shall be no greater than as expressly stated herein. Neither Party, its directors, officers, trustees, employees or agents, shall be liable to the other Party for any Losses, whether direct, indirect, incidental, punitive, special, exemplary or consequential, arising from that Party's performance or nonperformance under this Agreement, except to the extent that the Party is found liable for gross negligence or willful misconduct, in which case the Party responsible shall be liable only for direct and ordinary damages and not for any incidental, consequential, punitive, special, exemplary or indirect damages.

This section shall not limit amounts required to be paid for Emergency Energy under Schedule C to this Agreement. This section shall not apply to adjustments or corrections for errors in invoiced amounts due under Schedule C to this Agreement.

13.5 Liability for Interruptions

Except as set forth herein, neither Party shall be liable to the other Party for any Losses or damage, whether direct, indirect, incidental, punitive, special, exemplary or consequential, resulting from an occurrence on the circuits and system that are under the Operational Control of the other Party and which results in damage to or renders inoperative such circuits and system, or the separation of the systems in an Emergency, or interrupts or diminishes service, or increases, decreases or in any way affects for whatever length of time the voltage or frequency of the energy delivered hereunder to the other Party.

ARTICLE 14.0: APPLICABLE LAW

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware.

ARTICLE 15.0: LICENSE AND AUTHORIZATION

The agreements and obligations expressed herein are subject to such initial and continuing governmental permission and authorization as may be required. Each Party shall be responsible for securing and paying for any approvals required by it from any regulatory agency of competent jurisdiction relating to its participation in this Agreement and will reasonably cooperate with the other Party in seeking such approvals.

ARTICLE 16.0: ASSIGNMENT

This Agreement shall inure to the benefit of, and be binding upon and may be performed by, the successors and assigns of the Parties hereto respectively, but shall not be assignable by either Party without the written consent of the other.

ARTICLE 17.0: AMENDMENT

17.1 Review of Agreement

The terms of this Agreement are subject to review for potential amendment at the request of either Party. If, consequent to such review, the Parties agree that any of the provisions hereof, or the practices or conduct of either Party impose an inequity, hardship or undue burden upon the other Party, or if the Parties agree that any of the provisions of this Agreement have become obsolete or inconsistent with changes related to the Interconnection Facilities, the Parties shall endeavor in good faith to amend or supplement this Agreement in such a manner as will remove such inequity, hardship or undue burden, or otherwise appropriately address the cause for such change. Any amendment of this Agreement by the Parties must be done in accordance with Section 17.2.

17.2 Authorized Representatives

No amendment of this Agreement shall be effective unless effected by written instrument duly executed by the Parties' authorized representatives. For the purposes of this Section, an authorized person refers to individuals designated as such by Parties in their respective corporate by-laws.

ARTICLE 18.0: NOTICES

Except as otherwise agreed from time to time, any notice, invoice or other communication which is required by this Agreement to be given in writing, shall be sufficiently given at the earlier of the time of actual receipt or deemed time of receipt if delivered personally to a senior official of the Party for whom it is intended or electronically transferred or sent by registered mail, addressed as follows:

In the case of the NYISO to:

New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, New York 12144
Attention: Vice President of Operations

In the case of ISO-NE to:

ISO New England Inc.
One Sullivan Road
Holyoke, Massachusetts 01040-2841
Attention: Vice President of System Operations

or delivered to such other person or electronically transferred or sent by registered mail to such other address as either Party may designate for itself by notice given in accordance with this Section or delivered by any other means agreed to by the Parties hereto.

Any notice, or communication so mailed shall be deemed to have been received on the third business day following the day of mailing, or if electronically transferred shall be deemed to have been received on the same business day as the date of the electronic transfer, or if delivered personally shall be deemed to have been received on the date of delivery or if delivered by some other means shall be deemed to have been received as agreed to by the Parties hereto.

The use of a signed facsimile of notices and correspondence between the Parties related to this Agreement shall be accepted as proof of the matters therein set out. Follow-up with hard copy by mail will not be required unless agreed to by the Coordination Committee.

ARTICLE 19.0: DISPUTE RESOLUTION

In the event of a dispute arising out of or relating to this Agreement (a "Dispute") that is not resolved by the representatives of the Parties who have been designated under Section 7.1 of this Agreement within 7 days of the reference to such representatives of such Dispute, each Party shall, within 14 days' written notice by either Party to the other, designate a senior officer with authority and responsibility to resolve the Dispute and refer the Dispute to them. The senior officer designated by each Party shall have authority to make decisions on its behalf with respect to that Party's rights and obligations under this Agreement. The senior officers, once designated, shall promptly begin discussions in a good faith effort to agree upon a resolution of the Dispute. If the senior officers do not agree upon a resolution of the Dispute within 30 days of its referral to them (or within such longer period as the senior officers mutually agree to in writing), or do not mutually agree to submit their Dispute for binding or non-binding arbitration by the Federal Energy Regulatory Commission's Dispute Resolution Service, then the Parties shall request that the Federal Energy Regulatory Commission's Dispute Resolution Service mediate their efforts to resolve the Dispute. At any point in the mediation process, either Party may terminate the mediation and may pursue any and all remedies available to it at law or in equity.

Neither the giving of notice of a Dispute, nor the pendency of any Dispute resolution process as described in this Section shall relieve a Party of its obligations under this Agreement, extend any notice period described in this Agreement or extend any period in which a Party must act as described in this Agreement. Notwithstanding the requirements of this Section, either Party may terminate this Agreement in accordance with its provisions, or pursuant to an order of FERC or a court at equity. The issue of whether such a termination is proper shall not be considered a Dispute hereunder.

ARTICLE 20.0: REPRESENTATIONS

20.1 Good Standing

Each Party represents and warrants that it is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable.

20.2 Authority to Enter Into Agreement

Each Party represents and warrants that it has the right, power and authority to enter into this Agreement, to become a Party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms.

20.3 Organizational Formation Documents

Each Party represents and warrants that the execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, bylaws, operating agreement, or agency agreement of such Party, or any judgment, license, permit, regulatory order, or governmental authorization applicable to such Party.

20.4 Regulatory Authorizations

Each Party represents and warrants that it has, or applied for, all regulatory authorizations necessary for it to perform its obligations under this Agreement.

ARTICLE 21.0: EFFECTIVE DATE AND TERM

Subject to the conditions of Article 13.0 (License and Authorization) above, this Agreement shall take effect as of the date that all of the following have occurred: (i) upon the execution hereof by both Parties on the date set forth above; and (ii) acceptance or approval by the FERC. This Agreement shall continue in force until terminated in accordance with this Article.

This Agreement may be terminated at any time by mutual agreement in writing. It may also be terminated by either Party with prior written notice of at least ninety (90) days to the other Party of its intention to terminate.

ARTICLE 22.0: MISCELLANEOUS

22.1 Performance

The failure of a Party to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any right held by such Party. Any waiver on any specific occasion by either Party shall not be deemed a continuing waiver of such right, nor shall it be deemed a waiver of any other right under this Agreement.

22.2 Agreement

This Agreement, including all Schedules and Attachments hereto, is the entire agreement between the Parties with respect to the subject matter hereof, and supersedes all prior or contemporaneous understandings or agreements, oral or written, with respect to the subject matter of this Agreement.

22.3 Governmental Authorizations

This Agreement, including its future amendments is subject to the initial and continuing Federal Energy Regulatory Commission authorizations required to establish, operate and maintain the Interconnection Facilities as herein specified. Each Party shall take all actions necessary and reasonably within its control to maintain all rights and Federal Energy Regulatory Commission approvals required to perform its respective obligations under this Agreement.

If one Party determines that it is required to self-report a potential violation to the Commission's Office of Enforcement regarding its compliance with this Agreement or the administration of CTS, the reporting Party shall inform, and provide a copy of the self-report to the other Party. Any such report provided by one Party to the other shall be Confidential Information. Each Party shall make reasonable efforts to cooperate and assist in remedying any such violation, to the extent such assistance is necessary to resolve the matter and to the extent doing so is consistent with maintaining the Party's legal privilege.

22.4 Unenforceable Provisions

If any provision of this Agreement is deemed unenforceable, the rest of the Agreement shall remain in effect and the Parties shall negotiate in good faith and seek to agree upon a substitute provision that will achieve the original intent of the Parties.

22.5 Execution

This Agreement may be executed in multiple counterparts, each of which shall be considered an original instrument, but all of which shall be considered one and the same Agreement, and shall become binding when all counterparts have been signed by each of the Parties and delivered to each Party hereto. Delivery of an executed signature page counterpart by telecopier shall be as effective as delivery of a manually executed counterpart.

22.6 Regulatory Authority

If any Regulatory Authority having jurisdiction (or any successor boards or agencies), a court of competent jurisdiction or other governmental entity with the appropriate jurisdiction (collectively, the "Regulatory Bodies") issues a rule, regulation, law or order that has the effect of cancelling, changing or superseding any term or provision of this Agreement, including changes to section headings or numbering (the "Regulatory Requirement"), then this Agreement will be deemed modified to the extent necessary to comply with the Regulatory Requirement. Notwithstanding the foregoing, if the Regulatory Authority materially modifies the terms and conditions of this Agreement and such modification(s) materially affect the benefits flowing to one or both of the Parties, as determined by either of the Parties within twenty (20) business days of the receipt of the Agreement as materially modified, the Parties agree to attempt in good faith to negotiate an amendment or amendments to this Agreement or take other appropriate action(s) so as to put each Party in effectively the same position in which the Parties would have been had such modification not been made. In the event that, within sixty (60) days or some other time period mutually agreed upon by the Parties after such modification has been made, the Parties are unable to reach agreement as to what, if any, amendments are necessary and fail to take other appropriate action to put each Party in effectively the same position in which the Parties would have been had such modification not been made, then either Party shall have the right to unilaterally terminate this Agreement forthwith.

22.7 Headings

The headings used for the Articles and Sections of this Agreement are for convenience and reference purposes only, and shall not be construed to modify, expand, limit, or restrict the provisions of this Agreement.

IN WITNESS WHEREOF

IN WITNESS WHEREOF the Parties hereto have caused this Agreement to be executed in duplicate as of the day and year first written above.

NEW YORK INDEPENDENT SYSTEM OPERATOR

By: ____________________ Date: 5-17-2017

Ricardo T. Gonzales, Senior Vice President and Chief Operating Officer

ISO NEW ENGLAND INC.

By: ____________________ Date: 5/17/17

Vamsi Chadalavada, Executive Vice President and Chief Operating Officer

Schedule A: Description of Interconnection Facilities

The Coordination Agreement between ISO-NE and the NYISO covers the New England – NYISO Interconnection Facilities under the Operational Control of the NYISO and ISO-NE.

For Operational Control purposes, the point of demarcation for each of the Interconnection Facilities listed below is the point at which each Interconnection crosses the New England-New York State boundary, except as noted below.

There are presently three (3) ISO-NE-NYISO Interconnections. The three Interconnections are comprised of eight (8) alternating current ("AC") Interties and one (1) high-voltage direct current ("HVDC") Intertie. The first Interconnection (the "NY/NE Northern AC Interconnection") is comprised of seven (7) of the eight (8) AC Interties. The second Interconnection (the "NNC Interconnection") is comprised of the remaining AC Intertie. The third and final Interconnection (the "CSC Interconnection") is comprised of a single HVDC Intertie. For each Interconnection, NYISO and ISO-NE have identified respective associated external nodes for scheduling and pricing purposes. The nodes associated with each of the Interconnections are listed in Table 1 of Attachment A of Schedule C of this Agreement.

List of Interconnections

NY/NE Northern AC Interconnection - The NY/NE Northern AC Interconnection is comprised of the following seven (7) Interties (as ordered from North to South):

1. PV-20 Intertie (115 kV AC),
2. K7 Intertie (115 kV AC),
3. K6 Intertie (115 kV AC),
4. E205W Intertie (230 kV AC),
5. 393 Intertie (345 kV AC),
6. 690/FV Intertie (69 kV AC), and
7. 398 Intertie (345 kV AC).

NNC Interconnection - The Northport-Norwalk Harbor Cable ("NNC") Interconnection is comprised of the following Intertie:

1. NNC Intertie (138 kV AC).

CSC Interconnection - The Cross Sound Cable ("CSC") Interconnection is comprised of the following Intertie:

1. CSC Intertie (150 kV HVDC).

List of Interties (as ordered from North to South)

PV-20 Intertie - A 115 kV AC transmission circuit, designated PV-20, series switched reactor and phase shifting transformers, connecting the Plattsburgh transmission substation in NY to the Sandbar transmission substation in VT. The common meter point for this Intertie is located at the Plattsburg transmission substation.

K7 Intertie - A 115 kV AC transmission circuit, designated K7, and phase shifter transformer connecting the Whitehall transmission substation in NY to the Blissville transmission substation in VT. The common meter point for this Intertie is located at the Whitehall transmission substation.

K6 Intertie - A 115 kV AC transmission circuit, designated K6, connecting the Hoosick transmission substation in NY to the Bennington transmission substation in VT. The common meter point for this Intertie is located at the Hoosick transmission substation.

E205W Intertie - A 230 kV AC transmission circuit, designated E205W, connecting the Eastover Road transmission substation in NY to the Bear Swamp transmission substation in MA. The common meter point for this Intertie is located at the Bear Swamp transmission substation.

393 Intertie - A 345 kV AC transmission circuit, designated 393, connecting the Alps transmission substation in NY to the Berkshire transmission substation in MA. The common meter point for this Intertie is located at the Alps transmission substation.

690/FV Intertie - A 69 kV AC transmission circuit, designated 690/FV, connecting the Smithfield transmission substation in NY to the Salisbury transmission substation in CT. The common meter point for this Intertie is located at the Salisbury transmission substation.

398 Intertie - A 345 kV AC transmission circuit, designated 398, connecting the Pleasant Valley transmission substation in NY to the Long Mountain transmission substation in CT. The common meter point for this Intertie is located at the Pleasant Valley transmission substation.

NNC Intertie - Three 138 kV AC transmission circuits (designated 601, 602 and 603), transformer and phase shifting transformer, initially designated as the 1385 Cable Intertie and now the NNC Intertie, connecting the Northport transmission substation in NY to the Norwalk Harbor transmission substation in CT.[25] The common meter point for this Intertie is located at the Norwalk Harbor transmission substation.

CSC Intertie - A 150+/- kV HVDC transmission circuit and associated converter facilities, designated CSC, connecting the Tomson converter at Shoreham, NY to the Halvarsson converter at New Haven, CT. This entire facility is under ISO-NE operating authority, pursuant to the FERC Order containing approvals regarding the HVDC Cross Sound Cable. For Operational Control purposes, the point of demarcation for the HVDC Interconnection CSC is within New York State at the point where the converter facilities interconnect with LIPA's 138 kV AC facilities at Shoreham, NY. The common meter point for this Intertie is located at the Shoreham

25 The NNC Intertie may be referenced in the Parties individual operating documents as the Northport-Norwalk Harbor Cable ("NNC"), the 1385 Cable/Line or the 601, 602 and 603 Cables.

transmission substation.

Schedule B: Procedures for Development and Authorization of Operating Instructions

Overview

Operating Instructions (a) will be developed and recorded by the Parties, with assistance from the Coordination Committee, in accordance with this Schedule B, (b) will be contained in a document separate from this Agreement, and (c) may be modified by the Parties, with assistance from the Coordination Committee, without amending this Agreement.

The Parties, with assistance from the Coordination Committee, shall jointly develop Operating Instructions and review them at least annually. The Parties, with assistance from the Coordination Committee, shall submit draft material to one another for review and comment. The Parties, with assistance from the Coordination Committee, shall provide comment on the draft material promptly. The Parties, with assistance from the Coordination Committee, shall promptly provide such information as may reasonably be required in connection with establishing, or reviewing, the material. The Coordination Committee shall be responsible for approving final versions of Operating Instructions.

In the event that any conflicts arise or are made apparent to a Party regarding any Operating Instructions, they shall notify the other Party and engage the Coordination Committee, if necessary, to resolve such conflicts.

The Coordination Committee will periodically review applicable ISO-NE and NYISO individual procedures and processes to determine any benefits of sharing these procedures and processes. These benefits may be for the purpose of training or to satisfy Reliability Standards. The Coordination Committee will determine how best to share these individual procedures and processes.

A list of Operating Instructions and applicable ISO-NE and NYISO individual procedures will be maintained by the Coordination Committee.

Outlined below are the key principles and items of methodology to be observed while the Parties, with assistance from the Coordination Committee, are engaged in developing Operating Instructions, and issuing them to their respective operations staff.

Principles

Given that the Parties' respective operations staff benefit from following a single instruction for all aspects of their execution of interconnected operations, it is an acceptable practice to combine this content to achieve the single Operating Instructions for use by a respective Party's operations staff. The preferred methodology when appropriate is to use the NPCC Criteria, Guides and Procedures for the coordination and operation of the interconnected Transmission Systems. When the NPCC documentation is insufficient to accomplish this task separate instructions will be developed in accordance with this Schedule.

Each Party shall coordinate the issuance internally of any Operating Instructions developed and agreed to by the Parties, with assistance from the Coordination Committee, to ensure that their respective operations staff has these

Operating Instructions. In addition, annual review of the Operating Instructions and the Parties' internal procedures associated with the Operating Instructions shall be conducted by the Parties, with assistance from the Coordination Committee, to ensure consistency.

Operating Instructions, when approved by the Parties, shall be binding on the Parties insofar as they relate to the Interconnection Facilities until they expire, are changed, deleted, or superseded by authority of the Parties, with assistance from the Coordination Committee.

Items of Methodology

By mutual agreement of the Coordination Committee, one of the Parties shall be designated by the Coordination Committee to control the revision process of the Operating Instruction from the initial drafting of material through to the conversion of the Operating Instruction into its final form.

Schedule C: Emergency Energy Transactions Schedule

WHEREAS, ISO-NE, as the regional transmission organization for the New England Transmission System and the administrator of the New England markets, arranges for the sale and purchase of Emergency capacity and energy on behalf of Market Participants with neighboring Balancing Authority Areas, all in accordance with the ISO-NE Tariff, which includes the Open Access Transmission Tariff and ISO-NE market rules;

WHEREAS, ISO-NE is the responsible for, among other matters, procuring and acting as supplier of last resort of ancillary services (including arranging for the sale and purchase of Emergency capacity and energy with neighboring Balancing Authority Areas), in accordance with the ISO-NE Tariff;

WHEREAS, the NYISO, as the independent system operator of the New York Transmission System and the administrator of the New York wholesale electricity markets, arranges for the sale and purchase of Emergency capacity and energy on behalf of Market Participants with neighboring Balancing Authority Areas, all in accordance with the NYISO Tariffs;

WHEREAS, the NYISO is the administrator of the NYISO Tariffs and is responsible for, among other matters, procuring and acting as supplier of last resort of ancillary services (including arranging for the sale and purchase of Emergency capacity and energy with neighboring Balancing Authority Areas), in accordance with the NYISO Tariffs;

WHEREAS, either of the Parties may, from time to time, have insufficient Operating Reserve available on the respective systems that they operate, or need to supplement available resources to cover sudden and unforeseen circumstances such as loss of equipment or forecast errors, and such conditions could result in the need to arrange for the purchase of Emergency Energy for Reliability reasons;

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein set forth, the Parties mutually agree as follows:

ARTICLE I

1.0 DELIVERY POINT

The Delivery Point for energy delivered pursuant to the terms of this Schedule shall be at one of three points of Interconnection between the NYISO Balancing Authority Area and the ISO-NE Balancing Authority Area, and at such other points of Interconnection as may be established.

These three points of Interconnection are as follows: (1) the NY/NE Northern AC Interconnection[26]; (2) the NNC Interconnection; and (3) the Cross Sound Cable (CSC) Interconnection, which is a HVDC facility.

Unless otherwise agreed by the Coordination Committee, the price for energy for an hour delivered pursuant to this Schedule shall include all transmission costs of delivering such energy to the Delivery Point in that hour, and the Party taking delivery of such energy for the hour shall be responsible for all transmission costs beyond the Delivery Point for that hour.

ARTICLE II

2.0 CHARACTERISTICS OF EMERGENCY ENERGY

2.1 All Emergency Energy made available under this Schedule shall be three phase, 60 Hz alternating current at operating voltages established at the Delivery Point in accordance with system requirements and appropriate to the Interconnection Facilities or other such characteristics as may be agreed upon by the Parties.

ARTICLE III

3.0 NATURE OF SERVICE

3.1 ISO-NE and the NYISO shall, to the maximum extent each deems consistent with the safe and proper operation of its system, the furnishing of economical, dependable and satisfactory services by its participants, and the obligations of its participants to other parties, make available to the other Party when a system Emergency exists on the other Party's system, Emergency Energy from its system's available generating capability in excess of the system’s load requirements (i.e., load requirements alone, not load plus reserve requirements) up to the transfer limits in use between the two Balancing Authority Areas. Emergency Energy is provided in cases of emergency outages of generating units, transmission lines or other equipment, or to meet other sudden and unforeseen circumstances such as forecast errors, or to provide sufficient Operating Reserve. Normally, a Party requests Emergency Energy from the other Party as a last resort, when market-based real-time energy transactions are not available, or not

[26] The NY/NE Northern AC *Interconnection*, as defined in *Schedule* A – *Interconnection Facilities* (“*Schedule* A”) to the Coordination Agreement between ISO-NE Inc and the NYISO Inc.

available in a timely fashion in order to maintain its ten-minute reserve requirement. At the time the Emergency Energy sale is being initiated, the Party delivering such

Emergency Energy shall describe the Emergency Energy transaction as being one of the following: (1) “delivered out of ten-minute reserve”; (2) “delivered out of thirty-minute reserve” where such a delivery could reasonably be expected to be recalled if the Party delivering the Emergency Energy needed the generation for a reserve pick-up or other Emergency; or (3) “delivered above and beyond ten-minute and thirty-minute reserves” where the Party delivering such Emergency Energy is normally expected to be able to continue delivering the energy following a reserve pick-up.

3.2 The Parties are participants in the NPCC and are expected to comply with NPCC Criteria, Guides and Procedures. Such NPCC Criteria, Guides and Procedures include “Emergency Operation Criteria” (Document A-3), which describes the basic factors to be considered by a Balancing Authority Area in formulating plans and procedures to be followed in an Emergency. A principle of operation in this NPCC Criteria is that upon receiving a request for assistance to mitigate an Emergency, a Balancing Authority Area would provide “maximum reasonable assistance” to a neighboring Balancing Authority Area. Such reasonable assistance would not normally require the shedding of firm load.

3.3 Normally, the Party experiencing or anticipating an Emergency would request Emergency Energy from the other Party in accordance with this Schedule and applicable NPCC Criteria, Guides and Procedures after all market-based real-time transactions have been scheduled, unless there is an immediate need for such Emergency Energy in order to maintain system Reliability.

3.4 In the event a Party is unable to provide Emergency Energy to the other when needed, but there is energy available from a Third Party Balancing Authority Area supplier, the Party will use reasonable efforts to acquire and transmit such energy to the other Party where feasible.

ARTICLE IV

4.0 RATES AND CHARGES

4.1 The charge for Emergency Energy delivered to the NYISO or to ISO-NE shall be as set forth in Attachment A, attached hereto.

4.2 Should activations of reserve sharing be required by either of the Parties, inadvertent interchanges will intentionally be accumulated with each Balancing Authority Area providing assistance. In accordance with the NPCC “Procedures for Shared Activation of Ten Minute Reserve” (Document C-12), such inadvertent accumulations shall be treated as part of ordinary inadvertent energy.

ARTICLE V

5.0 MEASUREMENT OF ENERGY INTERCHANGED

5.1 All energy supplied at the Delivery Point shall be metered. The metered amounts shall be adjusted for actual losses to the Delivery Point on each of the Interconnection Facilities. This adjustment will be done to compensate for the difference in location between the Delivery Point and the meter.

5.2 Any properly designated representative of either of the Parties hereto shall have access, through coordination with the meter owner, during normal business hours, to all of the billing meters for the purpose of reading the same. The accuracy of the meters shall be verified by proper tests periodically and at any other time upon reasonable notice given by either of the Parties to the other, and each of the Parties shall be entitled to have a representative present at such verification, subject to coordination with the meter owner. In the event errors greater than +/-2% should be discovered, retroactive billing adjustments, if any, shall be determined by the Coordination Committee.

ARTICLE VI

6.0 BILLING AND PAYMENT

6.1 The procedure for rendering and payment of invoices for transactions pursuant to this Schedule shall be as set out hereunder unless otherwise agreed by the Coordination Committee.

6.2 The Party delivering energy pursuant to this Schedule shall promptly prepare, or cause to be prepared, and render an invoice to the other Party covering all transactions conducted under the terms of this Schedule. All transactions will be billed based on the schedule of energy agreed to by the Parties.

6.3 All invoices rendered by a Party shall be payable by the other Party in currency of the United States of America by electronic bank transfer within five (5) business days after the issuance of an invoice (the “Due Date”).

6.4 If the rendering of an invoice is unavoidably delayed, a Party may issue an interim invoice based on estimated charges. Each invoice shall be subject to adjustment for any errors in calculation, meter readings, estimating or otherwise. Any such billing adjustments shall be made as promptly as practical, but in no event later than six months after issuing the invoice.

6.5 Any amount not paid by the Due Date shall be subject to interest, calculated from the due date of the invoice to the date of payment, in accordance with the methodology specified for interest on refunds in the FERC’s regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

6.6 If any invoice remains unpaid by a Party for thirty (30) days after the Due Date, the Party rendering the invoice may, in addition to all other remedies available to it, and after giving the other Party at least five days written notice of the its intention to do so, present the issue in question to that Party's Board of Directors. The Party's Board of Directors shall contact the other Party's Board of Directors or its designee to develop a solution to a billing Dispute pursuant to Article 17 of this Agreement. The Boards of Directors may also choose to submit the billing Dispute to a form of alternative Dispute resolution to which the Boards of Directors may agree. Such action shall not be construed as a breach of contract by the Party rendering the invoice and shall not relieve the other Party of its obligations to pay for energy in accordance with the provisions of this Schedule.

6.7 The applicable provisions of this Schedule shall continue in effect after termination of this Schedule to the extent necessary to provide for final billing, billing adjustments, payments and disposition of any claims outstanding.

6.8 Each Party warrants that it has, or will have, the agreements and procedures in place to ensure the collection of payments from its participants for the delivery of Emergency Energy to it from the other Party.

ARTICLE VII

7.0 RECORDS

7.1 Each Party hereto shall keep or cause to be kept complete and accurate records and memoranda of its operations hereunder and shall maintain such data as may be necessary to determine with reasonable accuracy any item required hereunder. With respect to invoicing records, each Party shall maintain or cause to be maintained such records, memoranda and data for the current calendar year plus the previous calendar year. The Coordination Committee shall have the right to examine all such records and memoranda that are not confidential in so far as may be reasonably necessary for the purpose of ascertaining the reasonableness and accuracy of any statements of costs relating to transactions hereunder.

Attachment A
To the Emergency Energy Transactions Schedule

Emergency Energy Pricing

In accordance with the Emergency Energy Transactions Schedule between the NYISO and ISO-NE, the charge for Emergency Energy delivered to the Delivery Point by the NYISO or ISO-NE to the other shall be as defined within this Attachment A.

A.1. Direct NYISO/ISO-NE Emergency Energy Transaction

These are requests made by either the NYISO or ISO-NE to receive Emergency Energy in support of Emergency conditions and to protect Reliability in the event that there is a need for energy on its system that could not be supplied through the market.

The charge for Emergency Energy shall be calculated using the following two-part formula. The first part of the formula calculates the Energy Charge portion of the charge and the second part incorporates any Transmission Charge reasonably associated with the delivery of the Emergency Energy to the Delivery Point.

The Energy Charge portion of the Emergency Energy Charge (for an hour)

For NYISO as the delivering Party:

The Energy Charge portion of the Emergency Energy Charge for an hour equals the sum of the Energy Charges for each real-time interval in the hour. The Energy Charge for each real-time interval =

(Emergency Energy supplied in the real-time interval in megawatt hour(s) (“MWh”))
* (Delivering Party’s Cost of Energy in $/MWh)
* 110%

The Cost of Energy shall be the NYISO final real-time Locational Based Marginal Price (“LBMP”) at the external node associated with the Delivery Point (as used in the NYISO market system for energy exports from the NYISO Balancing Authority Area into the New England Balancing Authority Area, as such pricing node is defined in NYISO Tariffs and as summarized in Table 1), for the real-time interval of the Emergency Energy delivery. For purposes of this calculation, a real-time LBMP for an interval is set to $0.00 if the real-time LBMP in that interval was negative.

For ISO-NE as the delivering Party:

The Energy Charge portion of the Emergency Energy Charge for an hour equals the sum of the Energy Charges for each five minute settlement interval in the hour * 110%. For purposes of this calculation:

(1) The Energy Charge for a five-minute settlement interval equals the amount of Emergency Energy (in MWh) scheduled in the settlement interval at the external node associated with the Delivery Point (as used in the New England market system for energy exports from the New England Balancing Authority Area into the NYISO Balancing Authority Area), adjusted for any curtailment, multiplied by the Cost of Emergency Energy in the settlement interval.

(2) The Cost of Emergency Energy in a five-minute settlement interval equals the LMP at the external node associated with the Delivery Point for the settlement interval.

For purposes of this calculation, an LMP in a settlement interval is set to $0.00 if the LMP in the settlement interval was negative.

Table 1

Delivery Points and Associated Pricing Nodes, as Modeled by the Delivering Party		
	External Nodes for Pricing Node for the Delivering Party (as modeled in the Delivering Party's system)	
Delivery Point	Delivering Party: ISO-NE	Delivering Party: NYISO
NY/NE Northern AC Interconnection (excludes the NNC (or 1385 Cable) Intertie)	.I.ROSETON 345 1 (4011)	N.E._GEN_SANDY PD (24062)
NNC Interconnection	.I.NRTHPORT 1385 (4017)	NPX_1385_GEN (323591)
CSC Interconnection	.I.SHOREHAM138 99 (4014)	NPX_GEN_CSC (323557)

<u>The Transmission Charge portion of the Emergency Energy Charge (for an hour)</u>

The Transmission charge portion of the Emergency Energy Charge to the Delivery Point for an hour shall equal the actual ancillary services costs and any transmission costs reasonably associated with the delivery of such Emergency Energy for an hour by the delivering Party to the Delivery Point pursuant to the applicable tariff of the delivering Party, as filed with and accepted by the governmental agency with jurisdiction over such tariff.

A.2. NYISO/ISO-NE Emergency Energy Transaction From Third Party Balancing Authority Area Supplier

These are requests made by NYISO or ISO-NE to deliver Energy to the other to address system balancing or other Reliability conditions present on the exporting system, which could not be accomplished through the market.

The charge for Emergency Energy supplied to a Party from a Third Party Balancing Authority Area supplier shall be calculated using the following two-part formula. The first part of the formula calculates the Energy Charge portion of the charge, which in this case includes the total charge (energy and transmission) that the Third Party Balancing Authority Area supplier charges for delivery of the Emergency Energy to the delivering Party's Balancing Authority Area border. The second part of the formula incorporates any Transmission Charges reasonably associated with the delivery of the Emergency Energy by the delivering Party through its system to the Delivery Point. It is expected that that all such Third Party Balancing Authority Area supplier charges will be in accordance with rates filed and accepted by the governmental body with jurisdiction over such rates.

The Energy Charge portion of the Emergency Energy Charge (for an hour)

The Energy Charge portion of the Emergency Energy Charge for an hour =
(Emergency Energy supplied in the hour in MWh)
* (Third Party Balancing Authority Area supplier's total charge for such energy in $/MWh)

(Note: 10% adder does not apply to pricing of Emergency Energy from Third Party Balancing Authority Area suppliers.)

The Transmission Charge portion of the Emergency Energy Charge (for an hour)

The Transmission Charge portion of the Emergency Energy Charge to the Delivery Point for an hour shall equal the actual ancillary services costs and any transmission costs reasonably associated with the delivery of such energy for an hour to the Delivery Point pursuant to the applicable tariff of the delivering Party, as filed with and accepted by the governmental agency with jurisdiction over such tariff. Transmission costs would include, but not be limited to, any costs for congestion and losses that are associated with the delivery of such Emergency Energy through the delivering Party's Balancing Authority Area for an hour to the Delivery Point, as calculated by the amount of Emergency Energy supplied multiplied by: (1) when NYISO is the delivering Party, (the NYISO real-time LBMP of the external node at which the Emergency Energy exits the NYISO Balancing Authority Area minus the NYISO real-time LBMP of the external node at which the Emergency Energy enters the NYISO Balancing Authority Area); or (2) when ISO-NE is the delivering Party, (the ISO-NE real-time LMP of the external node at which the Emergency Energy exits the ISO-NE Balancing Authority Area minus the ISO-NE real-time LMP of the external node at which the Emergency Energy enters the ISO-NE Balancing Authority Area).

Schedule D: Coordinated Transaction Scheduling

WHEREAS, ISO-NE, as the regional transmission organization for the New England Transmission System and the administrator of the New England wholesale electricity markets, schedules the sale of energy by its Market Participants to, and the purchase of energy by its Market Participants from, neighboring Balancing Authority Areas, all in accordance with the ISO-NE Tariff, which includes the Open Access Transmission Tariff and ISO-NE market rules;

WHEREAS, ISO-NE is the administrator of the ISO-NE Tariff and is responsible for, among other matters, ensuring sufficient reserves are available to provide reliable service in its Balancing Authority Area, in accordance with the ISO-NE Tariff;

WHEREAS, the NYISO, as the independent system operator of the New York Transmission System and the administrator of the New York wholesale electricity markets, schedules the sale of energy by its Market Participants to, and the purchase of energy by its Market Participants from, neighboring Balancing Authority Areas, all in accordance with the NYISO Tariffs;

WHEREAS, the NYISO is the administrator of the NYISO Tariffs and is responsible for, among other matters, ensuring sufficient reserves are available to provide reliable service in its Balancing Authority Area, in accordance with the NYISO Tariffs;

WHEREAS, Coordinated Transaction Scheduling will improve interregional scheduling efficiency by taking into account relative price differences between the regions and scheduling bids and offers on a 15 minute basis at CTS Enabled Interfaces; and

WHEREAS, the Parties desire to schedule energy between their Balancing Authority Areas more efficiently, while continuing to ensure that each Party will maintain sufficient Operating Reserve available on its respective system to ensure the reliable operation thereof;

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein set forth, the Parties mutually agree as follows:

ARTICLE I

1.0 OVERVIEW OF COORDINATED TRANSACTION SCHEDULING

Coordinated Transaction Scheduling or "CTS" is an external transaction scheduling process implemented by the Parties at designated CTS Enabled Interfaces that allow real-time energy transactions to be scheduled based on a Market Participant's willingness to purchase energy at a source External Proxy Bus (in the NECA, or in the NYCA) and sell it at a sink External Proxy Bus in the other Control Area if the forecasted price at the sink minus the forecasted price at the corresponding source is greater than or equal to the bid price. The rules set forth in this Schedule D only apply at CTS Enabled Interfaces.

In accordance with the terms of this Schedule D and the Parties' respective tariffs, CTS Interface Bids are ordinarily evaluated on a 15-minute basis utilizing forecasted real-time prices and forecasted system information from NYISO and forecasted real-time prices and forecasted system information from ISO-NE. The evaluation will be performed by the NYISO's Real-Time Commitment (RTC) optimization consistent with the rules specified in the NYISO Services Tariff and this Schedule D.

As part of the iterative CTS process, NYISO will share forward looking RTC interchange schedules with ISO-NE and these schedules will be used by ISO-NE as an input to develop a new set of forecasted prices and system information, which ISO-NE will then provide to NYISO for use in the next RTC optimization.

In accordance with Section 4 below, the RTC optimization will determine the External Interface Congestion component of the RTC LMP at a CTS Enabled Interface, which will subsequently be incorporated into the Parties' real-time settlement LMPs.

Wheel-through transactions across a CTS Enabled Interface will be scheduled on an hourly basis. Wheels through the NYCA will use decremental or sink price cap bids at CTS Enabled Interfaces. Wheels through the NECA will use hourly CTS Interface Bids at CTS Enabled Interfaces for scheduling by the NYISO.

The Parties agree that CTS and its components will operate in accordance with this Schedule D and the terms of the Parties' respective tariffs.

ARTICLE II

2.0 SUBMITTAL OF CTS INTERFACE BIDS

2.1 CTS Interface Bid Submittal by New England Responsible Settlement Parties and their Representatives

NYISO is hosting the platform used by both New York and New England Responsible Settlement Parties to submit CTS Interface Bids. New York RSPs shall submit and confirm bids at CTS Enabled Interfaces in accordance with the NYISO Tariffs.

Authorized New England RSPs shall have access to the bidding platform for purposes of submitting bids at CTS Enabled Interfaces between the NECA and the NYCA. Such access will be provided under equivalent terms and conditions to New York RSPs.

On an hourly or more frequent basis ISO-NE shall provide NYISO with: (a) a list of all New England RSPs that are authorized to submit or confirm bids at CTS Enabled Interfaces and (b) identification information for each representative (*i.e*., an individual) that is authorized to submit or confirm bids at CTS Enabled Interfaces on behalf of a New England RSP. Only representatives designated by ISO-NE shall be permitted access to the platform that is used to submit bids at CTS Enabled Interfaces on behalf of a New England RSP. NYISO shall verify the authorization of a New England RSP and its representative at the time a bid is submitted, confirmed, modified or deleted. If it has been more than two hours since the NYISO last received from ISO-NE an updated list of all authorized New England RSPs and identification information for each representative that is authorized to submit or confirm bids at CTS Enabled Interfaces on behalf of a New England RSP, then NYISO shall not allow any New England RSP to access the platform that is used to submit bids at CTS Enabled Interfaces until an updated list is received.

In the event NYISO is not able to implement a new or changed status in a timely fashion, NYISO will inform ISO-NE of any delay it is aware of and the reason for the delay, and will implement the new or changed status as soon as possible.

2.2 Confirmation of New England Responsible Settlement Parties

A representative submitting an initial or revised CTS Interface Bid, or a bid to schedule a wheel through the NYCA at a CTS Enabled External Proxy Bus must belong to an authorized RSP in either NYISO or ISO-NE. In that submittal, the representative must identify the participating RSP in the other area. The other participating RSP must confirm the submittal of the CTS Interface Bid or bid to wheel through the NYCA, in order for the bid to be valid. A CTS Interface Bid or a bid to wheel through the NYCA can be withdrawn by either participating RSP; no confirmation is required.

An RSP may establish a Confirmed Trust Relationship with another RSP such that the required confirmation will be automatically granted for any submittal of a CTS Interface Bid or bid to wheel through the NYCA at a CTS Enabled External Proxy Bus that is submitted by the trusted RSP and includes both RSPs as parties to the transaction. Upon representative action to submit, update or revoke a Confirmed Trust Relationship, NYISO shall verify that (i) the submittal identifies two authorized RSPs, one in New York and one in New England and (ii) the representative belongs to the RSP that is granting the Confirmed Trust Relationship to the other RSP.

Upon representative action to submit or confirm an initial or revised CTS Interface Bid or bid to wheel through the NYCA, or to withdraw a CTS Interface Bid or bid to wheel through the NYCA at a CTS Enabled External Proxy Bus, the NYISO shall verify that (i) the submittal identifies two valid RSPs, one in New York and one in New England, and (ii) the representative belongs to an RSP that is identified on the submittal. If a Confirmed Trust Relationship exists between the two authorized RSPs and the action is taken by a representative that is associated with a trusted RSP to submit or confirm an initial or revised CTS Interface Bid or bid to wheel through the NYCA, the bid shall be deemed submitted and confirmed, or the revision confirmed.

Upon receiving ISO-NE's notice of suspension or termination of a New England RSP, which ISO-NE shall do consistent with its authority under the ISO-NE Tariff, NYISO will promptly:

1. cease honoring Confirmed Trust Relationships associated with the suspended or terminated New England RSP;

2. within the real-time market day on which NYISO receives the instruction from ISO-NE, remove the suspended or terminated New England RSP's bids at CTS Enabled Interfaces that are offered in the NECA to NYCA direction;

3. within the real-time market day on which NYISO receives the instruction from ISO-NE, remove bids at CTS Enabled Interfaces that are offered in the NECA to NYCA direction that include the New England RSP as a trusted RSP;

4. for all real-time market days subsequent to the real-time market day on which NYISO receives the instruction from ISO-NE, remove all of the suspended or terminated New England RSP's bids at CTS Enabled Interfaces; and

5. for all real-time market days subsequent to the real-time market day on which NYISO receives the instruction from ISO-NE, remove all bids at CTS Enabled Interfaces that include the suspended or terminated New England RSP as a trusted RSP.

The five changes enumerated above will be effectuated prospectively. The Parties will not effectuate changes one through three for a real-time market hour in which RSPs are no longer able to submit or modify bids.

ISO-NE will curtail the e-tags for the transactions associated with the bids NYISO is required to remove under the rules set forth above.

In the event NYISO is not able to implement a new or changed status that is addressed in this Section 2.2 in a timely fashion, NYISO will inform ISO-NE of any delay it is aware of and the reasons for the delay, and will implement the new or changed status as soon as possible.

If the NYISO is unable to verify that the required confirmations have been received, then the CTS Interface Bid or bid to wheel through the NYCA shall not be considered in the RTC optimization.

If the NYISO is not able to validate an RSP or a representative, then that entity or person will not be able to submit, modify, confirm or delete a CTS Interface Bid or a bid to wheel through the NYCA.

ARTICLE III

3.0 CALCULATION OF ISO-NE SUPPLY PRICE POINTS

Each quarter-hour, ISO-NE shall calculate a set of forecast energy prices at its External Proxy Buses for each CTS Enabled Interface corresponding to varying interchange levels on that interface. The results will be provided to NYISO as increasing MW-price pairs, where the MW value represents a net interchange level on the CTS Enabled Interface and the price value represents ISO-NE's forecast of its real-time LMP for its External Proxy Bus at that net interchange MW level. ISO-NE will provide no fewer than one and no more than 11 MW-price pairs for each of ten consecutive quarter-hour intervals, which are referred to as the "ISO-NE Supply Price Points."

The ISO-NE Supply Price Points are created with a forward-looking, security-constrained economic dispatch system that co-optimizes energy and reserve requirements. This forward-looking co-optimization will assume the same units are committed as are previously committed, or scheduled to be committed, in ISO-NE's real-time production system. The energy from currently uncommitted fast-start generation will also be considered for dispatch in the forward-looking co-optimization. ISO-NE Supply Price Points shall be calculated using the current production data for load forecasts, active transmission constraints, state estimator data, Market Participant energy re-offers, wind forecasts, forecasted net interchange on all Interconnections (including forward looking RTC interchange schedules provided by NYISO), and operator updates to resource limits.

ARTICLE IV

4.0 SCHEDULING EXTERNAL TRANSACTIONS AT CTS ENABLED INTERFACES

4.1 Evaluation of CTS Interface Bids

The RTC will use the CTS Interface Bids and the ISO-NE Supply Price Points to economically schedule the CTS Interface Bids and determine the net interchange schedules. The economic scheduling of the CTS Interface Bids will be performed simultaneously with the scheduling of internal NYCA resources and external transactions at other NYCA Interconnections.

For an RTC optimization that schedules hourly CTS Interface Bids, the RTC will use the ISO-NE Supply Price Points for each 15-minute interval of the hour. An hourly CTS Interface Bid will be scheduled if it is economic for the hour.

For an RTC optimization that schedules CTS Interface Bids at 15-minute intervals, the RTC optimization will use ISO-NE Supply Price Points that have been adjusted to account for the hourly RTC external transaction schedules established at CTS Enabled Interfaces, including any scheduled Emergency Energy.

When there are multiple CTS Interface Bids at the same bid price but not all of them can be economically scheduled, the CTS Interface Bids with the same price will be scheduled pro-rata.

The RTC optimization incorporates Ramp Limits and Transfer Limits in the manner described in Section 5 of this Schedule D to economically schedule CTS Interface Bids and shall determine: (1) the net interchange schedule for each CTS Enabled Interface, (2) the RTC LMP for each CTS Enabled External Proxy Bus, and (3) the External Interface Congestion at each CTS Enabled Interface.

4.2 External Interface Congestion Price Assignment

The RTC optimization will determine the External Interface Congestion at an External Proxy Bus for a CTS Enabled Interface if the net interchange schedule is limited in the RTC solution due to one or more of the following four reasons: (i) there are more economic transactions offered in a common direction (import or export) than the Transfer Limit of the External Proxy Bus can accommodate, or (ii) there are fewer economic transactions offered in a common direction (import or export) than the Transfer Limit requires, or (iii) the NYCA (system-wide) Ramp Limit prevents the RTC from scheduling one or more external transactions at the External Proxy Bus consistent with the economics of the underlying bids, or (iv) a Ramp Limit prevents the RTC from scheduling one or more external transactions consistent with the economics of the underlying bids (collectively, the "External Proxy Bus Constraints").

Whenever an External Proxy Bus Constraint at a CTS Enabled Interface is limiting in the RTC optimization, the External Interface Congestion at the External Proxy Bus will be assigned, in whole or in part, as set forth below.

ISO-NE Limiting: If the RTC optimization is limited by a Transfer Limit determined by an ISO-NE Operating Reserve limitation, an ISO-NE minimum generation limitation, or an ISO-NE capacity deliverability limit, including when the Transfer Limit is adjusted in accordance with Section 5.4 of this Schedule D to accommodate the Ramp Limit while implementing one of these limitations, then the portion of the External Interface Congestion associated with the External Proxy Bus Constraint shall be assigned to ISO-NE.

NYISO Limiting: If the RTC optimization is limited by NYCA-wide Ramp Limits, then the portion of the External Interface Congestion associated with the External Proxy Bus Constraint shall be assigned to NYISO.

NYISO and ISO-NE Limiting: If the RTC optimization is limited by any Ramp Limit or Transfer Limit that is not specifically addressed in the "ISO-NE Limiting" or "NYISO Limiting" paragraphs above, or by any Transfer Limit or Ramp Limit that results from an operator override, as described in Section 5.2.5 of this Schedule D, the portion of the External Interface Congestion for a CTS Enabled Interface that is associated with an External Proxy Bus Constraint shall be assigned to both Parties equally.

The RTC solution may be limited by multiple External Proxy Bus Constraints simultaneously. If this occurs, the foregoing rules will apply to each External Proxy Bus Constraint.

If there are not sufficient CTS Interface Bid MWs offered to achieve a Transfer Limit, RTC will schedule the available MWs. In these circumstances, RTC will determine the External Interface Congestion at the External Proxy Bus based on the NYISO's Transmission Shortage Costs as defined in the NYISO Tariff.

In order to provide consistent price signals between their respective real-time energy markets, the Parties shall each incorporate the foregoing process into the real-time settlement LMP at their External Proxy Bus for each CTS Enabled Interface.

ARTICLE V

5.0 CTS ENABLED INTERFACE OPERATING RULES

5.1 CTS Enabled Interface Ramp Limits

The default quarter-hour Ramp Limit for the NY/NE Northern AC Interconnection will be mutually agreed to by the Parties and posted on the NYISO's OASIS.

The default top-of-the-hour Ramp Limit for the NY/NE Northern AC Interconnection (for use when quarter-hour scheduling is unavailable) will be mutually agreed to by the Parties and posted on the NYISO's OASIS.

In real-time operations, when necessary to protect reliability, the Parties may mutually agree to temporarily change the Ramp Limit(s) at any CTS Enabled Interface. The Parties shall restore the modified Ramp Limit to the posted default Ramp Limit as soon as reliable system operations permit and it is practicable to do so.

5.2 Transfer Limits Reflecting Reliability Conditions

A Transfer Limit sets the minimum or maximum net interchange that can be scheduled on a CTS Enabled Interface in the RTC solution. Factors that can set the Transfer Limits include the following:

1. normal scheduling limits;
2. Operating Reserve limitations;
3. minimum generation limitations;
4. capacity requests;
5. operator overrides.

5.2.1 Normal Scheduling Limits

The normal scheduling limit for a CTS Enabled Interface is the amount of electric power that can normally be transferred over a CTS Enabled Interface. The Parties may mutually agree to change the normal scheduling limits that are used at CTS Enabled Interfaces due to transmission outages, generation outages or other changes in system conditions. In the event the change to a normal scheduling limit is planned in advance, the Parties will make reasonable efforts to change the values in time to be included in the clearing of their respective day-ahead energy markets and be publicly posted prior to implementation. For the real-time operating day, ISO-NE will send its normal scheduling limits at each CTS Enabled Interface to the NYISO via the electronic data exchange to cover the same ten consecutive quarter-hour intervals as ISO-NE's Supply Price Points.

5.2.2 Operating Reserve Limitations

If one Control Area experiences an Operating Reserve deficiency, the other Control Area is not obligated to go deficient in its reserves of the same or a higher quality product, but may go deficient in a lower-quality reserve product in order to prevent an Operating Reserve deficiency of a higher quality reserve product in the other Control Area. To ensure these mutual reliability objectives can be satisfied, the Parties may modify the Transfer Limits in certain conditions as described below.

The RTC optimization procures reserves to meet the NYISO's reserve requirements and prices shortages of reserves using the NYISO's Operating Reserve demand curves. The RTC does not have information on the amount of Operating Reserve in the NECA. Therefore, at CTS Enabled Interfaces, ISO-NE will use the electronic data exchange to provide to NYISO both the ISO-NE Supply Price Points and Transfer Limit values that reflect the net interchange required to meet ISO-NE's 10-minute and 30-minute reserve requirements. When calculated, these values will reflect the net interchange required to meet ISO-NE's 10-minute and 30-minute reserve requirements for the same ten consecutive quarter-hour intervals for which ISO-NE's Supply Price Points are provided. ISO-NE will calculate these Transfer Limit values for each interval based on the Operating Reserve surplus in the NECA when applying the forecasted RTC net interchange on the CTS Enabled Interface. For the purposes of Schedule D, the ISO-NE Transfer Limit associated with the 10-minute reserve requirement will always be less restrictive than the Transfer Limit associated with the ISO-NE 30-minute reserve requirement. When ISO-NE sends Transfer Limits that are associated with Operating Reserve requirements, the ISO-NE Supply Price Points must also reflect those expected reserve shortage prices. RTC will evaluate whether the ISO-NE Transfer Limit would preclude NYISO from meeting its reserve requirements for an equal or higher quality reserve product. If so, RTC may adjust the Transfer Limit in accordance with Section 5.3 of this Schedule D, based on the principles set forth in the preceding paragraph.

5.2.3 Minimum Generation Limitations

The RTC optimization dispatches the NYISO system's internal generation as needed when the NYCA approaches minimum generation conditions. The RTC does not have information to assess minimum generation conditions within the NECA. Therefore, at CTS Enabled Interfaces, ISO-NE will use the electronic data exchange to provide to NYISO Transfer Limit values that reflect the net interchange level beyond which ISO-NE cannot further dispatch down internal generation while maintaining reliable operations. When ISO-NE sends Transfer Limits for this purpose, the ISO-NE Supply Price Points must also reflect these requirements.

ISO-NE shall not send, and NYISO is not required to enforce, a minimum generation Transfer Limit that would require the NYCA to accept energy from the NECA.

ISO-NE shall not send both a minimum generation Transfer Limit and Operating Reserve Transfer Limits at the same time.

5.2.4 Capacity Transfer Limits

Day-Ahead Coordination

NYISO will provide its day-ahead operating plan to ISO-NE. Once ISO-NE determines that it expects to count on capacity resources located in New York to meet its reserve requirements, ISO-NE shall inform NYISO of the expected capacity call.

Real-Time Coordination

ISO-NE Capacity Requests at CTS Enabled Interfaces:

ISO-NE may request delivery of energy from capacity resources located in the NYCA that have obligations in the ISO-NE capacity market over a CTS Enabled Interface. The ISO-NE operator will call the NYISO operator to initiate the capacity request. Upon receiving the request, the NYISO operator will confirm what amount of the capacity request is deliverable based on projected transmission constraints ("Capacity Deliverable to ISO-NE"). If the Capacity Deliverable to ISO-NE is non-zero, RTC will determine the ISO-NE capacity that is available based on offers submitted by NYCA generators that have sold their capacity to ISO-NE and are projected to be available in real-time, subject to any real-time derates ("Capacity Available to ISO-NE").

Transactions to wheel capacity through the NYCA will be excluded from the ISO-NE/NYISO capacity request process.

NYISO Capacity Requests at CTS Enabled Interfaces:

If the NYISO projects the ISO-NE real-time capacity request could cause the NYISO to become capacity deficient, the NYISO may request delivery of energy associated with capacity resources located in ISO-NE that have an obligation in the NYISO capacity market over a CTS Enabled Interface. The NYISO operator will call the ISO-NE operator to initiate the capacity request. The NYISO will require that its eligible New England-based capacity submit CTS Interface Bids to be evaluated by RTC. It will be up to the supplier of New England-based capacity to ensure that the resource(s) backing capacity transactions are available to deliver their capacity to New York when they are called on to do so. At the time of the request, the ISO-NE operator will determine whether all or any part of the generation supporting the capacity is available and deliverable ("Capacity Available to NYISO").

Section 5.3 of this Schedule D sets forth how capacity data and Operating Reserve limitations are used to establish a Transfer Limit.

5.2.5 Operator Override Transfer Limits

Real-time system conditions may require that a NYISO or ISO-NE operator override the Transfer Limit to establish the flow that can be transferred over a CTS Enabled Interface in a reliable manner. Except when necessary to protect reliability, an operator override shall not be used to submit limits that can be submitted via the electronic data exchange.

5.3 Establishing Transfer Limits for RTC

RTC determines a net interchange for each interval that must be a value between an upper bound and lower bound. In this section, the high Transfer Limit is the upper bound on that range and the low Transfer Limit is the lower bound on that range. The rules in this Section 5.3 detail how the inputs from Section 5.2, which are first tested against the criteria set forth in Section 7.2, are used to determine the high and low Transfer Limits in RTC for each quarter-hour interval. For purposes of this Section 5.3, a positive value represents flow from New England to New York, and a negative value represents flow from New York to New England. The values associated with an ISO-NE capacity request, Capacity Deliverable to ISO-NE and Capacity Available to ISO-NE are all negative.

1. When a Minimum Generation Transfer Limit is provided by ISO-NE in accordance with Section 5.2.3, that value is the low Transfer Limit at a CTS Enabled Interface.

2. When ISO-NE provides Operating Reserve Transfer Limits but has not requested capacity from NYISO, the following rules are applied to determine the high Transfer Limit at a CTS Enabled Interface:

a) If the ISO-NE 30-minute Operating Reserve Transfer Limit is greater than or equal to zero, then:

i. If enforcing the ISO-NE 30-minute Operating Reserve Transfer Limit is projected to cause the NYISO to have a deficiency of 10-minute Operating Reserve, the high Transfer Limit is the minimum value that is not projected to result in a NYISO 10-minute Operating Reserve deficiency;

ii. Otherwise the high Transfer Limit is the ISO-NE 30-minute Operating Reserve Transfer Limit.

b) If the ISO-NE 30-minute Operating Reserve Transfer Limit is less than zero, then:

i. If enforcing the ISO-NE 30-minute Operating Reserve Transfer Limit is projected to cause the NYISO to have a deficiency of 30-minute Operating Reserve but is not projected to cause the NYISO to have a deficiency of 10-minute Operating Reserve, then the high Transfer Limit is the lesser of (a) the minimum value that is not projected to result in a NYISO 30-minute Operating Reserve deficiency, or (b) zero;

ii. If enforcing the ISO-NE 30-minute Operating Reserve Transfer Limit is projected to cause the NYISO to have a deficiency of 10-minute Operating Reserve, then the high Transfer Limit is the minimum value that is not projected to result in a NYISO 10-minute Operating Reserve deficiency;

iii. Otherwise the high Transfer Limit is the ISO-NE 30-minute Operating Reserve Transfer Limit.

3. When ISO-NE has requested capacity from NYISO, the high Transfer Limit at a CTS Enabled Interface shall be the greater of:

a) the ISO-NE 30-minute Operating Reserve Transfer Limit, or

b) [the minimum of (i) the total quantity of CTS Interface Bids backing Capacity Available to NYISO or (ii) the Capacity Available to NYISO] plus [the maximum of (iii) the ISO-NE capacity request, (iv) the Capacity Deliverable to ISO-NE or (v) the Capacity Available to ISO-NE].

4. When system conditions require that either a low or high Transfer Limit be overridden by the NYISO or ISO-NE operator to establish the flow that can be transferred over a CTS Enabled Interface in a reliable manner, the override shall establish the low or high Transfer Limit.

5. Otherwise, the NYISO shall use the normal scheduling Transfer Limit at a CTS Enabled Interface, as described in Section 5.2.1.

5.4. <u>Interaction Between Transfer Limits and Ramp Limits</u>

a) Except as provided in 5.4(b), when the NYISO's RTC is provided Transfer Limits that would cause it to develop net interchange schedules at a CTS Enabled Interface with ISO-NE that exceed the Ramp Limits, RTC will reset the provided Transfer Limits to ensure the agreed Ramp Limits are not exceeded.

b) If any Transfer Limit, other than a normal scheduling limit, is implemented via an operator override, then RTC shall permit the agreed Ramp Limits to be exceeded in order to enforce the Transfer Limit.

ARTICLE VI

6.0 SETTLEMENT PROVISIONS

ISO-NE shall settle CTS Interface Bids and other bids and offers scheduled at CTS Enabled Interfaces with its Market Participants in accordance with the rules set forth in the ISO-NE Tariff.

The NYISO shall settle CTS Interface Bids and other bids scheduled at CTS Enabled Interfaces, with its Market Participants in accordance with the rules set forth in the NYISO Tariffs.

Each Party shall address settlement-related corrections and disputes regarding that Party's settlement of CTS transactions in accordance with the settlement correction and dispute resolution provisions set forth in that Party's tariff(s).

Each Party agrees to provide support, including information and data that isn't otherwise available to the other Party, when the requested information is necessary to assist the requesting Party in addressing a settlement (but not price) correction or a settlement-related dispute between the requesting Party and one or more of its Market Participants regarding the settlement of CTS transactions.

If an erroneous price is determined at a CTS Enabled External Proxy Bus, independent of any price correction process ISO-NE may utilize, the NYISO shall follow the price correction process set forth in Attachment E to its Market Administration and Control Area Services Tariff.

If an erroneous price is determined at a CTS Enabled External Proxy Bus, independent of any price correction process NYISO may utilize, ISO-NE shall follow the price correction process set forth in the ISO-NE Tariff.

ARTICLE VII

7.0 NON-STANDARD CTS OPERATION

7.1 Permitted Modifications to ISO-NE Supply Price Points

In the event NYISO does not receive the ISO-NE Supply Price Points before it commences the RTC optimization, then the last set of ISO-NE Supply Price Points used to perform an RTC optimization will be used in the RTC optimization to determine the net interchange schedule until the NYISO receives and successfully validates a new set of ISO-NE Supply Price Points.

If one or more quarter-hour intervals within the ISO-NE Supply Price Points fail the NYISO's input checks, the last set of ISO-NE Supply Price Points used to perform an RTC optimization will be used in the RTC optimization.

When ISO-NE Supply Price Points do not cover the full quantity (in MWs) of bids that are evaluated by RTC, then the last pricing point on either end of the ISO-NE Supply Price Points will be extended by NYISO to cover all the bids and offers that are evaluated by RTC.

7.2 Permitted Modifications to ISO-NE Transfer Limits

In the event NYISO does not receive ISO-NE Transfer Limits or operator override values have not been entered before an RTC optimization commences, then the last set of ISO-NE Transfer Limits used to perform an RTC optimization will be used in the current RTC optimization.

If one or more quarter-hour intervals within the ISO-NE Transfer Limits fail any of the NYISO's input checks, including the input checks listed below, the last set of ISO-NE Transfer Limits used to perform an RTC optimization will be used in the RTC optimization.

- A Minimum Generation Transfer Limit and Operating Reserve Transfer Limits will not be sent at the same time.
- The Minimum Generation Transfer Limit will be less than or equal to zero.
- If an ISO-NE 10-minute Operating Reserve Transfer Limit is provided, an ISO-NE 30-minute Operating Reserve Transfer Limit will also be provided.
- The ISO-NE 30-minute Operating Reserve Transfer Limit will be less than the ISO-NE 10-minute Operating Reserve Transfer Limit.

7.3 Hourly Scheduling Under CTS

The Parties may agree to temporarily employ hourly scheduling in RTC on a CTS Enabled Interface when necessary to ensure or preserve system reliability or when not able to implement schedules as expected due to software or communication issues.

ARTICLE VIII

8.0 JOINT ENERGY SCHEDULING SYSTEM CUSTOMER SERVICE; MAINTENANCE; SUSPENSION OF CTS; COOPERATION

8.1 Joint Energy Scheduling System Customer Service

The NYISO developed and maintains the Joint Energy Scheduling System ("JESS") platform that both New York RSPs and New England RSPs use to submit bids at CTS Enabled Interfaces.

1. Each Party is the primary customer service contact for its respective Market Participants.

2. ISO-NE will have read-only access to bids associated with New England Market Participants at CTS Enabled Interfaces on the JESS platform.

8.2 Maintenance

Subject to reasonable expectations, it is the Parties' goal that the data links, software, and other systems necessary to implement CTS are available continuously. The Parties agree to employ regular maintenance, including scheduled maintenance outages when needed, to meet that goal.

In the event of a problem with a data link, software, computational system or data system, the responsible Party will use reasonable efforts to promptly address the problem. The Parties shall work together and shall keep each other informed regarding the problem and its resolution.

The Parties shall inform each other in advance of any scheduled testing activities or maintenance outages that will affect a CTS Enabled Interface. Notice shall be provided sufficiently in advance to allow each ISO to inform its Market Participants of any impacts on the operation of CTS.

8.3 Suspension of CTS

The Parties may suspend the scheduling of CTS transactions at CTS Enabled Interfaces due to: (1) the inability of the NYISO to receive bids for a CTS Enabled Interface; (2) a failure or outage of the data link between the Parties that prevents the timely exchange of information necessary to implement CTS transactions; (3) the actual or suspected failure of any software, computational, or data system that is necessary to implement CTS transactions; (4) the need to verify the functionality of the tools that are necessary to implement CTS; or (5) when necessary to ensure or preserve NYISO or ISO-NE system reliability.

A Party that determines that any of the foregoing conditions have occurred shall, as soon as practicable, notify the other Party.

The Parties shall resolve issues causing the failure or outage of the data link, software, computational systems, or data systems as soon as possible, and will use reasonable efforts to promptly address the problem. The Parties shall work together and shall keep each other informed regarding the problem and its resolution. The Parties shall resume implementation of CTS following, as applicable, the successful testing of the data link or relevant system(s) after the inability to receive offers or bids, failure, or condition is resolved, or after the resolution of the system reliability issue.

When CTS is suspended the Parties shall mutually agree to interchange schedules at CTS Enabled Interfaces.

8.4 Cooperation

The Parties will cooperate to review the data and mutually identify or resolve errors and anomalies. If one Party determines that it is required to self-report a potential violation to the Commission’s Office of Enforcement regarding its compliance with this Schedule D, the reporting Party shall inform, and provide a copy of the self-report to the other Party. Any such report provided by one Party to the other shall be Confidential Information.

ARTICLE IX

9.0 CTS CHANGE MANAGEMENT PROCESS

9.1 Notice

Prior to materially changing any tariff language, software or process that is directly involved in implementing this Schedule D, the Party desiring the change shall notify the other Party’s data exchange contact appointed under the Coordination Agreement, in writing or via email, of the proposed change. The notice shall include a complete and detailed description of the proposed change, the reason for the proposed change, and the impacts the proposed change is expected to have on the implementation of CTS.

9.2 Opportunity to Request Additional Information

Following receipt of the Notice described in Section 9.1, the receiving Party may make reasonable requests for additional information/documentation from the other Party. This may include a request by a Party to be involved in the testing of the changes. Absent mutual agreement of the Parties, the submission of a request for additional information under this Section shall not delay the obligation to timely note any objection pursuant to Section 9.3, below.

9.3 Objection to Change

Within ten business days after receipt of the Notice described in Section 9.1 (or within such longer period of time as the Parties mutually agree), the receiving Party may notify in writing or via email the other Party of its disagreement with the proposed change. Any such notice must specifically identify and describe the concern(s) that required the receiving Party to object to the described change.

9.4 Implementation of Change

The Party proposing a change to a process that is directly involved in implementing this Schedule D shall not implement such change until (a) it receives written or email notification from the other Party that the other Party concurs with the change, or (b) the receiving Party fails to notify in writing or via email the other Party of its disagreement with the proposed change within the notice period specified in Section 9.3, or (c) completion of any dispute resolution process initiated pursuant to this Agreement.

ARTICLE X

10.0 AUDITS, CERTIFICATION AND TESTING

Each Party shall provide to the other Party the results of any certification or audit it procures regarding CTS-related software functions, subject to the following conditions: (1) the disclosure may be limited to the portions of the certification or audit that addresses the CTS-related software, and need only include the portions of the certification or audit that address the CTS-related functioning of the software; (2) if the providing Party indicates that the certification or audit is Confidential Information it shall be treated as such by the receiving party; and (3) this provision does not require a Party to disclose information that is subject to a legal privilege.

Before CTS is implemented, and upon any material changes to any components thereof, the Parties shall test the processes and component software.

Each Party shall, at its sole expense, take appropriate actions to address any actual or apparent breach of cyber security related to CTS, and shall provide prompt notification to the other Party of any such incident.

Each party will undertake an annual Service Organization Controls report that covers CTS process-related controls prepared and opined by its external auditors in accordance with Statement on Standards for Attestation Engagements No. 16 or AICPA/CICA Principles and

Criterion for System Reliability (SSAE 16 engagement). The NYISO report will include controls related to the Joint Energy Scheduling System bidding platform.

Each Party shall promptly provide to the other Party the results of its annual Service Organization Controls report, subject to the following conditions: (1) the disclosure may be limited to the portions of the report or audit that address CTS, and need only include the portions of the report or audit that address CTS; (2) if the providing Party indicates that the certification or audit is Confidential Information it shall be treated as such by the receiving party; and (3) this provision does not require a Party to disclose information that is subject to a legal privilege.

38 Attachment FF – Generator Deactivation Process

38.1 Definitions

Whenever used in the **Generator Deactivation Process** requirements in this Section 38 with initial capitalization, the following terms shall have the meaning specified in this Section 38.1. Terms used in this Section 38 with initial capitalization that are not defined in this Section 38.1 shall have the meanings specified in Section 31.1.1 of Attachment Y of the ISO OATT or, if not defined therein, in Section 1 of the ISO OATT or Section 2 of the ISO Services Tariff.

Developer: A person or entity, including a Transmission Owner, sponsoring or proposing a solution to a Generator Deactivation Reliability Need pursuant to this Attachment FF.

Generator Deactivation Assessment: The ISO's analysis, in coordination with the Responsible Transmission Owner(s), of whether a Generator Deactivation Reliability Need will result from a Generator becoming Retired, entering into a Mothball Outage, or being unavailable due to an ICAP Ineligible Forced Outage.

Generator Deactivation Assessment Start Date: The date on which: (i) the ISO issues a written notice to a Market Participant pursuant to Section 38.3.1.4 indicating that the Generator Deactivation Notice for its Generator is complete, or (ii) a Market Participant's Generator enters into an ICAP Ineligible Forced Outage pursuant to Section 5.18.2.1 of the ISO Services Tariff.

Generator Deactivation Notice: The form set forth in Section 38.24 (Appendix A) of this Attachment FF.

Generator Deactivation Process: The process set forth in this Attachment FF by which the ISO evaluates and addresses the reliability impacts resulting from: (i) a Market Participant providing notice for its Generator to become Retired or enter into a Mothball Outage or (ii) a Market Participant's Generator entering into an ICAP Ineligible Forced Outage.

Generator Deactivation Reliability Need: A condition identified by the ISO in a Generator Deactivation Assessment as a violation or potential violation of one or more Reliability Criteria and applicable local criteria.

Generator Deactivation Solution: A solution to address a Generator Deactivation Reliability Need, which may include the Initiating Generator, a solution proposed pursuant to Section 38.4, or a Generator identified by the ISO pursuant to Section 38.5.

Generator Owner: (a) the entity or entities that have executed an RMR Agreement and assumed ultimate responsibility for the operation of an RMR Generator and its participation in the ISO Administered Markets; (b) the entity or entities that have indicated their willingness to execute an RMR Agreement and assume ultimate responsibility for the operation of an RMR Generator and its participation in the ISO Administered Markets by submitting a filing to FERC proposing a rate for providing RMR service or seeking to recover the cost of Capital Expenditures; or (c) the entity or entities that possess ultimate responsibility for the operation of an Interim Service Provider and its participation in the ISO Administered Markets. The Generator Owner may be a Market Party and/or a Market Participant, may include one or more Market Parties and/or Market Participants, or may participate in the ISO Administered Markets by and through one or more Market Parties and/or Market Participants.

Initiating Generator: A Generator that submits a Generator Deactivation Notice for purposes of becoming Retired or entering into a Mothball Outage or that has entered into an ICAP Ineligible Forced Outage pursuant to Section 5.18.2.1 of the ISO Services Tariff, which action is being evaluated by the ISO in accordance with its Generator Deactivation Process requirements in this Section 38 of the ISO OATT.

Interim Service Provider: A Generator that must remain in service during the 365 days that follow the Generator Deactivation Assessment Start Date beyond the later of (a) the 181st day of the 365 day period, or (b) the Generator's requested deactivation date. Interim Service Providers are compensated in accordance with Rate Schedule 8 to the ISO Services Tariff.

Market Party: Any person or entity that is, or proposes or plans (including any participant therein,) a project that would be, a buyer or a seller in, or that makes bids or offers to buy or sell in, or that schedules or seeks to schedule Transactions with the ISO in or affecting any of the ISO Administered Markets, or any combination of the foregoing.

Near-Term Generator Deactivation Reliability Need: A Generator Deactivation Reliability Need that the ISO determines will arise within three years of the conclusion of the 365 days that follow the Generator Deactivation Assessment Start Date.

Responsible Transmission Owner: The Transmission Owner or Transmission Owners designated by the ISO pursuant to this Attachment FF: (i) to conduct the necessary reliability studies to review the impact of a Generator's proposed deactivation on the reliability of the non-BPTFs that are part of the New York State Transmission System, (ii) to prepare a Generator Deactivation Solution and, if required, a conceptual permanent solution to address a Generator Deactivation Reliability Need, and (iii) to proceed with a Generator Deactivation Solution if directed to do so by the ISO. The Responsible Transmission Owner will normally be the Transmission Owner in whose Transmission District the ISO identifies a Generator Deactivation Reliability Need and/or that owns a transmission facility on which a Reliability Need arises.

RMR Service Offer: An offer submitted to the ISO by a Generator to provide RMR service.

RMR Start Date: The date an RMR Generator begins participating, offering, and operating in the ISO Administered Markets pursuant to the ISO Tariff rules that apply to RMR Generators and the terms of an RMR Agreement.

Viable and Sufficient: Term that describes a proposed Generator Deactivation Solution that the ISO has determined in accordance with Section 38.6 to be viable and sufficient to satisfy the identified Generator Deactivation Reliability Need individually or in conjunction with other solutions.

38.2 Scope of Generator Deactivation Process

The Generator Deactivation Process set forth in this Attachment FF establishes the process by which the ISO will address a Generator Deactivation Reliability Need that results from a Generator becoming Retired, entering into a Mothball Outage, or being unavailable due to an ICAP Ineligible Forced Outage. Pursuant to this process, the ISO will first determine through a Generator Deactivation Assessment whether a Generator Deactivation Reliability Need would result from a Generator's deactivation. If the Generator Deactivation Assessment identifies a Generator Deactivation Reliability Need that cannot timely be addressed through the ISO's biennial reliability planning process, the ISO will solicit and evaluate market-based and regulated Generator Deactivation Solutions to address the need, including, but not limited to, entering into an RMR Agreement with the Initiating Generator. Rules addressing cost allocation for Generator Deactivation Solutions are set forth in Section 38.22. Rules addressing cost recovery for Generator Deactivation Solutions are set forth in Section 38.23, Rate Schedules 14 and 16 to the ISO OATT, and Rate Schedule 8 to the ISO Services Tariff.

38.3 Generator Deactivation Requirements

38.3.1 Requirements for Initiating Generator Seeking to Be Retired or Enter into Mothball Outage

38.3.1.1 A Market Participant must provide the ISO with a minimum of 365 days prior notice (such period beginning after its Generator Deactivation Notice has been determined to be complete by the ISO) before its Generator may be Retired or enter into a Mothball Outage; except for Generators reclassified as Retired pursuant to Sections 5.18.2.3.1 or 5.18.3.3.1 of the ISO Services Tariff, or as provided for an RMR Generator under an RMR Agreement.

38.3.1.2 The Market Participant shall provide this notice to the ISO by submitting a Generator Deactivation Notice in the form set forth in Appendix A to this Attachment FF, along with all information required by that form, the supporting certification from a duly authorized officer, and the information required for an Initiating Generator in accordance with Sections 38.25.2, and 38.25.5 through 38.25.7 of Appendix B of this Attachment FF.

38.3.1.3 The Market Participant must specify in the Generator Deactivation Notice its proposed date for its Generator to be Retired or enter into a Mothball Outage.

38.3.1.4 The 365-day notice period applicable to a Generator proposing to be Retired or enter into a Mothball Outage will begin to run when the ISO issues a written notice to the Market Participant indicating that the Generator Deactivation Notice, including the supporting information and certification, is complete. For purposes of this Attachment FF, "complete" shall mean sufficiently complete for the ISO to begin its review of the reliability impacts that would result from a Generator being Retired or entering into a Mothball Outage under this Attachment

FF, and to review as required by Sections 38.7 and 38.8 the information provided in accordance with Appendix B of this Attachment FF.

38.3.1.5 Within ten (10) business days of receiving a Generator Deactivation Notice, the ISO shall review the notice form, along with the supporting information and affidavit submitted with it, and will inform the Market Participant whether its submission is complete or whether additional information is required. The Market Participant shall provide the ISO with any requested additional information, and the ISO will promptly review the information to determine whether the Market Participant's notice is complete. Within ten (10) business days of the ISO receiving all additional information it requested, the ISO will inform the Market Participant whether its submission is complete, or whether further information is needed. Upon its determination that a submitted Generator Deactivation Notice is complete, the ISO will concurrently notify the Generator and post a notice on its website that the Generator Deactivation Notice has been determined to be complete.

38.3.1.6 The Market Participant has a continuing obligation to promptly submit any additional information requested by the ISO in connection with the ISO's evaluation under this Attachment FF, as required by Section 38.25.4 of Appendix B of Attachment FF, and assessment of market impacts under Section 23 of Attachment H of the ISO Services Tariff.

38.3.2 Requirements for Initiating Generator that Has Entered into ICAP Ineligible Forced Outage

Within 20 days of a Market Participant's Generator entering into an ICAP Ineligible Forced Outage, the Market Participant shall submit the information required for an Initiating

Generator in accordance with Sections 38.25.2 and 38.25.5 through 38.25.7 of Appendix B of this Attachment FF. It shall also provide the information required by Section 38.25.4 of Appendix B of this Attachment FF.

38.3.3 Immediate Reliability Need

The ISO may take immediate action to implement an interim solution to maintain reliability if the ISO determines that a Generator Deactivation Reliability Need may not be timely addressed through the normal Generator Deactivation Process. To maintain reliability in such circumstances, the ISO may abbreviate, as necessary, the time periods and requirements set forth in this Attachment FF and make any necessary filings with the Commission.

38.3.4 Performance of Generator Deactivation Assessment

38.3.4.1 Following the Generator Deactivation Assessment Start Date, the ISO will perform, in coordination with the Responsible Transmission Owner(s) identified by the ISO, a Generator Deactivation Assessment concerning the Initiating Generator. The ISO will conduct the necessary reliability studies to review the impact on the reliability of the BPTFs that would result from the Generator being Retired, entering into a Mothball Outage, or being unavailable due to an ICAP Ineligible Forced Outage. The Responsible Transmission Owner(s) will conduct the necessary reliability studies to review the impact on the reliability of the non-BPTFs that are part of the New York State Transmission System, which studies the ISO will review and verify. For the Generator Deactivation Assessment, the ISO will use the most recent base case from the reliability planning process, updated in accordance with ISO Procedures. The study period for the assessment will be the five years following the conclusion of the 365-day notice period. The ISO will review the key study assumptions with its stakeholders.

38.3.4.2 As part of the assessment, the ISO shall review whether any potential Generator Deactivation Reliability Need can be addressed through the adoption of alternative ISO or Transmission Owner operating procedures or by updates to Local Transmission Owner Plans, other than an agreement with the Generator addressed in the Generator Deactivation Notice or a Generator already in a Mothball Outage, an ICAP Ineligible Forced Outage, or that has been mothballed since before May 1, 2015.

38.3.4.3 Within ninety days of the Generator Deactivation Assessment Start Date, the ISO shall concurrently notify the Initiating Generator and post on its website the results of the Generator Deactivation Assessment. The assessment will specify: (i) whether a Generator Deactivation Reliability Need would arise from an Initiating Generator being Retired, entering into a Mothball Outage, or being unavailable due to an ICAP Ineligible Forced Outage, and (ii) whether the ISO has determined that any Generator Deactivation Reliability Need can be timely addressed in the current or next planning cycle of the biennial reliability planning process, or must be addressed using this Generator Deactivation Process. The Generator Deactivation Process will conclude if the Generator Deactivation Assessment: (i) does not identify a Generator Deactivation Reliability Need, or (ii) states that a Generator Deactivation Reliability Need identified in the assessment will be addressed in the biennial reliability planning process. The Generator Deactivation Assessment will also state whether the Generation

Deactivation Reliability Need is only a reliability need on non-BPTFs for which solely the Responsible Transmission Owner may propose a regulated transmission Generator Deactivation Solution. Any Generator that the ISO determines is Viable and Sufficient may participate as a Generator Deactivation Solution to part or all of a Generator Deactivation Reliability Need, including a reliability need arising only on the non-BPTFs.

38.3.5 Near-Term Generator Deactivation Reliability Needs

38.3.5.1 As part of the Generator Deactivation Assessment, the ISO will determine whether there is a Near-Term Generator Deactivation Reliability Need. Any Generator that the ISO determines is Viable and Sufficient may participate as a Generator Deactivation Solution to part or all of a Near-Term Generator Deactivation Reliability Need, including a reliability need arising only on non-BPTFs.

38.3.5.2 If the ISO determines that a Generator Deactivation Reliability Need is a Near-Term Generator Deactivation Reliability Need, the ISO shall:

38.3.5.2.1 Include an explanation in the Generator Deactivation Assessment of the Near-Term Generator Deactivation Reliability Need in sufficient detail, including the reliability criteria violations and system conditions, to allow stakeholders to understand the need and why it is time sensitive.

38.3.5.2.2 Provide to stakeholders and post on its website a full and supported written explanation of the ISO's decision to solicit a regulated, non-generation Generator Deactivation Solution solely from a Responsible Transmission Owner, including an explanation of the other transmission and non-transmission options that the ISO considered, but concluded would not sufficiently address the Near-Term Generator Deactivation Reliability Need, the circumstances that generated the need, and an explanation of why the need was not identified earlier.

38.3.5.2.3 Provide the appropriate stakeholder working group a reasonable opportunity to provide comments to the ISO on the written explanation.

38.3.5.3 The ISO shall maintain and post on its website a list of all transmission solutions selected by the ISO in prior years to be built in response to Near-Term Generator Deactivation Reliability Needs for which the ISO designated solely the Responsible Transmission Owner to propose a regulated Generator Deactivation Solution. The list must include the Near-Term Generator Deactivation Reliability Need, the identity of the designated Responsible Transmission Owner, the transmission solution selected by the ISO, its in-service date, and the date on which the Responsible Transmission Owner energized or otherwise implemented the transmission solution. The ISO shall file the list with the Commission as an informational filing in January of each year covering the designations of the prior calendar year, if the ISO selected a Responsible Transmission Owner's regulated transmission solution to a Near-Term Generator Deactivation Reliability Need in the prior year.

38.3.6 Deactivation Prior to the Expiration of the 365 Day Notice Period

If: (i) the ISO determines in the Generator Deactivation Assessment either that a Generator Deactivation Reliability Need would not arise from a Market Participant's Generator being Retired or entering into a Mothball Outage, or that the need can be timely addressed in the ISO's biennial reliability planning process, and (ii) the Market Participant indicated in the

Generator Deactivation Notice an interest in deactivating its Generator earlier than the completion of the 365-day notice period, then the ISO will notify the Market Participant when its Generator has completed all required ISO administrative processes and procedures, and may be Retired or enter into a Mothball Outage, which deactivation date shall be no earlier than 91 days after the Generator Deactivation Assessment Start Date.

38.4 Solicitation of Generator Deactivation Solutions to a Generator Deactivation Reliability Need

38.4.1 If the ISO determines in its Generator Deactivation Assessment that a Generator Deactivation Reliability Need should be addressed in the Generator Deactivation Process, the ISO shall solicit Generator Deactivation Solutions to address the Generator Deactivation Reliability Need. A Developer must submit a proposed Generator Deactivation Solution within sixty (60) days of the ISO's request.

The solicitation process set forth in this Section 38.4 is not the process for offering a Market Participant's Generator that is in a Mothball Outage, an ICAP Ineligible Forced Outage, or has been mothballed since before May 1, 2015 as a proposed Generator Deactivation Solution. Such Generator may be offered as a Generator Deactivation Solution by submitting a statement of intent to participate in the Generator Deactivation Process in accordance with Section 38.5 and satisfying the other requirements of that Section.

38.4.2 In response to the ISO's solicitation of proposed Generator Deactivation Solutions:

38.4.2.1 The Responsible Transmission Owner must submit a proposed Generator Deactivation Solution. The proposed solution must, to the extent practicable, completely address the Generator Deactivation Reliability Need and satisfy the project information requirements in Sections 31.2.4.4.1, 31.2.4.4.2, and 31.2.6.5.1.1 of Attachment Y of the ISO OATT. The Responsible Transmission Owner's proposed Generator Deactivation Solution may include transmission, demand response, or generation resources; *provided, however*, only the ISO may enter into an RMR Agreement with a Generator to address the Generator Deactivation Reliability Need. The Responsible Transmission Owner may only allocate and recover under the ISO OATT the costs of a transmission solution in accordance with the requirements in Sections 38.22 and 38.23. If the Generator Deactivation Reliability Need is only a reliability need on non-BPTFs, then the Responsible Transmission Owner must submit a permanent Generator Deactivation Solution. If the ISO determines, after considering input from the Responsible Transmission Owner, that the Responsible Transmission Owner's proposed Generator Deactivation Solution is an interim solution, then the Responsible Transmission Owner must also submit a conceptual permanent solution to address the Generator Deactivation Reliability Need.

38.4.2.2 Any Developer may submit a proposed market-based Generator Deactivation Solution. A market-based Generator Deactivation Solutions may include generation, transmission, or demand response solutions and must satisfy the project information requirements in Section 31.2.4.6 of Attachment Y of the ISO OATT. Market-based solutions are not eligible for cost recovery under Rate Schedule 8 to the ISO Services Tariff, or Rate Schedules 14 or 16 to the ISO OATT.

38.4.2.3 Any Developer may submit a proposed new Generator that requires an RMR Agreement to operate as a temporary Generator Deactivation Solution. A proposed new Generator that requires an RMR Agreement must satisfy the project information requirements in Sections 31.2.4.8.1 and 31.2.4.8.2 of Attachment Y of the ISO OATT.

38.4.2.4 Any Developer that has been determined to be qualified under Section 31.2.4.1.1.2 of Attachment Y to the ISO OATT may submit a proposed regulated transmission Generator Deactivation Solution, unless: (i) the Generator Deactivation Reliability Need is a Near-Term Generator Deactivation Reliability Need, or (ii) the Generator Deactivation Reliability Need is only a reliability need on non-BPTFs as stated by the ISO in the Generator Deactivation Assessment pursuant to Section 38.3.4.3. The proposed regulated transmission solution must satisfy the project information requirements in Sections 31.2.4.8.1, 31.2.4.8.2, and 31.2.6.5.1.1 of Attachment Y of the ISO OATT.

38.4.3 As part of its submission of its proposed Generator Deactivation Solution, a Developer shall provide the information required for each proposed Generator Deactivation Solution in accordance with Sections 38.25.3, and 38.25.5 through 38.25.7 of Appendix B of this Attachment FF. It shall also provide the information required by Section 38.25.4 of Appendix B of this Attachment FF.

38.4.4 Generator Deactivation Solutions proposed under this Section 38.4 shall strive to be compatible with permanent market-based solutions and regulated solutions identified in the CSPP, as applicable. A permanent regulated solution may proceed in parallel with an interim solution selected in this Attachment FF.

38.4.5 The ISO may disclose to Market Participants and other interested parties the Generator Deactivation Solution and plans proposed pursuant to this Section 38.4; *provided, however,* that the ISO will maintain as confidential the following information if designated as "Confidential Information": (i) a Responsible Transmission Owner's conceptual permanent solution, except for its proposed project type, general geographic location, and in-service date; (ii) the information required to be maintained as confidential for a market-based solution pursuant to Sections 31.2.12.4 and 31.2.12.5 of Attachment Y to the ISO OATT, and (iii) any non-public financial qualification information submitted in accordance with Section 31.2.4.1.1.1.3 of Attachment Y of the ISO OATT.

38.4.6 Application Fee and Study Deposit

38.4.6.1 When the ISO performs a selection process among regulated transmission solutions, any Developer that proposes a regulated transmission Generator Deactivation Solution to address the Generator Deactivation Reliability Need shall submit to the ISO, at the same time it provides the project information required pursuant to Section 38.4.2, a non-refundable application fee of $10,000 and a study deposit of $100,000, which shall be applied to study costs and subject to refund as described in this Section 38.4.6.

38.4.6.2 If the ISO performs a selection process among regulated transmission solutions, the ISO shall charge, and a Developer proposing a regulated transmission Generator Deactivation Solution shall pay, the actual costs of the ISO's evaluation of the Developer's proposed transmission solution for purposes of the ISO's selection among transmission solutions to address the Generator Deactivation Reliability Need, including costs associated with the ISO's use of subcontractors. The ISO will track its staff and administrative costs, including any costs associated with using subcontractors, that it incurs in performing the evaluation of a Developer's proposed transmission solution and any supplemental evaluation or re-evaluation of the proposed transmission solution. If the ISO or its subcontractors perform study work for multiple proposed transmission solutions on a combined basis, the ISO will allocate the costs of the combined study work equally among the applicable Developers.

38.4.6.3 The ISO shall invoice the Developer monthly for study costs incurred by the ISO in evaluating the Developer's proposed transmission solution as described above. Such invoice shall include a description and an accounting of the study costs incurred by the ISO and estimated subcontractor costs. The Developer shall pay the invoiced amount within thirty (30) calendar days of the ISO's issuance of the monthly invoice. The ISO shall continue to hold the full amount of the study deposit until settlement of the final monthly invoice; *provided, however,* if a Developer: (i) does not pay its monthly invoice within the timeframe described above, or (ii) does not pay a disputed amount into an independent escrow account as described below, the ISO may draw upon the study deposit to recover the owed amount. If the ISO must draw on the study deposit, the ISO shall provide notice to the Developer, and the Developer shall within thirty (30) calendar days of such notice make payments to the ISO to restore the full study deposit amount. If the Developer fails to make such payments, the ISO may halt its evaluation of the Developer's proposed transmission solution and may disqualify the Developer's proposed transmission solution from further consideration. After the conclusion of the ISO's evaluation of the Developer's proposed transmission solution or if the Developer: (i) withdraws its proposed transmission solution or (ii) fails to pay an invoiced amount and the ISO halts its evaluation of the proposed transmission solution, the ISO shall issue a final invoice and refund to the Developer any portion of the Developer's study deposit submitted to the ISO under this Section 38.4.6 that exceeds outstanding amounts that the ISO has incurred in evaluating that Developer's proposed transmission solution, including interest on the refunded amount calculated in accordance with Section 35.19a(a)(2) of FERC's regulations. The ISO shall refund the remaining portion within sixty (60) days of the ISO's receipt of all final invoices from its subcontractors and involved Transmission Owners.

38.4.6.4 In the event of a Developer's dispute over invoiced amounts, the Developer shall: (i) timely pay any undisputed amounts to the ISO, and (ii) pay into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Developer fails to meet these two requirements, then the ISO shall not be obligated to perform or continue to perform its evaluation of the Developer's proposed transmission solution. Disputes arising under this section shall be addressed through the Dispute Resolution Procedures set forth in Section 2.16 of the ISO OATT and Section 11 of the ISO Services Tariff. Within thirty (30) Calendar Days after resolution of the dispute, the Developer will pay the ISO any amounts due with interest calculated in accordance with Section 35.19a(a)(2) of FERC's regulations.

38.5 Review and Notification of Generator(s) Currently in an Outage State

If the ISO determines that a Market Participant's Generator that is in a Mothball Outage, an ICAP Ineligible Forced Outage, or has been mothballed since before May 1, 2015, may be capable of satisfying in whole or in part the Generator Deactivation Reliability Need, the ISO will notify the Market Participant that its Generator is under review to determine whether it can satisfy the Generator Deactivation Reliability Need as a possible Generator Deactivation Solution. Within ten (10) days of the ISO's issuance of a written notification (including an email), a Market Participant that is interested in offering its Generator as a Generator Deactivation Solution to address the Generator Deactivation Reliability Need shall inform the ISO in writing whether it intends to offer its Generator as a Generator Deactivation Solution. A Market Participant that submits a statement of intent to offer its Generator shall provide to the NYISO within twenty (20) days of submitting its statement of intent the information required for a Generator identified under this Section 38.5 in accordance with Sections 38.25.3.1, 38.25.3.2, and 38.25.5 through 38.25.7 of Appendix B of this Attachment FF if it has not previously provided such information to the ISO. If the Market Participant has previously provided such information for the relevant Generator, then it shall update all such information, including, but not limited to, the updates required by Section 38.25.4 of Appendix B of this Attachment FF.

Notwithstanding whether a Market Participant submitted a statement of intent to offer its Generator as a Generator Deactivation Solution, the ISO may request at any time that a Market Participant submit the information required for a Generator identified under this Section 38.5 in accordance with Sections 38.25.3.1, 38.25.3.2, and 38.25.5 through 38.25.7 of Appendix B of this Attachment FF or any updates to previously submitted information addressing its Generator, which information must be submitted within twenty (20) days of the NYISO's request.

When the return to service of a Generator in a Mothball Outage or an ICAP Ineligible Forced Outage is the Generator Deactivation Solution, the return to service procedures set forth in Section 5.18.4 of the ISO Services Tariff shall apply.

38.6 Viability and Sufficiency Evaluation of Generator Deactivation Solutions

38.6.1 The ISO shall evaluate all Generator Deactivation Solutions and, if applicable, shall evaluate the conceptual permanent solution provided by the Responsible Transmission Owner pursuant to Section 38.4.2.1 to determine whether each is viable and sufficient to satisfy individually, or in conjunction with other solutions, the Generator Deactivation Reliability Need. The ISO shall perform this viability and sufficiency evaluation consistent with the requirements set forth in Sections 31.2.5.3 and 31.2.5.4 of Attachment Y of the ISO OATT. The ISO shall coordinate with the Responsible Transmission Owner(s), as necessary, in performing its evaluation.

38.6.2 If the ISO determines that there are adequate Viable and Sufficient market-based or demand response Generator Deactivation Solutions to satisfy completely the identified Generator Deactivation Reliability Need, the ISO will conclude the Generator Deactivation Process under this Attachment FF, and the ISO will monitor the development of the market-based and demand response Generator Deactivation Solutions in accordance with ISO Procedures. As part of its final Generator Deactivation Process report, the ISO shall present the results of its viability and sufficiency assessment to interested parties if the Generator Deactivation Process has been concluded because there are adequate market-based or demand response Generator Deactivation Solutions to satisfy completely the Generator Deactivation Reliability Need.

38.7 ISO Review of Information Pursuant to Appendix B

38.7.1 The ISO shall review, verify and/or validate to the extent necessary the information provided in accordance with Sections 38.3, 38.4, and 38.5 and Appendix B of this Attachment FF. The ISO's review, verification and/or validation, as applicable, of the financing cost of each capital expense that the ISO determines is necessary in accordance with Good Utility Practice shall consider the market interest rate available to the Market Party.

38.7.2 The ISO may reject, and may require a Market Party to re-submit, or substantiate information (including estimates) that the ISO determines is not adequately supported or otherwise verifiable. The Market Party shall promptly provide any additional information that the ISO may request, and update and revise information previously provided, and provide new information as set forth in Section 38.25.4 of Appendix B of this Attachment FF. Upon the ISO's prior notice, the Market Party shall make qualified representatives available to answer the ISO's question(s) and otherwise facilitate the ISO's review of the information. The NYISO may terminate its consideration of a proposed Generator Deactivation Solution if a Market Party fails to provide requested information.

38.8 Determining RMR Avoidable Costs

38.8.1 Determinations pursuant to this section are solely for purposes of determining the RMR Avoidable Cost of Initiating Generators and Generators that are determined to be a Viable and Sufficient Generator Deactivation Solution to a Generator Deactivation Reliability Need. The ISO shall determine the cost (net of estimated revenues, as applicable) of each Initiating Generator and of each Viable and Sufficient Generator Deactivation Solution to a Generator Deactivation Reliability Need that responds to the ISO's request for Generator Deactivation Solutions in accordance with Sections 38.4 and 38.5. The ISO may also determine the costs of Viable and Sufficient Generator Deactivation Solutions that do not respond to the ISO's request for Generator Deactivation Solutions. The ISO's determination for a Generator shall be its "RMR Avoidable Costs." The ISO shall use the costs, revenues, and other information submitted in accordance with Sections 38.3, 38.4, 38.5, 38.7, 38.8 and Appendix B of this Attachment FF that it verifies and/or validates, as applicable. If the ISO cannot verify and/or validate, as applicable, a cost or revenue submitted by a Market Party, the ISO shall substitute an estimated value. The ISO's cost determinations pursuant to this Section shall be for the shorter of (i) the duration of the Generator Deactivation Reliability Need identified by the ISO in its request for Generator Deactivation Solutions, and (ii) the period identified by the ISO that an Initiating Generator or Viable and Sufficient Generator Deactivation Solution can satisfy the Generator Deactivation Reliability Need.

38.8.1.1 Cost savings due to an Initiating Generator's continuation of service. Costs submitted in accordance with Sections 38.3, 38.4, 38.5, 38.7, 38.8, or Appendix B of this Attachment FF that arise out of an agreement that contains a cost, premium, or fee to terminate the agreement in whole or in part prior to the anticipated RMR Start Date, or commencement of service as a Generator Deactivation Solution, shall be reduced by the cost, premium or fee that would have been incurred had the Generator ceased operations on a date identified in the Generator Deactivation Notice, or such other date associated with performing service as a Generator Deactivation Solution.

38.8.1.2 For each transmission project that is proposed in accordance with this Attachment FF, the ISO shall calculate the net costs that would be incurred to provide the service identified in the Developer's response to the ISO's request for Generator Deactivation Solutions, considering any costs the Developer otherwise had a contractual or regulatory obligation to incur.

38.8.1.3 The ISO shall identify as "Capital Expenditures" the purchase or non-operational lease of, or modification to real property or assets (including, but not limited to, land, buildings, and equipment) that (a) are necessary to permit an Initiating Generator or Viable and Sufficient Generator Deactivation Solution to provide service to satisfy, in whole or in part, the Generator Deactivation Reliability Need identified in the ISO's request for Generator Deactivation Solutions, (b) have a useful life greater than one year, and (c) are not otherwise included in the ISO's calculation of RMR Avoidable Costs. The ISO shall also identify the reasonably anticipated date the Capital Expenditure will be placed into service, or otherwise integrated into the Generator Deactivation Solution.

38.8.1.4 Revenue Calculation. As a component to the ISO's calculation of the total net cost of each Initiating Generator and Viable and Sufficient Generator Deactivation Solution, the ISO shall calculate the estimated revenues thereof.

38.8.1.4.1 If an Initiating Generator or other Generator that has been determined to be a Viable and Sufficient Generator Deactivation Solution has a contract pursuant to which it provides energy, capacity, or ancillary services, the ISO shall also, for the period of such contract, calculate the estimated revenues for the provision of energy, capacity or ancillary services thereunder.

38.8.2 The ISO shall seek comment from the Market Monitoring Unit on matters relating to the inputs and the calculations performed pursuant to Section 38.8. The responsibilities of the Market Monitoring Unit that are addressed in this Section are also addressed in Section 38.18.1 of this Attachment FF and in Section 30.4.6.8.6 of Attachment O to the ISO Services Tariff.

38.9 RMR Service Offers

38.9.1 If: (i) there is only one Generator that is a Viable and Sufficient Generator Deactivation Solution to a Generator Deactivation Reliability Need, or (ii) there are multiple Generators that are a Viable and Sufficient Generator Deactivation Solution to a Generator Deactivation Reliability Need that are all owned or controlled by the same Generator Owner, then the ISO shall provide to that individual Generator or Generator Owner, as applicable, its RMR Avoidable Cost and an opportunity for it to enter into the Form of Reliability Must Run Agreement set forth in Appendix C of this Attachment FF to the ISO OATT. If there is more than one Generator that is a Viable and Sufficient Generator Deactivation Solution for a Reliability Need and the Generators are not all owned or controlled by the same Generator Owner, the ISO shall notify each such Generator that responded to the ISO's request for Generator Deactivation Solutions that it has been determined to be a Viable and Sufficient Generator Deactivation Solution that the ISO is requesting RMR Service Offers to provide service pursuant to an RMR Agreement.

38.9.2 The ISO shall concurrently post on its website that it has issued a request for RMR Service Offers.

38.9.3 The ISO's notice to each Generator of a request for RMR Service Offers shall include (a) the Generator's RMR Avoidable Costs determined pursuant to Section 38.8, and separately identify the Capital Expenditure amount that is included in the RMR Avoidable Costs and the reasonably anticipated date the Capital Expenditure will be placed into service, or otherwise integrated into the

Generator, (b) the duration of the period for which the ISO determined the Generator was viable and sufficient to meet (in whole or in part) the Generator Deactivation Reliability Need, (c) the deadline by which offers must be received by the ISO, and (d) any other information that must be provided in the Generator's response in accordance with ISO Procedures.

38.9.4 Offers in response to a request for RMR Service Offers shall (A) state the price at which the Generator is willing to enter into an RMR Agreement with (i) an Availability and Performance Rate or (ii) an Owner Developed Rate for which the Generator would be seeking approval from the Commission, (B) separately state the anticipated timing and cost of each Capital Expenditure that is included in the offer, (C) if any provision of the Form of Reliability Must Run Agreement set forth in Appendix C of Attachment FF to the ISO OATT is incompatible with the Generator's ability to provide service absent a modification to a term or condition, provide a blackline marking any and all changes that are necessary to permit the Generator to provide RMR service, and explain why, absent such changes, the Generator would be unable to provide RMR service, (D) state the duration for which the Generator is being made available to provide the RMR service (which shall be no longer than the duration the ISO determined the Generator is a viable and sufficient solution,) and specify whether the offer would be the same for any shorter period of time, and (E) state whether the offer is for less than or equal to the generator's full cost of service. The offer must be executed by a duly authorized officer with authority to bind the Market Party to an RMR Agreement. The ISO will not consider offers that indicate they are for an amount greater than the Generator's full cost of service. The ISO shall exclude from consideration offers that are received after the deadline.

38.10 ISO Selection of Solution to Address Generator Deactivation Reliability Need

38.10.1 An Initiating Generator and other Viable and Sufficient Generator Deactivation Solutions are eligible for selection by the ISO to address a Generator Deactivation Reliability Need. In selecting a solution to address a Generator Deactivation Reliability Need the ISO will first consider the expected impact of any Viable and Sufficient market-based or demand response Generator Deactivation Solutions it identifies on the scope of the need. Prior to the ISO making its selection pursuant to this Section 38.10, the ISO may enter into an RMR Agreement with one or more Generators, if necessary, to provide the ISO sufficient time to complete the selection process.

A Viable and Sufficient transmission solution selected by the ISO shall be eligible for cost allocation in accordance with Section 38.22 and cost recovery in accordance with Section 38.23. An Initiating Generator or another Viable and Sufficient generation solution selected by the ISO shall be eligible to enter into an RMR Agreement with the ISO in accordance with Section 38.11.

38.10.1.1 If the ISO determines that there is a Viable and Sufficient permanent transmission solution that completely satisfies the Generator Deactivation Reliability Need, the ISO may select that solution.

38.10.1.2 If the Generator Deactivation Reliability Need is only a reliability need on non-BPTFs, in addition to selecting any interim solution it determines is necessary, the ISO will select a Viable and Sufficient permanent transmission Generator Deactivation Solution.

38.10.1.3 If, following completion of the identification of solutions pursuant to Sections 38.10.1 and 38.10.1.1 or 38.10.1.2, there remains a Generator Deactivation Reliability Need, then the ISO shall perform the selection process set forth in Sections 38.10.2 through 38.10.5.

38.10.2 Selection Process if a Viable and Sufficient Transmission Solution Is Available

38.10.2.1 This solution selection process is designed to ensure that executing an RMR Agreement with a Generator is a last resort to addressing a Generator Deactivation Reliability Need. The ISO will select a Viable and Sufficient transmission solution to address the Generator Deactivation Reliability Need if: (i) there are one or more Viable and Sufficient transmission solutions, and (ii) none of the Viable and Sufficient generation solutions have a "distinctly higher net present value" than a transmission solution. If the ISO is selecting between and among Viable and Sufficient transmission solutions, the ISO will perform its selection based on the degree to which each transmission solution satisfies the metrics set forth in Section 38.10.4.

38.10.2.2 Determining if a Solution has a "Distinctly" Higher Net Present Value

A Generator Deactivation Solution has a "distinctly" higher net present value if it is the Viable and Sufficient solution with the lowest reasonably calculated net cost to consumers to meet the identified Reliability Need until the permanent solution can be implemented. A generation solution has a "distinctly" higher net present value than a transmission solution if, after accounting for the accuracy range of each transmission project cost estimate and generation revenue estimate using the confidence interval the ISO selects, the ISO determines that the range of net present values of the generation solution is higher than the range of the net present values of the transmission solution. If there is an overlap between the ranges of net present values between a generation solution and a transmission solution, then the generation solution does not have a distinctly higher net present value than the transmission solution. If the ISO determines that a generation solution has a distinctly higher net present value than a transmission solution, then both solutions will be considered in accordance with Section 38.10.2.4 of this solution selection process.

The net present value of a generation solution is the present value of the difference between the generation solution's offered service cost and its expected market revenues for the expected duration of an RMR Agreement. The net present value of a transmission solution is the present value of the difference between the transmission solution's estimated costs and its expected market revenues (if any).

To account for the accuracy of cost estimates in comparing the net present values of Viable and Sufficient generation and transmission solutions, the NYISO will:

1. Undertake reasonable efforts to validate the information submitted in the time available; and
2. Determine an accuracy range for each solution's estimated, submitted and verified costs, including the assumptions used to develop the cost estimate based on (i) the age, operating status and technology type of each generation or transmission solution, (ii) the assumptions used to develop each cost estimate, and (iii) data from credible independent resources, including but not limited to consultants hired by the ISO.

38.10.2.3 Multi-Element Solutions

If there are no Viable and Sufficient generation solutions that have a distinctly higher net present value than a Viable and Sufficient transmission solution, but the transmission solution or combination of transmission solutions selected by the ISO only partially satisfy the duration or the size of the Generator Deactivation Reliability Need, then the ISO may supplement the partial transmission solution with one or more Viable and Sufficient generation solutions that will be eligible to enter into an RMR Agreement with the ISO. The ISO will select the supplemental Generator or Generators primarily based on which RMR Service Offer, or set of RMR Service Offers from more than one Generator, results in the highest net present value solution to the Generator Deactivation Reliability Need. The ISO shall also consider any blacklined modifications to the Form of Reliability Must Run Agreement set forth in Appendix C of this Attachment FF of the ISO OATT when selecting a generation solution. If these two criteria do not provide for a clear delineation between two or more RMR Service Offers, the ISO shall also consider the operational, performance, and market impacts and the size of the Generators when selecting the generation component of a multi-element solution.

Alternatively, the ISO may select a Viable and Sufficient generation solution in place of a multi-element solution that includes transmission if it determines that the generation solution has a distinctly higher net present value than the combination of partial transmission and generation solutions the ISO might otherwise select under this Section 38.10.2.3. The ISO shall choose between a multi-element solution that includes transmission and a generation solution that has a distinctly higher net present value than the multi-element solution using the selection criteria specified in Section 38.10.2.4.

38.10.2.4 Viable and Sufficient generation solutions that have a distinctly higher net present value than a Viable and Sufficient transmission solution will be considered when the ISO selects the solution or combination of solutions to address the Generator Deactivation Reliability Need based on: (i) the net present value of each solution calculated in accordance with Section 38.8 and 38.9, and (ii) the degree to which each solution satisfies the metrics set forth in Section 38.10.4.

38.10.3 Selection Process if a Viable and Sufficient Transmission Solution Is Not Available

If there is not a Viable and Sufficient transmission solution, the ISO will select among the Viable and Sufficient generation solutions as follows. The ISO will select the Generator or Generators primarily based on which RMR Service Offer, or set of RMR Service Offers from more than one Generator, results in the highest net present value solution to the Generator Deactivation Reliability Need. The ISO shall also consider any blacklined modifications to the Form of Reliability Must Run Agreement set forth in Appendix C of this Attachment FF of the ISO OATT. If these two criteria do not provide for a clear delineation between two or more RMR Service Offers, the ISO shall also consider the operational, performance and market impacts, and the size of the Generators.

38.10.4 Metrics for Evaluating Solution to Address Generator Deactivation Reliability Need

The ISO will consider the following metrics in its evaluation of each Viable and Sufficient solution, as applicable:

38.10.4.1 The capital cost estimates for the proposed transmission Generator Deactivation Solution or the cost information submitted by the Initiating Generator or the generation Generator Deactivation Solution, including the accuracy of the proposed estimates.

38.10.4.2 The cost per MW ratio of the proposed transmission Generator Deactivation Solution or the RMR Service Offers of the Initiating Generator or the generation Generator Deactivation Solution. For this evaluation, the ISO will first determine the present worth, in dollars, of the total capital cost of the proposed solution in current year dollars. The ISO will then determine the MW value of the solution by summing the Generator Deactivation Reliability Need, in MW, with the additional improvement, in MW, that the proposed solution offers beyond serving the Generator Deactivation Reliability Need. The ISO will then determine the cost per MW ratio by dividing the present worth of the total capital cost by the MW value.

38.10.4.3 The expandability of the proposed solution. The ISO will consider the impact of the proposed solution on future construction. The ISO will also consider the extent to which any subsequent expansion will continue to use this proposed solution within the context of system expansion.

38.10.4.4 The operability of the proposed solution. The ISO will consider how the proposed solution may affect additional flexibility in operating the system, such as dispatch of generation, access to operating reserves, access to ancillary services, or ability to remove transmission for maintenance. The ISO will also consider how the proposed solution may affect the cost of operating the system, such as how it may affect the need for operating generation out of merit for reliability needs, reducing the need to cycle generation, or providing more balance in the system to respond to system conditions that are more severe than design conditions.

38.10.4.5 The performance of the proposed solution. The ISO will consider how the proposed solution may affect the utilization of the system (e.g. interface flows, percent loading of facilities).

38.10.4.6 The extent to which the Developer of a proposed transmission Generator Deactivation Solution or each generation Generator Deactivation Solution has the property rights, or ability to obtain the property rights, required to implement the solution. The ISO will consider, as applicable, whether the Developer or Market Participant: (i) already possesses property rights or the rights of way necessary to implement the solution; (ii) has completed a transmission routing study or Generator siting study, which (a) identifies, for transmission, a specific routing plan with alternatives, (b) includes a schedule indicating the timing for obtaining siting and permitting, and (c) provides specific attention to sensitive areas (*e.g.*, wetlands, river crossings, protected areas, and schools); or (iii) has specified a plan or approach for determining routing or siting and for acquiring property rights.

38.10.4.7 The potential issues associated with delay in constructing the proposed transmission Generator Deactivation Solution or in entering or in returning to service the Initiating Generator or a generation Generator Deactivation Solution, consistent with the major milestone schedule and the schedule for obtaining any permits and other certifications as required to timely meet the need.

38.10.4.8 The impact on other pending Generator Deactivation Reliability Needs, other system reliability needs, and pending solutions to those needs.

38.10.5 Generation Deactivation Process Report

The ISO shall post on its website a written determination indicating its selection of a solution or combination of solutions, along with a reasoned explanation regarding why particular generation and/or transmission solutions were selected. The ISO will review the results of its determination with stakeholders.

38.11 Entry into RMR Agreements

38.11.1 The ISO may enter into an RMR Agreement for service from one or more of the Generators that the ISO selected in accordance with Section 38.10 that can individually, or in conjunction with other Viable and Sufficient Generator Deactivation Solutions, satisfy the identified Reliability Need. If multiple Generators are capable of satisfying in whole or in part the identified Reliability Need, the ISO may execute an RMR Agreement with the Generator, or more than one Generator that the ISO selected pursuant to Section 38.10, provided that the RMR Service Offer accepts the Availability and Performance Rate, does not exceed the RMR Avoidable Costs determined by the ISO, and that the amount of Capital Expenditures in any given year included in the RMR Service Offer does not exceed 10,000,000 U.S. Dollars if a non-nuclear Generator, and 25,000,000 U.S. Dollars if a nuclear Generator. If the RMR Service Offer satisfies the stated requirements, but the amount of Capital Expenditures in any given year included in the RMR Service Offer exceeds the applicable limit in the preceding sentence, then the ISO may accept the RMR Service Offer conditioned upon the Commission approving the Capital Expenditure amount. If the RMR Service Offer exceeds the RMR Avoidable Costs determined by the ISO, and if there are no modifications, or only modifications which the ISO has determined are reasonable, to the *Form of Reliability Must Run Agreement* set forth in Appendix C of this Attachment FF, then the ISO will identify the Generator, and the ISO and the Generator Owner will submit filings to the Commission in accordance with Section 38.11.5. If a Generator's RMR Service Offer is lower than the other

RMR Service Offers but the Generator's proposed revisions to the *Form of Reliability Must Run Agreement* are not acceptable to the ISO, then the ISO may proceed to enter into an RMR Agreement, in accordance with this section, with one or more Generator(s) that submitted the next best offer or offers pursuant to Section 38.10.3.

38.11.2 The ISO will tender to the Generator Owner(s) of the selected Generator(s) the *Form of Reliability Must Run Agreement* set forth in Appendix C of this Attachment FF. The term of the RMR Agreement will be determined by the ISO based on: (i) the in-service date of the conceptual permanent solution to the identified Reliability Need submitted by the Responsible Transmission Owner(s) pursuant to Section 38.4.2.1, and (ii) any modifications to the scope and timing of the Generator Deactivation Reliability Need resulting from circumstances including information provided by the NYPSC (or other agency or authority with jurisdiction over the implementation or siting of non-generation Generator Deactivation Solutions), information provided by the Responsible Transmission Owner, the ISO's identification of market-based solutions, and RMR Agreements entered into between the ISO and other Generators. If the Generator Deactivation Reliability Need is identified pursuant to a Generator Deactivation Assessment, the effective date of the RMR Agreement shall be no earlier than the completion of the 365-day notice period, except as provided in Section 38.3.3 of this Attachment FF.

38.11.3 Filing of Executed RMR Agreement

The ISO will submit an RMR Agreement, including a proposed Availability and Performance Rate, to the Commission pursuant to Section 205 of the Federal Power Act if the ISO and Generator Owner agree on the terms and conditions of the RMR Agreement, Generator Owner accepts the Availability and Performance Rate calculated by the ISO for its Generator, and the ISO and Generator Owner execute the RMR Agreement. The ISO's filing shall specifically identify and explain any changes to the *Form of Reliability Must Run Agreement* terms and conditions that ISO and Generator Owner have mutually agreed to.

38.11.4 Filing of Unexecuted RMR Agreement by ISO and Capital Expenditures in Excess of Annual Limit by Generator Owner

The ISO will submit an RMR Agreement, including a proposed Availability and Performance Rate, to the Commission pursuant to Section 205 of the Federal Power Act if the ISO and Generator Owner agree on the terms and conditions of the RMR Agreement and Generator Owner accepts the Availability and Performance Rate calculated by the ISO for its Generator. The ISO's filing shall specifically identify and explain any changes to the *Form of Reliability Must Run Agreement* terms and conditions that ISO and Generator Owner have mutually agreed to. Generator Owner shall submit a filing pursuant to Section 205 of the Federal Power Act in addition to the ISO's filing of the RMR Agreement that proposes the inclusion of the costs of certain Capital Expenditures in the Availability and Performance Rate that exceed the U.S. Dollar limits specified in Section 38.11.1, which filing shall be consistent with the terms and conditions of service proposed in the RMR Agreement that the ISO submits, and shall track the format of the RMR Agreement that the ISO submits.

38.11.5 Filing of Unexecuted RMR Agreement and Generator Owner Developed Rate

If the ISO and Generator Owner agree on the terms and conditions of the RMR Agreement, but Generator Owner rejects the Availability and Performance Rate calculated by the ISO for its Generator and proposes an Owner Developed Rate, the ISO will submit an unexecuted RMR Agreement to the Commission pursuant to Section 205 of the Federal Power Act that sets forth the agreed upon terms and conditions of the RMR Agreement. The ISO's filing shall specifically identify and explain any changes to the *Form of Reliability Must Run Agreement* terms and conditions that ISO and Generator Owner have mutually agreed to. Generator Owner shall submit a separate filing to the Commission pursuant to Section 205 of the Federal Power Act that proposes an "Owner Developed Rate," which filing shall be consistent with the terms and conditions of service proposed in the RMR Agreement the ISO submitted and shall track the format of the RMR Agreement the ISO submitted.

38.11.6 As part of its submission of an executed RMR Agreement pursuant to 38.11.3 or an unexecuted RMR Agreement pursuant to Sections 38.11.4 or 38.11.5, the ISO will include: (i) a description of the methodology and results of the reliability studies that identified a Generator Deactivation Reliability Need requiring a Generator Deactivation Solution, which description will specify identified violations of Reliability Criteria and local criteria and describe the impacted criteria, and (ii) a description of the alternative solutions evaluated by the ISO and why the term of the RMR Agreement is appropriate in light of these alternative solutions.

38.12 Developer’s Responsibility Following Selection of Its Transmission Solution

38.12.1 Responsible Transmission Owner’s Obligation to Develop and Construct a Generator Deactivation Solution

The Responsible Transmission Owner must develop and construct its proposed Generator Deactivation Solution if it is selected by the ISO pursuant to Section 38.10. The Responsible Transmission Owner shall be entitled to the full recovery of all reasonably incurred costs, including a reasonable return on investment and any applicable incentives, related to the development, construction, operation, and maintenance of the selected transmission Generator Deactivation Solution, as set forth in Section 38.23.

38.12.2 Developer’s Responsibility to Obtain Necessary Approvals and Authorizations

38.12.2.1 Upon the selection of a Developer’s transmission Generator Deactivation Solution pursuant to Section 38.10, the ISO will inform the Developer that it should submit the selected Generator Deactivation Solution to the appropriate governmental agency(ies) and/or authority(ies) to begin the necessary approval process to the site, construct, and operate the project, if such approvals are required. In response to the ISO’s request, the Developer shall make such a submission to the appropriate governmental agency(ies) and/or authority(ies) to the extent such authorization has not already been requested or obtained.

38.12.2.2 If the appropriate federal, state or local agency(ies) either rejects a necessary authorization, or approves and later withdraws its authorization of the selected transmission Generator Deactivation Solution, the Developer may recover all of the necessary and reasonable costs it incurred and commitments made up to the final federal, state or local regulatory decision, including reasonable and necessary expenses incurred to implement an orderly termination of the project, to the extent permitted by the Commission in accordance with its regulations on abandoned plant recovery. The ISO shall allocate these costs among Load Serving Entities in accordance with Section 38.22 the ISO OATT, except as otherwise determined by the Commission. The ISO shall recover such costs in accordance with Section 38.23.

38.12.3 Development Agreement

As soon as reasonably practicable following the ISO's selection of a transmission Generator Deactivation Solution, the ISO shall tender to the Developer that proposed the selected transmission Generator Deactivation Solution a draft Development Agreement, with draft appendices completed by the ISO to the extent practicable, for review and completion by the Developer. The draft Development Agreement shall be in the form of the ISO's Commission-approved Development Agreement for its reliability planning process, which is in Appendix C in Section 31.7 of Attachment Y of the ISO OATT, as amended by the ISO to reflect the Generator Deactivation Process.

The ISO and the Developer shall finalize the Development Agreement and appendices as soon as reasonably practicable after the ISO's tendering of the draft Development Agreement. For purposes of finalizing the Development Agreement, the ISO and Developer shall develop the description and dates for the milestones necessary to develop and construct the selected project by the required in-service date identified in the Generator Deactivation Assessment, including the milestones for obtaining all necessary authorizations. Any milestone that requires action by a Connecting Transmission Owner or Affected System Operator identified pursuant to Attachment

P of the ISO OATT to complete must be included as an Advisory Milestone, as that term is defined in the Development Agreement.

If the ISO or the Developer determines that negotiations are at an impasse, the ISO may file the Development Agreement in unexecuted form with the Commission on its own, or following the Developer's request in writing that the agreement be filed unexecuted. If the Development Agreement is executed by both parties, the ISO shall file the agreement with the Commission for its acceptance within ten (10) Business Days after the execution of the Development Agreement by both parties. If the Developer requests that the Development Agreement be filed unexecuted, the ISO shall file the agreement at the Commission within ten (10) Business Days of receipt of the request from the Developer. The ISO will draft, to the extent practicable, the portions of the Development Agreement and appendices that are in dispute and will provide an explanation to the Commission of any matters as to which the parties disagree. The Developer will provide in a separate filing any comments that it has on the unexecuted agreement, including any alternative positions it may have with respect to the disputed provisions. Upon the ISO's and the Developer's execution of the Development Agreement or the ISO's filing of an unexecuted Development Agreement with the Commission, the ISO and the Developer shall perform their respective obligations in accordance with the terms of the Development Agreement that are not in dispute, subject to modification by the Commission. The Connecting Transmission Owner(s) and Affected System Operator(s) that are identified in Attachment P of the ISO OATT in connection with the selected transmission Generator Deactivation Solution shall act in good faith in timely performing their obligations that are required for the Developer to satisfy its obligations under the Development Agreement.

38.12.4 Process for Addressing Inability of Developer to Complete Selected Transmission Generator Deactivation Solution

38.12.4.1 The ISO may take the action set forth in this Section 38.12.4 if: (i) the ISO has selected a regulated transmission Generator Deactivation Solution, and (ii) one of the following events occur: (A) the Developer that proposed the transmission solution does not execute the Development Agreement or does not request that it be filed unexecuted with the Commission as described in Section 38.12.3, or (B) an effective Development Agreement is terminated under the terms of the agreement prior to the completion of the term of the agreement.

38.12.4.2 If the Development Agreement has been filed with and accepted by the Commission, the ISO shall, upon terminating the Development Agreement under the terms of the agreement, file a notice of termination with the Commission.

38.12.4.3 If the ISO determines that it must identify a solution to the Generator Deactivation Reliability Need prior to the next planning cycle of the biennial reliability planning process, the ISO may take one or more of the following actions to address a Generator Deactivation Reliability Need based on the particular circumstances: (i) address the Generator Deactivation Reliability Need as an immediate reliability need pursuant to Section 38.3.3, (ii) direct the Developer to continue with the development of its Generator Deactivation Solution for completion beyond the in-service date required to address the Generator Deactivation Reliability Need, or (iii) request that the Responsible Transmission Owner complete the selected Generator Deactivation Solution if it is an alternative transmission Generator Deactivation Solution.

38.12.4.4 If the Responsible Transmission Owner agrees to complete the selected alternative transmission Generator Deactivation Solution, the Responsible Transmission Owner and the Developer that proposed the selected solution shall work cooperatively with each other to implement the transition, including negotiating in good faith with each other to transfer the project; *provided, however*, that the transfer is subject to: (i) any required approvals by the appropriate governmental agency(ies) and/or authority(ies), (ii) any requirements or restrictions on the transfer of Developer's rights-of-way under law, conveyance, or contract, and (iii), if the Developer is a New York public authority, any requirements or restrictions on the transfer under the New York Public Authorities Law; *provided*, *further*, that the Responsible Transmission Owner and the Developer will address any disputes regarding the transfer of the project in accordance with the dispute resolution provisions in Article 11 of the ISO Services Tariff.

38.13 Interim Service Providers

38.13.1 At the time the ISO issues its Generator Deactivation Assessment, the ISO shall inform an Initiating Generator that requested a deactivation date prior to the conclusion of the 365 day notice period in its Generator Deactivation Notice whether the Generator will be permitted to deactivate on its requested deactivation date, or will need to remain in service for the 365 day notice period.

38.13.2 If the NYISO does not authorize an Initiating Generator to deactivate by the later of: (a) day 181 of the 365 day notice period, or (b) the date on which the Initiating Generator indicated it wanted to deactivate in its Generator Deactivation Notice, then for the remainder of the 365 day notice period, the Initiating Generator shall be an Interim Service Provider, subject to the following rules and exceptions.

38.13.2.1 Interim Service Providers shall be compensated in accordance with Rate Schedule 8 to the ISO Services Tariff.

38.13.2.1.1 The ISO shall use the costs, revenues, and other information submitted in accordance with Sections 38.3, 38.4, 38.5, 38.7, 38.8 and Appendix B of this Attachment FF that it verifies and/or validates, as applicable to calculate an Interim Service Provider's rate. If the ISO cannot verify and/or validate, as applicable, a cost or revenue submitted by a Market Party, the ISO shall substitute an estimated value.

38.13.2.2 Generators are not eligible to be Interim Service Providers while they are in an ICAP Ineligible Forced Outage.

38.13.2.3 The ISO may allow a Generator that it determined is needed to remain in service as an Interim Service Provider to deactivate prior to the conclusion of the 365 day notice period if the NYISO provides at least 60 days prior notice that the Generator may deactivate. After the conclusion of this notice period, the Generator will be permitted to deactivate and will no longer be an Interim Service Provider.

38.13.2.4 The ISO may allow a Generator that it determined is needed to remain in service as an Interim Service Provider to deactivate prior to the conclusion of the 365 day notice period if the Generator experiences a Forced Outage of ten days or greater duration, and the ISO provides at least 30 days prior notice that the Generator may deactivate. After the conclusion of this notice period, the Generator will be permitted to deactivate and will not be an Interim Service Provider.

38.13.2.5 Interim Service Providers must comply with the RMR Generator Energy and Ancillary Service Market Participation Rules that are set forth in Section 23.6 of the ISO Services Tariff.

38.13.2.6 Interim Service Providers that have Capacity Resource Interconnection Rights, pursuant to the applicable provisions of Attachment X, Attachment S and Attachment Z to the ISO OATT, must take all required actions to qualify as an Installed Capacity Supplier pursuant to Section 5.12 of the ISO Services Tariff. Interim Service Providers must also comply with the rules that are set forth in Sections 5.14.1.1 and 15.8.6 of the ISO Services Tariff.

38.13.2.7 A Generator that was an Interim Service Provider that has deactivated and that wants to return to participating in any of the ISO Administered Markets while it is eligible to receive market-based rates must give the ISO at least 60 days advance notice of its desire to return to the ISO Administered Markets in order to permit the ISO to determine a repayment obligation (if any) in accordance with Services Tariff Rate Schedule 8, and an associated credit requirement in accordance with Sections 26.4 and 26.5 of the ISO Services Tariff.

38.13.2.8 A Generator that is an Interim Service Provider that wants to continue participating in the ISO Administered Markets while it is eligible to receive market-based rates (after it is no longer an Interim Service Provider and when it is not operating pursuant to an RMR Agreement) must give the ISO at least 30 days advance notice of its desire to continue participating in the ISO Administered Markets in order to permit the ISO to determine and impose a repayment obligation (if any) in accordance with Services Tariff Rate Schedule 8, and an associated credit requirement in accordance with Sections 26.4 and 26.5 of the ISO Services Tariff.

38.14 Initiating Generator's Failure to Timely Deactivate

38.14.1 A Market Participant's Generator that satisfies the requirements to be Retired or enter into a Mothball Outage may be Retired or enter into a Mothball Outage, as applicable, within 365 days of: (i) the conclusion of the 365-day notice period, or (ii) the date specified in the Generator Deactivation Notice for the Generator to be Retired or enter into a Mothball Outage if the Market Participant provided greater than 365 days prior notice. If the Generator is not Retired or does not enter into a Mothball Outage within this time period, the Market Participant must submit a new Generator Deactivation Notice and satisfy anew the requirements of Sections 38.3.1 before the Generator may be Retired or enter into a Mothball Outage.

38.14.2 If (i) a Market Participant rescinds its Generator Deactivation Notice, or (ii) a Market Participant's Generator has not Retired or entered into a Mothball Outage within the timeframes described in Section 38.14.1 and is not operating under an RMR Agreement, the Market Participant must reimburse the ISO and the Responsible Transmission Owner(s) the actual costs that each incurred in performing their responsibilities under this Section 38 in response to the Market Participant's submission of a Generator Deactivation Notice, including any costs associated with using contractors. In the event that a Market Participant rescinds its Generator Deactivation Notice before the ISO posts the results of the Generator Deactivation Assessment conducted under Section 38.3.4, the ISO will not thereafter post the results of said assessment.

38.14.3 If the Initiating Generator was an Interim Service Provider and (i) it rescinds its Generator Deactivation Notice, or (ii) it has not Retired or entered into a Mothball Outage within the timeframes described in Section 38.14.1 and is not operating under an RMR Agreement, then the Initiating Generator may also be subject to a repayment obligation pursuant to Section 15.8.7 of Rate Schedule 8 to the ISO Services Tariff.

38.15 Halting of Regulated Transmission Generator Deactivation Solution

38.15.1 The ISO may determine to halt a regulated transmission Generator Deactivation Solution that the ISO has selected pursuant to Section 38.10 to address a Generator Deactivation Reliability Need if: (a) a Market Participant rescinds the Generator Deactivation Notice that resulted in the Generator Deactivation Reliability Need, (b) the Market Participant's Generator has not Retired or entered into a Mothball Outage within the timeframes described in Section 38.14.1 and is not operating under an RMR Agreement, or (c) the Generator Deactivation Reliability Need has been otherwise addressed or eliminated (*e.g.*, a market-based solution that satisfies the Generator Deactivation Reliability Need has commenced operation). In making its determination whether to halt a transmission Generator Deactivation Solution under this Section 38.15.1, the ISO will consider, among other things: (i) whether the Developer has executed a Development Agreement or requested that it be filed unexecuted with the Commission; (ii) the status of the Developer's progress against the milestones in the Development Agreement (*e.g.*, completion of engineering design, procurement of major equipment and materials, execution of key contracts, completion of project financing, obtaining Site Control, commencing physical construction, including excavation and pouring for foundations or the installation or erection of improvements); (iii) the status of Developer's obtaining required permits or authorizations; (iv) whether the Generator Deactivation Solution is an interim or permanent project; and (v) the operational and performance benefits of the Generator Deactivation Solution. If the ISO determines to halt a regulated transmission Generator Deactivation Solution, it will notify the Developer of the project and post the notice on its website. If a selected regulated transmission Generator Deactivation Solution is halted by the ISO, all of the costs incurred and commitments made by the Developer up to that point, including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable by the Developer in accordance with Section 38.23 and the cost recovery mechanism in Rate Schedule 16 of the ISO OATT.

38.15.2 Notwithstanding Section 38.15.1, the ISO shall not halt a regulated transmission Generator Deactivation Solution once the Developer: (i) has received its Article VII certification or other applicable siting permits or authorizations under New York State law or (ii) if permitting or regulatory approval is not required, has commenced physical construction of the Generator Deactivation Solution, including excavation and pouring for foundations or the installation or erection of improvements.

38.16 RMR Generator Additional Costs

38.16.1 Proposed Additional Costs

During the performance of an RMR Agreement, the Generator Owner of one or more RMR Generators shall promptly notify the ISO of an event that (a) could not reasonably have been foreseen at the time the rate in the RMR Agreement was executed, and that (b) it reasonably expects may require it to incur costs that in the aggregate exceed the lesser of (x) $250,000, and (y) five (5) percent of the annual RMR Avoidable Costs excluding the cost of Capital Expenditures, that (i) it can reasonably demonstrate was not among the costs (A) submitted to the ISO prior to the execution of an RMR Agreement with an Availability and Performance Rate, or (B) within the categories of costs submitted to the Commission in a petition for an Owner Developed Rate, and (ii) are necessary to incur in order for the RMR Generator to be able to continue to perform its obligations under the RMR Agreement after the event (a "Notice of Event of Proposed Additional Cost").

If the NYISO informs an Initiating Generator that submitted a Generator Deactivation Notice that the Generator will need to remain in service for the 365 day notice period, the Generator Owner of the Initiating Generator shall promptly notify the ISO of an event (a) that occurred after the Generator Deactivation Notice was submitted, but prior to the conclusion of the 365 day notice period, and (b) that could not reasonably have been foreseen at the time the Generator Deactivation Notice was submitted; where (i) Generator Owner reasonably expects it will be required to incur unanticipated costs that, in the aggregate, will exceed $100,000 to operate for the remainder of the 365 day notice period, and (ii) incurring the costs is necessary for the Generator to be able to perform or continue to perform as an Interim Service Provider after the event (also a "Notice of Event of Proposed Additional Cost").

Following its submission of the required Notice of Event of Proposed Additional Cost, the Generator Owner shall promptly notify the ISO of, and provide updates addressing the following: (i) the reason(s) why the expense was or must be incurred, (ii) viable alternatives to incurring the expense, (iii) actions examined or taken to avoid the need to incur the expense, and to minimize the expense, (iv) the potential impact on the RMR Generator's ability to perform its obligations under an RMR Agreement if the expense is not incurred, (v) the estimated and actual costs of the proposed expense, (vi) the plan specifying the schedule and timing of any planned action or expenditure, (vii) an explanation and supporting documentation of how that plan compares with the Generator Owner's past similar actions and protocols, (viii) whether each cost is associated solely with the RMR Generator or are for services or functions shared with other units or businesses; and if a shared cost, the Generator Owner shall identify the other entities with which the cost is shared, the entity that allocates the cost to it, and accounting protocols and methodology used to allocate the units and businesses across which the cost is allocated.

38.16.1.1 If the cost of returning an RMR Generator to service does not exceed the lesser of (x) $250,000, and (y) five (5) percent of the annual RMR Avoidable Costs excluding the cost of Capital Expenditures, then the Generator Owner shall promptly return the RMR Generator to service without additional recompense.

38.16.1.2 If the cost of returning an Interim Service Provider to service is not expected to exceed $100,000, then the Generator Owner shall promptly return the Generator to service without additional recompense.

38.16.1.3 ISO Identification of Proposed Additional Costs

If the ISO determines that the Notice of Event of Proposed Additional Cost was timely provided and each of the requirements in Subsections (a) and (b) of Section 38.16.1 have been met, and the information required by Subsections (i) through (viii) has been provided, it shall be a "Proposed Additional Cost."

38.16.2 Proposed Additional Cost Eligibility for Recovery

38.16.2.1 The ISO shall review, verify, and/or validate the information provided by the Generator Owner for a Proposed Additional Cost. The ISO may require the Generator Owner to re-submit or to submit additional information to support statements and costs that the ISO determines are not adequately supported or otherwise verifiable. A "Substantiated Additional Cost" shall mean a Proposed Additional Cost that the ISO has either verified is the actual cost, or verified and validated the estimated cost information received from the Generator Owner, provided that (a) the Generator Owner demonstrates it took measures to minimize the expense, or if the ISO determines that the Generator Owner did not demonstrate it took such steps, such amount estimated by the ISO that would be the expense had the RMR Generator or Interim Service Provider taken measures to reduce it, and (b) it is or was necessary for the Generator Owner to incur these costs for the RMR Generator to perform its obligations under the RMR Agreement or for the Interim Service Provider to operate during the 365 day notice period; provided the ISO has not issued a notice of shut-down (or similar notice) to Generator Owner for the RMR Generator pursuant to the RMR Agreement or to Generator Owner of the Interim Service Provider pursuant to Section 38.13.2.3 or 38.13.2.4 of this Attachment FF. If the cost information provided by the Generator Owner cannot be verified and validated by the ISO, the ISO shall substitute the amount it reasonably determines. The ISO shall also identify if the Substantiated Additional Costs, or a component thereof, is a Capital Expenditure by using the applicable criteria set forth in Section 38.8.1.3. The ISO shall notify the Generator Owner of its determination regarding whether Proposed Additional Costs are Substantiated Additional Costs.

38.16.2.2 The ISO shall seek comment from the Market Monitoring Unit on its review of Proposed Additional Costs and determinations of Substantiated Additional Costs. The responsibilities of the Market Monitoring Unit that are addressed in this Section are also addressed in Section 38.18.1 of this Attachment FF and in Section 30.4.6.8.6 of Attachment O of the ISO Services Tariff.

38.16.3 ISO's Authority to Recover and Pay Substantiated Additional Costs that Are Capital Expenditures to RMR Generators with Availability and Performance Rates

This Section shall apply only to RMR Agreements with an Availability and Performance Rate. If a Substantiated Additional Cost is determined by the ISO to be a Capital Expenditure and it does not exceed 10,000,000 U.S. Dollars if a non-nuclear Generator, or 25,000,000 U.S. Dollars if a nuclear Generator, on the basis of the total expenditure needed to address the event that resulted in the Notice of Event of Proposed Additional Cost, then the ISO may recover the Substantiated Additional Cost that is a Capital Expenditure pursuant to OATT Rate Schedule 14 and pay that amount to Generator Owner in accordance with (a) the rules in Section 38.17 that address the ISO's payment of Capital Expenditures, and (b) Rate Schedule 8 to the Services Tariff. The ISO shall submit an informational filing to the Commission identifying any Capital Expenditures it is paying pursuant to the authority granted in this section.

38.16.4 ISO's Authority to Recover and Pay Substantiated Additional Costs that are Capital Expenditures to Interim Service Providers

This Section shall apply only to Interim Service Providers. If a Substantiated Additional Cost is determined by the ISO to be a Capital Expenditure and it does not exceed 1,000,000 U.S. Dollars, on the basis of the total expenditure needed to address the event that resulted in the Notice of Event of Proposed Additional Cost, then the ISO may recover the Substantiated Additional Cost that is a Capital Expenditure pursuant to OATT Rate Schedule 14 and pay that amount to Generator Owner in accordance with (a) the rules in Section 38.17 that address the ISO's payment of Capital Expenditures, and (b) Rate Schedule 8 to the Services Tariff. The ISO shall submit an informational filing to the Commission identifying any Capital Expenditures it is paying pursuant to the authority granted in this section.

38.16.5 Owner May **Request** Commission Approval for Recovery of Additional Costs.

If the Owner makes such a filing, it shall also submit the ISO's determinations pursuant to Sections 38.16.1.2 and 38.16.2.1 with its filing, or promptly after receipt of either determination. The ISO shall only be obligated to pay the Owner under this section if (a) the Commission determines that the cost filed for the RMR Generator or Interim Service Provider is eligible for recovery as a Proposed or Substantiated Additional Cost, and (b) the Commission approves the specific amount and authorizes its recovery. If the Proposed or Substantiated Additional Cost that the Commission authorizes payment of is for a Capital Expenditure, the ISO will pay in accordance with (a) the rules in Section 38.17 that address the ISO's payment of Capital Expenditures, and (b) Rate Schedule 8 to the Services Tariff. If the Proposed or Substantiated Additional Cost that the Commission authorizes payment of is an Avoidable Cost that is not a Capital Expenditure then payment directed by a Commission order shall be made in accordance with Rate Schedule 8 to the ISO Services Tariff.

38.17 Payment of Capital Expenditures to RMR Generators and Interim Service Providers

38.17.1 Capital Expenditures that are specifically identified (including an estimated cost and estimated in-service date) in a Commission-accepted Availability and Performance Rate or in a Commission-accepted Owner Developed Rate are eligible for recovery in accordance with the rules set forth in Section 38.17, Section 23.6.5 of the ISO Services Tariff, Rate Schedule 8 of the ISO Services Tariff, Schedule 14 of the ISO OATT, and any relevant Commission order.

38.17.2 Capital Expenditures that are Proposed Additional Costs or Substantiated Additional Costs are eligible for recovery in accordance with the rules set forth in Sections 38.16 and 38.17 of the ISO OATT, Section 23.6.5 of the ISO Services Tariff, Rate Schedule 8 of the ISO Services Tariff, Schedule 14 of the ISO OATT, and any relevant Commission order.

38.17.3 The ISO may agree to permit an Interim Service Provider to recover the cost of Capital Expenditures during the 365 day period that follows the Generator Deactivation Assessment Start Date if (a) recovery is authorized as an Additional Cost under Section 38.16 of the ISO OATT, or (b) the Capital Expenditure is necessary to permit the Interim Service Provider to address the Reliability Need, and Generator Owner enters into a written agreement with the ISO in which the Generator Owner commits that the Capital Expenditure will be completed and placed in-service by a specified date or within a range of dates that fall within the 365 day period that follows the Generator Deactivation Assessment Start Date.

38.17.4 ISO Authority to Authorize Capital Expenditures

If the ISO determines that (a) Capital Expenditures are necessary for a Generator to provide service under an RMR Agreement, and (b) work on one or more of the Capital Expenditures must commence in advance of Commission action in order to timely, or more timely, address a Generator Deactivation Reliability Need, then the ISO may authorize the Generator Owner to spend up to 10,000,000 U.S. Dollars if a non-nuclear Generator, or 25,000,000 U.S. Dollars if a nuclear Generator, in total, to develop the Capital Expenditure(s) in advance of receiving an order from the Commission. The ISO shall submit an informational filing to the Commission identifying any Capital Expenditures it is authorizing pursuant to the authority granted in this Section. The ISO may recover the cost of such a Capital Expenditure pursuant to Schedule 14 of the ISO OATT and pay the Generator Owner in accordance with (i) the rules in this Section 38.17, and (ii) Rate Schedule 8 to the ISO Services Tariff. If the Commission issues an order rejecting the proposed Capital Expenditure, then the Generator Owner shall cease work on the Capital Expenditure and take reasonable efforts to minimize the costs it incurs. Reimbursement of a rejected Capital Expenditure shall be limited to actual costs incurred, including reasonable wind-down costs, shall be subject to the dollar limits set forth in this section, and shall be reviewed in accordance with Section 38.17.7 below. Allowed wind-down costs shall be reimbursed as additional Avoidable Costs that are not Capital Expenditures. ISO review pursuant to Section 38.17.7 shall include consideration of whether the Generator Owner timely ceased developing a Capital Expenditure and made reasonable efforts to minimize its wind-down costs.

For an Interim Service Provider, if the ISO determines that (x) the requirements of Section 38.17.3 have been satisfied, and (y) the Capital Expenditure does not exceed 1,000,000 U.S. Dollars on the basis of the total expenditure needed, then the ISO may recover the Capital

Expenditure pursuant to OATT Rate Schedule 14 and pay that amount to Generator Owner in accordance with (a) the rules in this Section 38.17 that address the ISO's payment of Capital Expenditures, and (b) Rate Schedule 8 to the ISO Services Tariff. The ISO shall submit an informational filing to the Commission identifying any Capital Expenditures it is paying to an Interim Service Provider pursuant to the authority granted in this section.

38.17.5 Early Termination of RMR Agreement

If the Generator Owner is working to complete a Capital Expenditure consistent with an accepted RMR Agreement or consistent with an approved or accepted Proposed Additional Cost or Substantiated Additional Cost and the RMR Agreement is terminated early because (x) the Generator Deactivation Reliability Need is resolved sooner than expected, or (y) the RMR Generator suffers a forced outage that would require significant costs to repair, or (z) for any other reason that does not involve an uncured Generator Owner default under the RMR Agreement or the RMR Generator failing to satisfy one or more of the operating standards described in Sections 38.19.4(A) and (B) below, and if Generator Owner ceased work on the Capital Expenditure and made reasonable efforts to minimize the costs it incurred, then, following review, the ISO shall recover the actual costs the Generator Owner incurred to construct the Capital Expenditure and to wind-down its work on the Capital Expenditure pursuant to Schedule 14 of the ISO OATT and pay Generator Owner in accordance with (a) the rules in this Section 38.17, and (b) Rate Schedule 8 to the ISO Services Tariff. Allowed wind-down costs shall be reimbursed as additional Avoidable Costs that are not Capital Expenditures. ISO review pursuant to Section 38.17.7 below shall include consideration of whether the Generator Owner timely ceased developing a Capital Expenditure and made reasonable efforts to minimize its wind-down costs.

38.17.6 The ISO shall not reimburse Interim Service Providers for Capital Expenditures that are not completed and placed in service during the 365 day period that follows the Generator Deactivation Assessment Start Date. The ISO shall not pay wind-down costs to Interim Service Providers. Subject to the foregoing requirements, the ISO's obligation to pay for Capital Expenditures that are not timely completed in accordance with the written agreement between the Generator Owner and the ISO that is described in Section 38.17.3 shall be addressed in that agreement. Even if a Capital Expenditure by an Interim Service Provider or potential Interim Service Provider is not eligible for compensation under Sections 38.17.3 or 38.17.6, the ISO may agree to pay Capital Expenditure costs that were incurred during the 365 day period that follows the Generator Deactivation Assessment Start Date in an RMR Agreement.

38.17.7 ISO Review of Actual Costs Incurred Prior to Commencing Payment

After the Generator Owner expends money for an allowed or accepted Capital Expenditure, including expenditures that may be eligible for recovery under Sections 38.17.4 and 38.17.5 above, it shall submit to the ISO copies of original documentation of the expenditure (including the financing costs) and an explanation of any difference between the estimated amount and the actual expenditure. If Generator Owner submits an actual total amount for a Capital Expenditure that is five (5) percent or more above (a) the estimate that was used by the ISO to develop an Availability and Performance Rate or to authorize recovery of a Substantiated Additional Cost; or (b) the estimate that was presented to the Commission to recover Capital Expenditure costs that exceed the dollar thresholds specified in Section 38.11.1, in an Owner Developed Rate, or in a request by the Generator Owner to recover a Proposed or Substantiated

Additional Cost; or (c) an appropriate portion of the estimate provided pursuant to (a) or (b) if the Capital Expenditure was not completed plus wind-down costs (if any), then the Generator Owner shall demonstrate to the ISO that reasonable efforts were made to expend the least amount necessary. The ISO shall review, verify and/or validate the actual expenditure provided by the Generator Owner. The ISO may require the Generator Owner to re-submit, information that the ISO determines is not adequately supported or otherwise verifiable. The amount due for Capital Expenditure shall be equal to the amount verified and validated by the ISO as the actual expenditure. If the ISO cannot verify and/or validate, as applicable, the information the Generator Owner provides, or if the ISO determines that reasonable efforts were not made to expend the least amount necessary, then compensation for the Capital Expenditure shall only be due after the Generator Owner submits its Capital Expenditure to the Commission and the Commission determines the amount to be paid.

38.17.7.1 If the Commission specified the amount that it authorized to be recovered for a particular Capital Expenditure in an order, then the ISO shall permit the Generator Owner to recover the actual amount verified and validated by the ISO, up to the limit(s) specified in the Commission order.

38.17.8 ISO Payment and Recovery of Authorized or Accepted Capital Expenditures

38.17.8.1 The ISO shall commence paying for Capital Expenditures as soon as practicable after (i) the capital asset that is a Capital Expenditure (a) has been placed into service, or otherwise integrated into the Generator, or (b) was not placed into service solely due to the ISO instructing the RMR Generator to halt implementation of the Capital Expenditure, or issuing a Notice of Shut-down or terminating the RMR Agreement after costs had already been incurred; and

(ii) the amount paid by the Owner is verified and /or validated, as applicable, by the ISO as described in Section 38.17.7, or is determined by the Commission.

38.17.8.2 The ISO shall implement a repayment schedule in accordance with the formula specified in Section 38.17.8.2.1 below for each Capital Expenditure that will permit the Capital Expenditure to be completely repaid by the end date specified in Section 2.2.5 of the *Form of Reliability Must Run Agreement* set forth in Appendix C of this Attachment FF or by the equivalent date specified in an RMR Agreement that is not a *Form of Reliability Must Run Agreement*, or by the conclusion of the 365 day notice period if the ISO is repaying an allowed Capital Expenditure to an Interim Service Provider. If an RMR Agreement terminates prior to the end date that is specified in the RMR Agreement, then the ISO may continue repaying any Capital Expenditures the Generator Owner remains eligible to receive until that end date.

38.17.8.2.1 Repayment Schedule for Capital Expenditures

For each Capital Expenditure *CapExMonthly Payment* is the amount that Generator Owner is permitted to recover each month:

$$CapEx\ Monthly\ Payment = \frac{Verified\ CapEx_{g,k}}{M_{E-k}}$$

Where:

$Verified\ CapEx_{\mathrm{g,k}}$ = the amount due for a Capital Expenditure, verified and validated by the ISO as an actual expenditure for Generator g.

Month *k* is the month in which Repayment of a Capital Expenditure commences.

Month *E* is the month that includes the end date specified in Section 2.2.5 in the *Form of Reliability Must Run Agreement* or by the equivalent date specified in an RMR

Agreement that is not a *Form of Reliability Must Run Agreement* for Generator *g*, or the conclusion of the 365 day notice period for an Interim Service Provider.

M_{E-k} = the number of months from month *k* to month *E*, including month *k* and month *E*.

38.17.8.3 The ISO shall pay the Generator Owner amounts due for Capital Expenditures as a component of RMR Avoidable Costs (for an RMR Agreement with an Availability and Performance Rate or an Interim Service Provider) or RMR Cost (for an RMR Agreement with an Owner Developed Rate) under Rate Schedule 8 to the ISO Services Tariff. The ISO shall recover the cost of Capital Expenditures from RMR LSEs in accordance with Schedule 14 to the OATT.

38.17.8.4 Unless the Commission issues an order instructing it to pay, the ISO shall not pay the cost of Capital Expenditures that Section 23.6.5.2 of the ISO Services Tariff prohibits it from paying, even if the Capital Expenditures might otherwise be payable under the rules specified in this Attachment FF.

38.17.8.5 A Generator Owner that recovers the cost of Capital Expenditures may be required to repay to the ISO the depreciated value of the Capital Expenditure costs it recovered before the RMR Generator or Interim Service Provider at or for which the Capital Expenditure was incurred is permitted to be offered into or scheduled in the ISO Administered Markets. *See* Section 15.8.7 of Rate Schedule 8 to the Services Tariff.

38.18 Market Monitoring Unit Review of Determinations

38.18.1 The ISO shall seek comments from the Market Monitoring Unit on matters relating to the inputs and the calculations the ISO performed pursuant to Section 38.8 of this Attachment FF.

38.18.2 The ISO shall seek comments from the Market Monitoring Unit on its review of Proposed Additional Costs and its determinations of Substantiated Additional Costs under Section 38.16 of this Attachment FF.

38.18.3 Concurrent with the ISO or a Generator filing with the Commission an RMR Agreement pursuant to Sections 38.11.3, 38.11.4 or 38.11.5, the Market Monitoring Unit shall publish a report. The report shall review the ISO's determination of the highest net present value offer (or more than one offer) to provide RMR service in accordance with Sections 38.8, 38.9 and 38.10. In the event that cost alone did not provide for a clear delineation between two or more RMR Service Offers, the report shall also review the ISO's consideration of the Generator Owner's proposed changes to the *Form of Reliability Must Run Agreement* and the operational, performance and market impacts, and the size of the Generators. If the RMR Agreement contains RMR Avoidable Costs and an Availability and Performance Rate, the report shall also review the inputs to, and ISO's calculation of, the RMR Avoidable Costs and the Availability and Performance Rate.

38.18.4 The responsibilities of the Market Monitoring Unit that are addressed in this Section 38.18 are also addressed in Section 30.4.6.8.6 of Attachment O of the ISO Services Tariff.

38.19 Terminating RMR Agreements

38.19.1 Each RMR Agreement shall include an end date. RMR Agreements may incorporate a different end date for each RMR Generator that operates pursuant to the RMR Agreement.

38.19.2 RMR Agreements that include more than one RMR Generator shall permit the ISO to terminate the RMR Agreement for an RMR Generator without requiring the ISO to terminate the RMR Agreement for any or all of the other RMR Generator(s) that are operating pursuant to the same RMR Agreement.

38.19.3 The ISO shall timely terminate an RMR Agreement for an RMR Generator when that RMR Generator is no longer needed to address identified Generator Deactivation Reliability Need(s).

38.19.4 The ISO may terminate an RMR Agreement for an RMR Generator under any of the following circumstances: (A) if the RMR Generator fails to satisfy any of the minimum operating standards specified in the RMR Agreement; (B) if the RMR Generator repeatedly fails to operate as requested when it is called upon by the ISO or by a Transmission Owner to address one or more of the identified Generator Deactivation Reliability Need(s) the RMR Generator is being retained to address; (C) when the RMR Generator suffers a forced outage that will prevent it from being available for 180 or more days to address the identified Generator Deactivation Reliability Need(s) that the RMR Generator is being retained to address; or (D) if significant Additional Costs arise (*see* Section 38.16) that make the RMR Generator more expensive than other solutions to the identified Generator Deactivation Reliability Need(s).

38.20 – **Reserved**

38.21 Reserved

38.22 Cost Allocation Methodology for Generator Deactivation Process

The cost allocation mechanism under this Section 38.22 sets forth the basis for allocating costs associated with: (i) a Responsible Transmission Owner's transmission Generator Deactivation Solution proposed in accordance with Section 38.4 and, if applicable, its conceptual permanent transmission Generator Deactivation Solution, (ii) a Developer's transmission Generator Deactivation Solution selected by the ISO to address the Generator Deactivation Reliability Need pursuant to Section 38.10, or (iii) a Generator operating under an RMR Agreement to address a Generator Deactivation Reliability Need.

The formula is not applicable to that portion of the cost of a regulated transmission reliability project that is, pursuant to Section 25.7.12 of Attachment S to the ISO OATT, paid for with funds (1) previously committed by or collected from Developers through their acceptance of a Project Cost Allocation for System Deliverability Upgrades required for the interconnection of generation or merchant transmission projects, or (2) funds collected as a Highway Facilities Charge pursuant to Rate Schedule 12 of the ISO OATT.

This Section 38.22 establishes the allocation of the costs related to resolving Generator Deactivation Reliability Needs resulting from resource adequacy, BPTF thermal transmission security, local transmission security, dynamic stability, and short circuit issues. Costs will be allocated in accordance with the following hierarchy: (i) resource adequacy pursuant to Section 38.22.1, (ii) BPTF thermal transmission security pursuant to Section 38.22.2, (iii) BPTF voltage security pursuant to Section 38.22.3, (iv) local transmission security pursuant to Section 38.22.4, (v) dynamic stability pursuant to Section 38.22.5, and (vi) short circuit pursuant to Section 38.22.6.

38.22.1 Resource Adequacy Reliability Solution Cost Allocation Formula

For purposes of solutions eligible for cost allocation under this Section 38.22, this section sets forth the cost allocation methodology applicable to that portion of the costs of the solution attributable to resolving resource adequacy. The same cost allocation formula is applied regardless of the project or sets of projects being triggered; however, the nature of the solution set may lead to some terms equaling zero, thereby dropping out of the equation. To ensure that appropriate allocation to the LCR and non-LCR zones occurs, the zonal allocation percentages are developed through a series of steps that first identify responsibility for LCR deficiencies, followed by responsibility for remaining need. The following formula shall apply to the allocation of the costs of the solution attributable to resource adequacy:

$$\text{Resource Adequacy Cost Allocation}_i = \left[\frac{\text{LCRdef}_i}{\text{Soln Size}} + \left(\frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_i)}{\sum_{k=1}^{n} \text{Coincident Peak}_k * (1 + \text{IRM} - \text{LCR}_k)} * \frac{\text{Soln STWdef}}{\text{Soln Size}}\right) + \left(\frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_i)}{\sum_{l=1}^{m} \text{Coincident Peak}_l * (1 + \text{IRM} - \text{LCR}_l)} * \frac{\text{Soln CIdef}}{\text{Soln Size}}\right)\right] *100\%$$

Where *i* is for each applicable zone, *n* represent the total zones in NYCA, *m* represents the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, LCRdef_i is the applicable zonal LCR deficiency, SolnSTWdef is the STWdef for each applicable project, SolnCIdef is the CIdef for each applicable project, and Soln_Size represents the total compensatory MW addressed by each applicable project for all reliability cost allocation steps in this Section 38.22.

Three step cost allocation methodology for regulated reliability solutions:

38.22.1.1 Step 1 - LCR Deficiency

38.22.1.1.1 Any deficiencies in meeting the LCRs for the Target Year will be referred to as the LCRdef. If the reliability criterion is met once the LCR deficiencies have been addressed, that is LOLE ≤ 0.1 for the Target Year is achieved, then the only costs allocated will be those related to the LCRdef MW. Cost responsibility for the LCRdef MW will be borne by each deficient locational zone(s), to the extent each is individually deficient.

For a single solution that addresses only an LCR deficiency in the applicable LCR zone, the equation would reduce to:

$$\text{Allocation}_i = \frac{\text{LCRdef}_i}{\text{Soln\_Size}} * 100\%$$

Where *i* is for each applicable LCR zone, LCRdef_i represents the applicable zonal LCR deficiency, and Soln_Size represents the total compensatory MW addressed by the applicable project.

38.22.1.1.2 Prior to the LOLE calculation, voltage constrained interfaces will be recalculated to determine the resulting transfer limits when the LCRdef MW are added.

38.22.1.2 Step 2 - Statewide Resource Deficiency. If the reliability criterion is not met after the LCRdef has been addressed, that is an LOLE > 0.1, then a NYCA Free Flow Test will be conducted to determine if NYCA has sufficient resources to meet an LOLE of 0.1.

38.22.1.2.1 If NYCA is found to be resource limited, the ISO, using the transfer limits and resources determined in Step 1, will determine the optimal distribution of additional resources to achieve a reduction in the NYCA LOLE to 0.1.

38.22.1.2.2 Cost allocation for compensatory MW added for cost allocation purposes to achieve an LOLE of 0.1, defined as a Statewide MW deficiency (STWdef), will be prorated to all NYCA zones, based on the NYCA coincident peak load. The allocation to locational zones will take into account their locational requirements. For a single solution that addresses only a statewide deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_\text{i})}{\sum_{k=1}^{n} \text{Coincident Peak}_k * (1 + \text{IRM} - \text{LCR}_\text{k})} * \frac{\text{Soln STWdef}}{\text{Soln Size}} \right] *100\%$$

Where *i* is for each applicable zone, *n* is for the total zones in NYCA, IRM is the statewide reserve margin, and LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, Soln STWdef is the STWdef for the applicable project, and Soln_Size represents the total compensatory MW addressed by the applicable project.

38.22.1.3 Step 3 - Constrained Interface Deficiency. If the NYCA is not resource limited as determined by the NYCA Free Flow Test, then the ISO will examine constrained transmission interfaces, using the Binding Interface Test.

38.22.1.3.1 The ISO will provide output results of the reliability simulation program utilized for the RNA that indicate the hours that each interface is at limit in each flow direction, as well as the hours that coincide with a loss of load event. These values will be used as an initial indicator to determine the binding interfaces that are impacting LOLE within the NYCA.

38.22.1.3.2 The ISO will review the output of the reliability simulation program utilized for the RNA along with other applicable information that may be available to make the determination of the binding interfaces.

38.22.1.3.3 Bounded Regions are assigned cost responsibility for the compensatory MW, defined as CIdef, needed to reach an LOLE of 0.1.

38.22.1.3.4 If one or more Bounded Regions are isolated as a result of binding interfaces identified through the Binding Interface Test, the ISO will determine the optimal distribution of compensatory MW to achieve a NYCA LOLE of 0.1. Compensatory MW will be added until the required NYCA LOLE is achieved.

38.22.1.3.5 The Bounded Regions will be identified by the ISO's Binding Interface Test, which identifies the bounded interface limits that can be relieved and have the greatest impact on NYCA LOLE. The Bounded Region that will have the greatest benefit to NYCA LOLE will be the area to be first allocated costs in this step. The ISO will determine if after the first addition of compensating MWs the Bounded Region with the greatest impact on LOLE has changed. During this iterative process, the Binding Interface Test will look across the state to identify the appropriate Bounded Region. Specifically, the Binding Interface Test will be applied starting from the interface that has the greatest benefit to LOLE (the greatest LOLE reduction per interface compensatory MW addition), and then extended to subsequent interfaces until a NYCA LOLE of 0.1 is achieved.

38.22.1.3.6 The CIdef MW are allocated to the applicable Bounded Region isolated as a result of the constrained interface limits, based on their NYCA coincident peaks. Allocation to locational zones will take into account their locational requirements.

For a single solution that addresses only a binding interface deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_\text{i})}{\sum_{l=1}^{m} \text{Coincident Peak}_l * (1 + \text{IRM} - \text{LCR}_\text{l})} * \frac{\text{SolnCIdef}}{\text{Soln Size}} \right] *100\%$$

Where *i* is for each applicable zone, *m* is for the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, SolnCIdef is the CIdef for the applicable project and Soln_Size represents the total compensatory MW addressed by the applicable project.

38.22.2 BPTF Thermal Transmission Security Cost Allocation Formula

For purposes of solutions eligible for cost allocation under this Section 38.22, this section sets forth the cost allocation methodology applicable to that portion of the costs of the solution attributable to resolving BPTF thermal transmission security issues. If, after consideration of the compensatory MW identified in the resource adequacy reliability solution cost allocation in accordance with Section 38.22.1, there remains a BPTF thermal transmission security issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the BPTF thermal transmission security issue(s) to the Subzones that contribute to the BPTF thermal transmission security issue(s) in the following manner.

38.22.2.1 Calculation of Nodal Distribution Factors

The ISO will calculate the nodal distribution factor for each load bus modeled in the power flow case utilizing the output of the reliability simulation program that identified the

Generator Deactivation Reliability Need, including the NYCA generation dispatch and NYCA coincident peak Load. The nodal distribution factor represents the percentage of the Load that flows across the facility subject to the Generator Deactivation Reliability Need. The sign (positive or negative) of the nodal distribution factor represents the direction of flow.

38.22.2.2 Calculation of Nodal Flow

The ISO will calculate the nodal megawatt flow, defined as Nodal Flow, for each load bus modeled in the power flow case by multiplying the amount of Load in megawatts for the bus, defined as Nodal Load, by the nodal distribution factor for the bus. Nodal Flow represents the number of megawatts that flow across the facility subject to the Generator Deactivation Reliability Need due to the Load.

38.22.2.3 Calculation of Contributing Load and Contributing Flow

The Nodal Load for a load bus with a positive nodal distribution factor is a contributing Load, defined as CLoad, and the Nodal Flow for that Load is contributing flow, defined as CFlow. To identify contributing Loads that have a material impact on the Generator Deactivation Reliability Need, the ISO will calculate a contributing materiality threshold, defined as CMT, as follows:

$$CMT = \frac{\sum_{k=1}^{m} \sum_{Lk=1}^{n} CFlow_{Lk}}{\sum_{k=1}^{m} \sum_{Lk=1}^{n} CLoad_{Lk}}$$

Where *m* is for the total number of Subzones and *n* is for the total number of load buses in a given Subzone.

38.22.2.4 Calculation of Helping Load and Helping Flow

The Nodal Load for a load bus with a negative or zero nodal distribution factor is a helping Load, defined as HLoad, and the Nodal Flow for that Load is helping flow, defined as

HFlow. To identify helping Loads that have a material impact on the Generator Deactivation Reliability Need, the ISO will calculate a helping materiality threshold, defined as HMT, as follows:

$$HMT = \frac{\sum_{k=1}^{m} \sum_{Lk=1}^{n} HFlow_{Lk}}{\sum_{k=1}^{m} \sum_{Lk=1}^{n} HLoad_{Lk}}$$

Where *m* is for the total number of Subzones and *n* is for the total number of load buses in a given Subzone.

38.22.2.5 Calculation of Net Material Flow for Each Subzone

The ISO will identify material Nodal Flow for each Subzone and calculate the net material flow for each Subzone. For each load bus, the Nodal Flow will be identified as material flow, defined as MFlow, if the nodal distribution factor is (i) greater than or equal to CMT, or (ii) less than or equal to HMT. The net material flow for each Subzone, defined as SZ_NetFlow, is calculated as follows:

$$SZ\_NetFlow_j = \sum_{Lj=1}^{n} MFlow_{Lj}$$

Where *j* is for each Subzone and *n* is for the total number of load buses in a given Subzone.

38.22.2.6 Identification of Allocated Flow for Each Subzone

The ISO will identify the allocated flow for each Subzone and verify that sufficient contributing flow is being allocated costs. For each Subzone, if the SZ_NetFlow is greater than zero, that Subzone has a net material contribution to the Generator Deactivation Reliability Need and the SZ_NetFlow is identified as allocated flow, defined as SZ_AllocFlow. If the SZ_NetFlow is less than or equal to zero, that Subzone does not have a net material contribution to the Generator Deactivation Reliability Need and the SZ_AllocFlow is zero for that Subzone.

If the total SZ_AllocFlow for all Subzones is less than 60% of the total CFlow for all Subzones, then the CMT will be reduced and SZ_NetFlow recalculated until the total SZ_AllocFlow for all Subzones is at least 60% of the total CFlow for all Subzones.

38.22.2.7 Cost Allocation for a Single BPTF Thermal Transmission Security Issue

For a single solution that addresses only a BPTF thermal transmission security issue, the equation for cost allocation would reduce to:

$$BPTF\ Thermal\ Cost\ Alloction_j = \frac{SZ\_AllocFlow_j}{\sum_{k=1}^{m} SZ\_AllocFlow_k} \times \frac{SolnBTSdef}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones; SZ_AllocFlow is the allocated flow for each Subzone; SolnBTSdef is the number of compensatory MW for the BPTF thermal transmission security issue for the applicable project; and Soln_Size represents the total compensatory MW addressed by the applicable project.

38.22.2.8 Cost Allocation for Multiple BPTF Thermal Transmission Security Issues

If a single solution addresses multiple BPTF thermal transmission security issues, the ISO will calculate weighting factors based on the ratio of the present value of the estimated costs for individual solutions to each BPTF thermal transmission security issue. The present values of the estimated costs for the individual solutions shall be based on a common base date that will be the beginning of the calendar month in which the cost allocation analysis is performed (the “Base Date”). The ISO will apply the weighting factors to the cost allocation calculated for each Subzone for each individual BPTF thermal transmission security issue. The following example illustrates the cost allocation for such a solution:

- A cost allocation analysis for the selected solution is to be performed during a given month establishing the beginning of that month as the Base Date.

- The ISO has identified two BPTF thermal transmission security issues, Overload X and Overload Y, and the ISO has selected a single solution (Project Z) to address both BPTF thermal transmission security issues.
- The cost of a solution to address only Overload X (Project X) is Cost(X), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is N(X).
- The cost of a solution to address only Overload Y (Project Y) is Cost(Y), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project Y is N(Y).
- The discount rate, D, to be used for the present value analysis shall be the current after-tax weighted average cost of capital for the Transmission Owners.
- Based on the foregoing assumptions, the following formulas will be used:
  - Present Value of Cost (X) = PV Cost (X) = Cost (X) / $(1+D)^{N(X)}$
  - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / $(1+D)^{N(Y)}$
  - Overload X weighting factor = PV Cost (X)/[PV Cost (X) + PV Cost (Y)]
  - Overload Y weighting factor = PV Cost (Y)/[PV Cost (X) + PV Cost (Y)]
- Applying those formulas, if:

  Cost (X) = $100 Million and N(X) = 6.25 years

  Cost (Y) = $25 Million and N(Y) = 4.75 years

  D = 7.5% per year

  Then:

  PV Cost (X) = $100/(1+0.075)^{6.25}$ = 63.635 Million

  PV Cost (Y) = $25/(1+0.075)^{4.75}$ = 17.732 Million

Overload X weighting factor = 63.635 / (63.635 + 17.732) = 78.21%

Overload Y weighting factor = 17.732 / (63.635 + 17.732) = 21.79%

- Applying those weighing factors, if:

Subzone A cost allocation for Overload X is 15%

Subzone A cost allocation for Overload Y is 70%

Then:

Subzone A cost allocation % for Project Z =

(15% * 78.21%) + (70% * 21.79%) = 26.99%

38.22.2.9 Exclusion of Subzone(s) Based on *De Minimis* Impact

If a Subzone is assigned a BPTF thermal transmission security cost allocation less than a *de minimis* dollar threshold of the total project costs, that Subzone will not be allocated costs; *provided however*, that the total *de minimis* Subzones may not exceed 10% of the total BPTF thermal transmission security cost allocation. The *de minimis* threshold is initially $10,000. If the total allocation percentage of all *de minimis* Subzones is greater than 10%, then the *de minimis* threshold will be reduced until the total allocation percentage of all *de minimis* Subzones is less than or equal to 10%.

38.22.3 BPTF Voltage Security Cost Allocation

If, after consideration of the compensatory MW identified in the resource adequacy cost allocation in accordance with Section 38.22.1 and BPTF thermal transmission security cost allocation in accordance with Section 38.22.2, there remains a BPTF voltage security issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the BPTF voltage security issue(s) to the Subzones that contribute to the BPTF voltage security issue(s). The cost responsibility for the portion (MW or MVAr) of the solution attributable to resolving the BPTF voltage security issue(s), defined as SolnBVSdef, will be allocated on a Load-ratio share to each Subzone to which each bus with a voltage issue is connected, as follows:

$$BPTF\ Voltage\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{SolnBVSdef}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones that are subject to BPTF voltage cost allocation; Coincident Peak is for the total peak Load for each Subzone; SolnBVSdef is for the portion of the solution necessary to resolve the BPTF voltage security issue(s); and Soln_Size represents the total compensatory MW addressed by the applicable project.

38.22.4 Local Transmission Security Cost Allocation

If, after consideration of the compensatory MW identified in the resource adequacy cost allocation in accordance with Section 38.22.1, the BPTF thermal transmission security cost allocation in accordance with Section 38.22.2, and BPTF voltage security cost allocation in accordance with Section 38.22.3, there remains a non-BPTF thermal security issue or a non-BPTF voltage security issue, the ISO will allocate the costs of resolving the local security issue(s) to the Subzones that contribute to the local security issue(s).

38.22.4.1 The Subzone in which the receiving terminal of the non-BPTF facility is located is assigned cost responsibility for the megawatt portion of the solution needed to eliminate the non-BPTF thermal issue(s), defined as LocalThermalMW. If multiple non-BPTF thermal issues in multiple Subzones are addressed by the solution, the LocalThermalMW will be allocated on a Load-ratio share to each identified Subzone as follows:

$$Local\ Thermal\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{LocalThermalMW}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones that are subject to local thermal cost allocation; Coincident Peak is for the total peak load for each Subzone; LocalThermalMW is for the megawatt portion of the solution needed to eliminate the non-BPTF thermal issue(s); and Soln_Size represents the total compensatory MW addressed by the solution.

38.22.4.2 If there remains a voltage issue after consideration of LocalThermalMW, then the cost responsibility for the megawatt portion of the solution necessary to resolve the voltage issue(s), defined as LocalVoltageMW, will be allocated on a Load-ratio share to each Subzone to which each bus with a voltage issue is connected, as follows:

$$Local\ Voltage\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{LocalVoltageMW}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones that are subject to local voltage cost allocation; Coincident Peak is for the total peak Load for each Subzone; LocalVoltageMW is for the megawatt portion of the RMR Agreement necessary to resolve the voltage issue(s); and Soln_Size represents the total compensatory MW addressed by the solution.

38.22.5 Dynamic Stability Cost Allocation

If, after consideration of the compensatory MW identified in the resource adequacy cost allocation in accordance with Section 38.22.1, BPTF thermal transmission security cost allocation in accordance with Section 38.22.2, BPTF voltage security cost allocation in accordance with Section 38.22.3, and local transmission security cost allocation in accordance with Section 38.22.4, there remains a dynamic stability issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the dynamic stability issue(s) to all Subzones in the NYCA on a Load-ratio share basis, as follows:

$$Dynamic\ Stability\ Cost\ Alloction_j = \frac{Coincident\ Peak_j}{\sum_{k=1}^{m} Coincident\ Peak_k} \times \frac{DynamicMW}{Soln\_Size}$$

Where *j* is for each Subzone; *m* is for the total number of Subzones; Coincident Peak is for the total peak Load for each Subzone; DynamicMW is for the megawatt portion of the solution necessary to resolve the dynamic stability issue(s) for the applicable project; and Soln_Size represents the total compensatory MW addressed by the applicable project.

38.22.6 Short Circuit Issues

If, after the completion of the prior reliability cost allocation steps, there remains a short circuit issue, the short circuit issue will be deemed a local issue and related costs will not be allocated under this process.

38.23 Cost Recovery for Generator Deactivation Process

38.23.1 The Responsible Transmission Owner or the Developer that proposes a transmission Generator Deactivation Solution that is selected by the ISO pursuant to Section 38.10 to address a Generator Deactivation Reliability Need shall be entitled to full recovery of all reasonably incurred costs, including a reasonable return on investment and any applicable incentives, related to the development, construction, operation and maintenance of the transmission Generator Deactivation Solution. The Responsible Transmission Owner shall also be entitled to recover its costs for developing its proposed transmission Generator Deactivation Solution and, if applicable, its conceptual permanent Generator Deactivation Solution, whether or not such solutions were selected by the ISO. The Responsible Transmission Owner or Developer will recover its costs in accordance with Schedule 16 of this ISO OATT, or as determined by the Commission. The period for cost recovery will be determined by the Commission and will begin if and when the Generator Deactivation Solution is completed or halted, or as otherwise determined by the Commission. The NYISO does not provide cost recovery related to projects undertaken by Transmission Owners through their Local Transmission Owner Planning Processes pursuant to Sections 31.1.3 and 31.2.1 of Attachment Y of the ISO OATT.

38.23.2. If a selected regulated transmission Generator Deactivation Solution is halted by the ISO, all of the costs incurred and commitments made by the Developer up to that point, including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable by the Developer in accordance with Schedule 16 of the ISO OATT.

38.23.3 If the appropriate federal, state or local agency(ies) either rejects a necessary authorization, or approves and later withdraws authorization, for the selected transmission Generator Deactivation Solution, the Developer may recover all of the necessary and reasonable costs incurred and commitments made up to the final federal, state or local regulatory decision, including reasonable and necessary expenses incurred to implement an orderly termination of the project, to the extent permitted by the Commission in accordance with its regulations on abandoned plant recovery. The ISO shall recover such costs in accordance with Schedule 16 of the ISO OATT.

38.23.4 If a Market Participant's Generator is operating under an RMR Agreement pursuant to Section 38.11 to address a Generator Deactivation Reliability Need, the Market Participant will be paid in accordance with Rate Schedule 8 of the ISO Services Tariff. The ISO will recover costs related to RMR Agreements from LSEs in accordance with Schedule 14 of the ISO OATT.

38.23.5 With the exception of a Generator operating under an RMR Agreement, costs related to non-transmission regulated Generator Deactivation Solutions to Generator Deactivation Reliability Needs will be recovered by Responsible Transmission Owners or Developers in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law.

38.24 Appendix A – Generator Deactivation Notice Form

38.24.1 Instructions

38.24.1.1 Before a Generator may be Retired or enter into a Mothball Outage, the Market Participant must satisfy the requirements set forth in Attachment FF to the OATT, including submitting to the NYISO a completed Generator Deactivation Notice using the form set forth in this Appendix A of Attachment FF to the OATT, and providing the information required by Appendix B of Attachment FF to the OATT.

38.24.1.2 In accordance with the requirements set forth in Section 38.3.1 of Attachment FF to the OATT and ISO Procedures, the Market Participant shall submit to the NYISO via electronic mail (a) the Generator Deactivation Notice form to generator_retirement@nyiso.com and (b) all information required by Appendix B of Attachment FF to NYISO Stakeholder Services, to the attention of the Director of Market Mitigation and Analysis.

38.24.1.3 The NYISO will review the information received pursuant to Section 38.3.1.5 of the OATT to determine whether it is complete. The NYISO will notify the Market Participant to provide any additional information that is required in order for the Generator Deactivation Notice to be determined to be complete.

38.24.1.4 The 365 day notice period applicable to a Generator(s) proposing to be Retired or enter into a Mothball Outage will begin to run on the date that the NYISO issues a written notice to the Market Participant indicating that the Generator Deactivation Notice (including the information received and supporting certification) are complete.

38.24.1.5 The Market Participant has a continuing obligation to timely submit additional information pursuant to Section 38.25.4 of Appendix B, under Attachment FF to the NYISO OATT, and as otherwise required under the ISO Tariffs. All such information shall be sent to NYISO Stakeholder Services, to the attention of the Director of Market Mitigation and Analysis.

38.24.2 Submitting Entity's Information

38.24.2.1 Name of entity submitting notice:

____ ("submitting entity")

38.24.2.2 Submitting entity's interest in and relationship with Generator(s) (check all that apply):

[ ] Owner (and if part owner, percent) of Generator(s)
[ ] Operator of Generator(s)

[ ] Market Participant
[ ] Other ___________________________

If the submitting entity is not both the owner and operator, provide the following information for (a) the owner, (b) the operator, (c) Market Participant, and (d) the submitting entity:

38.24.2.3 State of organization or incorporation:

____

38.24.2.4 Contact information

Name of contact person and alternate contact person, title, relationship to the submitting entity, mailing address, e-mail address, office phone number, and cell phone number:

38.24.3 Identity of Generator(s) Subject to Generator Deactivation Notice

Location:

Unit Name:_________ PTID _______ Nameplate Capacity in MW: ___________

Unit Name:_________ PTID _______ Nameplate Capacity in MW: ___________

Unit Name:_________ PTID _______ Nameplate Capacity in MW: ___________

Unit Name:_________ PTID _______ Nameplate Capacity in MW: ___________

Revenue Meter Location(s) (Use PTIDs):

38.24.4 Proposed Generator Deactivation

38.24.4.1 The Generator Deactivation Notice is for the Generator(s) (check one):

[ ] to be Retired
[ ] to enter into a Mothball Outage.

38.24.4.2 If the submitting entity is proposing to enter into a Mothball Outage, please check the box below to acknowledge that the Generator(s) is able to return to service within 180 days.

[ ] Generator(s) is able to return to service within 180 days

Please note: If the submitting entity believes that there is good cause for why a Generator will not be able to return to service within 180 days, the submitting entity must separately provide for each such Generator the proposed number of days for return and supporting information to the NYISO for review. The NYISO will determine whether the information provided satisfies the requirements of Section 5.18.3.2 of the ISO Services Tariff. If the Generator Deactivation Notice is for more than one Generator, and the response to this subsection 38.24.4.2 is not the same for all Generators, specify by Unit Name and PTID which Generators are able and which are not able to return to service within 180 days.

38.24.4.3 If the submitting entity is proposing for the Generator(s) to be Retired on a date other than 365 days after the Generator Deactivation Assessment Start Date (as that term is defined in Section 38.1 of Attachment FF to the NYISO OATT), the desired retirement date is: [day] of [month] of [year].

38.24.4.4 If the submitting entity is proposing for the Generator(s) to enter into a Mothball Outage on a date other than 365 days after the Generator Deactivation Assessment Start Date, the desired date to enter into a Mothball Outage is: [day] of [month] of [year]. The submitting entity proposes to resume operation and participation in the ISO Administered Markets on: [day] of [month] of [year].

38.24.5 Acknowledgments

By submitting the Generator Deactivation Notice, the submitting entity acknowledges:

- After the NYISO determines that the Generator Deactivation Notice is complete, the NYISO will post a notice of that determination (and will notify the submitting entity.)
- If the submitting entity rescinds this Generator Deactivation Notice after the NYISO determines it to be complete, the submitting entity must reimburse the NYISO and the relevant New York Transmission Owner(s) in accordance with Section 38.14.2 of Attachment FF of the NYISO OATT the actual costs that each incurred in performing their responsibilities under Attachment FF of the NYISO OATT and Section 23.4.5.6 of the ISO Services Tariff in response to the submitting entity's submission of this Generator Deactivation Notice, including any costs associated with using contractors.

38.24.6 Submitted By:

Certification

The undersigned certifies that he or she is an officer of the submitting entity, that he or she is authorized to execute this Certification and submit this Generator Deactivation Notice on behalf of the submitting entity, and that the information and statements contained herein (including any and all attachments, and information required by Appendix B of Attachment FF to the NYISO OATT submitted herewith,) and in this certification are true and correct to the best of his or her information, knowledge and belief, having conducted due diligence.

____
Signature

Name: ______________________________ Title: __________________________

Date: ______________________________

38.25 Appendix B – Generator Deactivation Process Cost, Revenue, and Other Information Requirements

38.25.1 Overview of Information Requirements

This Appendix B governs the information that must be received by the ISO from Market Parties for Generator Deactivation Solutions, including Initiating Generators, Generator Deactivation Solutions proposed pursuant to Section 38.4 of Attachment FF, and Generators that have submitted a statement of intent or are otherwise required by the ISO to submit this information pursuant to 38.5 of this Attachment FF. The term "information" as used in this Appendix B and in Attachment FF includes all sources and types of information and data. The information required by this Appendix shall be separately stated from and is in addition to the information requirements for Generators in certain outages set forth in Section 5.18 of the ISO Services Tariff, the information required by the ISO pursuant to Section 23.4.5.6 of the ISO Services Tariff, and the Generator Deactivation Process project information requirements set forth in Section 38.4 of this Attachment FF. If the information required by this Appendix does not exist on the date due to the ISO, the Market Party shall promptly provide it to the ISO if and when it does exist in whole or in part.

38.25.2 Information Requirements Applicable to Initiating Generators

38.25.2.1 The Market Party for an Initiating Generator must submit the information specified below, and any other information specified by the ISO on the section of its website identified for RMR Information Requirements, in the form and manner directed by the ISO. The items and their costs identified for (a) through (d), and (e) in this Section shall include only those costs necessary for the Initiating Generator to operate in accordance with Good Utility Practice for the duration of the relevant information period (as set forth in Section 38.25.8).

(a) Capital expenses, including those necessary to comply with federal or state environmental or safety laws, rules, regulations, and requirements, separately stating the financing cost (*e.g.*, interest and fees) for each item;

(b) Fixed operating and maintenance costs;

(c) Variable operating and maintenance costs, such as fuel, emissions, and start up costs, and other costs identified by the ISO in accordance with ISO Procedures; and if there is any difference between the submitted information and the information in the ISO's Reference Level System at the time of the submission, and an explanation of the reason for the difference;

(d) The quantity of specific items of inventory necessary to be maintained, and costs thereof;

(e) The cost of expenditures other than those identified in (a) through (d) of this section that are necessary for the Generator to operate;

(f) All information pertaining to the capital structure of the Generator and its financing structure, the sources of capital, financing agreements, and dividend payout schedules;

(g) If the Generator Deactivation Notice is for the Generator to be Retired, (a) all existing agreements and proposals pertaining to the cost of opportunities that would be foregone if the Generator is not retired, such agreements being for the reuse, repurposing, or distribution of the real property of or on which the unit is located, its personal property or appurtenances; and (b) all agreements that contain a cost, premium, or fee for termination of all or a portion thereof;

(h) If the Generator is in an ICAP Ineligible Forced Outage or is Mothballed, and the Generator Deactivation Notice is for a retirement prior to the expiration of the period set forth in Section 5.18 of the ISO Services Tariff, the costs that are necessary to enable the Generator to return to service; and

(i) All sources of revenue, and the amount of, and terms and conditions associated with each source of revenues related to the construction of, investment in, upgrade to, or operation of the Generator.

38.25.2.2 For each item of cost or revenue, the Market Party shall specify whether it can be avoided, in whole or in part or diminished, if the Generator (a) ceases operations in the manner specified in its Generator Deactivation Notice, or (b) does not resume service from an ICAP Ineligible Forced Outage or Mothball Outage state. For each cost that can be avoided, the Market Party shall specify how it plans to do so and the potentially viable options examined to minimize the cost.

38.25.3 Information Requirements Applicable to Generator Deactivation Solutions Proposed Pursuant to Section 38.4 and Generators that Submit Statements of Intent or that Are Otherwise Required to Provide Information Pursuant to Section 38.5

38.25.3.1 The Market Party for a Generator Deactivation Solution proposed pursuant to Section 38.4, or for a Generator that submitted a statement of intent or that is otherwise required by the ISO to provide the information in Appendix B pursuant to Section 38.5, shall submit the information identified below, and any other information specified by the ISO on the ISO's website, in the form and manner directed by the ISO.

38.25.3.2 If a Market Party has submitted a statement of intent to offer its Generator, or if the ISO otherwise requires the Market Party to provide the information in Appendix B regarding the Generator pursuant to Section 38.5, then the Market Party shall submit the information set forth in Section 38.25.2.1 and 38.25.2.2.

38.25.3.3 If a proposed Generator Deactivation Solution is a new Generator, the Market Party shall submit those costs necessary for the Generator to be sited, permitted, and constructed, and the information below. The items and their costs identified for (a) through (d) in this Section shall include only those costs necessary for the Generator to operate in accordance with Good Utility Practice for the duration of the relevant information period.

(a) Capital expenses, including those necessary to comply with federal or state environmental or safety laws, rules, regulations, and requirements, separately stating the financing cost (*e.g.*, interest and fees) for each item;

(b) Fixed operating and maintenance costs;

(c) Variable operating and maintenance costs;

(d) The quantity of specific items of inventory necessary to be maintained, and costs thereof;

(e) All information pertaining to the capital structure of the Generator and its financing structure, including the sources of capital, financing agreements, and dividend payout schedules;

(f) All existing agreements and proposals pertaining to opportunity costs that would be foregone if the Generator served as a Generator Deactivation Solution; and

(g) All sources of revenue, and the amount of, and terms and conditions associated with each source of revenues related to the construction of, investment in, upgrade to, or operation of the proposed Generator Deactivation Solution or Generator.

38.25.3.4 If a proposed Generator Deactivation Solution is a transmission project, the Market Party shall provide:

(a) Capital expenses, including the following elements:

(i) Capital expenses necessary to comply with federal or state environmental or safety requirements, separately stating the financing cost (*e.g.*, interest and fees) for each item;

(ii) Worksheets setting forth all relevant material and labor cost assumptions. These assumptions should be itemized, and should include the following elements:

(A) equipment, including, to the extent applicable and available, sub-itemized estimates for equipment associated with each of the following categories: (i) the proposed project; (ii) interconnection facilities (including Attachment Facilities and Direct Assignment Facilities); and (iii) System Upgrade Facilities, System Deliverability Upgrades, Network Upgrades, and Distribution Upgrades

(B) engineering and design work

(C) permitting

(D) site acquisition

(E) procurement

(F) construction work

(G) other commissioning work;

(iii) For each category or sub-category of cost estimate, a quantification of cost variance, including an assumed plus/minus range around the capital cost estimate.

(b) Fixed operating and maintenance costs;

(c) Variable operating and maintenance costs;

(d) The quantity of specific items of inventory necessary to be maintained, and costs thereof;

(e) The cost of expenditures other than those identified in (a) through (d) of this Section that are necessary to enable the project to operate, including any costs to obtain right of way, siting, and other federal, state and local permits;

(f) All information pertaining to the capital structure of the project and its financing structure, including the sources of capital, financing agreements, and dividend payout schedules;

(g) All existing agreements and proposals pertaining to opportunity costs that would be foregone if the project served as a Generator Deactivation Solution; and

(h) All sources of revenue, and the amount of, and terms and conditions associated with each source of revenue related to the construction of, investment in, upgrade to, or operation of the project.

38.25.4 Obligation to Submit Further Information

Market Parties for Generator Deactivation Solutions, including Initiating Generators, Generator Deactivation Solutions proposed pursuant to Section 38.4, Generators that submitted a statement of intent pursuant to Section 38.5, and Generators otherwise required to provide the information in Appendix B pursuant to Section 38.5, shall provide any new information, and shall update and revise information previously submitted to the ISO in accordance with Sections 38.25.2 or 38.25.3, (i) no more than fifteen days after (a) a material change (or a series of changes that results in a material change) in (I) the physical condition of a proposed or potential Generator Deactivation Solution or any aspect of its proposal, or (II) the information previously submitted, (b) an event occurring that makes any element of the information submitted materially inaccurate, (c) actual cost information becoming available where estimated information had been provided, (d) changes to costs based on physical events or regulatory developments that might reasonably be expected to impact planned operations, and also (ii) promptly upon the request of the ISO for any other information. The obligation to provide information pursuant to this Section 38.25.4 shall cease (a) for any proposed or potential Generator Deactivation Solution (other than an Initiating Generator) on the earlier of the date (x) the ISO provides notice that a Generator Deactivation Solution is not needed, (y) the request for Generator Deactivation Solutions is withdrawn, or (z) that the ISO determines a Generator Deactivation Solution other than it is expected to satisfy the Generator Deactivation Reliability Need, and (b) for any Initiating Generator, upon the earlier of the date that (x) it withdraws its Generator Deactivation Notice if it stated it was a notice of retirement, or (y) it permanently retires.

38.25.5 The Market Party shall provide the ISO the actual costs and revenues for each item in Sections 38.25.2 through 38.25.4 to the greatest extent practicable. If actual costs and revenues are not available, the Market Party shall provide estimated costs and revenues along with a description of how the estimates were prepared. The Market Party must identify and describe the accounting protocols used to identify or determine all actual and estimated costs and revenues.

38.25.6 For each cost identified under Subsections (a), (b), (d) and (e) of Sections 38.25.2.1, 38.25.3.1, 38.25.3.4, or 38.25.3.5, or Subsections (a), (b) and (d) of Section 38.25.3.3, the Market Party shall provide a detailed plan specifying the schedule and timing of the planned action and expenditure, and if it is an existing Resource, an explanation and supporting documentation of how that plan compares to the Market Party’s past similar expenditures, actions, and protocols. The Market Party shall also specify the terms in any contracts associated with (a) avoidable capital expenses, normal maintenance, extraordinary maintenance and repairs, or variable costs that contain a cost, premium, and/or fee for termination of the agreement in whole or for a portion thereof, and shall provide a copy of the contract and documents pertinent to the calculation of the early termination premium, cost, and fee, and (b) revenues, and shall provide a copy of the contract and documents pertinent to the calculation of the revenues, and the historic revenues.

38.25.7 The Market Party shall specify whether each cost is associated solely with the individual unit(s) of the Generator, or a component of the transmission project, or whether the cost is for services or functions shared with other units or businesses. If a cost is a shared cost, the Market Party shall identify the other entities with which the cost is shared, the entity that allocates the cost to it; and the accounting protocols and methodology used in the allocation of the costs, and across which units and business the cost is allocated.

38.25.8 Information Periods

38.25.8.1 Information provided under Sections 38.25.2.1 and 38.25.2.2 shall encompass one year periods, for the five (5) years prior to and (a) if by an Initiating Generator or a Generator that submits a statement of intent pursuant to Section 38.5 for six (6) years from the date of the initial provision of information, and each annual update thereto, and (b) if by a Generator that did not provide a statement of intent, but is required to provide information by the ISO pursuant to 38.5, for the number of years identified by the ISO in the notification provided pursuant to 38.5 of Attachment FF.

38.25.8.2 Information provided by proposed Generator Deactivation Solutions, other than an Initiating Generator or a Generator that has submitted a statement of intent or is otherwise required to provide information in Appendix B pursuant to Section 38.5, shall encompass one year periods, from the date of the initial provision of information for the period identified in the request of Generator Deactivation Solutions.

38.25.8.3 For the financing cost of any mandatory capital expense, the Market Party shall provide information and data for: (a) the one-year period beginning on the estimated date of expenditure for the item of capital expense; and in addition (b) the period beginning on the estimated date of expenditure for the item of capital expense and ending, respectively, (i) if an Initiating Generator or a Generator that submitted a statement of intent pursuant to Section 38.5 two years, three years, four years, five years, and six years, from the date of the Generator Deactivation Notice or statement of intent (but excluding data and information beyond the date that is six years from the Generator Deactivation Notice or statement of intent); (ii) if a Generator that did not provide a statement of intent, but is required to provide information by the ISO pursuant to Section 38.5, for the number of years identified by the ISO in the notification provided pursuant to Section 38.5, from the date of its initial submission of information in accordance with Section 38.25.3, and (iii) if a proposed Generator Deactivation Solution (other than an Initiating Generator or a Generator that has submitted a statement of intent or its otherwise required by the ISO to provide information pursuant to Section 38.5), for the duration of the Generator Deactivation Reliability Need identified by the ISO in its request for Generator Deactivation Solutions.

38.26 Appendix C - Form of Reliability Must Run Agreement

FORM OF RELIABILITY MUST RUN AGREEMENT

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RELIABILITY MUST RUN AGREEMENT

This RELIABILITY MUST RUN AGREEMENT ("Agreement") is made as of the______day of _________, 20__, among ____{fill in names and types of legal entity or entities} (collectively, "Owner"), and the New York Independent System Operator, Inc., a New York not-for-profit corporation ("ISO").

RECITALS

Owner owns and has operational control over ____________(PTID No. __________), a ___MW electrical Generator together with appurtenant facilities and structures, located at ________(a/the "RMR Generator"). {If the station is comprised of more than one unit, describe all units at the station, including their MW and PTIDs, and then identify each unit or sets of units that is a distinct "RMR Generator" under this Agreement}.

The ISO is the Independent System Operator for New York and is responsible for the operation of the New York Control Area ("NYCA") to ensure reliability and for the administration of the ISO Administered Markets.

Owner submitted a Generator Deactivation Notice [to mothball or to retire] each RMR Generator, which the ISO determined was complete on [ISO to fill-in date]. The 365 Day Notice Period concludes or concluded on [date one year from the date that the ISO determined the Generator Deactivation Notice was complete].

The ISO has concluded that the RMR Generator[s] will be needed for reliability purposes during the Term of this Agreement. Schedule 1 to this Agreement contains a description of the Reliability Need that the RMR Generator[s] are being kept in service to address.

The Parties have agreed: [ALT. 1, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS, OWNER ACCEPTS THE APR, AND THE PARTIES EXECUTE THE AGREEMENT (i) that the ISO shall submit this executed Agreement, including the proposed Availability and Performance Rate ("APR"), to the Federal Energy Regulatory Commission ("FERC") in a Federal Power Act ("FPA") Section 205 filing on the Parties' behalf;] [ALT. 2, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS, OWNER ACCEPTS THE APR, BUT THERE ARE CAPITAL EXPENDITURES THAT REQUIRE FERC APPROVAL (i) that the ISO shall submit this Agreement to the Federal Energy Regulatory Commission ("FERC"), including the agreed-to components of a proposed Availability and Performance Rate ("APR"), in a Federal Power Act ("FPA") Section 205 filing on the Parties' behalf, and that Owner shall submit a separate FPA Section 205 filing that is consistent with the terms and conditions of service proposed in this Agreement, and that tracks the format of this Agreement, proposing the inclusion of the cost of certain Capital Expenditures in the APR;] [ALT. 3, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS BUT OWNER REJECTS THE APR AND SUBMITS AN OWNER DEVELOPED RATE (i) that the ISO shall submit this unexecuted Agreement that sets forth the Parties' agreed-upon terms and conditions of service to the Federal Energy Regulatory Commission ("FERC"), in a Federal Power Act ("FPA") Section 205 filing on the Parties' behalf, and that Owner shall submit a separate FPA Section 205 filing proposing an Owner Developed Rate that is consistent with the terms and conditions of service proposed in this Agreement, and that tracks the format of this Agreement;] and (ii) to enter into this Agreement to establish the terms and conditions under which each RMR Generator shall be obligated to offer and provide Energy, Ancillary Services and Unforced Capacity to the ISO Administered Markets; and (iii) [to set certain components of the Availability and Performance Rate ("APR") that determines the payments by which Owner shall recover the avoidable and variable costs of each RMR Generator, and makes available possible monthly and seasonal incentive payments based on each RMR Generator's availability to operate and its performance when scheduled to operate] OR [to incorporate the Owner Developed Rate that is ultimately accepted by FERC].

NOW THEREFORE, in consideration of the agreements and covenants set forth herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, and intending to be legally bound by this Agreement as of its Start Date, the Parties covenant and agree as follows:

ARTICLE 1 - DEFINITIONS AND RULES OF INTERPRETATION

1.1 Definitions.

Except for the terms defined below and in the attached schedules, capitalized terms shall be as defined in the ISO Tariffs. The definitions set forth below are only intended for use in this Agreement and shall not be relied upon to interpret the ISO's Tariffs.

1.1.1 "365 Day Notice Period" means the 365 days that follow the Generator Deactivation Assessment Start Date.

1.1.2 "Additional Costs" has the meaning set forth in Section 4.3.3 of this Agreement.

1.1.3 "Affiliate" has the meaning set forth in Section 2.1 of the Services Tariff.

1.1.4 "Ancillary Services" means services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services that RMR Generators may be able to provide include Voltage Support Service, Regulation Service, Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves), and Restoration Services (black start).

1.1.5 "Availability & Performance Rate" or "APR" means the compensation that an RMR Generator is eligible to receive in accordance with Sections 15.8.1, 15.8.2, 15.8.3 and 15.8.4 of Rate Schedule 8 to the ISO's Services Tariff during the Term of this Agreement. The APR consists of a daily calculation that is developed to permit an RMR Generator to recover its avoidable costs and variable costs, plus the opportunity to periodically earn financial incentives for availability to the markets and for performing consistent with the ISO's dispatch when scheduled.

1.1.6 "Capital Expenditures" has the meaning set forth in Section 38.8.1.3 of the OATT.

1.1.7 "Contract" means any agreement, commitment, policy, document or similar instrument creating mutual obligations among two or more parties.

1.1.8 "FERC Effective Date" has the meaning set forth in Section 2.1 of this Agreement.

1.1.9 "Force Majeure Event" has the meaning set forth in Section 8.1 of this Agreement.

1.1.10 "Forced Outage" has the meaning set forth in Section 2.6 of the Services Tariff.

1.1.11 "FPA" means the Federal Power Act (16 U.S.C. § 791a).

1.1.12 "Generator Deactivation Notice" has the meaning set forth in Section 38.1 of the OATT.

1.1.13 "Generator Deactivation Assessment Start Date" has the meaning set forth in Section 38.1 of the OATT.

1.1.14 "Governmental Authority" means the government of any nation, state or other political subdivision thereof, including any entity lawfully exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government.

1.1.15 "ISO Procedures" has the meaning set forth in Section 2.9 of the Services Tariff.

1.1.16 "ISO Tariffs" means the ISO's Market Administration and Control Area Services Tariff ("Services Tariff") and the ISO's Open Access Transmission Tariff ("OATT") collectively.

1.1.17 "Law" means any law, treaty, code, rule, regulation, or order or determination of an arbitrator, court or other Governmental Authority, or any license, permit, certificate, authorization, qualification, or approval granted by a Governmental Authority, each as amended, modified, supplemented or replaced from time to time, to the extent binding on a Party or any of its property.

1.1.18 "Market Mitigation and Analysis Department" or "MMA" has the meaning set forth in Section 30.2 of the Services Tariff.

1.1.19 "Market Monitoring Unit" or "MMU" has the meaning set forth in Section 30.2 of the Services Tariff.

1.1.20 "Month" means the period beginning at hour beginning zero on the first day of the calendar month and ending at hour beginning zero of the first day of the next succeeding calendar month.

1.1.21 "Notice of Forced Outage" has the meaning set forth in Section 7.2.3 of this Agreement.

1.1.22 "Notice of Event of Proposed Additional Cost" has the meaning set forth in Section 38.16.1 of the OATT.

1.1.23 "Notice of Shut-down" has the meaning set forth in Section 7.2.5 of this Agreement.

1.1.24 "Order" means any determination, command, mandate or similar directive made by a Governmental Authority.

1.1.25 "Owner" has the meaning set forth in the preamble of this Agreement and, where applicable and appropriate, includes Owner's agent, assignee and/or designee.

1.1.26 "Owner-Developed Rate" means a rate that Owner filed with the Federal Energy Regulatory Commission ("FERC") under Section 205 of the Federal Power Act, including any modifications required by FERC in its Order accepting the rate for filing. An Owner Developed Rate is different from the ISO-developed Availability & Performance Rate. The charges that the ISO pays pursuant to an Owner Developed Rate are represented by the "RMRCost" term that is used in Rate Schedule 8 to the Services Tariff.

1.1.27 "Party" means either the ISO or Owner, as the context requires. "Parties" means ISO and Owner.

1.1.28 "Permit" means any license, certificate, authorization, qualification, or similar approval granted by a Governmental Authority empowering the grantee to do some act.

1.1.29 "Planned Outage" means a planned interruption, in whole or in part, to the availability of a Generator to permit Owner to perform maintenance and repair of the Generator.

1.1.30 "Reference Level" means the ISO's best estimate of an RMR Generator's incremental marginal costs, and of an RMR Generator's physical capabilities. The ISO determines Reference Levels in accordance with the requirements of its Market Power Mitigation Measures that are set forth in Section 23 of its Services Tariff. This term does not include UCAP Offer Reference Levels.

1.1.31 "RMR Avoidable Costs" has the meaning set forth in Section 1.18 of the OATT.

1.1.32 "RMR Generator" has the meaning set forth in Section 1.18 of the OATT.

1.1.33 "Shut-down Date" has the meaning set forth in Section 7.2.9 of this Agreement.

1.1.34 "Start Date" has the meaning set forth in Section 2.1 of this Agreement.

1.1.35 "Substantiated Additional Cost" has the meaning set forth in Section 38.16.2.1 of the OATT.

1.1.36 "Term" has the meaning set forth in Section 2.1 of this Agreement.

1.2 Interpretation.

In this Agreement, unless otherwise indicated or otherwise required by the context, the following rules of interpretation shall apply:

1.2.1 Reference to and the definition of any document (including this Agreement, an ISO Tariff or the ISO Procedures) shall be deemed a reference to such document as it may be amended, supplemented, revised or modified from time to time, and to any document that is a successor thereto but only to the extent the amendment or other modification is not prohibited by this Agreement or the ISO's Tariffs.

1.2.2 The table of contents, article and section headings, and other captions in this Agreement are for the purpose of reference only and do not limit or affect its meaning.

1.2.3 Defined terms in the singular shall include the plural and vice versa, and the masculine, feminine or neuter gender shall include all genders.

1.2.4 The terms "include," "includes," or "including" when used herein shall not be considered limitations.

1.3 Construction.

1.3.1 The Parties shall comply with the ISO's Tariffs, as they may be amended from time to time.

1.3.2 This Agreement has been drafted by the Parties hereto and shall not be construed against any Party as the sole drafter.

ARTICLE 2 – TERM

2.1 Start Date, FERC Effective Date and Term.

2.1.1 This Agreement shall become effective at the beginning of the hour beginning zero, on [the first day of a month] (the "Start Date") and shall terminate at the end of the operating hour beginning 23 as of the date of the termination of the [last] RMR Generator as provided in Section 2.2 ("Term"). The [Parties or filing Party] request[s] that FERC set the date that this Agreement shall become legally effective under the FPA (the "FERC Effective Date") to be consistent with the Start Date.

2.1.2 Following the ISO's submission to FERC of an executed or unexecuted Agreement: (a) commencing on the proposed Start Date the Parties shall implement and comply with the Agreement, subject to any condition or modification directed by FERC, and (b) if the Parties agree, then Owner may begin incurring costs for Capital Expenditures that are included in the Agreement for recovery pending FERC action.

2.2 Termination.

This Agreement may be terminated as follows:

2.2.1 Conclusion of Reliability Need. ISO may unilaterally terminate this Agreement as to [the/an] RMR Generator effective upon ninety (90) days written notice to Owner if ISO determines that [the/an] RMR Generator is no longer or will no longer be needed to meet a Reliability Need. The ninety (90) day notice may be issued by ISO at any time. If two or more RMR Generators are subject to this Agreement, the Agreement shall be terminated with respect to one or more individual RMR Generators that are no longer needed to meet a Reliability Need. Concurrent with the ISO's notice to [the/an] RMR Generator, the ISO shall inform the New

York Public Service Commission that the RMR Generator will not be needed to meet a Reliability Need after the conclusion of the ninety (90) day notice period.

2.2.2 Termination for cause. ISO may unilaterally terminate this Agreement as to [the/an] RMR Generator effective upon thirty (30) days written notice to Owner if [the/an] RMR Generator does not satisfy the Minimum Availability Standard set forth in Section 7.3.1 of this Agreement, or if [the/an] RMR Generator fails to satisfy the Minimum Performance Standard set forth in Section 7.3.2 of this Agreement, or if [the/an] RMR Generator fails to satisfy the Operation to Address the Reliability Need Standard set forth in Section 7.3.3 of this Agreement. If two or more RMR Generators are subject to this Agreement, the Agreement may be terminated with respect to one or more individual RMR Generators that have failed to satisfy a Minimum Operating Standard. The consequences of termination for cause are addressed in Section 2.2.7 of this Agreement and in Section 23.6.5 of the Services Tariff.

2.2.3 This Agreement may also be terminated for an RMR Generator as provided in Section 7.2.9 (Forced Outages), and Section 9.4 (Termination for Default).

2.2.4 This Agreement terminates as of the date that there are no longer any RMR Generators that are subject to the Agreement.

2.2.5 If this Agreement is not terminated earlier, except as set forth in Section 2.3 hereof, it shall terminate at the end of hour beginning 23 on [the End Date, which shall be the last day of a month], unless the Parties agree in writing to extend the Term because the Reliability Need has not been resolved yet.

2.2.6 Events upon termination or expiration of this Agreement. Events that will occur upon the termination or expiration of this Agreement include the following: (a) the ISO will cease paying the APR or Owner Developed Rate (however, in some limited circumstances, the ISO may continue paying Owner for Capital Expenditures, *see* Section 4.3.2 below, or may pay wind-down costs in accordance with Section 4.8 below), (b) the RMR Generator will not be prohibited by the ISO Tariffs or this Agreement from entering a Mothball Outage or becoming Retired, consistent with the status that was indicated in a Generator Deactivation Notice and used to determine the RMR Generator's RMR Avoidable Costs or Owner Developed Rate, although such action may be subject to an audit and review, and a penalty under Sections 23.2.4.1.1, 23.3.1.1 and 23.4.5.6 of the Services Tariff; (c) where appropriate, the ISO will inform the New York State Public Service Commission that the RMR Generator will no longer be needed to meet a Reliability Need; and (d) if Owner wants an RMR Generator to continue participating in the ISO Administered Markets following the conclusion of an RMR Agreement, then Owner must provide notice to the ISO in accordance with Section 2.2.9 below and timely post adequate credit, including any additional credit that may be required in accordance with Sections 26.4 and 26.5 of the Services Tariff.

2.2.6.1 If the status that was indicated in a Generator Deactivation Notice and used to determine the RMR Generator's RMR Avoidable Costs or Owner Developed Rate is Retired, then Owner may elect to temporarily enter an Inactive Reserves state for up to sixty (60) days following the conclusion of an RMR Agreement before it must Retire or elect to continue participating in the ISO Administered Markets by submitting a Notice of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates in accordance with Section 2.2.9 of this Agreement, timely posting adequate credit, including any additional credit that may be required in accordance with Sections 26.4 and 26.5 of the Services Tariff and repaying the cost of any Capital Expenditures and other above market revenues in accordance with the requirements of Rate Schedule 8 to the ISO's Services Tariff that are due. This provision does not excuse the twenty-one (21) day prior notice requirement that applies to all Notices of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates.

2.2.6.2 Owner shall decide whether a Generator that returned from a mothball or ICAP Ineligible Forced Outage to become an RMR Generator will enter a Mothball Outage or become Retired at the conclusion of its participation in the RMR Agreement. Alternatively, Owner may elect to have such a Generator continue participating in the ISO Administered Markets by submitting a Notice of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates in accordance with Section 2.2.9 of this Agreement and timely posting adequate credit, including any additional credit that may be required in accordance with Sections 26.4 and 26.5 of the Services Tariff. This provision does not excuse the twenty-one (21) day prior notice requirement that applies to all Notices of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates.

2.2.7 Consequence of termination of this Agreement (a) by the ISO "for cause" (*see* Section 2.2.2), or (b) due to a default by Owner (*see* Section 9.4). If the ISO terminates this Agreement for cause, or if this Agreement is terminated due to the default of Owner, following the termination date, consistent with Section 23.6.5.2 of the Services Tariff the ISO shall not be obligated by this Agreement to, and shall not continue to pay for, any Capital Expenditure that was incurred at or for a terminated RMR Generator. This includes Capital Expenditures that were included in the RMR Avoidable Cost component of an RMR Generator's APR or in an Owner Developed Rate, that were authorized for recovery as Substantiated Additional Costs by the ISO, or that were otherwise reviewed and accepted by FERC.

2.2.8 Providing notice of cancellation to FERC. The ISO shall file all required notices of cancellation with FERC, and shall seek to make such cancellations effective on the date of termination under this Agreement.

2.2.9 Notice of Intent to Continue Participating in the ISO Administered Markets at Market-Based Rates following the conclusion of this Agreement. Owner shall provide the ISO with notice at least twenty-one (21) days in advance of the date this Agreement will terminate for an RMR Generator, identifying the RMR Generator(s) that Owner intends will continue participating in the ISO Administered Markets following the conclusion of this Agreement. If Owner intends to reduce the scope of a (former) RMR Generator's participation in the ISO Administered Markets following the conclusion of this Agreement, it may so inform the ISO in its notice. Following the conclusion of this Agreement, the ISO shall not permit Energy, Ancillary Services or Unforced Capacity to be offered into or scheduled in the ISO Administered Markets from a former RMR Generator unless and until (a) adequate credit, including any additional credit that may be required in accordance with Sections 26.4 and 26.5 of the Services Tariff is timely posted, and (b) all obligations under Rate Schedule 8 to the Services Tariff to repay Capital Expenditures and other above market revenues are being complied with.

2.3 Survival.

Notwithstanding the termination of this Agreement, the Parties shall continue to be bound by the provisions of this Agreement which by their nature are intended to, and shall, survive such termination, including Sections 3.2.4 (Refund of Insurance Proceeds), 3.3.7 (Inform Subsequent Purchaser of Repayment Obligations), 4.3.4 (Obligation to Repay Capital Expenditures and Other Above Market Revenues), 4.7 (Penalties), 4.8 (Wind-Down Costs), 6.2 (Books and Records, Audit Rights), 7.2.8 (Refund of Insurance Proceeds), 9.2.1 and 9.2.2 (Liability), 9.2.3 (Indemnification), and 11.10 (Confidentiality). The ISO shall continue to apply Services Tariff Rate Schedule 8 and OATT Rate Schedule 14 when addressing any remaining charges, payments, credits or revenues earned or owed pursuant to this Agreement.

ARTICLE 3 - RIGHTS AND OBLIGATIONS

3.1 In General.

3.1.1 During the Term, the Owner shall operate, maintain, offer and administer each RMR Generator in accordance with (a) the ISO Tariffs, (b) this Agreement, and (c) the ISO Procedures. If Owner identifies an apparent conflict between the rules it is expected to follow, it should promptly contact the ISO to resolve the concern.

3.1.2 Except as otherwise limited by this Agreement, including Section 11.1 hereof, Owner may designate one or more agents to perform its obligations under this Agreement. Actions taken by Owner's agents are considered actions by Owner. Owner shall require its agents to comply with the terms and conditions of this Agreement, and Owner shall remain primarily liable for the performance of its agents. Owner hereby ratifies and confirms all actions undertaken by its agents on behalf of Owner.

3.1.3 Owner is responsible for performing all billing obligations for each RMR Generator irrespective of whether or not it is the registered billing organization for each RMR Generator. Owner may designate or change the registered billing organization Owner relies on to fulfill these obligations in accordance with ISO Procedures.

3.2 Insurance.

3.2.1. At all times during the Term, Owner shall maintain insurance, written for amounts and by insurance companies acceptable to the ISO. Owner's insurance shall include (a) <u>All Risk Property Insurance</u> against "all risks" of physical loss or damage to the RMR Generator(s), (b) <u>Commercial General Liability Insurance</u> for personal injury, bodily injury, including death and property damage, and (c) <u>Umbrella Liability Insurance</u>.

3.2.2. Owner shall cause its insurance providers to issue endorsements (a) waiving all rights of subrogation in favor of ISO, its directors, officers, agents and employees, and (b) naming ISO as a cancellation notice recipient for all coverages.

3.2.3 Prior to the Start Date, Owner shall provide certificates of insurance for all insurance required in this Agreement. Owner shall also provide ISO with written notice of renewals, or any material changes in, or cancellation of, any required insurance policy or endorsement, no later than ten (10) days prior to the effective date thereof, including a revised certificate of insurance with evidence providing details sufficient to demonstrate Owner's continuous and uninterrupted coverage.

3.2.4 If Owner receives insurance proceeds from an insurance policy that Owner identified as an avoidable cost, and if Owner does not use those insurance proceeds to repair or improve the RMR Generator, then Owner shall make a reconciliation ("true-up") filing with the FERC and pay all such insurance proceeds to ISO that exceed the amount actually expended by the Owner to repair or improve the RMR Generator. The ISO shall distribute any insurance proceeds it receives pursuant to the requirements of this Section 3.2.4 consistent with Section 6.14.6.1 of Rate Schedule 14 to the ISO OATT.

3.3 Contracts, Permits and Orders.

3.3.1 Providing Contracts and Permits affecting each RMR Generator when requested by the ISO. Owner shall promptly provide a complete, up-to-date copy of any Contract, Permit or Order the ISO requests that: (a) addresses the ownership or control of an RMR Generator, (b) is relevant to determining the costs and revenues of an RMR Generator (including the cost of a repair, addition or modification), (c) addresses the operation of an RMR Generator, or (d) could impact the availability, production or sale of Energy, Unforced Capacity, or Ancillary Services from an RMR Generator. If a Contract, Permit or Order that the ISO requests is in the process of being renewed, extended, modified or re-negotiated, Owner shall so inform the ISO when it provides the requested Contract, Permit or Order to the ISO.

3.3.2 Consistent with Section 5.12.4(c) of the Services Tariff, Owner shall not enter into any Contracts during the Term of this Agreement that would impair or otherwise diminish the ability of an RMR Generator to perform the requirements of this Agreement or of the ISO's Tariffs or Procedures, nor will Owner cause or authorize other entities to enter into a Contract that would prevent an RMR Generator from operating consistent with the requirements of this Agreement or of the ISO's Tariffs or Procedures.

3.3.3 Consistent with Sections 5.12.7, 5.12.8, 23.4.5.8 and 23.6.1.1 of the Services Tariff and Sections 3.5 and 3.7 of this Agreement, during the Term of this Agreement Owner shall offer all of the Energy and Ancillary Services that each RMR Generator is capable of producing directly to the ISO Administered Markets, and shall offer all of each RMR Generator's Unforced Capacity in each ICAP Spot Market Auction, unless Owner is precluded from doing so by a Contract that was in effect before Owner executed this Agreement, but only to the extent and for the duration of the obligation under such Contract.

3.3.4 Owner shall submit a summary of the key terms and conditions of all Contracts (1) that were executed prior to the execution of this Agreement, and (2) that prevent all or any portion of the Energy or Ancillary Services that one or more RMR Generator(s) are capable of producing, or prevent all or any portion of one or more RMR Generator(s) Unforced Capacity, from being offered directly to the ISO Administered Markets to FERC, along with this Agreement as part of the Federal Power Act Section 205 filing that includes this Agreement and an APR or an Owner Developed Rate. Owner's submission must list all of the parties to each Contract and specifically identify all Affiliates with which it executed Contracts.

3.3.4.1 The following RMR Generators are subject to Contracts that predate the execution of this Agreement that affect the quantity of Energy, Ancillary Services or Unforced Capacity that will be offered directly to the ISO Administered Markets by each identified RMR Generator:

[OWNER TO ADD/PROVIDE ONE OR MORE TABLES THAT INCLUDE THE INFORMATION REQUIRED IN THE COLUMNS BELOW, SPECIFICALLY IDENTIFYING ANY AFFILIATES.]

RMR Generator Description of Contract Obligation Date Contract was Executed or Last Renewed End Date of Contract Other Parties to Contract

3.3.5 During the Term of this Agreement, Owner shall not enter into, modify, extend or renew any Contract to sell Energy, Ancillary Services or Unforced Capacity from an RMR Generator in a manner that is inconsistent with Owner's obligation to offer all of the Energy, Ancillary Services each RMR Generator is capable of producing, and to offer all of each RMR Generator's Unforced Capacity, directly to the ISO Administered Markets. The prohibition applies to the renewal of Contracts that are temporarily accommodated under Section 3.3.3 of this Agreement.

3.3.6 Transfer of ownership or control during the Term. [The/An] RMR Generator that is the subject of this Agreement may not be sold or leased, and control over [the/an] RMR Generator may not be transferred to a different entity during the Term of this Agreement unless: (a) the sale or lease receives any necessary regulatory approvals, including FERC approval under Section 203 of the FPA; (b) Owner and the entity that is purchasing or leasing the RMR

Generator fully comply with all ISO Procedures that address the transfer of Generators; (c) the purchaser or lessee satisfies the ISO's credit requirements, (d) the purchaser or lessee becomes an ISO Customer, and (e) the purchaser or lessee agrees, in writing, to assume all of Owner's obligations under this Agreement. If the transfer is temporary, or does not include the full capability of the RMR Generator owned or controlled by Owner, then Owner shall retain all of its obligations under this Agreement and the ISO Tariffs, and the purchaser or lessee shall become subject to Owner's obligations under this Agreement and the ISO Tariffs.

3.3.7 Obligation to inform subsequent purchaser of an RMR Generator of obligation to repay cost of Capital Expenditures and other above market revenues, less depreciation, prior to re-entering ISO Administered Markets. If Owner sells an RMR Generator or an interest in an RMR Generator, during or following the Term of this Agreement, then Owner shall inform any and all purchasers of any Capital Expenditures and other above market revenues that must be repaid in accordance with Rate Schedule 8 to the ISO's Services Tariff in order for the ISO to permit Energy, Ancillary Services or Unforced Capacity to be offered into, or to be scheduled in, the ISO Administered Markets from the (former) RMR Generator following the conclusion of this Agreement with regard to that Generator.

3.4 Testing.

3.4.1. RMR Generators shall timely comply with all ISO requirements that are necessary for an RMR Generator to provide a product or service it is required to provide under the ISO's Tariffs or this Agreement. When necessary, Owner shall arrange in advance with the ISO, in accordance with the ISO's Outage Scheduling Manual, to self-schedule an RMR Generator in order to perform a required test.

3.4.2. If, prior to or during the 365 Day Notice Period, an RMR Generator that is required to provide Voltage Support Services under Section 3.8 of this Agreement did not perform all testing that would be required to permit the RMR Generator to provide Voltage Support in the ISO Administered Markets during the Term of this Agreement, then the ISO shall require the RMR Generator to promptly test and shall permit the RMR Generator to provide Voltage Support in the ISO Administered Markets during the Term of this Agreement, consistent with Section 15.2 of the Services Tariff.

3.5 Energy Market Participation.

In accordance with Sections 23.6.1.1 through 23.6.1.5 of the Services Tariff, Owner shall offer for sale into the Day-Ahead and Real-Time Markets all of the Energy and Ancillary Services each RMR Generator is capable of providing by submitting ISO-committed flexible Bids (offers) at or below (equally or less restrictive than for physical parameters) the Reference Levels that are currently on-file with the ISO and approved for use by the ISO's MMA. RMR Generators that are not Installed Capacity Suppliers, or that have not sold all of their Unforced Capacity, must still be offered into the Energy and Ancillary Services markets consistent with this obligation. *See also* Services Tariff Sections 5.12.7 and 5.12.8.

Consistent with Section 23.6.1.1 of the Services Tariff, Owner shall offer Energy, Operating Reserves and Regulation at prices that are equal to or less than each RMR Generator's ISO-approved Reference Levels. Consistent with Sections 23.6.3.1 through 23.6.3.3 of its Services Tariff, the ISO will mitigate dollar-denominated Bids that exceed an RMR Generator's currently effective Reference Levels and will perform all other Tariff-authorized mitigation.

Consistent with Sections 23.3.1.4.6.1 and 23.6.2.5 of the Services Tariff, Owner shall timely submit fuel price updates and fuel type updates to the ISO so that they can be incorporated to develop accurate Reference Levels for each RMR Generator. Submission of an inaccurate fuel price update or fuel type update may require the ISO to assess a financial penalty in accordance with Section 23.4.3.3.3 of the Services Tariff, or may result in the ISO's referral of Owner's failure to submit accurate fuel cost information to its Market Monitoring Unit for possible referral to FERC's Office of Enforcement.

Owner is not required to submit hourly offers in the Real-Time Market for an RMR Generator that is not capable of being committed by the ISO's Real-Time Commitment ("RTC") if the RMR Generator was not committed Day-Ahead. If such an RMR Generator was committed Day-Ahead, Owner shall offer the RMR Generator into the Real-Time Market for the hours of its Day-Ahead schedule and for additional real-time hours consistent with the RMR Generator's operating capabilities. Owner is required to timely respond to a Supplemental Resource Evaluation ("SRE") or an Out-of-Merit ("OOM") commitment request issued by the ISO or by a Transmission Owner for an RMR Generator. *See* Services Tariff Sections 23.6.1.1.4 and 23.6.1.1.5.

If and to the extent an RMR Generator is not available, or is not fully available, Owner shall timely notify the ISO of the outage or derate in accordance with ISO Procedures and accurately reflect each RMR Generator's availability in its Bids. If an RMR Generator's Variable Costs change as a result of the derate, then Owner must contact the ISO's MMA Department to request changes to the RMR Generator's Reference Levels. *See* Services Tariff Sections 23.6.1.1.6.

3.6 RMR Generator Reference Levels.

3.6.1 In advance of the execution of this Agreement the ISO, Owner and the ISO's External Market Monitoring Unit performed a thorough review of each RMR Generator's Reference Levels consistent with Section 23.6.2.3 of the Services Tariff. Before it executed this Agreement, Owner reviewed and is aware of the Reference Levels that the ISO determined for each RMR Generator that is subject to this Agreement. During the Term of this Agreement changes to an RMR Generator's Reference Levels shall only be made consistent with Section 23.6.2 of the Services Tariff.

3.6.2 Changes to an RMR Generator's variable costs for purposes of providing Energy, Reserves and Regulation shall be addressed via modifications to the RMR Generator's Reference Levels using the adjustment process set forth in Section 23 of the Services Tariff. Owner is responsible for ensuring that an RMR Generator's fuel costs and Reference Levels remain accurate and up-to-date. If Owner fails to provide updated information to the ISO on a timely basis mitigation, including financial penalties, may be applied in accordance with Section 23 of the Services Tariff. Failure to timely update RMR Generator information could also violate FERC's regulations. *See* 18 CFR § 1c.2(a)(2).

3.7 Capacity Market Participation.

3.7.1 Each RMR Generator shall perform all obligations that an Installed Capacity Supplier of its resource type is required to perform under the Services Tariff and in accordance therewith.

3.7.2 Except as set forth in Section 3.3.3 above, during the Term of this Agreement Owner shall offer all of an RMR Generator's Unforced Capacity directly into each ICAP Spot Market Auction at $0.00/KwMonth.

[ALTERNATE LANGUAGE If the RMR Generator has a pre-existing bilateral contract that satisfies the requirements of Section 3.3.3 of this Agreement, add to Section 3.7.2: For the Obligation Procurement Period of months [ ] through [ ] (the "bilateral period"), the RMR Generator shall offer {insert UCAP MW obligation and offer price consistent with the bilateral agreement}, and (a) for any Unforced Capacity in excess of such amount and for any Obligation Procurement Period beyond the bilateral period, the Unforced Capacity shall be offered at a price of $0.00/KwMonth.]

3.8 Restoration Services and Voltage Support Services.

3.8.1 Each RMR Generator that provided Restoration Services (including black start service) at any time during the most recent previous twelve (12) months that it participated in the ISO Administered Markets must provide Restoration Services during the Term of this Agreement unless Owner demonstrates to the ISO that an RMR Generator is not presently capable of providing Restoration Services.

[State whether each RMR Generator will provide Restoration Services or identify the RMR Generators that will provide Restoration Services.]

3.8.2 Each RMR Generator that provided Voltage Support Service at any time during the most recent previous twelve (12) months that it participated in the ISO Administered Markets must provide Voltage Support Service during the Term of this Agreement unless Owner demonstrates to the ISO that an RMR Generator is not presently capable of providing the service.

[State whether each RMR Generator will provide Voltage Support or identify the RMR Generators that will provide Voltage Support.]

3.9 Self-Scheduling.

Owner is expected to offer each RMR Generator into the NYISO's Energy and Ancillary Service markets using the ISO-committed flexible bid mode at its Reference Levels for economic scheduling. However, Owner may request permission to self-schedule an RMR Generator for operational and maintenance considerations, including required testing or for fuel management purposes. The ISO may accept or reject the requested self-schedule in its sole discretion.

Variable Costs during ISO-approved self schedules will be the self-scheduled RMR Generator's Reference Levels.

ARTICLE 4 - COMPENSATION AND SETTLEMENT

4.1 In General.

In lieu of receiving market compensation Owner shall receive the APR that FERC accepted for filing, [*or* Owner shall receive an Owner Developed Rate that Owner submitted to FERC under Section 205 of the Federal Power Act and that FERC accepted for filing,] including any modifications required by FERC.

[ALTERNATIVE LANGUAGE IS INCLUDED SO THAT THE *PRO FORMA* AGREEMENT CAN BE USED FOR AN AVAILABILITY AND PERFORMANCE RATE OR FOR AN OWNER DEVELOPED RATE.]

There are four components to the APR: RMR Avoidable Costs, Variable Costs, the Availability Incentive and the Performance Incentive. Each component of the APR is explained below and a rate is set forth for each component below.

The ISO will pay the APR in accordance with Rate Schedule 8 to its Services Tariff. RMR Avoidable Costs and Variable Costs are calculated daily and paid on a weekly basis. The Performance Incentive (if any) is paid on a monthly basis. The Availability Incentive (if any) is paid on a seasonal basis. When necessary, Penalties are assessed on monthly invoices.

[OWNER DEVELOPED RATE ALTERNATIVE LANGUAGE. THERE ARE TWO COMPONENTS TO AN OWNER DEVELOPED RATE. THE FIRST COMPONENT IS VARIABLE COSTS, WHICH IS DETERMINED IN THE SAME MANNER AS VARIABLE COSTS ARE DETERMINED UNDER THE APR. THE SECOND COMPONENT IS THE FERC AUTHORIZED COMPONENT. THE FERC AUTHORIZED COMPONENT EFFECTIVELY REPLACES THE RMR AVOIDABLE COST COMPONENT OF THE APR

WITH THE COSTS THAT FERC AUTHORIZES FOR RECOVERY IN AN ORDER ISSUED PURSUANT TO SECTION 205 OF THE FEDERAL POWER ACT. BECAUSE AN OWNER DEVELOPED RATE IS EXPECTED TO EXCEED AN RMR GENERATORS RMR AVOIDABLE COSTS, NO AVAILABILITY OR PERFORMANCE INCENTIVES ARE AVAILABLE.

THE ISO WILL PAY AN OWNER DEVELOPED RATE IN ACCORDANCE WITH RATE SCHEDULE 8 TO ITS SERVICES TARIFF. FERC AUTHORIZED COSTS AND VARIABLE COSTS SHALL BE CALCULATED DAILY AND PAID ON A WEEKLY BASIS.]

In addition to setting forth the APR for each RMR Generator, this Agreement sets forth the obligation, or references the obligation in the ISO Tariffs, of RMR Generators that are subject to an APR to pay penalties prescribed by the ISO's Tariffs, each RMR Generator's obligation to repay the cost of Capital Expenditures and other above market revenues that were paid for under an APR or under an Owner Developed Rate, if and when the RMR Generator returns to the ISO-Administered Markets following the conclusion of this Agreement, the circumstances under which the ISO will continue to repay Capital Expenditures after an RMR Generator's obligation to provide service under this Agreement ends and the RMR Generator becomes Retired or enters a Mothball Outage, and the circumstances under which the ISO will pay wind-down costs to RMR Generators whose RMR Agreements are terminated early by the ISO due to the conclusion of the Reliability Need.

4.2 Recovery of Variable Costs.

Variable Costs are the incremental costs an available RMR Generator incurs to produce Energy or Ancillary Services. Variable Costs may change frequently; for example, when fuel prices change.

4.2.1. Cost of Providing Energy, Operating Reserves and Regulation

Consistent with Rate Schedule 8 to the Services Tariff, Owner shall be compensated on a weekly basis for providing Energy, Operating Reserves and Regulation based on the lesser of (a) the Bids that were submitted for an RMR Generator, or (b) the Reference Levels that are in place for an RMR Generator. The ISO will not compensate an RMR Generator for unscheduled overproduction that exceeds Compensable Overgeneration, as defined in the Services Tariff.

The ISO develops Reference Levels in accordance with Section 23 of its Services Tariff. The process the ISO uses to develop Reference Levels for each RMR Generator is described in Section 3.6 of this Agreement. The rules for changing a Reference Level that applies to an RMR Generator are set forth in Sections 23.3.1.4 and 23.6.2 of the Services Tariff.

4.2.2 Costs of Providing Voltage Support and Restoration Services

Voltage Support and Restoration Services (black start) are components of an RMR Generator's Variable Costs. Consistent with Rate Schedule 8 to the Services Tariff, Owner shall be compensated on a weekly basis for providing Voltage Support and/or Restoration Services. When determining the compensation an RMR Generator is eligible to receive for Voltage Support and/or Restoration Services the ISO shall treat each RMR Generator's cost of providing either service as being equal to the Tariff-authorized compensation that the ISO pays Generators for providing the service. RMR Generators that require additional or different compensation to provide Voltage Support or Restoration Services must file at FERC and obtain a different rate from FERC for providing these services.

4.3 Recovery of RMR Avoidable Costs.

RMR Avoidable Costs are the fixed costs that would be avoided if an RMR Generator were to exit the ISO Administered Markets in the manner described in the Generator Deactivation Notice (to enter a Mothball Outage or become Retired), including, but not limited to, mandatory capital expenditures, fixed operating and maintenance costs, and forgone opportunity costs, determined by the ISO in accordance with Rate Schedule 8 to the Services Tariff and Section 38.8 of Attachment FF to the OATT, but not including variable costs and any other cost that may be included in the RMR Generator's Reference Level.

The RMR Generator-specific rates set forth below identify when each RMR Generator's RMR Avoidable Costs will change, and the amount of each change, or the expected amount of the change for Capital Expenditures. The RMR Avoidable Cost component of RMR Generator's APR may change on specific dates, or when specified milestones are met, such as the entry into service of a Capital Expenditure. In addition to the expected changes in RMR Avoidable Costs specified below, an RMR Generator's RMR Avoidable Costs may change due to the need for unexpected extraordinary maintenance or repairs (Additional Expenses) during the Term of this Agreement.

4.3.1 Generator-Specific RMR Avoidable Costs.

The RMR Avoidable Costs each RMR Generator that is providing service under an APR is authorized to recover are set forth in the table(s) below. However, the Capital Expenditures identified in the table(s) below are only estimates. The ISO will instead use the actual costs incurred for each Capital Expenditure to determine the APR, in accordance with Section 38.17 of Attachment FF to the OATT, as explained in Section 4.3.2 of this Agreement.

[FOR EACH RMR GENERATOR, ADD A TABLE SPECIFYING (1) THE INITIAL RMR AVOIDABLE COST (IDENTIFYING THE SIGNIFICANT COST COMPONENTS), (2) DATES WHEN, AND/OR SPECIFIC MILESTONES WHEN AVOIDABLE COSTS WILL CHANGE, SPECIFYING HOW MUCH THE COSTS WILL CHANGE (OR ARE EXPECTED TO CHANGE, WHEN THE MILESTONE IS THE IN-SERVICE DATE OF A CAPITAL EXPENDITURE) ON EACH DATE/AT EACH MILESTONE AND BRIEFLY STATING THE REASON FOR EACH CHANGE.]

[ADDITIONAL COSTS THAT ARE FILED FOR FERC REVIEW/ACCEPTANCE SHOULD BE ADDED TO THESE TABLES.]

4.3.2 Capital Expenditures.

Capital Expenditures are purchases, non-operational leases of or modifications to real property and/or assets (including, but not limited to, land, buildings and equipment) that (a) are required for the continued operation of one or more RMR Generator(s) during the term of an RMR Agreement, (b) have a useful life greater than one year, and (c) are not otherwise included in the NYISO's calculation of RMR Avoidable Costs. Consistent with Section 38.17.1 of Attachment FF to the OATT, each Capital Expenditure must be distinctly identified in the tables set forth in Section 4.3.1 of this Agreement for RMR Generators that are receiving an APR, or in Section 4.6 of this Agreement for RMR Generators that are being compensated pursuant to an Owner Developed Rate. An expected cost and an expected in-service or completion date must be specified for each Capital Expenditure.

4.3.2.1 Submission of Capital Expenditures in initial FERC filing(s) by ISO and/or Owner. Consistent with Section 38.11 of Attachment FF to the OATT, Capital Expenditures of $10 million per year or less (or $25 million per year or less for nuclear-powered RMR Generators) (hereafter, the "10/25 *per annum* limit") may be included in an executed RMR agreement with an APR that is filed by the ISO for FERC's review. If Capital Expenditures that exceed the 10/25 *per annum* limit are necessary in any year of the Term of this Agreement, then Owner must file separately at FERC to recover any Capital Expenditure costs that exceed the 10/25 *per annum* limit. Owner Developed Rates must separately delineate Capital Expenditures so that the cost of Capital Expenditures can be recovered in accordance with the rules set forth in Section 38.17 of Attachment FF to the OATT.

4.3.2.2 ISO review of Capital Expenditures prior to commencing reimbursement. In accordance with Section 38.17.7 of the OATT the ISO is required to verify and validate Owner's actual expenditures. If the actual cost of a Capital Expenditure exceeds the estimate set forth in Section 4.3.1 of this Agreement by more than five (5) percent, or exceeds the Substantiated Additional Cost that was verified and validated by the ISO or the Proposed Additional Cost that was approved by FERC by more than five (5) percent, then the ISO must also review the reasonableness of the expenditure. To the extent the ISO is not able to verify and validate an expense, or if the ISO is not able to determine that the actual cost of an expenditure that exceeded the estimate presented to the ISO or to the Commission by more than five (5) percent was reasonable, then Owner must present its Capital Expenditure costs to FERC for recovery.

4.3.2.3 Reimbursement of Capital Expenditures. Consistent with Section 38.17.8.1 of the OATT, the ISO will not provide initial financing for Capital Expenditures. When an authorized or accepted Capital Expenditure enters service or is otherwise integrated into an RMR Generator, the ISO will commence reimbursing Owner for the actual, demonstrated cost of the Capital Expenditure following completion of the review process described below. Consistent with Sections 38.17.8.2 and 38.17.8.2.1 of the OATT, the ISO will reimburse Owner for each Capital

Expenditure on an accelerated basis, repaying the cost of Capital Expenditures by the End Date specified in Section 2.2.5 of this Agreement.

4.3.2.4 Development of Capital Expenditures on an expedited basis. In accordance with the requirements of Section 38.16.3 of the OATT (addressing Substantiated Additional Costs incurred during the Term of this Agreement) and Section 38.17.4 of the OATT (addressing development of a Capital Expenditure in advance of FERC action on Owner's or ISO's initial filing), when it is necessary to commence development of one or more Capital Expenditures before FERC has issued a ruling on Owner's authority to recover the cost of that or those Capital Expenditure(s), the ISO has authority to reimburse Owner for the actual costs that Owner demonstrated that it reasonably incurred constructing the Capital Expenditures up to limits of $10 million or less (or $25 million or less for nuclear-powered RMR Generators). Capital Expenditure costs that are authorized by the ISO pursuant to Section 38.16.3 of the OATT count toward the 10/25 *per annum* limit described in Section 4.3.2.1 above. Capital Expenditure costs that are authorized by the ISO pursuant to Section 38.17.4 of the OATT are not subject to the 10/25 *per annum* limit. Instead, the ISO may authorize additional expenditures of up to $10 million (or $25 million for nuclear-powered RMR Generators) each time an extraordinary event requires Owner to incur Substantiated Additional Costs. *See* Section 4.3.3 below.

4.3.2.5 ISO Approval to commence development of Capital Expenditures. In order to improve coordination between ISO and Owner, and to reduce the potential for Owner to incur costs developing a Capital Expenditure that is not needed, Owner shall obtain written approval from the ISO before it commences development of a Capital Expenditure that is scheduled to enter service more than one year after the Start Date specified in Section 2.1 of this Agreement.

4.3.2.6 Reimbursement of costs of Capital Expenditures that are not completed. If FERC issues an Order rejecting recovery of the cost of one or more Capital Expenditure(s), or if the ISO instructs Owner to cease work on a Capital Expenditure, then consistent with Sections 38.17.4, 38.17.5 and 38.17.7 of the OATT, Owner shall promptly cease its efforts and take reasonable steps to minimize any additional costs it incurs. If this Agreement is terminated early for an RMR Generator for reasons other than Owner's default or the RMR Generator's failure to satisfy one of the Minimum Operating Standards set forth in Section 7.3 of this Agreement, then the ISO shall reimburse the cost of Capital Expenditures that Owner was working to complete, subject to the requirements of Sections 38.17.5 and 38.17.7 of the OATT.

4.3.3 Additional Costs.

During the Term of this Agreement an RMR Generator that is providing service under an APR or an Owner Developed Rate may require additional Capital Expenditures or other RMR Avoidable Costs that could not have been reasonably anticipated, and are not included in or scheduled to be recovered as components of an RMR Generators RMR Avoidable Costs, or its Owner Developed Rate or its Variable Costs (hereafter, "Additional Costs").

Before it may permit recovery of Additional Costs, the ISO must first determine that (1) the Additional Costs could not have been reasonably anticipated by Owner and included in this RMR Agreement, and (2) the Additional Costs are necessary for the RMR Generator to continue to provide reliable service during the Term. The complete set of rules the ISO must follow when administering Proposed Additional Costs and Substantiated Additional Costs are set forth under Section 38.16 of the OATT.

For an RMR Generator that is providing service under an APR, the ISO is authorized by Section 38.16.3 of the OATT to allow up to $10 million (or up to $25 million for nuclear-powered RMR

Generators) per event in actual, incurred and verified additional Capital Expenditures to be recovered as Substantiated Additional Costs. As with any Capital Expenditure, the ISO must limit recovery of such Substantiated Additional Costs to the actual, demonstrated costs incurred and may not begin repaying the Substantiated Additional Costs until the necessary addition, maintenance or repair is completed or enters service. The ISO shall submit an informational filing to FERC informing FERC of any Substantiated Additional Costs it includes in an RMR Generator's APR.

Consistent with Section 38.16.5 of the OATT, Additional Costs (a) that involve RMR Avoidable Costs that are not Capital Expenditures, or (b) that exceed the ISO's authority to authorize, or (c) that the ISO is not able to verify or validate, or (d) that exceeded the cost estimate provided to the ISO or to FERC by more than 5 percent, and where the ISO is not able to determine that Owner made reasonable efforts to expend the least amount necessary, or (e) any Substantiated Additional Costs that an RMR Generator that is subject to an Owner Developed Rate must incur, are not eligible for recovery under this Agreement unless and until they are filed with and accepted by FERC.

4.3.4 Requirement to Repay Capital Expenditures and Other Above Market Revenues in Accordance with Services Tariff Rate Schedule 8 in Order for the ISO to Permit a Former RMR Generator to Produce Energy, Ancillary Services or Unforced Capacity, and Associated Credit Obligations.

If, pursuant to the terms of an RMR agreement, the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was incurred to permit an RMR Generator to provide service during the Term of the RMR Agreement, and the Generator is no longer the subject of this RMR Agreement or any other RMR Agreement, and is not an Interim Service Provider, then in order for the ISO to permit the Generator to be offered into or be scheduled in the ISO Administered

Markets, the cost of all Capital Expenditures that the ISO paid to enable the RMR Generator to provide service under an RMR Agreement, less depreciation, may be required to be repaid to the ISO, over time, in accordance with the rules set forth in Rate Schedule 8 to the Services Tariff. If, pursuant to the terms of an RMR Agreement, the ISO paid an RMR Generator a rate that provided revenues in excess of the revenues the Generator would have earned if it had been participating in the ISO Administered Markets at market-based rates (using the market participation, commitment, scheduling and dispatch that occurred in the ISO Administered Markets during the Term of the RMR Agreement to perform the comparison), and the Generator is no longer the subject of this RMR Agreement or any other RMR Agreement, and is not an Interim Service Provider, then in order for the ISO to permit the Generator to be offered into or be scheduled in the ISO Administered Markets, the difference between the revenues the RMR Generator received under an RMR Agreement (including money provided to reimburse Capital Expenditures) and the revenues the Generator would have earned if it had been participating in the ISO Administered Markets at market-based rates (taking into account applicable depreciation and the time value of money) may be required to be repaid to the ISO, over time, in accordance with the rules set forth in Rate Schedule 8 to the Services Tariff.

The ISO shall only allow a former RMR Generator to participate in the ISO Administered Markets if it is meeting all of its credit and repayment obligation(s), or has fully satisfied its repayment obligation(s). Otherwise, the ISO shall not permit Energy, Ancillary Services or Unforced Capacity to be offered into or scheduled in the ISO Administered Markets from the former RMR Generator.

The repayment obligation applies when a former RMR Generator is participating in the ISO Administered Markets while it is eligible to receive market-based rates, until the obligation has been fully repaid. The repayment obligation is not imposed while a former RMR Generator or former Interim Service Provider is in a Mothball Outage or ICAP Ineligible Forced Outage, or is Retired. If a former RMR Generator or former Interim Service Provider returns from being Retired, or from being in a Mothball Outage or ICAP Ineligible Forced Outage, to participate in the ISO Administered Markets while it is eligible to receive market-based rates, then the ISO will recalculate and reinstate an updated repayment obligation in accordance with Rate Schedule 8 to its Services Tariff.

A former RMR Generator that returns to participating in the ISO Administered Markets at market-based rates must re-complete the Generator Deactivation Process before it will be permitted to exit the ISO Administered Markets. Until the former RMR Generator enters a Mothball Outage or becomes Retired, it may continue to accrue repayment obligations in accordance with Rate Schedule 8 to the Services Tariff.

If Owner notices an RMR Generator's return to the ISO Administered Markets consistent with Section 2.2.9 of this Agreement, but it has not timely posted adequate credit, including any additional credit that may be required in accordance with Sections 26.4 and 26.5 of the Services Tariff, then the ISO shall not permit the Generator to submit offers or receive schedules and shall place the unit in Inactive Reserve for up to sixty (60) days. If Owner has not met its obligation to post adequate credit, including any additional credit that may be required in accordance with Sections 26.4 and 26.5 of the Services Tariff at the end of the sixty (60) days, then the ISO shall place the Generator in the state that it originally noticed (mothballed or retired). If the Generator returned from a mothball to provide RMR service, then the ISO shall return the Generator to a Mothball Outage. If the Generator returned from an ICAP Ineligible Forced Outage to provide RMR service, then the ISO shall place the Generator in a Mothballed Outage or Retired state, at

Owner's election.

4.4 Availability Incentive.

The baseline used to calculate the Availability Incentive each RMR Generator that is being compensated under an APR is eligible to recover is set forth in the table below. The incentive shall be calculated in accordance with Rate Schedule 8 to the Services Tariff. The ISO shall use each RMR Generator's actual availability and the baseline specified in the table below to determine the incentive (if any) it shall pay for availability over a six-month Capability Period.

[ADD TABLE SPECIFYING THE AVAILABILITY BASELINE FOR EACH RMR GENERATOR.]

4.5 Performance Incentive.

The baseline used to calculate the Performance Incentive each RMR Generator that is being compensated under an APR is eligible to recover is set forth in the table below. The incentive shall be calculated in accordance with Rate Schedule 8 to the Services Tariff. The ISO shall use each RMR Generator's actual performance and the baseline specified in the table below to determine the incentive (if any) it shall pay for performance each month.

[ADD TABLE SPECIFYING THE PERFORMANCE BASELINE FOR EACH RMR GENERATOR.]

4.6 Owner Developed Rate.

Owner Developed Rates may not exceed an RMR Generator's full cost of service. Owner must separately file its Owner Developed Rate for FERC review and acceptance.

If Owner has agreed to follow, and the ISO has separately filed the *pro forma* terms and conditions of service, then the ISO shall incorporate the accepted Owner Developed Rate, including any modifications instructed by FERC, into this Agreement after FERC issues an Order accepting the Owner Developed Rate.

The costs each RMR Generator is authorized to recover under an Owner Developed Rate are explained below (using the explanation(s) provided by Owner) and set forth in the table(s) below. The table(s) below must distinctly identify and set forth the estimated cost of each Capital Expenditure, and the date on which each Capital Expenditure is expected to enter service.

The rules for recovering the cost of Capital Expenditures under an Owner Developed Rate, including the rules that apply if an RMR Generator continues to, or returns to participate in the ISO-Administered Markets following the conclusion of this Agreement, are the same rules that apply to Generators that are compensated pursuant to an APR. *See* Section 4.3.2 of this Agreement.

RMR Generators that are compensated pursuant to an Owner Developed Rate are not eligible to receive an Availability Incentive or a Performance Incentive. RMR Generators that are compensated pursuant to an Owner Developed Rate must obtain FERC approval to recover Substantiated Additional Costs.

[OWNER TO ADD EXPLANATION OF PROPOSED OWNER-DEVELOPED RATE THAT IS CONSISTENT WITH THE REQUIREMENTS OF THIS AGREEMENT AND THE ISO'S TARIFFS, INCLUDING BUT NOT LIMITED TO THE RULES FOR IMPLEMENTING RMR RATES THAT ARE SET FORTH IN RATE SCHEDULE 8 TO THE SERVICES TARIFF AND THE RULES IN SECTION 38.17 OF THE OATT ADDRESSING THE RECOVERY OF CAPITAL EXPENDITURES. OWNER SHALL INCLUDE ONE OR MORE TABLES THAT SPECIFY THE RATE THAT WILL APPLY TO EACH RMR GENERATOR.]

4.7 Penalties.

Each RMR Generator that is providing service under an APR is subject to all of the potential penalties, sanctions, deficiency charges and any similar charges, except for under-generation penalties (collectively, for purposes of this paragraph, "penalties"), that may apply to Generators under the ISO Tariffs. *Provided*, *however*, that the total amount of penalties that can be assessed to an RMR Generator that is providing service under an APR shall be capped at the total, cumulative amount of Performance Incentive payments and Availability Incentive payments computed by the ISO to be due to that RMR Generator through the end of the month in which one or more penalties are charged.

RMR Generators that are compensated pursuant to an Owner Developed Rate are subject to all of the potential penalties, sanctions, deficiency charges and any similar charges, including under-generation penalties, that may be assessed to Generators under the ISO Tariffs, without limitation.

4.8 Wind-Down Costs.

If the ISO terminates this Agreement early due to the conclusion of the Reliability Need prior to the end of the Term of this Agreement (*see* Section 2.2.1 above), then the ISO shall pay any demonstrated, actual additional wind-down costs that Owner must incur to place an RMR Generator in a Mothballed Outage or Retired state at the conclusion of this Agreement because the ISO terminated the Agreement early, in accordance with Sections 38.17.5 and 38.17.7 of the OATT. The ISO shall not pay such costs if a (former) RMR Generator continues to participate in the ISO Administered Markets following the conclusion of this Agreement. If Owner does not agree with the ISO's determination of the actual additional costs it had to incur due to the ISO's early termination of this Agreement, then Owner may submit a filing to FERC under Section 205 of the FPA seeking recovery of additional costs it will incur due to the ISO's early termination of this Agreement. The ISO may pay wind-down fees after the termination of this Agreement pursuant to Services Tariff Rate Schedule 8 and recover them from the (former) RMR LSEs under OATT Rate Schedule 14.

ARTICLE 5 - MARKET MONITORING

5.1 Market Power Mitigation.

Although this Agreement requires the submission of Energy and Ancillary Service Bids for the RMR Generator(s) at fuel-adjusted Reference Levels, nothing herein shall preclude the ISO from applying any provision of its Market Power Mitigation Measures (Section 23 of the Services Tariff) to Owner, any Affiliate of Owner, the RMR Generator, or any other resources of Owner or of any Affiliate of Owner, including (a) the mitigation of Bids submitted for RMR Generators that are covered by this Agreement, and (b) conducting audits and reviews and imposing penalties pursuant to Sections 23.2.4.1.1, 23.3.1.1 and 23.4.5.6 of the Services Tariff.

The ISO's assessment of financial penalties, sanctions, deficiency charges and the like, for failure to comply with the Market Power Mitigation Measures or other provisions of the ISO's Tariffs, are addressed in Section 4.7 of this Agreement.

ARTICLE 6 - REPORTING AND AUDIT

6.1 Information Access.

Owner shall maintain and shall promptly make available to ISO upon request, any books, records, documents or information in its possession or control that are necessary for ISO to: (a) audit, determine, substantiate or verify any of the costs that Owner has incurred, or that Owner is permitted to recover under this Agreement and the ISO Tariffs, and (b) carry out its responsibilities under this Agreement and its Tariffs.

6.2 Books and Records; Audit Rights.

6.2.1 During the Term and for six (6) years thereafter (or for a longer term, if necessary to permit the ISO to repay the cost of a Capital Expenditure and other above market revenues that a former RMR Generator is required to repay under Rate Schedule 8 to the ISO's Services Tariff), Owner shall keep detailed and accurate books and records, together with any supporting documents, pertaining to (a) the performance of its obligations under this Agreement, (b) the operation of each RMR Generator, including its availability, performance and Variable Costs, and (c) all components that went into developing the APR or the Owner-Developed Rate, including all adjustments thereto, Capital Expenditures and Substantiated Additional Costs.

6.2.2 Subject to the confidentiality requirements in Section 11.10 of this Agreement, Owner shall provide or make such books and records (including copies and extracts) available to ISO for inspection and audit at any time, upon reasonable notice.

ARTICLE 7 - RESOURCE OPERATION AND MAINTENANCE

7.1 Planned Outages.

7.1.1 First year of RMR operation. The ISO and Owner have developed a planned outage schedule covering the first year of each RMR Generator's operation under this Agreement. The agreed upon schedule is included as Confidential Schedule 2 to this Agreement. The ISO will accommodate limited, reasonable changes to the agreed planned outage schedule requested by Owner, so long as such changes will not interfere with the ability of the RMR Generator to meet the Reliability Need. Planned outage schedules for subsequent years will be developed in accordance with this Article 7.

7.1.2 Owner shall be entitled to take the RMR Generator out of operation or reduce the net capability of the RMR Generator during ISO-approved Planned Outages, in accordance with the schedule for Planned Outages as established and implemented pursuant to the ISO's Outage Scheduling Manual. The ISO may amend or cancel ISO-approved Planned Outages if necessary to protect system reliability. Consistent with Section 4.4 of this Agreement and Section 15.8.3 of Rate Schedule 8 to the Services Tariff, Planned Outages may reduce the Availability Incentive (if any) paid to an RMR Generator. Performance Incentives can be earned when an RMR Generator is scheduled in real-time.

7.1.3 The ISO and the MMU shall monitor deviations from each RMR Generator's historic planned outage schedules. Owner shall promptly respond to ISO and MMU requests for explanations, information and data regarding or supporting outage schedules.

7.2 Forced Outages.

7.2.1 Generally. Owner shall be entitled to take the RMR Generator out of operation or reduce the net capability of the RMR Generator upon the occurrence of a Forced Outage. Consistent with Section 4.4 of this Agreement and Section 15.8.3 of Rate Schedule 8 to the Services Tariff, Forced Outages may reduce the Availability Incentive (if any) paid to an RMR Generator. Performance Incentives can be earned when an RMR Generator is scheduled in real-time.

7.2.2 The ISO and the MMU shall monitor deviations from each RMR Generator's historic forced outage rate. Owner shall promptly respond to ISO and MMU requests for explanations, information and data regarding or supporting forced outages, including the time required to return from a Forced Outage.

7.2.3 Notice of Forced Outage. In the event of a Forced Outage that is anticipated to last for more than ten (10) days, in addition to any other notification obligation arising under the ISO Tariffs and Procedures, Owner shall promptly notify the ISO, in accordance with the Outage Scheduling Manual, in writing that a Forced Outage has occurred and estimate its duration (a "Notice of Forced Outage").

7.2.4 Notice of Proposed Additional Costs. Owner shall also submit a Notice of Proposed Additional Costs to the ISO if it expects that costs that exceed the lesser of (a) $250,000, or (b) five (5) percent of annual RMR Avoidable Costs (excluding Capital Expenditures), will need to be incurred to return the RMR Generator to service, and if it satisfies the other requirements of Section 38.16.1 of the OATT. If the cost of returning an RMR Generator to service does not exceed the lesser of (a) $250,000, or (b) five (5) percent of annual RMR Avoidable Costs, excluding Capital Expenditures, then Owner shall promptly return the RMR Generator to service without additional recompense, consistent with Section 38.16.1.1 of the OATT.

7.2.5 Notice of Shut-down. As soon as reasonably practicable after the date of a Notice of Forced Outage but in no event greater than thirty (30) days from the start of such Forced Outage, either Party may, after assessing the nature, expected duration, and expected incurrence of Proposed Additional Costs or Substantiated Additional Costs, notify the other in writing of its determination that the RMR Generator shall, subject to the provisions of Section 7.2.9 of this Agreement, be Shut-down (a "Notice of Shut-down") and if such notice applies to the entire RMR Generator that this Agreement should be terminated with regard to the affected RMR Generator.

7.2.6 In the event that an RMR Generator is Shut-down, Owner shall only be entitled to receive the APR or Owner Developed Rate through the Shut-down Date for that RMR Generator. However, the ISO may continue to repay the cost of Capital Expenditures incurred at the shut-down Generator in accordance with Section 4.3.2 of this Agreement and Section 38.17.5 of the OATT. With respect to a Shut-down applying only to some of the units that together comprise an RMR Generator, this Agreement shall remain in full force and effect with respect to the remaining unit(s).

7.2.7 Restoration following Owner Notice of Shut-down. With respect to a Notice of Shut-down made by Owner, if within thirty (30) days of receipt of Owner's Notice of Shut-down ISO provides written notice to Owner that it is willing to allow or support (as appropriate) recovery of any Substantiated Additional Costs that may be required to recover from such Forced Outage in accordance with Section 4.3.3 of this Agreement and Sections 38.16.2.1, 38.16.3, 38.16.5 and 38.17.2 of the OATT, Owner agrees that it will, with reasonable dispatch, take the action requested by ISO, *i.e.*, not Shut-down the RMR Generator, take all actions necessary to obtain any required FERC approval, and incur the costs necessary to return the RMR Generator to service from such Forced Outage, subject to reimbursement by the ISO in accordance with Section 4.3.3 of this Agreement and Sections 38.17.7 and 38.17.8 of the OATT.

7.2.8 Owner is obligated to use its best efforts to minimize any costs it must incur, and the Substantiated Additional Costs that the ISO reimburses Owner for will be subject to offset by any proceeds from any and all third-party sources, including insurance proceeds, paid to Owner to return the RMR Generator from the Forced Outage. If Owner receives insurance proceeds or other compensation after the ISO pays Owner's Substantiated Additional Costs, then Owner shall make a subsequent reconciliation ("true-up") filing with the FERC and refund any payments to ISO for Substantiated Additional Costs that exceed the amount actually expended by the Owner, after offsets. The ISO shall distribute any insurance proceeds or other compensation it receives pursuant to the requirements of this Section 7.2.8 consistent with Section 6.14.6.1 of Rate Schedule 14 to the OATT.

7.2.9 Shut-down Date. With respect to a Notice of Shut-down issued by ISO pursuant to Section 7.2.5, the "Shut-down Date" shall be the end of hour beginning 23 at the end of the month that includes the date that is the later of (a) ten (10) days after the receipt of such Notice of Shut-down by the Owner, or (b) sixty (60) days after the Forced Outage began. With respect to a Notice of Shut-down issued by Owner pursuant to Section 7.2.5, the Shut-down Date shall be the end of the month that includes the date that is the later of (x) thirty (30) days after the receipt of such Notice of Shutdown by ISO, or (y) sixty (60) days after the Forced Outage began, unless ISO has agreed to pay Owner's Substantiated Additional Costs in accordance with Section 7.2.7, in which case no Shut-down Date will have occurred with respect to such Notice of Shut-down.

As of the Shut-down Date, Owner may place the former RMR Generator in an ICAP Ineligible Forced Outage or reclassify the former RMR Generator's status to Retired.

7.3 Minimum Operating Standards.

The requirements set forth below specify the Minimum Availability, Minimum Performance and Operation to Address the Reliability Need Standards that each RMR Generator is expected to achieve in order to continue to be entitled to compensation under this Agreement, including recovery of the cost of Capital Expenditures and Additional Costs.

7.3.1 Minimum Availability Standards.

The ISO developed the Minimum Availability Standard(s) set forth below for each RMR Generator based on (a) the RMR Generator's historical performance, (b) any deferred maintenance, repair or capital expenditure costs that are included in RMR Avoidable Costs for an RMR Generator that can reasonably be expected to improve the RMR Generator's availability, and (c) other factors that are specific to the particular RMR Generator for which the Minimum Availability Standard was developed.

[ADD TABLE WITH THE MINIMUM AVAILABILITY STANDARD THAT THE ISO WILL APPLY TO EACH RMR GENERATOR THAT IS SUBJECT TO THE RMR AGREEMENT.]

7.3.2 Minimum Performance Standards.

The ISO developed the Minimum Performance Standard(s) set forth below for each RMR Generator based on (a) the RMR Generator's historical performance when scheduled to operate in real-time by the ISO, (b) any deferred maintenance, repair or capital expenditure costs that are included in RMR Avoidable Costs for an RMR Generator that can reasonably be expected to improve the RMR Generator's performance, and (c) other factors that are specific to the particular RMR Generator for which the Minimum Performance Standard was developed.

[ADD TABLE WITH THE MINIMUM PERFORMANCE STANDARD THAT THE ISO WILL APPLY TO EACH RMR GENERATOR THAT IS SUBJECT TO THE RMR AGREEMENT.]

7.3.3 Operation to Address the Reliability Need Standard.

If an RMR Generator fails to operate as requested when it is called upon by the ISO or by a Transmission Owner to address the Reliability Need that is described in Schedule 1 to this Agreement on three or more occasions over the Term of this Agreement, then the ISO may terminate this Agreement as to that RMR Generator.

ARTICLE 8 - FORCE MAJEURE EVENTS

8.1 Definition of Force Majeure Event.

"Force Majeure Event" shall mean a cause or occurrence preventing a Party from performing its obligations under this Agreement, which cause or occurrence is beyond the reasonable control of the Party affected, not reasonably foreseeable by such Party, not due to an act or omission of the Party affected, and which could not have been avoided by the exercise of reasonable diligence. A Force Majeure Event shall not include any economic hardship, the cost of or inability to procure fuel, or changes in market conditions that affect the price of energy or transmission.

8.2 Notice of Force Majeure Event.

If any Party is unable to perform its obligations under this Agreement due to a Force Majeure Event, the Party that is unable to perform shall promptly notify the other Party of this occurrence, the effect on its performance, the nature of any corrective action needed, its efforts to remedy its inability to perform, and when it estimates it will be able to resume performance. Thereafter the nonperforming Party shall update that information as reasonably necessary.

8.3 Effect of Force Majeure Event.

If a Force Majeure event results in a Forced Outage then Sections 7.2.1. through 7.2.9 of this Agreement shall apply. If a Force Majeure Event prevents a Party from complying with any one or more obligations under this Agreement, that inability to comply will not constitute a default if (a) that Party uses reasonable efforts to remediate the Force Majeure Event in accordance with Section 8.4, and (b) that Party complies with its notice obligations under Section 8.2.

8.4 Remedial Efforts.

If a Force Majeure Event occurs, the Party unable to perform by reason of that Force Majeure Event shall use reasonable efforts to resume its performance under this Agreement as soon as practicable, to mitigate the consequences of the Force Majeure Event, and to limit damages to the other Party; provided that no Party shall be required to settle any strike, walkout, lockout, or other labor dispute on terms which, in the Party's sole discretion, are contrary to its interests.

ARTICLE 9 - DISPUTE RESOLUTION AND REMEDIES

9.1 Dispute Resolution.

The Parties shall make reasonable efforts to settle any dispute arising out of or in connection with this Agreement. The process and timeframe for Owner to challenge invoices related to this Agreement is set forth in Section 7.4 of the Services Tariff. For all other disputes, the Parties shall designate officers or other senior representatives to confer and attempt to resolve a dispute on an informal basis within two (2) calendar days after receiving written notice of a dispute. If the Parties are unable to resolve the dispute by mutual agreement within ten (10) business days after receiving written notice of a dispute (such period may be extended by the mutual, written agreement of the Parties), then the dispute may be referred to FERC's Dispute Resolution Division by either Party.

9.2 Liability and Indemnification.

9.2.1 Liability of ISO. The ISO shall not be liable, whether based on contract, indemnification, warranty, equity, tort, strict liability or otherwise, to Owner or any third party or other person for any damages whatsoever arising or resulting from any actions or omissions by ISO in performing its obligations under this Agreement, except to the extent ISO is found liable for gross negligence or willful misconduct, in which case ISO will only be liable for direct damages.

9.2.2 Liability of Owner. Except as set forth in Section 4.7 (Penalties) of this Agreement, or as set forth in the ISO's Tariffs, in no event shall Owner be liable to ISO for any incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance of this Agreement except to the extent Owner is found liable for gross negligence or willful misconduct.

9.2.3 Indemnification. Owner shall indemnify, defend and save harmless the ISO and its directors, officers, employees and agents from any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by ISO under this Agreement or the actions or omissions of Owner in connection with this Agreement, except in cases of gross negligence or willful misconduct by the ISO or its directors, officers, employees or agents.

9.3 Specific Performance.

The Parties agree that irreparable damage would occur in the event that any of the provisions of this Agreement were not performed in accordance with their specific terms and that monetary damages alone, even if available, would not be an adequate remedy. It is accordingly agreed that the Parties shall be entitled to specific performance of the terms hereof, this being in addition to any other remedy to which they are entitled at Law or in equity.

9.4 Termination for Default.

If any Party shall fail to perform any material obligation imposed on it by this Agreement and that obligation has not been suspended pursuant to this Agreement, the other Party, at its option, may terminate this Agreement by giving the Party in default written notice setting out specifically the circumstances constituting the default and declaring its intention to terminate this Agreement. If the Party receiving the notice does not within ten (10) days after receiving the notice, remedy the default, the Party not in default shall be entitled by a further written notice to terminate this Agreement. The Party not in default shall have a duty to mitigate damages. Termination of this

Agreement pursuant to this Section 9.4 shall be without prejudice to the right of any Party to collect any amounts due to it under this Agreement.

9.5 Waiver.

The failure to exercise any remedy or to enforce any right provided in this Agreement or applicable Law shall not constitute a waiver of such remedy or right or of any other remedy or right. A Party shall be considered to have waived any remedies or rights only if the waiver is in writing. A waiver given by a Party will be applicable only to the specific instance for which it is given.

9.6 No Third-Party Beneficiaries.

Except as is specifically set forth in this Agreement, nothing in this Agreement, whether express or implied, confers any rights or remedies under, or by reason of, this Agreement on any persons other than the Parties and their respective successors and permitted assigns, nor is anything in this Agreement intended to relieve or discharge the obligations or liability of any third party, nor give any third person any rights of subrogation or action against any Party.

9.7 Remedies Cumulative.

The rights and remedies of the Parties are cumulative and not alternative.

ARTICLE 10 - COVENANTS OF THE PARTIES

10.1 ISO represents and warrants to Owner as follows:

10.1.1 The ISO is a validly existing corporation with full authority to enter into this Agreement.

10.1.2 The ISO has full power and authority to enter into this Agreement and perform all of the ISO's obligations, representations, warranties, and covenants under this Agreement.

10.1.3 The ISO has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of the ISO.

10.1.4 The ISO has all regulatory authorizations necessary for it to perform its obligations under this Agreement.

10.1.5 The execution, delivery, and performance of this Agreement are within ISO's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

10.2 Owner represents and warrants to ISO as follows:

10.2.1 Owner is duly organized, validly existing and in good standing under the Laws of the jurisdiction under which it is organized, and is authorized to do business in New York.

10.2.2 Owner has full power and authority to enter into this Agreement and to perform (directly, or through its agents and assigns that are authorized pursuant to Section 11.1 of this Agreement) all of Owner's duties, obligations, representations, warranties, and covenants under this Agreement, including the power to offer Energy, Unforced Capacity, and Ancillary Services from each RMR Generator, and to operate, maintain, and administer each RMR Generator, all in accordance with (a) the ISO Tariffs, (b) this Agreement, and (c) the ISO Procedures.

10.2.3 Owner has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of Owner.

10.2.4 Owner possesses, or has applied for, all regulatory authorizations, necessary for it to perform its obligations under this Agreement.

10.2.5 The execution, delivery, and performance of this Agreement are within the Owner's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

10.2.6 Owner is not in violation of any Laws, ordinances, or governmental rules, regulations or Order of any Governmental Authority or arbitration board materially affecting the performance of this Agreement.

10.2.7 Owner is not bankrupt, does not contemplate becoming bankrupt nor, to its knowledge, will become bankrupt.

10.2.8 Owner is an ISO Customer [and an ISO Transmission Customer,] and acknowledges that it has reviewed and is familiar with the ISO Tariffs.

10.2.9 Owner acknowledges and affirms that the foregoing representations, warranties, and covenants are continuing in nature throughout the Term of this Agreement. For purposes of this Section, "materially affecting performance" means resulting in a materially adverse effect on Owner's performance of its obligations under this Agreement.

ARTICLE 11 - MISCELLANEOUS PROVISIONS

11.1 Assignment.

A Party shall not assign its rights or delegate its duties under this Agreement without the prior written consent of the other Party. Any such assignment or delegation made without such written consent shall be null and void. Upon any assignment made in compliance with this Section 11.1, this Agreement shall inure to and be binding upon the successors and assigns for the assigning Party.

11.2 Notices.

Except as otherwise expressly provided in this Agreement or required by Law, all notices, consents, requests, demands, approvals, authorizations and other communications provided for in this Agreement shall be in writing and shall be sent by personal delivery, certified mail, return receipt requested, facsimile transmission, electronic mail, or by recognized overnight courier service, to the intended Party at such Party's address set forth below. All such notices shall be deemed to have been duly given and to have become effective: (a) upon receipt if delivered in person, by facsimile, or by electronic mail; (b) two days after having been delivered to an air courier for overnight delivery; or (c) seven days after having been deposited in the United States mail as certified or registered mail, return receipt requested, all fees pre-paid, addressed to the applicable addresses set forth below. Each Party's address for notices shall be as follows (subject to change by notice in accordance with the provisions of this Section 11.2):

If to Owner:

[OFFICER NAME]

[OFFICER TITLE]

[STREET ADDRESS]

[CITY, STATE, ZIP]

[PHONE NUMBER]

[FAX NUMBER]

[E-MAIL ADDRESS]

If to ISO:

[OFFICER NAME]

[OFFICER TITLE]

10 Krey Boulevard

Rensselaer, New York 12144

[PHONE NUMBER]

[FAX NUMBER]

[E-MAIL ADDRESS]

With a copy to:

[INSERT LEGAL CONTACT]

The persons designated to receive Notice for a Party may be modified by providing Notice to the other Party of a change.

11.3 Parties' Representatives.

Owner and the ISO shall ensure that throughout the Term of this Agreement, duly appointed representatives are available for communications between the Parties. The representatives shall have full authority to deal with all day-to-day matters arising under this Agreement. Acts and omissions of representatives shall be deemed to be acts and omissions of the Party. Owner and ISO shall be entitled to assume that the representatives of the other Party are at all times acting within the limits of the authority given by the representatives' Party. Owner's representatives shall be identified on Exhibit A. The ISO's representatives shall be identified on Exhibit B. The Parties may at any time replace their representatives by sending the other Party a revision to its respective Exhibit.

11.4 Effect of Invalidation, Modification, or Condition.

Each covenant, condition, restriction, and other term of this Agreement is intended to be, and shall be construed as, independent and severable from each other covenant, condition, restriction, and other term. If any covenant, condition, restriction, or other term of this Agreement is held to be invalid or otherwise modified or conditioned by any Governmental Authority, the invalidity, modification, or condition of such covenant, condition, restriction, or other term shall not affect the validity of the remaining covenants, conditions, restrictions, or other terms hereof. If an invalidity, modification, or condition has a material impact on the rights and obligations of the

Parties, the Parties shall make a good faith effort to renegotiate and restore the benefits and burdens of this Agreement as they existed prior to the determination of the invalidity, modification, or condition.

11.5 Amendments.

Amendments or modifications of this Agreement may be made only by a written instrument duly executed by all Parties, or through a filing with FERC under Section 206 of the FPA. Mutually agreed to amendments or modifications shall become effective only after the Parties have received any authorizations required from FERC. The Parties agree to negotiate in good faith any amendments to this Agreement that are needed to reflect the intent of the Parties as expressed herein and to reflect any changes to the design of the ISO Administered Markets that are approved by the Commission from time to time. Alternatively, either Party shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 of the FPA and FERC's rules and regulations thereunder. The Parties agree that any such filing shall not be subject to the "public interest" application of the just and reasonable standard of review as clarified in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish County, Washington*, 554 U.S. 527 (2008) and refined in *NRG Power Mktg. v. Maine Pub. Utils. Comm'n*, 130 S. Ct. 693, 700 (2010). Each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered.

Nothing in this Section 11.5 shall be interpreted to require the ISO's concurrence before Owner may submit a filing under Section 205 of the FPA to propose an initial rate to FERC, or to recover costs that Owner (or an RMR Generator) is specifically authorized to submit or to seek to recover under Sections 38.1 to 38.17 of the OATT. Nothing in this Section 11.5 shall be interpreted to require Owner's concurrence before the ISO may submit a filing under Section 205 of the FPA to comply with the requirements of its Tariffs, or to submit a filing in accordance with Sections 2.2.8 or 4.6 of this Agreement.

11.6 Governing Law.

This Agreement shall be governed by and construed under the Laws of the State of New York without regard to conflicts of laws principles.

11.7 Entire Agreement.

This Agreement, as well as any appendices, schedules, exhibits or other attachments hereto, which are incorporated by reference herein and made a part hereof, constitutes the entire agreement between the Parties with respect to the subject matter hereof and supersedes all prior negotiations, undertakings, agreements and understandings.

11.8 Independent Contractors.

Owner and ISO acknowledge that as between Owner and ISO there is an independent contractor relationship, and that nothing in this Agreement shall create any association, joint venture, partnership, or principal/agent relationship between the Parties. Neither Owner nor ISO shall have any right, power, or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other Party in any way.

11.9 Counterparts.

This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same agreement.

11.10 Confidentiality.

Confidential Information or Protected Information identified as such by a Party and provided to the other Party pursuant to this Agreement shall be governed by the confidentiality provisions in the Code of Conduct, contained in Attachment F of the OATT, and the confidentiality provisions in the Market Monitoring Plan, contained in Attachment O of the Services Tariff, subject to the following:

11.10.1 Nothing herein or therein shall limit the right of a Party to file a copy of this Agreement with the Commission, without redaction, to the extent that Law, regulation, or agency Order makes such filing necessary or appropriate.

11.10.2 Notwithstanding anything in this Agreement to the contrary, if during the course of an investigation or otherwise, the Commission requests that a Party (the "responding Party") provide to it information that has been designated by the other Party to be treated as confidential under this Agreement, the responding Party shall provide the requested information to the FERC or its staff within the time provided for in the request for information. The responding Party shall, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure.

11.11 Further Assurances.

The Parties agree to do such further acts and things and to execute and deliver such additional agreements and instruments as may be reasonably necessary to carry out the provisions and purposes of this Agreement.

11.12 Submittal to the Commission.

The Parties acknowledge and agree [ALT. 1, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS AND OWNER ACCEPTS THE APR that the ISO shall submit the executed Agreement to the FERC, including the proposed APR, in a FPA Section 205 filing on the Parties' behalf;] [ALT. 2, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS, OWNER ACCEPTS THE APR, BUT THERE ARE CAPITAL EXPENDITURES THAT REQUIRE FERC APPROVAL (i) that the ISO shall submit this Agreement to the FERC, including the agreed-to components of the proposed APR, in a FPA Section 205 filing on the Parties' behalf, and that Owner will submit a separate FPA Section 205 filing that is consistent with the terms and conditions of service proposed in this Agreement, and that tracks the format of this Agreement, proposing the inclusion of the cost of certain Capital Expenditures in the APR;]

[ALT. 3, IF OWNER AND ISO AGREE ON TERMS AND CONDITIONS BUT OWNER REJECTS THE APR AND SUBMITS AN OWNER DEVELOPED RATE that the ISO shall submit the Parties' agreed-upon terms and conditions of service to the FERC, in a FPA Section 205 filing on the Parties' behalf, and that Owner will submit a separate FPA Section 205 filing proposing an Owner Developed Rate that is consistent with the terms and conditions of service proposed in this Agreement and that tracks the format of this Agreement.]

Following the ISO's submission to FERC of an executed or unexecuted Agreement, the Parties will implement and comply with this Agreement in accordance with Section 2.1.2 hereof.

IN WITNESS WHEREOF, this Agreement has been executed as of the date first above written.

[OWNER NAME]

By: ______________________________

Name:

Title:

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

By: ______________________________

Name:

Title:

EXHIBIT A - OWNER'S REPRESENTATIVES

[OWNER TO PROVIDE]

EXHIBIT B - ISO'S REPRESENTATIVES

[NAME OF NYISO OFFICER WITH AUTHORITY TO EXECUTE AN RMR AGREEMENT]

[OFFICER TITLE] New York Independent System Operator, Inc.

10 Krey Boulevard

Rensselaer, New York 12144

New York Independent System Operator, Inc.
Market Administration and Control Area Services Tariff

1 Introduction and Purpose

The New York Independent System Operator Market Administration and Control Area Services Tariff (the "ISO Services Tariff" or the "Tariff") sets forth the provisions applicable to the services provided by the ISO related to its administration of competitive markets for the sale and purchase of Energy and Capacity and for the payments to Suppliers who provide Ancillary Services to the ISO in the ISO Administered Markets ("Market Services") and the ISO's provision of Control Area Services ("Control Area Services"), including services related to ensuring the reliable operation of the NYS Power System. The Tariff addresses the Market Services and the Control Area Services provided by the New York ISO, and the terms and conditions under which those services are provided. Market Services are addressed in Article 4 of the Tariff, and Control Area Services are addressed in Article 5 of the Tariff. Transmission Service is provided under the ISO's Open Access Transmission Tariff (the "ISO OATT"). All references to Sections, Schedules and Attachments, unless otherwise noted, are references to the ISO Services Tariff.

2 DEFINITIONS

The following definitions are applicable to the ISO Services Tariff:

2.1 Definitions - A

Actual Energy Injections: Energy injections which are measured using a revenue-quality real-time meter.

Actual Energy Withdrawals: Energy withdrawals which are either: (1) measured with a revenue-quality real-time meter; (2) assessed (in the case of Load Serving Entities ("LSEs") serving retail customers where withdrawals are not measured by revenue-quality real-time meters) on the basis provided for in a Transmission Owner's retail access program; or (3) calculated (in the case of wholesale customers where withdrawals are not measured by revenue-quality real-time meters), until such time as revenue - quality real-time metering is available on a basis agreed upon by the unmetered wholesale customers.

Adjusted Actual Load: Actual Load adjusted to reflect: (i) Load relief measures such as voltage reduction and Load Shedding; (ii) Load reductions provided by Demand Side Resources; (iii) normalized design weather conditions; (iv) Station Power delivered that is not being self supplied pursuant to Section 4.7 of the ISO Services Tariff; and (v) adjustments for Special Case Resources and EDRP.

Adjusted DMGC: The value, in MW, of a BTM:NG Resource's capability in a Capability Period, as calculated pursuant to Section 5.12.6.1.1 of this Services Tariff.

Adjusted Host Load ("AHL"): The value, in MW, of a BTM:NG Resource's Load calculated pursuant to Section 5.12.6.1.2 of this Services Tariff for the purposes of determining the Resource's Capacity.

Advance Reservation: (1) A reservation of transmission service over the Cross-Sound Scheduled Line that is obtained in accordance with the applicable terms of Schedule 18 and the Schedule 18 Implementation Rule of the ISO New England Inc. Transmission, Markets and Services Tariff, or in accordance with any successors thereto; or (2) A right to schedule transmission service over the Neptune Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff; or (3) A right to schedule transmission service over the Linden VFT Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff; or (4) A right to schedule transmission service over the HTP Scheduled Line that is obtained in accordance with the rules and procedures established pursuant to Section 38 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff.

Adverse Conditions: Those conditions of the natural or man-made environment that threaten the adequate reliability of the NYS Power System, including, but not limited to, thunderstorms, hurricanes, tornadoes, solar magnetic flares and terrorist activities.

Affiliate: With respect to a person or entity, any individual, corporation, partnership, firm, joint venture, association, joint-stock company, trust or unincorporated organization, directly or indirectly controlling, controlled by, or under common control with, such person or entity. The term "Control" shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Ancillary Services: Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or "Voltage Support Service"); Regulation Service; Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability.

Application: A request to provide or receive service pursuant to the provisions of the ISO Services Tariff, that includes all information reasonably requested by the ISO.

Automatic Generation Control ("AGC"): The **automatic** regulation of the power output of electric Generators within a prescribed range in response to a change in system frequency, or tie-line loading, to maintain system frequency or scheduled interchange with other areas within predetermined limits.

Available Generating Capacity: Generating Capacity that is on line to serve Load and/or provide Ancillary Services, or is capable of initiating start-up for the purpose of serving Transmission Customers or providing Ancillary Services, within thirty (30) minutes.

Available Operating Capacity: For purposes of determining a Scarcity Reserve Requirement, the capability of all Suppliers that are eligible to provide Operating Reserves and have submitted Energy Bids in the Real-Time Market to provide Energy in greater than 30 minutes but less than or equal to 60 minutes; provided, however, that this value shall not include any quantity of Energy and Operating Reserves scheduled to be provided by all such Suppliers. The Available Operating Capacity value (in MW) shall be calculated by the RTD software for each normal RTD run. For purposes of calculating a Scarcity Reserve Requirement in accordance with Section 15.4.6.2 of Rate Schedule 4 of this ISO Services Tariff, each RTD run shall utilize the value of Available Operating Capacity calculated during the immediately preceding normal RTD run and each RTC run shall utilize the value of Available Operating Capacity calculated during the most recently-completed normal RTD run prior to the RTC run.

Availability: A measure of time that a Generator, transmission line or other facility is or was capable of providing service, whether or not it actually is in-service.

Average Coincident Host Load ("ACHL"): The value calculated for a Capability Year in accordance with Section 5.12.6.1.2.1 of this Tariff. The ACHL shall account for weather normalization and Load growth.

Average Coincident Load ("ACL"): The value in each Capability Period calculated for each Special Case Resource, except those that are eligible to report a Provisional Average Coincident

Load, that is equal to the average of the SCR's metered hourly Load that is supplied by the NYS Transmission System and/or the distribution system during the Capability Period SCR Load Zone Peak Hours applicable to such SCR, and computed and reported in accordance with Section 5.12.11.1.1 of this Services Tariff and ISO Procedures. Any Load supported by generation produced from a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter operating during the Capability Period SCR Load Zone Peak Hours may not be included in the SCR's metered Load values reported for the ACL.

Average Coincident Load of an SCR Aggregation: The value that is equal to the sum of the Average Coincident Loads and Provisional Average Coincident Loads for all Special Case Resources in an SCR Aggregation, assigned by the Responsible Interface Party to an SCR Aggregation in a single Load Zone, computed and reported monthly in accordance with Section 5.12.11.1.4 of this Services Tariff and ISO Procedures.

2.2 Definitions - B

Back-Up Operation: The procedures for operating the NYCA in a safe and reliable manner when the ISO's normal communication or computer systems are not fully functional as set forth in Section 5.3 of this ISO Services Tariff and Article 2.12 of the ISO OATT.

Balance-of-Period Auction: As defined in the ISO OATT.

Base Point Signals: Electronic signals sent from the ISO and ultimately received by Generators or Demand Side Resources specifying the scheduled MW output for the Generator. Real-Time Dispatch ("RTD") Base Point Signals are typically sent to Generators or Demand Side Resources on a nominal five (5) minute basis. AGC Base Point Signals are typically sent to Generators or Demand Side Resources on a nominal six (6) second basis.

Basis Amount: The amount owed to the ISO for purchases of Energy and Ancillary Services excluding External Transactions in the Basis Month, after applying the Price Adjustment, as further adjusted by the ISO to reflect material changes in the extent of the Customer's participation in the ISO-administered Energy and Ancillary Services markets.

Basis Month: The month during the Prior Equivalent Capability Period in which the amount owed by the Customer for purchases of Energy and Ancillary Services excluding External Transactions, after applying the Price Adjustment, was greatest.

Behind-the-Meter Net Generation Resource ("BTM:NG Resource"): A facility within a defined electrical boundary comprised of a Generator and a Host Load located at a single point identifier (PTID), where the Generator routinely serves, and is assigned to, the Host Load and has excess generation capability after serving that Host Load. The Generator of the BTM:NG Resource must be electrically located in the NYCA, have a minimum nameplate rating of 2 MW and a minimum net injection to the NYS Transmission System or distribution system of 1 MW. The Host Load of the BTM:NG Resource must also have a minimum ACHL of 1 MW. A facility that otherwise meets these eligibility requirements, but either (i) is an Intermittent Power resource, (ii) whose Host Load consists only of Station Power, or (iii) has made an election pursuant to Section 5.12.1.12, does not qualify to be a BTM:NG Resource. BTM:NG Resources cannot simultaneously participate as a BTM:NG Resource and in any ISO and/or Transmission Owner administered demand response or generation buy-back programs.

Bid/Post System: An electronic information system used to allow the posting of proposed transmission schedules and Bids for Energy and Ancillary Services by Market Participants for use by the ISO and to allow the ISO to post LBMPs and schedules.

Bid: Offer to sell or bid to purchase Energy, Demand Reductions or Transmission Congestion Contracts and an offer to sell Ancillary Services at a specified price that is duly submitted to the ISO pursuant to ISO Procedures. Bid shall mean a mitigated Bid where appropriate.

Bid Price: The price at which the Customer offering the Bid is willing to provide the product or service, or is willing to pay to receive such product or service, as applicable. In the case of a CTS Interface Bid, the Bid Price is a dollar value that indicates the bidder's willingness to purchase Energy at a CTS Source and sell it at a CTS Sink across a CTS Enabled Interface if, at the time of scheduling, the forecasted CTS Sink Price minus the forecasted CTS Source Price is greater than, or equal to, the dollar value specified in the Bid.

Bid Production Cost: Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running cost, Minimum Generation Bid, and Start-Up Bid).

Bidder: An entity that bids to purchase Unforced Capacity in an Installed Capacity auction.

Bidding Requirement: The credit requirement for bidding in certain ISO-administered auctions, calculated in accordance with Section 26.4.3 of Attachment K to this Services Tariff.

Bilateral Transaction: A Transaction between two or more parties for the purchase and/or sale of Capacity or Energy other than those in the ISO Administered Markets. A request to schedule a Bilateral Transaction in the Energy Market shall be considered a request to schedule Point-to-Point Transmission Service.

Billing Period: The period of time designated in Sections 7.2.2.1, 7.2.3.1, or 7.2.3.2 of this ISO Services Tariff over which the ISO will aggregate and settle a charge or a payment for services furnished under this ISO Services Tariff or the ISO OATT.

2.3 Definitions - C

Capability Period: Six-month periods which are established as follows: (i) from May 1 through October 31 of each year ("Summer Capability Period"); and (ii) from November 1 of each year through April 30 of the following year ("Winter Capability Period").

Capability Period Auction: An auction conducted no later than thirty (30) days prior to the start of each Capability Period in which Unforced Capacity may be purchased and sold in a six-month strip.

Capability Period SCR Load Zone Peak Hours: The top forty (40) coincident peak hours that, prior to the Summer 2014 Capability Period include hour beginning thirteen through hour beginning eighteen and beginning with the Summer 2014 Capability Period include hour beginning eleven through hour beginning nineteen. The Capability Period SCR Load Zone Peak Hours shall be determined by the NYISO from the Prior Equivalent Capability Period and shall be used by RIPs to report ACL values for the purpose of SCR enrollment. For a SCR enrolled with a Provisional ACL that requires verification data to be reported at the end of the Capability Period in which the SCR was enrolled, the Capability Period SCR Load Zone Peak Hours shall be determined from the Capability Period in which the SCR was enrolled. Such hours shall not include (i) hours in which Special Case Resources located in the specific Load Zone were called by the ISO to respond to a reliability event or test and (ii) hours for which the Emergency Demand Response Program resources were deployed by the ISO in each specific Load Zone. In addition, beginning with the Summer 2014 Capability Period, the NYISO shall not include, in descending rank order of NYCA Load up to a maximum of eight hours per Capability Period, a) the hour before the start time of a reliability event or performance test, in which SCRs located in the specific Load Zone were called by the ISO to respond to a reliability event or performance test, or b) the hour immediately following the end time of such reliability event or performance test.

Capability Year: A Summer Capability Period, followed by a Winter Capability Period (*i.e.*, May 1 through April 30).

Capacity: The capability to generate or transmit electrical power, or the ability to control demand at the direction of the ISO, measured in megawatts ("MW").

Capacity Limited Resource: A Resource that is constrained in its ability to supply Energy above its Normal Upper Operating Limit by operational or plant configuration characteristics. Capacity Limited Resources must register their Capacity limiting characteristics with, and justify them to, the ISO consistent with ISO Procedures. Capacity Limited Resources may submit a schedule indicating that their Normal Upper Operating Limit is a function depending on one or more variables, such as temperature or pondage levels, in which case the Normal Upper Operating Limit applicable at any time shall be determined by reference to that schedule.

Capacity Reservation Cap: As defined in the ISO OATT.

CARL Data: Control Area Resource and Load ("CARL") data submitted by Control Area System Resources to the ISO.

Centralized Transmission Congestion Contracts ("TCC") Auction ("Auction"): As defined in the ISO OATT.

Code of Conduct: The rules, procedures and restrictions concerning the conduct of the ISO directors and employees, contained in Attachment F to the ISO Open Access Transmission Tariff.

Commission ("FERC"): The Federal Energy Regulatory Commission, or any successor agency.

Compensable Overgeneration: A quantity of Energy injected over a given RTD interval in which a Supplier has offered Energy that exceeds the Real-Time Scheduled Energy Injection established by the ISO for that Supplier and for which the Supplier may be paid pursuant to this Section and ISO Procedures.

For Suppliers not covered by other provisions of this Section and Intermittent Power Resources depending on wind as their fuel for which the ISO has imposed a Wind Output Limit in the given RTD interval, Compensable Overgeneration shall initially equal three percent (3%) of the Supplier's Normal Upper Operating Limit which may be modified by the ISO if necessary to maintain good Control Performance.

For a Generator which is operating in Start-Up or Shutdown Periods, or Testing Periods, or which is an Intermittent Power Resource that depends on solar energy or landfill gas for its fuel and which has offered its Energy to the ISO in a given interval not using the ISO-committed Flexible or Self-Committed Flexible bid mode, Compensable Overgeneration shall mean all Energy actually injected by the Generator that exceeds the Real-Time Scheduled Energy Injection established by the ISO for that Generator. For a Generator operating in intervals when it has been designated as operating Out of Merit at the request of a Transmission Owner or the ISO, Compensable Overgeneration shall mean all Energy actually injected by the Generator that exceeds the Real-Time Scheduled Energy Injection up to the Energy level directed by the Transmission Owner or the ISO.

For Intermittent Power Resources that depend on wind as their fuel and Limited Control Run of River Hydro Resources not using the ISO-Committed Flexible or Self-Committed Flexible bid mode, that were in operation on or before November 18, 1999 within the NYCA, plus an additional 3,300 MW of such Resources, Compensable Overgeneration shall mean that quantity of Energy injected by a Generator, over a given RTD interval that exceeds the Real-Time Scheduled Energy Injection established by the ISO for that Generator and for which the Generator may be paid pursuant to ISO Procedures; provided however, this definition of Compensable Overgeneration shall not apply to an Intermittent Power Resource depending on wind as its fuel for any interval for which the ISO has imposed a Wind Output Limit.

For a Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, Compensable Overgeneration shall mean that quantity of Energy injected by the Generator, during the period when one of its grouped generating units is operating in a Start-Up or Shutdown Period, that exceeds the Real-Time Scheduled Energy Injection established by the ISO for that period, for that Generator, and for which the Generator may be paid pursuant to ISO Procedures.

Completed Application: An Application that satisfies all of the information and other requirements for service under the ISO Services Tariff.

Confidential Information: Information and/or data that has been designated by a Customer to be proprietary and confidential, provided that such designation is consistent with the ISO Procedures, the ISO Services Tariff, and the ISO Code of Conduct.

Congestion: A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of Energy to serve the next increment of Load, exclusive of losses, at different locations on the transmission system is unequal.

Congestion Component: The component of the LBMP measured at a location or the Transmission Usage Charge between two locations that is attributable to the cost of transmission Congestion as is more completely defined in Attachment B of the Services Tariff.

Congestion Rent: As defined in the ISO OATT.

Congestion Rent Shortfall: As defined in the ISO OATT.

Constraint: An upper or lower limit placed on a variable or set of variables that are used by the ISO in its SCUC, RTC, or RTD programs to control and/or facilitate the operation of the NYS Transmission System.

Contingency: An actual or potential unexpected failure or outage of a system component, such as a Generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Area: An electric system or combination of electric power systems to which a common Automatic Generation Control scheme is applied in order to: (1) match, at all times, the power output of the Generators within the electric power system(s) and Capacity and Energy purchased from entities outside the electric power system(s), with the Load within the electric power system(s); (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient Capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Control Area System Resource: A set of Resources owned or controlled by an entity within a Control Area that also is the operator of such Control Area. Entities supplying Unforced Capacity using Control Area System Resources will not designate particular Resources as the suppliers of Unforced Capacity.

Control Performance: A standard for measuring the degree to which a Control Area is providing Regulation Service in conformance with NERC requirements.

Controllable Transmission: Any Transmission facility over which power-flow can be directly controlled by power-flow control devices without having to re-dispatch generation.

Commenced Repair: A determination by the ISO that a Market Participant with a Generator i) has decided to pursue the repair of its Generator, and based on the ISO's technical/engineering evaluation ii) has a Repair Plan for the Generator that is consistent with a Credible Repair Plan, and iii) has made appropriate progress in pursuing the repair of its Generator when measured against the milestones of a Credible Repair Plan.

Credible Repair Plan: A Repair Plan that meets the requirements described in Section 5.18.1.4 of this Services Tariff and in ISO Procedures**.**

Credit Assessment: An assessment of a Customer's creditworthiness, conducted by the ISO in accordance with Section 26.5.3 of Attachment K to this Services Tariff.

Cross-Sound Scheduled Line: A transmission facility that interconnects the NYCA to the New England Control Area at Shoreham, New York and terminates near New Haven, Connecticut.

CTS Enabled Interface: An External Interface at which the ISO has authorized the use of Coordinated Transaction Scheduling ("CTS") market rules and which includes a CTS Enabled Proxy Generator Bus for New York and a CTS Enabled Proxy Generator Bus for the neighboring Control Area.

CTS Enabled Proxy Generator Bus: A Proxy Generator Bus at which the ISO either requires or permits the use of CTS Interface Bids for Import and Export Transactions in the Real-Time Market and requires the use of Decremental Bids for Wheels Through in the Real-Time Market. A CTS Enabled Proxy Generator Bus at which the ISO permits CTS Interface Bids will also permit Decremental and Sink Price Cap Bids.

CTS Interface Bid: A Real-Time Bid provided by an entity engaged in an External Transaction at a CTS Enabled Interface. CTS Interface Bids shall include a MW amount, a direction indicating whether the proposed Transaction is to Import Energy to, or Export Energy from, the New York Control Area, and a Bid Price.

CTS Sink: Representation of the location(s) within a Control Area where energy associated with a CTS Interface Bid is withdrawn. The NYCA CTS Sinks are Proxy Generator Buses.

CTS Sink Price: The price at a CTS Sink.

CTS Source: Representation of the location(s) within a Control Area where energy associated with a CTS Interface Bid is injected. The NYCA CTS Sources are Proxy Generator Buses.

CTS Source Price: The price at a CTS Source.

Curtailment or Curtail: A reduction in Transmission Service in response to a transmission Capacity shortage as a result of system reliability conditions.

Curtailment Customer Aggregator: A Curtailment Services Provider that produces real-time verified reductions in NYCA load of at least 100 kW through contracts with retail end-users. The procedure for qualifying as a Curtailment Customer Aggregator is set forth in ISO procedures.

Curtailment Initiation Cost: The fixed payment, separate from a variable Demand Reduction Bid, required by a qualified Demand Reduction Provider in order to cover the cost of reducing demand.

Curtailment Services Provider: A qualified entity that can produce real-time, verified reductions in NYCA Load of at least 100 kW in a single Load Zone, pursuant to the Emergency Demand Response Program and related ISO procedures. The procedure for qualifying as a Curtailment Services Provider is set forth in Section 3 below and in ISO Procedures.

Curtailment Services Provider Capacity: Capacity from a Demand Side Resource nominated by a Curtailment Services Provider for participation in the Emergency Demand Response Program.

Customer: An entity which has complied with the requirements contained in the ISO Services Tariff, including having signed a Service Agreement, and is qualified to utilize the Market Services and the Control Area Services provided by the ISO under the ISO Services Tariff; provided, however, that a party taking services under the Tariff pursuant to an unsigned Service Agreement filed with the Commission by the ISO shall be deemed a Customer.

2.4 Definitions - D

DADRP Component: The credit requirement for a Demand Reduction Provider to bid into the Day-Ahead Market, and a component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Day-Ahead: Nominally, the twenty-four (24) hour period directly preceding the Dispatch Day, except when this period may be extended by the ISO to accommodate weekends and holidays.

Day-Ahead LBMP: The LBMPs calculated based upon the ISO's Day-Ahead Security Constrained Unit Commitment process.

Day-Ahead Margin: That portion of Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for an hour that represents the difference between the Supplier's accepted Day-Ahead offer price and the Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for that hour.

Day-Ahead Margin Assurance Payment: A supplemental payment made to an eligible Supplier that buys out of a Day-Ahead Energy, Regulation Service, or Operating Reserves schedule such that an hourly balancing payment obligation offsets its Day-Ahead Margin. Rules for calculating these payments, and for determining Suppliers' eligibility to receive them, are **set** forth in Attachment J to this ISO Services Tariff.

Day-Ahead Market: The ISO Administered Market in which Capacity, Energy and/or Ancillary Services are scheduled and sold Day-Ahead consisting of the Day-Ahead scheduling process, price calculations and Settlements.

Day-Ahead Reliability Unit: A Day-Ahead committed Resource which would not have been committed but for a request by a Transmission Owner that the unit be committed in the Day-Ahead Market in order to meet the reliability needs of the Transmission Owner's local system or as the result of the ISO's analysis indicating the unit was needed in order to meet the reliability requirements of the NYCA.

Decremental Bid: A monotonically increasing Bid curve provided by an entity engaged in a Bilateral Import, other than an entity submitting a CTS Interface Bid, or Internal Transaction to indicate the LBMP below which that entity is willing to reduce its Generator's output, and purchase Energy in the LBMP Markets, or by an entity engaged in a Wheel Through Transaction to indicate the Congestion Component cost at or below which that entity is willing to accept Transmission Service.

Demand Reduction: A quantity of reduced electricity demand from a Demand Side Resource that is bid, produced, purchased or sold over a period of time and measured or calculated in Megawatt hours. Demand Reductions offered by a Demand Side Resource as Energy in the LBMP Markets may only be offered in the Day-Ahead Market, and shall be offered only by a Demand Reduction Provider. The same Demand Reduction may not be offered by a Demand Reduction Provider and by a customer as Operating Reserves or Regulation Service.

Demand Reduction Aggregator: A Demand Reduction Provider, qualified pursuant to ISO Procedures, that bids Demand Side Resources of at least 1 MW through contracts with Demand Side Resources and is not a Load Serving Entity.

Demand Reduction Incentive Payment: A payment to Demand Reduction Providers that are scheduled to make Day-Ahead Demand Reductions. The payment shall be equal to the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction bus; and (b) the lesser of the actual hourly Demand Reduction or the Day-Ahead scheduled hourly Demand Reduction in MW.

Demand Reduction Provider: A Customer that is eligible, pursuant to the relevant ISO Procedures, to bid Demand Side Resources of at least 1 MW as Energy into the Day-Ahead Market. A Demand Reduction Provider can be (i) a Load Serving Entity or (ii) a Demand Reduction Aggregator.

Demand Side Ancillary Service Program (DSASP): An ISO program that allows qualified DSASP Resources to participate in the ISO's Day-Ahead and Real-Time Markets for Operating Reserves and Regulation Service in accordance with the ISO Services Tariff and ISO Procedures.

Demand Side Ancillary Service Program Resource (DSASP Resource): A Demand Side Resource or an aggregation of Demand Side Resources located in the NYCA with at least 1 MW of load reduction that is represented by a point identifier (PTID) and is assigned to a Load Zone or Subzone by the ISO and that is:

i. Capable of controlling demand in a responsive, measurable and verifiable manner within time limits prescribed by the ISO; and

ii. Qualified to participate in the ISO's Ancillary Services market as a Supplier of Operating Reserves or Regulation Service pursuant to the ISO Services Tariff and ISO Procedures.

Demand Side Ancillary Service Program Provider (DSASP Provider): A Customer that is eligible, pursuant to the ISO Tariff and ISO Procedures, to offer DSASP Resource(s) as Operating Reserves or Regulation Service in the Day-Ahead or Real-Time Market. A DSASP Provider is responsible for enrolling its DSASP Resource(s), and, when communicating directly with the ISO via telemetry, is responsible for dispatching its DSASP Resource(s).

Demand Side Resource: A Resource located in the NYCA that: (i) is capable of controlling demand by either curtailing its Load or by operating a Local Generator to reduce Load from the NYS Transmission System and/or the distribution system at the direction of the ISO, in a responsive, measurable and verifiable manner within time limits, and (ii) is qualified to participate in competitive Energy, Capacity, Operating Reserves or Regulation Service markets, or in the Emergency Demand Response Program pursuant to this ISO Services Tariff and the ISO Procedures.

Dennison Scheduled Line: A transmission facility that interconnects the NYCA to the Hydro Quebec Control Area at the Dennison substation, located near Massena, New York and extends through the province of Ontario, Canada (near the City of Cornwall) to the Cedars substation in Quebec, Canada.

Dependable Maximum Gross Capability ("DMGC"): The sustained maximum output of the Generator of a BTM:NG Resource, as demonstrated by the performance of a test or through actual operation in accordance with, and averaged over a continuous time period as defined in, ISO Procedures.

Dependable Maximum Net Capability ("DMNC"): The sustained maximum net output of a Generator, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period as defined in the ISO Procedures.

Desired Net Interchange ("DNI"): A mechanism used to set and maintain the desired Energy interchange (or transfer) between two Control Areas; it is scheduled ahead of time and can be changed manually in real-time.

Direct Sale: As defined in the ISO OATT.

Dispatchable: A bidding mode in which Generators or Demand Side Resources indicate that they are willing to respond to real-time control from the ISO. A Dispatchable Generator, not including the Generator of a BTM:NG Resource, may be either ISO-Committed Flexible or Self-Committed Flexible. A Dispatchable Generator that is the Generator serving a BTM:NG Resource must be Self-Committed Flexible. Dispatchable Demand Side Resources must be ISO-Committed Flexible. Dispatchable Resources that are not providing Regulation Service will follow five-minute RTD Base Point Signals. Dispatchable Resources that are providing Regulation Service will follow six-second AGC Base Point Signals.

Dispatch Day: The twenty-four (24) hour (or, if appropriate, the twenty-three (23) or twenty-five (25) hour) period commencing at the beginning of each day (0000 hour).

Dispute Resolution Administrator ("DRA"): An individual hired by the ISO to administer the Expedited Dispute Resolution Procedures in Section 5.17 of the ISO Services Tariff.

DMNC Test Period: The period within a Capability Period during which a Resource shall conduct a DMNC test, or a BTM:NG Resource shall conduct a DMGC test, if such a test is required. Such periods will be established pursuant to the ISO Procedures.

DSASP Baseline MW: The value of the Load level of a DSASP resource in the dispatch interval immediately preceding the interval with a non-zero Base Point Signal, where the status of the regulation flag is set to the off condition for either Operating Reserves or Regulation service.

DSASP Component: The credit requirement for a Demand Side Resource to offer Ancillary Services, and a component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Dynamically Scheduled Proxy Generator Bus: A Proxy Generator Bus for which the ISO may schedule Transactions at 5 minute intervals in real time. Dynamically Scheduled Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

2.5 Definitions - E

East of Central-East: An electrical area comprised of Load Zones F, G, H, I, J, and K, as identified in the ISO Procedures.

East of Central-East Excluding Long Island: An electrical area comprised of Load Zones F, G, H, I, and J, as identified in the ISO Procedures.

East of Central-East Excluding New York City and Long Island: An electrical area comprised of Load Zones F, G, H, and I, as identified in the ISO Procedures.

Economic Operating Point: The megawatt quantity which is a function of: i) the real-time LBMP at the Resource bus; and ii) the Supplier's real-time eleven constant cost step Energy Bid, for the Resource, such that (a) the offer price associated with Energy offers below that megawatt quantity (if that megawatt quantity is not that Resource's minimum output level) must be less than or equal to the real-time LBMP at the Resource bus, and (b) the offer price associated with Energy offers above that megawatt quantity (if that megawatt quantity is not that Resource's maximum output level) must be greater than or equal to the real-time LBMP at the Resource bus. In cases where multiple megawatt values meet conditions (a) and (b), the Economic Operating Point is the megawatt value meeting these conditions that is closest to the Resource's real-time scheduled Energy injection. In cases where the Economic Operating Point would be less than the minimum output level, the Economic Operating Point will be set equal to the MW value of the first point on the Energy Bid curve and in cases where the Economic Operating Point would be greater than the maximum output level, the Economic Operating Point will be set equal to the MW value of the last point on the Energy Bid curve. When evaluating the Economic Operating Point of a BTM:NG Resource, only Energy offers corresponding to quantities in excess of its Host Load will be considered.

Emergency: Any abnormal system condition that requires immediate automatic or manual action to prevent or limit loss of transmission facilities or Generators that could adversely affect the reliability of an electric system.

Emergency Demand Response Program ("EDRP"): A program pursuant to which the ISO makes payments to Curtailment Service Providers that voluntarily take effective steps in real time, pursuant to ISO procedures, to reduce NYCA demand in Emergency conditions.

Emergency State: The state that the NYS Power System is in when an abnormal condition occurs that requires automatic or immediate, manual action to prevent or limit loss of the NYS Transmission System or Generators that could adversely affect the reliability of the NYS Power System.

Emergency Upper Operating Limit (UOL_E): The upper operating limit that a Generator, except for the Generator of a BTM:NG Resource, indicates it expects to be able to reach, the upper operating limit that a BTM:NG Resource indicates it expects to be able to inject into the grid after serving its Host Load and subject to its Injection Limit, or the maximum amount of demand that a Demand Side Resource expects to be able to reduce, at the request of the ISO during extraordinary conditions. Each Resource shall specify a UOL_E in its bids that shall be equal to or greater than its stated Normal Upper Operating Limit.

Energy ("MWh"): A quantity of electricity that is bid, produced, purchased, consumed, sold, or transmitted over a period of time, and measured or calculated in megawatt hours.

Energy and Ancillary Services Component: A component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Energy Limited Resource: Capacity resources, not including BTM:NG Resources, that, due to environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis, but are able to operate for at least four consecutive hours each day. Energy Limited Resources must register their Energy limiting characteristics with, and justify them to, the ISO consistent with ISO Procedures.

Equivalent Demand Forced Outage Rate: The portion of time a unit is in demand, but is unavailable due to forced outages.

Equivalency Rating: A rating determined by the ISO, at a Customer's request, based on the ISO's financial evaluation of an Unrated Customer that shall serve as the starting point of the ISO's determination of an amount of Unsecured Credit to be granted to the Customer, if any, as provided in Table K-1 of Attachment K to this Services Tariff.

ETA Agent: As defined in the ISO OATT.

ETCNL TCC: As defined in the ISO OATT.

Excess Amount: The difference, if any, between the dollar amounts charged to purchasers of Unforced Capacity in an ISO–administered Unforced Capacity auction and the dollar amounts paid to sellers of Unforced Capacity in that ISO–administered Installed Capacity auction.

Excess Congestion Rents: As defined in the ISO OATT.

Existing Transmission Capacity for Native Load ("ETCNL"): As defined in the ISO OATT.

Existing Transmission Agreement ("ETA"): As defined in the ISO OATT.

Expected EDRP/SCR MW: The aggregate Load reduction (in MW) expected to be realized from EDRP and/or SCRs during the real-time intervals that the ISO has called upon EDRP and/or SCRs to provide Load reduction in a Scarcity Reserve Region, as determined based on the ISO's calculation of the historical performance of EDRP and SCRs. There will be separate values for voluntary and mandatory Load reductions. When determining the historical performance of SCRs, provision of Load reduction shall be deemed mandatory if the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of this ISO Services Tariff as it relates to the SCRs in the applicable Load Zone, otherwise provision of such Load reduction shall be deemed voluntary. When determining the historical performance of the EDRP, provision of Load reduction by EDRP shall be deemed voluntary.

Expected Load Reduction: For purposes of determining the Real-Time Locational Based Marginal Price, the reduction in Load expected to be realized in real-time from activation of the

Emergency Demand Response Program and from Load reductions requested from Special Case Resources, as established pursuant to ISO Procedures.

Expedited Dispute Resolution Procedures: The dispute resolution procedures applicable to disputes arising out of the Installed Capacity provisions of this ISO Services Tariff (as set forth in Section 5.17) and the Customer settlements provisions of this ISO Services Tariff (as set forth in Section 7.4.3).

Export: A Bilateral Transaction or purchase from the LBMP Market where the Energy is delivered to an NYCA Interconnection with another Control Area.

Export Credit Requirement: A component of the External Transaction Component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

External: An entity (e.g., Supplier, Transmission Customer) or facility (e.g., Generator, Interface) located outside the Control Area being referenced or between two or more Control Areas. Where a specific Control Area is not referenced, the NYCA is the intended reference.

External Transaction Component: A component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

External Transactions: Purchases, sales or exchanges of Energy, Capacity or Ancillary Services for which either the Point of Injection ("POI") or Point of Withdrawal ("POW") or both are located outside the NYCA (i.e., Exports, Imports or Wheels Through).

2.6 Definitions - F

Facility Flow-Based Methodology: As defined in the ISO OATT.

Federal Power Act ("FPA"): The Federal Power Act, as may be amended from time-to-time (See 16 U.S.C. § 796 et seq.).

Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is scheduled between specified Points of Receipt and Delivery pursuant to the ISO OATT. Firm Point-To-Point Transmission Service is service for which the Transmission Customer has agreed to pay the Congestion associated with its service. A Transmission Customer may fix the price of Congestion associated with its Firm Point-To-Point Transmission Service by acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service.

Firm Transmission Service: Transmission service requested by a Transmission Customer willing to pay Congestion Rent.

First Settlement: The process of establishing binding financial commitments on the part of Customers participating in the Day-Ahead Market based on Day-Ahead LBMP.

Fixed Block Unit: A unit that, due to operational characteristics, can only be dispatched in one of two states: either turned completely off, or turned on and run at a fixed capacity level.

Fixed Price TCC: As defined in the ISO OATT.

Forced Outage: An unscheduled inability of a Market Participant's Generator to produce Energy that does not meet the notification criteria to be classified as a scheduled outage or de-rate as established in ISO Procedures. If the Forced Outage of a Generator starts on or after May 1, 2015, the Forced Outage will expire at the end of the month which contains the 180th day of its Forced Outage but may be extended if the Market Participant has Commenced Repair of its Generator.

2.7 Definitions - G

GADS Data: Data submitted to the NERC for collection into the NERC's Generating Availability Data System ("GADS").

Gap Solution: This term shall have the meaning given in Attachment Y to the OATT.

Generator: A facility, including the Generator of a BTM:NG Resource, capable of supplying Energy, Capacity and/or Ancillary Services that is accessible to the NYCA. A Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, and each unit within that group, shall be considered a Generator.

G-J Locality: The Locality comprised of Load Zones G, H, I, and J collectively.

Good Utility Practice: Any of the practices, methods or acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to delineate acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Grandfathered Rights: As defined in the ISO OATT.

Grandfathered TCCs: As defined in the ISO OATT.

2.8 Definitions - H

Host Load: The Load that is electrically interconnected within the defined electrical boundary of a BTM:NG Resource that is routinely served by, and assigned to, the Generator of a BTM:NG Resource. Station Power will be included in the calculation of the BTM:NG Resource's Host Load if it is self-supplied by the Generator of the BTM:NG Resource, and it is not separately metered pursuant to Section 5.12.6.1.1 and ISO Procedures.

HTP Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection, L.L.C. Control Area at the West 49th Street Substation, New York, New York and terminates in Ridgefield, New Jersey.

2.9 Definitions - I

ICAP Demand Curve: A series of prices which decline until reaching zero as the amount of Installed Capacity increases.

ICAP Demand Curve Reset Filing Year: A calendar year in which the ISO files ICAP Demand Curves, in accordance with Section 5.14.1.2.1.11 or Section 5.14.1.2.2.4.11.

ICAP Ineligible Forced Outage: The outage state of a Market Participant's Generator after: i) the expiration or termination of its Forced Outage pursuant to the provisions in Section 5.18.1.6 of this Services Tariff, which Forced Outage started on or after May 1, 2015; ii) the Market Participant voluntarily reclassified its Forced Outage pursuant to the provisions in Section 5.18.2.1 of this Services Tariff, which Forced Outage started on or after May 1, 2015; or iii) substantial actions have been taken, such as dismantling or disabling essential equipment, which actions are inconsistent with an intention to return the Generator to operation and the Energy market. A Generator in an ICAP Ineligible Forced Outage is subject to the return-to-service provisions in Section 5.18.4 of this Services Tariff and is ineligible to participate in the Installed Capacity market.

ICAP Spot Market Auction: An auction conducted pursuant to Section 5.14.1.1 of this Tariff to procure and set LSE Unforced Capacity Obligations for the subsequent Obligation Procurement Period, pursuant to the Demand Curves applicable to each respective LSE and the supply that is offered.

Import Constrained Locality: New York City and the G-J Locality.

Import Credit Requirement: A component of the External Transaction Component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Import Curtailment Guarantee Payment: A payment made in accordance with Section 4.5.3.2 and Attachment J of this ISO Services Tariff to compensate a Supplier whose Import is Curtailed by the ISO.

Imports: A Bilateral Transaction or sale to the LBMP Market where Energy is delivered to a NYCA Interconnection from another Control Area.

Imputed LBMP Revenue: Revenue developed for calculating a Generator or Import Bid Production Cost guarantee, for any interval, which equals the product of (i) the Bilateral Transaction scheduled MW in the Day-Ahead Market or real-time market, as appropriate, from the Generator bus or Proxy Generator Bus, as appropriate, for the interval, (ii) the LBMP, in units of $/MWh, either Day-Ahead or real-time as appropriate, at the Generator or Proxy Generator Bus for that interval and (iii) the length of the interval, in units of hours.

Inactive Reserves: The outage state in which a Market Participant's Generator is unavailable to produce Energy for a limited period of time not to exceed six months, for reasons that are not equipment related, which state does not meet the criteria to be classified as any other outage pursuant to the provisions of this Services Tariff or of ISO Procedures. A Generator in Inactive Reserves is ineligible to participate in the Installed Capacity market.

Inadvertent Energy Accounting: The accounting performed to track and reconcile the difference between net actual Energy interchange and scheduled Energy interchange of a Control Area with adjacent Control Areas.

In-City: Located electrically within the New York City Locality (LBMP Load Zone J).

Incremental Average Coincident Load ("Incremental ACL"): Beginning with the Summer 2014 Capability Period, the amount of qualifying Load that may be added to the Average Coincident Load of a Special Case Resource. In order to qualify to use Incremental ACL the SCR must enroll with an ACL and report an increase in the Load of the facility that is supplied by the NYS Transmission System and/or distribution system that meets or exceeds the SCR Load Change Reporting Threshold in accordance with this Services Tariff. The Incremental ACL reported in a Capability Period cannot exceed one-hundred percent (100%) of the ACL that has been calculated for the SCR when it first enrolls in the Capability Period. For resources reporting an Incremental ACL, the Net Average Coincident Load shall equal the enrolled ACL plus the reported Incremental ACL less any applicable SCR Change of Status. Each resource for which a RIP reports an Incremental ACL is subject to verification subsequent to the Capability Period pursuant to reporting requirements and calculations using the SCR's metered Load values provided in Section 5.12.11.1.5 of this Services Tariff and ISO Procedures.

Incremental Energy Bid: A series of monotonically increasing constant cost incremental Energy steps that indicate the quantities of Energy for a given price that an entity is willing to supply to the ISO Administered Markets.

Incremental TCC: As defined in the ISO OATT.

Independent System Operator ("ISO"): The New York Independent System Operator, Inc., a not-for-profit corporation established pursuant to the ISO Agreement.

Independent System Operator Agreement ("ISO Agreement"): The agreement that establishes the New York ISO.

Independent System Operator/New York State Reliability Council ("ISO/NYSRC Agreement"): The agreement between the ISO and the New York State Reliability Council governing the relationship between the two organizations.

Independent System Operator-Transmission Owner Agreement ("ISO/TO Agreement"): The agreement that establishes the terms and conditions under which the Transmission Owners transferred to the ISO Operational Control over designated transmission facilities.

Indicative NCZ Locational Minimum Installed Capacity Requirement: The amount of capacity that must be electrically located within a New Capacity Zone, or possess an approved Unforced Capacity Deliverability Right, in order to ensure that sufficient Energy and Capacity are available in that NCZ and that appropriate reliability criteria are met.

Injection Limit: The maximum injection of a BTM:NG Resource, in MW, into the NYS Transmission System or distribution system at the BTM:NG Resource's Point of Injection. The Injection Limit for a BTM:NG Resource must be at least 1 MW.

Installed Capacity ("ICAP"): External or Internal Capacity, in increments of 100 kW, that is made-available pursuant to Tariff requirements and ISO Procedures.

Installed Capacity Equivalent: The Resource capability that corresponds to its Unforced Capacity, calculated in accordance with ISO Procedures.

Installed Capacity Marketer: An entity which has signed this Tariff and which purchases Unforced Capacity from qualified Installed Capacity Suppliers, or from LSEs with excess Unforced Capacity, either bilaterally or through an ISO-administered auction. Installed Capacity Marketers that purchase Unforced Capacity through an ISO-administered auction may only resell Unforced Capacity purchased in such auctions in the NYCA.

Installed Capacity Supplier: An Energy Limited Resource, Generator, Installed Capacity Marketer, Responsible Interface Party, Intermittent Power Resource, Limited Control Run of River Hydro Resource, municipally-owned generation, BTM:NG Resource, System Resource or Control Area System Resource that satisfies the ISO's qualification requirements for supplying Unforced Capacity to the NYCA.

Interconnection or Interconnection Points ("IP"): The point(s) at which the NYCA connects with a distribution system or adjacent Control Area. The IP may be a single tie line or several tie lines that are operated in parallel.

Interface: A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas.

Interface MW - Mile Methodology: As defined in the ISO OATT.

Interim Service Provider ("ISP"): As defined in Attachment FF to the OATT.

Intermittent Power Resource: A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. In New York, resources that depend upon wind, solar energy or landfill gas for their fuel have been classified as Intermittent Power Resources. Each Intermittent Power Resource that depends on wind as its fuel shall include all turbines metered at a single scheduling point identifier (PTID).

Internal: An entity (e.g., Supplier, Transmission Customer) or facility (e.g., Generator, Interface) located within the Control Area being referenced. Where a specific Control Area is not referenced, internal means the NYCA.

Internal Transactions: Purchases, sales or exchanges of Energy, Capacity or Ancillary Services where the Generator and Load are located within the NYCA.

Investment Grade Customer: A Customer that meets the criteria set forth in Section 26.3 of Attachment K to this Services Tariff.

Investor-Owned Transmission Owners: At the present time these include: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

ISO Administered Markets : The Day-Ahead Market and the Real-Time Market (collectively the "LBMP Markets") and any other market or auction administered by the ISO.

ISO-Committed Fixed: In the Day-Ahead Market, a bidding mode in which a Generator requests that the ISO commit and schedule it. In the Real-Time Market, a bidding mode in which a Generator, with ISO approval, requests that the ISO schedule it no more frequently than every 15 minutes. A Generator scheduled in the Day-Ahead Market as ISO-Committed Fixed will participate as a Self-Committed Fixed Generator in the Real-Time Market unless it changes bidding mode, with ISO approval, to participate as an ISO-Committed Fixed Generator. A BTM:NG Resource is not permitted to utilize the ISO-Committed Fixed bidding mode.

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator or Demand Side Resource follows Base Point Signals and is committed by the ISO. A BTM:NG Resource is not permitted to utilize the ISO-Committed Flexible bidding mode.

ISO Market Power Monitoring Program: The monitoring program approved by the Commission and administered by the ISO and the Market Monitoring Unit that is designed to monitor the possible exercise of market power in ISO Administered Markets.

ISO OATT: The ISO Open Access Transmission Tariff.

ISO Procedures: The procedures adopted by the ISO in order to fulfill its responsibilities under the ISO OATT, the ISO Services Tariff and the ISO Related Agreements.

ISO Related Agreements: Collectively, the ISO Agreement, the ISO/TO Agreement, the NYSRC Agreement, and the ISO/NYSRC Agreement.

ISO Services Tariff (the "Tariff"): The ISO Market Administration and Control Area Services Tariff.

ISO Tariffs: The ISO OATT and the ISO Services Tariff, collectively.

ISP UCAP MW: The quantity of Unforced Capacity determined by the ISO in accordance with Section 5.14.1.1 of this Services Tariff.

2.10 Definitions - J

2.11 Definitions - K

2.12 Definitions - L

LBMP Market(s): The Real-Time Market or the Day-Ahead Market or both.

Limited Control Run-of-River Hydro Resource: A Generator above 1 MW in size that has demonstrated to the satisfaction of the ISO that its Energy production depends directly on river flows over which it has limited control and that such dependence precludes accurate prediction of the facility's real-time output.

Limited Customer: An entity that is not a Customer but which qualifies to participate in the ISO's Emergency Demand Response Program by complying with Limited Customer requirements set forth in the ISO Procedures.

Limited Energy Storage Resource ("LESR"): A Generator authorized to offer Regulation Service only and characterized by limited Energy storage, that is, the inability to sustain continuous operation at maximum Energy withdrawal or maximum Energy injection for a minimum period of one hour. LESRs must bid as ISO-Committed Flexible Resources.

Limited Energy Storage Resource ("LESR") Energy Management: Real-time Energy injections or withdrawals scheduled by the ISO to manage the Energy storage capacity of a Limited Energy Storage Resource, pursuant to ISO Procedures, for the purpose of maximizing the Capacity bid as available for Regulation Service from such Resource.

Linden VFT Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection, L.L.C. Control Area in Linden, New Jersey.

LIPA Tax Exempt Bonds: Obligations issued by the Long Island Power Authority, the interest on which is not included in gross income under the Internal Revenue Code.

Load : A term that refers to either a consumer of Energy or the amount of demand (MW) or Energy (MWh) consumed by certain consumers.

Load Serving Entity ("LSE"): Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail customers located within the NYCA, including an entity that takes service directly from the ISO to supply its own Load in the NYCA.

Load Shedding: The systematic reduction of system demand by disconnecting Load in response to a Transmission System or area Capacity shortage, system instability, or voltage control considerations under the ISO OATT.

Load Zone: One (1) of eleven (11) geographical areas located within the NYCA that is bounded by one (1) or more of the fourteen (14) New York State Interfaces.

Local Furnishing Bonds: Tax-exempt bonds issued by a Transmission Owner under an agreement between the Transmission Owner and the New York State Energy Research and

Development Authority ("NYSERDA"), or its successor, or by a Transmission Owner itself, and pursuant to Section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).

Local Generator: A resource operated by or on behalf of a Load that is either: (i) not synchronized to a local distribution system; or (ii) synchronized to a local distribution system solely in order to support a Load that is equal to or in excess of the resource's Capacity. Local Generators supply Energy only to the Load they are being operated to serve and do not supply Energy to the distribution system.

Locality: A single LBMP Load Zone or set of adjacent LBMP Load Zones within which a minimum level of Installed Capacity must be maintained, and as specifically identified in this subsection to mean (1) Load Zone J; (2) Load Zone K; and (3) Load Zones G, H, I, and J collectively (*i.e.*, the G-J Locality)**.**

Locality Exchange MW: The MW of Locational Export Capacity excluding the MW to be transmitted using UDRs, that the ISO determines in accordance with Section 5.11.4 of the Services Tariff.

Locality Exchange Factor: The percentage of Locational Export Capacity that the ISO determines annually in accordance with Section 5.11.4.1 of the Services Tariff.

Local Reliability Rule: A Reliability Rule established by a Transmission Owner, and adopted by the NYSRC, to meet specific reliability concerns in limited areas of the NYCA, including without limitation, special conditions and requirements applicable to nuclear plants and special requirements applicable to the New York City metropolitan area.

Locational Based Marginal Pricing ("LBMP"): The price of Energy at each location in the NYS Transmission System as calculated pursuant to Section 17 Attachment B of this Services Tariff.

Locational Export Capacity: The MW of a Generator electrically located in an Import Constrained Locality that (a) has Capacity Resource Interconnection Service, pursuant to the applicable provisions of Attachment X, Attachment S and Attachment Z to the ISO OATT, and (b) that meets the eligibility requirements set forth in Section 5.9.2.2 of the Services Tariff.

Locational Minimum Installed Capacity Requirement: The portion of the NYCA Minimum Installed Capacity Requirement provided by Capacity Resources that must be electrically located within a Locality (including those combined with a Unforced Capacity Deliverability Right except for rights returned in an annual election to the ISO in accordance with ISO Procedures) in order to ensure that sufficient Energy and Capacity are available in that Locality and that appropriate reliability criteria are met.

Locational Minimum Unforced Capacity Requirement: The Unforced Capacity equivalent of the Locational Minimum Installed Capacity Requirement.

Long Island ("L.I."): An electrical area comprised of Load Zone K, as identified in the ISO Procedures.

Lost Opportunity Cost: The foregone profit associated with the provision of Ancillary Services, which is equal to the product of: (1) the difference between (a) the Energy that a Generator could have sold at the specific LBMP and (b) the Energy sold as a result of reducing the Generator's output to provide an Ancillary Service under the directions of the ISO; and (2) the LBMP existing at the time the Generator was instructed to provide the Ancillary Service, less the Generator's Energy bid for the same MW segment.

LSE Unforced Capacity Obligation: The amount of Unforced Capacity that each NYCA LSE must obtain for an Obligation Procurement Period as determined by the ICAP Demand Curve for the NYCA, the G-J Locality, New York City Locality, and/or the Long Island Locality, as applicable, for each ICAP Spot Market Auction. The amount includes, at a minimum, each LSE's share of the NYCA Minimum Unforced Capacity Requirement and the Locational Minimum Unforced Capacity Requirement, as applicable.

2.13 Definitions - M

Major Emergency State: An Emergency accompanied by abnormal frequency, abnormal voltage and/or equipment overloads that create a serious risk that the reliability of the NYS Power System could be adversely affected.

Marginal Losses: The NYS Transmission System Real Power Losses associated with each additional MWh of consumption by Load, or each additional MWh transmitted under a Bilateral Transaction as measured at the Points of Withdrawal.

Marginal Losses Component: The component of LBMP at a bus that accounts for the Marginal Losses, as measured between that bus and the Reference Bus.

Market-Clearing Price: The price determined in an Installed Capacity auction for each ISO-defined Locality, the remainder of the NYCA and each adjacent External Control Area for which all offers to sell and bids to purchase Unforced Capacity are in equilibrium.

Market Mitigation and Analysis Department: A department, internal to the ISO, that is responsible for participating in the ISO's administration of its Tariffs. The Market Mitigation and Analysis Department's duties are described in Section 30.3 of the Market Monitoring Plan that is set forth in Attachment O to this Services Tariff.

Market Monitoring Unit: "Market Monitoring Unit" shall have the same meaning in this ISO Services Tariff as it has in the Market Monitoring Plan that is set forth in Attachment O to this Services Tariff.

Market Participant: An entity, excluding the ISO, that produces, transmits, sells, and/or purchase for resale Unforced Capacity, Energy or Ancillary Services in the Wholesale Market. Market Participants include: Transmission Customers under the ISO OATT, Customers under the ISO Services Tariff, Power Exchanges, Transmission Owners, Primary Holders, LSEs, Suppliers and their designated agents. Market Participants also include entities buying or selling TCCs.

Market Problem: An issue which requires notification to Market Participants, the Commission and the Market Monitoring Unit pursuant to Section 3.5.1 of this Services Tariff. It includes market design flaws, software implementation and modeling anomalies or errors, market data anomalies or errors, and economic inefficiencies that have a material effect on the ISO-administered markets or transmission service. The term does not include erroneous Energy or Ancillary Services prices (which are managed through procedures outlined in Attachment E to the Services Tariff) or erroneous customer settlements.

Market Services: Services provided by the ISO under the ISO Services Tariff related to the ISO Administered Markets for Energy, Capacity and Ancillary Services.

MCZ Import Constrained Locality: A Mitigated Capacity Zone that is also an Import Constrained Locality.

Member Systems: The eight Transmission Owners that comprise the membership of the New York Power Pool.

Minimum Generation Bid: A two-parameter Bid that identifies the minimum operating level a Supplier requires to operate a Generator, and the payment a Supplier requires to operate its Generator at that level, or the minimum quantity of Demand Reduction a Demand Side Resource requires to provide Demand Reduction and the payment the Supplier requires to provide that level of Demand Reduction. If the Supplier is a BTM:NG Resource, it shall not submit a Minimum Generation Bid.

Minimum Generation Level: For purposes of describing the eligibility of ten minute Resources to be committed by the Real Time Dispatch for pricing purposes pursuant to the Services Tariff, Section 4.4.3.3, an upper bound, established by the ISO, on the physical minimum generation limits specified by ten minute Resources. Ten minute Resources with physical minimum generation limits that exceed this upper bound will not be committed by the Real Time Dispatch for pricing purposes. The ISO shall establish a Minimum Generation Level based on its evaluation of the extent to which it is meeting its reliability criteria including Control Performance. The Minimum Generation Level, in megawatts, and the ISO's rationale for that level, shall be made available through the ISO's website or comparable means. If the Supplier is a BTM:NG Resource, it shall not submit a Minimum Generation Level.

Minimum Payment Nomination: An offer, submitted by a Responsible Interface Party, in dollars per Megawatt-hour and not to exceed $500 per Megawatt-hour, to reduce Load equal to the Installed Capacity Equivalent of the amount of Unforced Capacity a Special Case Resource is supplying to the NYCA.

Mitigated Capacity Zone: New York City and any Locality added to the definition of "Locality" accepted by the Commission on or after March 31, 2013.

Modified Wheeling Agreement ("MWA"): A Transmission Wheeling Agreement between Transmission Owners that was in existence at the time of ISO start-up, as amended and modified as described in Attachment K. Modified Wheeling Agreements are associated with Generators or power supply contracts existing at ISO start-up. All Modified Wheeling Agreements are listed in Attachment L, Table 1A, and are designated in the "Treatment" column of Table 1A, as "MWA".

Monthly Auction: An auction administered by the ISO pursuant to Section 5.13.3 of the ISO Services Tariff.

Monthly Average Coincident Load ("Monthly ACL"): Beginning with the Summer 2014 Capability Period, the Load value calculated for each month during a Capability Period applicable to a Special Case Resource with a reported Incremental Average Coincident Load. The Monthly ACL is an average of the SCR's metered hourly Load that is supplied by the NYS Transmission System and/or the distribution system and reported for the Monthly SCR Load Zone Peak Hours applicable to such SCR. The calculation and verification data reporting requirements are provided in Section 5.12.11.1.5 of this Services Tariff and ISO Procedures. Any Load supported by generation produced from a Local Generator, other behind-the-meter generator, or other supply source located behind the meter operating during the Monthly SCR Zone Load Peak Hours may not be included in the metered Load values reported for the Monthly ACL.

Monthly SCR Load Zone Peak Hours: Beginning with the Summer 2014 Capability Period, the top forty (40) coincident peak hours for each month within a Capability Period that include hour beginning eleven through hour beginning nineteen as identified by the ISO for each Load Zone; provided, however, that such hours shall not include (i) hours in which Special Case Resources located in the specific Load Zone were called by the ISO to respond to a reliability event or test, (ii) hours for which the Emergency Demand Response Program resources were deployed by the ISO in each specific Load Zone and (iii) in descending rank order of NYCA Load up to a maximum of eight hours per month, a) the hour before the start time of a reliability event or performance test, in which SCRs located in the specific Load Zone were called by the ISO to respond to a reliability event or performance test, or b) the hour immediately following the end time of such reliability event or performance test.

Mothball Outage: The outage state in which a Market Participant's Generator is voluntarily removed from service on or after May 1, 2015, with applicable prior notice, for reasons not related to equipment failure. A Generator in Mothball Outage is subject to the return-to-service provisions in Section 5.18.4 of this Services Tariff and is ineligible to participate in the Installed Capacity market.

2.14 Definitions - N

Native Load Customers: The wholesale and retail power customers of the Transmission Owners on whose behalf the Transmission Owners, by statute, franchise, regulatory requirement, or contract, have undertaken an obligation to construct and operate the Transmission Owners' systems to meet the reliable electric needs of such customers.

NCZ Locational Minimum Installed Capacity Requirement: The amount of Capacity that must be electrically located within an NCZ, or possess an approved Unforced Capacity Deliverability Right, designed to ensure that sufficient Energy and Capacity are available in that NCZ and that appropriate reliability criteria are met.

NCZ Study Capability Period: The Summer Capability Period that begins five years from May 1 in a calendar year including an NCZ Study Start Date.

NCZ Study Start Date: September 1 or the next business day thereafter in the calendar year prior to an ICAP Demand Curve Reset Filing Year.

Neptune Scheduled Line: A transmission facility that interconnects the NYCA to the PJM Interconnection LLC Control Area at Levittown, Town of Hempstead, New York and terminates in Sayerville, New Jersey.

NERC: The North American Electric Reliability Council or, as applicable, the North American Electric Reliability Corporation.

Net Auction Revenue: As defined in the ISO OATT.

Net Average Coincident Load ("Net ACL"): The effective Average Coincident Load calculated and used by the ISO for a Special Case Resource during a specific month in which a SCR Change of Status was reported for the resource or, beginning with the Summer 2014 Capability Period, an Incremental Average Coincident Load was reported for the resource.

Net Benefits Test: The monthly calculations performed by the ISO in accordance with Section 4.2.1.9 of the ISO Services Tariff and ISO Procedures to determine the Monthly Net Benefit Offer Floor, the threshold price at which the dispatch of demand response resources meets the test required by Commission Order No. 745.

Net Congestion Rent: As defined in the ISO OATT.

Net Installed Capacity ("Net-ICAP"): The amount of Installed Capacity that a BTM:NG Resource has demonstrated (in accordance with ISO Procedures) it is capable of supplying in accordance with Section 5.12.6.1 of this Tariff, used to determine its Net Unforced Capacity.

Net Unforced Capacity ("Net-UCAP"): The amount of Unforced Capacity a BTM:NG Resource can offer in the ISO's Installed Capacity market.

Network Integration Transmission Service: The Transmission Service provided under Part 4 of the ISO OATT.

New Capacity Zone (“NCZ”): A single Load Zone or group of Load Zones that is proposed as a new Locality, and for which the ISO shall establish a Demand Curve.

New York City: The electrical area comprised of Load Zone J, as identified in the ISO Procedures.

New York Control Area (“NYCA”): The Control Area that is under the control of the ISO which includes transmission facilities listed in the ISO/TO Agreement Appendices A-1 and A-2, as amended from time-to-time, and generation located outside the NYS Power System that is subject to protocols (e.g., telemetry signal biasing) which allow the ISO and other Control Area operator(s) to treat some or all of that generation as though it were part of the NYS Power System.

New York Power Pool (“NYPP”): An organization established by agreement (the “New York Power Pool Agreement”) made as of July 21, 1966, and amended as of July 16, 1991, by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the Power Authority of the State of New York. LIPA became a Member of the NYPP on May 28, 1998 as a result of the acquisition of the Long Island Lighting Company by the Long Island Power Authority.

New York State Bulk Power Transmission Facility: This term shall have the meaning given in Attachment Y to the OATT.

New York State Power System (“NYS Power System”): All facilities of the NYS Transmission System, and all those Generators located within the NYCA or outside the NYCA, some of which may from time-to-time be subject to operational control by the ISO.

New York State Reliability Council ("NYSRC"): An organization established by agreement among the Member Systems to promote and maintain the reliability of the NYS Power System.

New York State Reliability Council Agreement ("NYSRC Agreement"): The agreement which established the NYSRC.

New York State Transmission System ("NYS Transmission System"): The entire New York State electric transmission system, which includes: (1) the Transmission Facilities Under ISO Operational Control; (2) the Transmission Facilities Requiring ISO Notification; and (3) all remaining transmission facilities within the NYCA.

Non-Competitive Proxy Generator Bus: A Proxy Generator Bus for an area outside of the New York Control Area that has been identified by the ISO as characterized by non-competitive Import or Export prices, and that has been approved by the Commission for designation as a Non-Competitive Proxy Generator Bus. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff., as set forth in Section 4.4.2.2 of the MST

Non-Firm-Point-To-Point Transmission Service: Point-To-Point Transmission Service for which a Transmission Customer is not willing to pay Congestion. Such service is not available in the markets that the NYISO administers.

Non-Investment Grade Customer: A Customer that does not meet the criteria necessary to be an Investment Grade Customer, as set forth in Section 26.3 of Attachment K to this Services Tariff.

Non-Utility Generator ("NUG," "Independent Power Producer" or "IPP"): Any entity that owns or operates an electric generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other non-utility electricity producers, such as exempt wholesale Generators that sell electricity.

Normal State: The condition that the NYS Power System is in when the Transmission Facilities Under ISO Operational Control are operated within the parameters listed for Normal State in the Reliability Rules. These parameters include, but are not limited to, thermal, voltage, stability, frequency, operating reserve and Pool Control Error limitations.

Normal Upper Operating Limit (UOL_N): The upper operating limit that a Generator, except for the Generator of a BTM:NG Resource, indicates it expects to be able to reach, or the upper operating limit a BTM:NG Resource indicates it expects to be able to inject into the grid after serving its Host Load and subject to its Injection Limit, or the maximum amount of demand that a Demand Side Resource expects to be able to reduce, during normal conditions. Each Resource will specify its UOL_N in its Bids which shall be reduced when the Resource requests that the ISO derate its Capacity or the ISO derates the Resource's Capacity. A Normal Upper Operating Limit may be submitted as a function depending on one or more variables, such as temperature or pondage levels, in which case the Normal Upper Operating Limit applicable at any time shall be determined by reference to that schedule.

Northport-Norwalk Scheduled Line: A transmission facility that originates at the Northport substation in New York and interconnects the NYCA to the ISO New England Control Area at the Norwalk Harbor substation in Connecticut.

Notice of Intent to Return: The notice a Supplier with a Generator that is in a Mothball Outage or ICAP Ineligible Forced Outage provides to the ISO, pursuant to ISO Procedures, that gives the date by which it intends to return to the Energy market, which proposed return date shall be no later than the expiration date of the Generator's Mothball Outage or ICAP Ineligible Forced Outage.

NPCC: The Northeast Power Coordinating Council.

NRC: The Nuclear Regulatory Commission or any successor thereto.

NYCA Installed Reserve Margin: The ratio of the amount of additional Installed Capacity required by the NYSRC in order for the NYCA to meet NPCC reliability criteria to the forecasted NYCA upcoming Capability Year peak Load, expressed as a decimal.

NYCA Minimum Installed Capacity Requirement: The requirement established for each Capability Year by multiplying the NYCA peak Load forecasted by the ISO by the quantity one plus the NYCA Installed Reserve Margin.

NYCA Minimum Unforced Capacity Requirement: The Unforced Capacity equivalent of the NYCA Minimum Installed Capacity Requirement.

NYPA: The Power Authority of the State of New York.

NYPA Tax-Exempt Bonds: Obligations of the New York Power Authority, the interest on which is not included in gross income under the Internal Revenue Code.

2.15 Definitions - O

Obligation Procurement Period: The period of time for which LSEs shall be required to satisfy their Unforced Capacity requirements. Starting with the 2001-2002 Winter Capability Period, Obligation Procurement Periods shall be one calendar month in duration and shall begin on the first day of each calendar month.

Off-Peak: The hours between 11 p.m. and 7 a.m., prevailing Eastern Time, Monday through Friday, and all day Saturday and Sunday, and NERC-defined holidays, or as otherwise decided by the ISO.

Offeror: An entity that offers to sell Unforced Capacity in an auction.

On-Peak: The hours between 7 a.m. and 11 p.m. inclusive, prevailing Eastern Time, Monday through Friday, except for NERC-defined holidays, or as otherwise decided by the ISO.

Open Access Same-Time Information System ("OASIS"): The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Operating Agreement: An agreement between the ISO and a non-incumbent owner of transmission facilities in the New York Control Area concerning the operation of the transmission facilities in the form of the agreement set forth in Appendix H (Section 31.11) of Attachment Y of the OATT.

Operating Capacity: Capacity that is readily converted to Energy and is measured in MW.

Operating Committee: A standing committee of the ISO created pursuant to the ISO Agreement, which coordinates operations, develops procedures, evaluates proposed system expansions and acts as a liaison to the NYSRC.

Operating Data: Pursuant to Section 5.12.5 of this Tariff, Operating Data shall mean GADS Data, data equivalent to GADS Data, CARL Data, metered Load data, or actual system failure occurrences data, all as described in the ISO Procedures.

Operating Requirement: The amount calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Operating Reserves : Capacity that is available to supply Energy or reduce demand and that meets the requirements of the ISO. The ISO will administer Operating Reserves markets, in the manner described in this Article 4 and Rate Schedule 4 of this ISO Services Tariff, to satisfy the various Operating Reserves requirements, including locational requirements, established by the Reliability Rules and other applicable reliability standards. The basic Operating Reserves products that will be procured by the ISO on behalf of the market are classified as follows:

(1) Spinning Reserve: Operating Reserves provided by Generators and Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO

Services Tariff that are already synchronized to the NYS Power System and can respond to instructions to change their output level, or reduce their Energy usage, within ten (10) minutes. Spinning Reserves may not be provided by Demand Side Resources that are Local Generators or by Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit;

(2)	10-Minute Non-Synchronized Reserve: Operating Reserves provided by Generators Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit,, or Demand Side Resources, including Demand Side Resources using Local Generators, that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can be started, synchronized and can change their output level within ten (10) minutes; and

(3)	30-Minute Reserve: Synchronized Operating Reserves provided by Generators, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, and Demand Side Resources that are not Local Generators; or non-synchronized Operating Reserves provided by Generators, Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, or Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can respond to instructions to change their output level within thirty (30) minutes, including starting and synchronizing to the NYS Power System.

Operating Reserve Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Operating Reserves meeting a particular Operating Reserve requirement corresponding to each possible quantity of Resources that the ISO's software may schedule to meet that requirement. A single Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for each of the ISO's twelve Operating Reserve requirements.

Operating Study Power Flow: A Power Flow analysis that is performed at least once before each Capability Period that is used to determine each Interface Transfer Capability for the Capability Period (See Attachment M to the ISO OATT).

Operational Control: Directing the operation of the Transmission Facilities Under ISO Operational Control to maintain these facilities in a reliable state, as defined by the Reliability Rules. The ISO shall approve operational decisions concerning these facilities, made by each Transmission Owner before the Transmission Owner implements those decisions. In accordance with ISO Procedures, the ISO shall direct each Transmission Owner to take certain actions to restore the system to the Normal State. Operational Control includes security monitoring, adjustment of generation and transmission resources, coordination and approval of changes in transmission status for maintenance, determination of changes in transmission status for reliability, coordination with other Control Areas, voltage reductions and Load Shedding, except that each Transmission Owner continues to physically operate and maintain its facilities, including those facilities that it has agreed to operate and maintain in accordance with an operation and maintenance agreement.

Optimal Power Flow ("OPF"): As defined in the ISO OATT.

Order Nos. 888 et seq.: The Final Rule entitled Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, issued by the Commission on April 24, 1996, in Docket Nos. RM95-8-000 and RM94-7-001, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles January 1991 - June 1996] ¶ 31,036 (1996) ("Order No. 888"), on reh'g, III FERC Stats. & Regs. ¶ 31,048 (1997) ("Order No. 888-A"), on reh'g, 81 FERC ¶ 61,248 (1997) ("Order No. 888-B"), order on reh'g, 82 FERC ¶ 61,046 (1998) ("Order No. 888-C")).

Order Nos. 889 et seq.: The Final Rule entitled Open Access Same-Time Information System (formerly Real- Time Information Networks) and Standards of Conduct, issued by the Commission on April 24, 1996, in Docket No. RM95-9-000, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31,035 (1996) ("Order No. 889"), on reh'g, III FERC Stats. & Regs. ¶ 31,049 (1997) ("Order No. 889-A"), on reh'g, 81 FERC ¶ 61,253 (1997) ("Order No. 889-B")).

Original Residual TCC: As defined in the ISO OATT.

Out-of-Merit: The designation of Resources committed and/or dispatched by the ISO at specified output limits for specified time periods to meet Load and/or reliability requirements that differ from or supplement the ISO's security constrained economic commitment and/or dispatch.

2.16 Definitions - P

Performance Index: An index, described in ISO Procedures, that tracks a Generator's response to AGC signals from the ISO.

Performance Tracking System: A system designed to report metrics for Generators and Loads which include but are not limited to actual output and schedules. This system is used by the ISO to measure compliance with criteria associated with the provision of Energy and Ancillary Services.

Point-to-Point Transmission Service: The reservation and transmission of Capacity and Energy on a firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the ISO Tariffs.

Point(s) of Delivery: Point(s) on the NYS Transmission System or Proxy Generator Buses where Energy transmitted by the ISO will be made available to the Transmission Customer under the OATT. The Point(s) of Delivery shall be specified pursuant to ISO Procedures.

Point(s) of Injection ("POI" or "Point of Receipt"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy, Capacity and Ancillary Services will be made available to the ISO by the delivering party under the ISO OATT or the ISO Services Tariff. (May be referred to as "Point of Receipt" or similar in some Existing Transmission Agreements.)

Point(s) of Receipt: Point(s) of interconnection on the NYS Transmission System or Proxy Generator Buses where Energy will be made available to the ISO by the Transmission Customer under the OATT. The Point(s) of Receipt shall be specified pursuant to ISO Procedures.

Point(s) of Withdrawal ("POW" or "Point of Delivery"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy, Capacity and Ancillary Services will be made available to the receiving party under the ISO OATT or the ISO Services Tariff. (May be referred to as "Point of Delivery" or similar in some Existing Transmission Agreements.)

Pool Control Error ("PCE"): The difference between the actual and scheduled interchange with other Control Areas, adjusted for frequency bias.

Post Contingency: Conditions existing on a system immediately following a Contingency.

Power Exchange ("PE"): A commercial entity meeting the requirements for service under the ISO OATT or the ISO Services Tariff that facilitates the purchase and/or sale of Energy, Unforced Capacity and/or Ancillary Services in a New York Wholesale Market. A PE may transact with the ISO on its own behalf or as an agent for others.

Power Factor: The ratio of real power to apparent power (the product of volts and amperes, expressed in megavolt-amperes, MVA).

Power Factor Criteria: Criteria to be established by the ISO to monitor a Load's use of Reactive Power.

Power Flow: A simulation which determines the Energy flows on the NYS Transmission System and adjacent transmission systems.

Price Adjustment: For each month in the Prior Equivalent Capability Period, the Price Adjustment equals the quotient of dividing (a) the Henry Hub futures gas price for the like month in the succeeding same-season Capability Period by (b) the average Henry Hub spot gas price for that month in the Prior Equivalent Capability Period.

Primary Holder: As defined in the ISO OATT.

Prior Equivalent Capability Period: The previous same-season Capability Period.

Provisional Average Coincident Load ("Provisional ACL"): Prior to the Summer 2014 Capability Period, the value that may be used in lieu of Average Coincident Load for an eligible Special Case Resource for a maximum duration no greater than three consecutive Capability Periods and only where the SCR (i) has not previously been enrolled with the ISO and (ii) never had interval metering Load data available from the Prior Equivalent Capability Period. Beginning with the Summer 2014 Capability Period, the value that may be used in lieu of ACL for an eligible SCR as provided in Section 5.12.11.1.2 of this Services Tariff. A SCR's Provisional ACL is verified subsequent to each eligible Capability Period pursuant to calculations using the SCR's metered Load values in accordance with Sections 5.12.11.1.1 and 5.12.11.1.2 of this Services Tariff and ISO Procedures. Any Load supported by generation produced from a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter operating during the applicable Capability Period SCR Load Zone Peak Hours may not be included in the SCR's metered Load values reported for the verification of its Provisional ACL.

Proxy Generator Bus: A proxy bus located outside the NYCA that is selected by the ISO to represent a typical bus in an adjacent Control Area and at which LBMP prices are calculated. The ISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services at the Interface.

PSC: The Public Service Commission of the State of New York or any successor agency thereto.

PSL: The New York Public Service Law, Public Service Law § 1 et seq. (McKinney 1989 & Supp. 1997-98).

Public Power Entity: An entity which is either (i) a public authority or corporate municipal instrumentality, including a subsidiary thereof, created by the State of New York that owns or operates generation or transmission and that is authorized to produce, transmit or distribute electricity for the benefit of the public, or (ii) a municipally owned electric system that owns or controls distribution facilities and provides electric service, or (iii) a cooperatively owned electric system that owns or controls distribution facilities and provides electric service.

2.17 Definitions - Q

Qualified Change of Load Condition: A Special Case Resource enrolled with an Average Coincident Load, Provisional Average Coincident Load, or Net Average Coincident Load, in accordance with this Services Tariff, meets a Qualified Change of Load Condition when: (i) the SCR is expected to have a reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that is expected to continue for a total period that is greater than seven (7) consecutive days, (ii) the SCR is experiencing a reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that is expected to continue for a total period that is greater than seven (7) consecutive days, or (iii) the SCR experienced an unanticipated reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold for a period greater than seven (7) consecutive days within any month in which the SCR sold capacity or adjoining months in which the SCR sold capacity in either month.

Qualified Change of Status Condition: A Special Case Resource enrolled with an Average Coincident Load, Provisional Average Coincident Load, or Net Average Coincident Load, in accordance with this Services Tariff meets a Qualified Change of Status Condition when: (i) the SCR is expected to have a reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that will extend for a period of greater than sixty (60) consecutive days, (ii) the SCR is experiencing a reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that is expected to continue for a total period that is greater than sixty (60) consecutive days, or (iii) the SCR has experienced an unanticipated reduction in total Load that meets or exceeds the SCR Load Change Reporting Threshold that has existed for a period greater than sixty (60) consecutive days in which the SCR sold capacity.

Qualified Non-Generator Voltage Support Resource: A resource that is neither a Generator nor a synchronous condenser but that is capable of providing the ISO with Reactive Power on a dynamic basis, that is energized and under the operational control of the ISO, or a Transmission Owner, that meets the resource-specific technical and testing criteria specified in the ISO Procedures, and that is ineligible to receive Reactive Power compensation other than as a Qualified Non-Generator Voltage Support Resource. The Cross-Sound Scheduled Line shall be a Qualified Non-Generator Voltage Support Resource, provided that it meets the technical and testing criteria in the ISO Procedures.

Quick Start Mode: The setting of a block of generator units capable of remote start-up by a Transmission Owner so that it can synchronize and reach full output within fifteen (15) minutes.

Quick Start Reserves: Capacity of a block of generator units that is set to Quick Start Mode by request of a Transmission Owner.

2.18 Definitions - R

Ramp Capacity: The amount of change in the Desired Net Interchange that generation located in the NYCA can support at any given time. Ramp capacity may be calculated for all Interfaces between the NYCA and neighboring Control Areas as a whole or for any individual Interface between the NYCA and an adjoining Control Area.

RCRR TCC: As defined in the ISO OATT.

Reactive Power (MVAr): The product of voltage and the out-of-phase component of alternating current. Reactive Power, usually measured in MVAr, is produced by capacitors (synchronous condensers), Qualified Non-Generator Voltage Support Resources, and over-excited Generators and absorbed by reactors or under-excited Generators and other inductive devices including the inductive portion of Loads.

Real Power Losses: The loss of Energy, resulting from transporting power over the NYS Transmission System, between the Point of Injection and Point of Withdrawal of that Energy.

Real-Time Bid: A Bid submitted into the Real-Time Commitment before the close of the Real-Time Scheduling Window. A Real-Time Bid shall also include a CTS Interface Bid.

Real-Time Commitment ("RTC"): A multi-period security constrained unit commitment and dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves and Regulation Service on a least as-bid production cost basis over a two hour and fifteen minute optimization period. The optimization evaluates the next ten points in time separated by fifteen minute intervals. Each RTC run within an hour shall have a designation indicating the time at which its results are posted; "$RTC_{00,}$" "$RTC_{15,}$" "$RTC_{30,}$" and "RTC_{45}" post on the hour, and at fifteen, thirty, and forty-five minutes after the hour, respectively. Each RTC run will produce binding commitment instructions for the periods beginning fifteen and thirty minutes after its scheduled posting time and will produce advisory commitment guidance for the remainder of the optimization period. RTC_{15} will also establish hourly External Transaction schedules, while all RTC runs may establish 15 minute External Transaction schedules at Variably Scheduled Proxy Generator Buses. Additional information about RTC's functions is provided in Section 4.4.2 of this ISO Services Tariff.

Real-Time Dispatch ("RTD"): A multi-period security constrained dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least-as-bid production cost basis over a fifty, fifty-five or sixty-minute period (depending on when each RTD run occurs within an hour). The Real-Time Dispatch dispatches, but does not commit, Resources, except that RTD may commit, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting in ten minutes. RTD may also establish 5 minute External Transaction schedules at Dynamically Scheduled Proxy Generator Buses. Real-Time Dispatch runs will normally occur every five minutes. Additional information about RTD's functions is provided in Section 4.4.3 of this ISO Services Tariff. Throughout this ISO Services Tariff the term "RTD" will normally be used to refer to both the Real-Time Dispatch and to the specialized Real-Time Dispatch Corrective Action Mode software.

Real-Time Dispatch–Corrective Action Mode (“RTD-CAM”): A specialized version of the Real-Time Dispatch software that will be activated when it is needed to address unanticipated system conditions. RTD-CAM is described in Section 4.4.4 of this ISO Services Tariff.

Real-Time LBMP: The LBMPs established through the ISO Administered Real-Time Market.

Real-Time Market: The ISO Administered Markets for Energy and Ancillary Services resulting from the operation of the RTC and RTD.

Real-Time Minimum Run Qualified Gas Turbine: One or more gas turbines, offered in the Real-Time Market, which, because of their physical operating characteristics, may qualify for a minimum run time of two hours in the Real-Time Market. Characteristics that qualify gas turbines for this treatment are established by ISO Procedures and include using waste heat from the gas turbine-generated electricity to make steam for the generation of additional electricity via a steam turbine.

Real-Time Scheduled Energy: The quantity of Energy that a Supplier is directed to inject or withdraw in real-time by the ISO. Injections are indicated by positive Base Point Signals and withdrawals are indicated by negative Base Point Signals. Unless otherwise directed by the ISO, Dispatchable Supplier’s Real-Time Scheduled Energy is equal to its RTD Base Point Signal, or, if it is providing Regulation Service, to its AGC Base Point Signal, and an ISO Committed Fixed or Self-Committed Fixed Supplier’s Real-Time Scheduled Energy is equal to its bid output level in real-time.

Real-Time Scheduling Window: The period of time within which the ISO accepts offers and bids to sell and purchase Energy and Ancillary Services in the Real-Time Market for a given hour which period closes seventy-five (75) minutes before the start of that hour, or eighty-five (85) minutes before the start of that hour for Bids to schedule External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line.

Reconfiguration Auction: As defined in the ISO OATT.

Reference Bus: The location on the NYS Transmission System relative to which all mathematical quantities, including Shift Factors and penalty factors relating to physical operation, will be calculated. The NYPA Marcy 345 kV transmission substation is designated as the Reference Bus.

Regulation Capacity: The Energy or Demand Reduction capability, measured in MW, that a Regulation Service provider offers and/or which it is scheduled to provide for Regulation Service.

Regulation Capacity Market Price: The price for Regulation Capacity determined by the ISO pursuant to section 15.3 of this Services Tariff.

Regulation Capacity Response Rate: The Regulation Capacity a Resource is capable of providing over five minutes, measured in MW/minute which shall not exceed the lowest normal energy response rate provided for the Resource and which must be sufficient to permit that

Resource to provide the Regulation Capacity (in MW) offered within a five-minute RTD interval. Reference to a Regulation response rate shall be a reference to the Regulation Capacity Response Rate.

Regulation Movement: The absolute value of the change in Energy or Demand Reduction over a six second interval, measured in MW, that a Regulation Service provider is instructed to deliver for the purpose of providing Regulation Service.

Regulation Movement Market Price: The price for Regulation Movement as determined by the ISO pursuant to section 15.3 of this Services Tariff.

Regulation Movement Multiplier: A factor with the value of thirteen (13), used with the Regulation Movement Bids, to schedule Regulation Service providers in both the Day-Ahead and Real-Time Energy markets. The ISO calculates the Regulation Movement Multiplier based on the historical relationship between the number of MW of Regulation Capacity that the ISO seeks to maintain in each hour and the number of Regulation Movement MW instructed by AGC in each hour.

Regulation Movement Response Rate: The amount of Regulation Movement a Regulation Service provider is capable of delivering in six seconds which shall not be less than, but can be equal to or greater than, the Regulation Capacity Response Rate equivalent.

Regulation Service: The Ancillary Service defined by the Commission as "frequency regulation" and that is instructed as Regulation Capacity in the Day-Ahead Market and as Regulation Capacity and Regulation Movement in the Real-Time Market as is further described in Section 15.3 of the Services Tariff. Day-Ahead and Real-Time Bids to provide Regulation Service shall include a Bid for Regulation Capacity and a Bid for Regulation Movement. The Regulation Service requirement or target level shall be for MW of Regulation Capacity.

Regulation Service Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Regulation Service corresponding to each possible quantity of Resources that the ISO's software may schedule to satisfy the ISO's Regulation Service constraint. A single Regulation Service Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for Regulation Service. The Shadow Price for Regulation Service shall be used to calculate Regulation Service payments under Rate Schedule 3 of this ISO Services Tariff.

Regulation Revenue Adjustment Charge ("RRAC"): A charge that will be assessed against certain Generators that are providing Regulation Service under Section 15.3.6 of Rate Schedule 3 to this ISO Services Tariff.

Regulation Revenue Adjustment Payment ("RRAP"): A payment that will be made to certain Generators that are providing Regulation Service under Section 15.3.6 of Rate Schedule 3 to this ISO Services Tariff.

Reliability Rules: Those rules, standards, procedures and protocols developed and promulgated by the NYSRC, including Local Reliability Rules, in accordance with NERC, NPCC, FERC, PSC and NRC standards, rules and regulations and other criteria and pursuant to the NYSRC Agreement.

Repair Plan: A work plan, set of actions, and time frame for such actions, that is necessary to repair a Generator and return it to service as described in Section 5.18.1 of this Services Tariff**.**

Required System Capability: Generation capability required to meet an LSE's peak Load plus Installed Capacity Reserve obligation as defined in the Reliability Rules.

Reserve Performance Index: An index created by the ISO for the purpose of calculating the Day Ahead Margin Assurance Payment pursuant to Attachment J of this Services Tariff made to Demand Side Resources scheduled to provide Operating Reserves in the Day-Ahead Market.

Residual Adjustment: The adjustment made to ISO costs that are recovered through Schedule 1 of the OATT. The Residual Adjustment is calculated pursuant to Schedule 1 of the OATT.

Residual Capacity Reservation Right ("RCRR"): As defined in the ISO OATT.

Residual Transmission Capacity: As defined in the ISO OATT.

Resource: An Energy Limited Resource, Generator, Installed Capacity Marketer, Special Case Resource, Intermittent Power Resource, Limited Control Run of River Hydro Resource, municipally-owned generation, System Resource, BTM:NG Resource, Demand Side Resource or Control Area System Resource.

Responsible Interface Party ("RIP"): A Customer that is authorized by the ISO to be the Installed Capacity Supplier for one or more Special Case Resources and that agrees to certain notification and other requirements as set forth in this Services Tariff and in the ISO Procedures.

Rest of State: The set of all non-Locality NYCA LBMP Load Zones. As of the 2014/2015 Capability Year, Rest of State includes all NYCA LBMP Load Zones other than LBMP Load Zones G, H, I, J and K.

Retired: A Generator that has permanently ceased operating on or after May 1, 2015 either: i) pursuant to applicable notice; or ii) as a result of the expiration of its Mothball Outage or of its ICAP Ineligible Forced Outage.

RMR Agreement: shall have the meaning specified in Section 1.18 of the ISO's Open Access Transmission Tariff.

RMR Avoidable Costs: shall have the meaning specified in Section 1.18 of the ISO's Open Access Transmission Tariff.

RMR Generator: shall have the meaning specified in Section 1.18 of the ISO's Open Access Transmission Tariff.

Rolling RTC: The RTC run that is used to schedule a given 15-minute External Transaction. The Rolling RTC may be an RTC00, RTC15, RTC30 or RTC45 run.

2.19 Definitions - S

Safe Operations: Actions which avoid placing personnel and equipment in peril with regard to the safety of life and equipment damage.

Scarcity Reserve Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Operating Reserves to meet a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(b) of Rate Schedule 4 of this ISO Services Tariff apply corresponding to each possible quantity of Resources that the ISO's software may schedule to satisfy that requirement. A single Scarcity Reserve Demand Curve will apply to the Real-Time Market for each such Scarcity Reserve Requirement.

Scarcity Reserve Region: A Load Zone or group of Load Zones containing EDRP and/or SCRs that have been called by the ISO to address the same reliability need, as such reliability need is determined by the ISO.

Scarcity Reserve Requirement: A 30-Minute Reserve requirement established by the ISO for a Scarcity Reserve Region in accordance with Rate Schedule 4 of this ISO Services Tariff.

Scheduled Energy Injections: As defined in the ISO OATT.

Scheduled Energy Withdrawals: As defined in the ISO OATT.

Scheduled Line: A transmission facility or set of transmission facilities: (a) that provide a distinct scheduling path interconnecting the ISO with an adjacent control area, (b) over which Customers are permitted to schedule External Transactions, (c) for which the ISO separately posts TTC and ATC, and (d) for which there is the capability to maintain the Scheduled Line actual interchange at the DNI, or within the tolerances dictated by Good Utility Practice. Each Scheduled Line is associated with a distinct Proxy Generator Bus. Transmission facilities shall only become Scheduled Lines after the Commission accepts for filing revisions to the NYISO's tariffs that identify a specific set or group of transmission facilities as a Scheduled Line. The transmission facilities that are Scheduled Lines are identified in Section 4.4.4 of the Services Tariff.

SCR Aggregation: One or more Special Case Resources registered by the Responsible Interface Party at a single PTID, with the Load of each Special Case Resource electrically located within the same single Load Zone and the total of all Loads at the PTID greater than or equal to 0.1 MW.

SCR Change of Load: A decrease in the Load of the SCR that meets the criteria of a Qualified Change of Load Condition and the SCR Load Change Reporting Threshold in accordance with this Services Tariff and results in a total Load reduction, within the range of hours that corresponds with the Capability Period SCR Load Zone Peak Hours, and the total Load reduction persists for more than seven (7) and less than or equal to sixty (60) continuous days from the first date of the reduction of the Load.

SCR Change of Status: The decrease to be treated as an adjustment to the applicable Average Coincident Load of a Special Case Resource when the SCR meets the criteria of a Qualified

Change of Status Condition and the SCR Load Change Reporting Threshold in accordance with this Services Tariff and results in a total Load reduction, within the range of hours that corresponds with the Capability Period SCR Load Zone Peak Hours, and the total Load reduction persists for more than sixty (60) continuous days from the first date of the reduction of the Load.

SCR Load Change Reporting Threshold: For a Special Case Resource with an applicable ACL greater than or equal to 500 kW, a reduction or increase in total Load not attributable to fluctuations in Load due to weather as described in ISO Procedures, that is equal to or greater than (i) thirty (30) percent of the applicable ACL for any month within the Capability Period, or (ii) five (5) MW in the NYC Locality or ten(10) MW if in any other Load Zone; whichever is less. For SCRs that elect to enroll with an Incremental ACL and do not increase the eligible Installed Capacity associated with the SCR, the RIP may enroll the SCR with a lower percentage change to its total Load increase as specified in Section 5.12.11.1.5 of this Services Tariff.

SCUC: Security Constrained Unit Commitment, described in Section 4.2.4 of this ISO Services Tariff.

Secondary Holder: As defined in the ISO OATT.

Second Settlement: The process of: (1) identifying differences between Energy production, Energy consumption or NYS Transmission System usage scheduled in a First Settlement and actual production, consumption, or usage during the Dispatch Day; and (2) assigning financial responsibility for those differences to the appropriate Customers and Market Participants. Charges for Energy supplied (to replace generation deficiencies or unscheduled consumption), and payments for Energy consumed (to absorb consumption deficiencies or excess Energy supply) or changes in transmission usage will be based on the Real-Time LBMPs.

Secondary Market: As defined in the ISO OATT.

Security Coordinator: An entity that provides the security assessment and Emergency operations coordination for a group of Control Areas. A Security Coordinator must not participate in the wholesale or retail merchant functions.

Self-Committed Fixed: A bidding mode in which a Generator is self-committed and opts not to be Dispatchable over any portion of its operating range.

Self-Committed Flexible: A bidding mode in which a Dispatchable Generator follows Base Point Signals within a portion of its operating range, but self-commits.

Self-Supply: The provision of certain Ancillary Services, or the provision of Energy to replace Marginal Losses by a Transmission Customer using either the Transmission Customer’s own Generators or generation obtained from an entity other than the ISO.

Service Agreement: The agreement, in the form of Attachment A to the Tariff, and any amendments or supplements thereto entered into by a Customer and the ISO of service under the Tariff, or any unexecuted Service Agreement, amendments or supplements thereto, that the ISO unilaterally files with the Commission.

Service Commencement Date: The date that the ISO begins to provide service pursuant to the terms of a Service Agreement, or in accordance with the Tariff.

Settlement: The process of determining the charges to be paid to, or by, a Customer to satisfy its obligations.

Shadow Price: The marginal value of relieving a particular Constraint which is determined by the reduction in system cost that results from an incremental relaxation of that Constraint.

Shift Factor ("SF"): A ratio, calculated by the ISO, that compares the change in power flow through a transmission facility resulting from the incremental injection and withdrawal of power on the NYS Transmission System.

Shutdown Period: An ISO approved period of time immediately following a shutdown order, such as a zero base point, that has been designated by the Customer, during which unstable operation prevents the unit from accurately following its base points.

Sink Price Cap Bid: A monotonically increasing Bid curve provided by an entity engaged in an Export, other than an entity submitting a CTS Interface Bid, to indicate the relevant Proxy Generator Bus LBMP at or below which that entity is willing to either purchase Energy in the LBMP Markets or, in the case of Bilateral Transactions, to accept Transmission Service, where the MW amounts on the Bid curve represent the desired increments of Energy that the entity is willing to purchase at various price points.

Southeastern New York ("SENY"): An electrical area comprised of Load Zones G, H, I, J, and K, as identified in the ISO Procedures.

Special Case Resource ("SCR"): Demand Side Resources whose Load is capable of being interrupted upon demand at the direction of the ISO, and/or Demand Side Resources that have a Local Generator, which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System or the distribution system at the direction of the ISO. Special Case Resources are subject to special rules, set forth in Section 5.12.11.1 of this ISO Services Tariff and related ISO Procedures, in order to facilitate their participation in the Installed Capacity market as Installed Capacity Suppliers. SCRs that do not use Local Generators may be offered as synchronized Operating Reserves and Regulation Service and Energy in the Day-Ahead Market. SCRs, using Local Generators rated 100 kW or higher, that are not visible to the ISO's Market Information System may also be offered as non-synchronized Operating Reserves.

Special Case Resource Capacity: The Installed Capacity Equivalent of the Unforced Capacity which has been sold by a Special Case Resource in the Installed Capacity market during the current Capability Period.

Start-Up Period: An ISO approved period of time immediately following synchronization to the Bulk power system, which has been designated by a Customer and bid into the Real-Time Market, during which unstable operation prevents the unit from accurately following its base points. The Start-Up Period shall be set to zero for a BTM:NG Resource.

Station Power: Station Power shall mean the Energy used by a Generator:

1. for operating electric equipment located on the Generator site, or portions thereof, owned by the same entity that owns the Generator, which electrical equipment is used by the Generator exclusively for the production of Energy and any useful thermal energy associated with the production of Energy; and
2. for the incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are: owned by the same entity that owns the Generator; located on the Generator site; and
3. used by the Generator exclusively in connection with the production of Energy and any useful thermal energy associated with the production of Energy.

Station Power does not include any Energy: (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility or for charging a Limited Energy Storage Resource; or (iii) provided during a Black Start restoration by Generators that provide Black Start Capability Service.

Start-Up Bid: A Bid parameter that may vary hourly and that identifies the payment a Supplier requires to bring a Generator up to its specified minimum operating level from an offline state or a Demand Side Resource from a level of no Demand Reduction to its specified minimum level of Demand Reduction. If the Supplier is a BTM:NG Resource, it shall not submit a Start-Up Bid.

Start-Up Bids submitted for a Generator that is not able to complete its specified minimum run time (of up to a maximum of 24 hours) within the Dispatch Day are expected to include expected net costs related to the hour(s) that a Generator needs to run on the day following the Dispatch Day in order to complete its minimum run time. The component of the Start-Up Bid that incorporates costs that the Generator expects to incur on the day following the Dispatch Day is expected to reflect the operating costs that the Supplier does not expect to be able to recover through LBMP revenues while operating to meet the Generator’s minimum run time, at the minimum operating level Bid for that Generator for the hour of the Dispatch Day in which the Generator is scheduled to start-up. Settlement rules addressing Start-Up Bids that incorporates costs related to the hours that a Generator needs to run on the day following the Dispatch Day on which the Generator is committed are set forth in Attachment C to this ISO Services Tariff.

Storm Watch: Actual or anticipated severe weather conditions under which region-specific portions of the NYS Transmission System are operated in a more conservative manner by reducing transmission transfer limits.

Strandable Costs: Prudent and verifiable expenditures and commitments made pursuant to a Transmission Owner’s legal obligations that are currently recovered in the Transmission Owner’s retail or wholesale rate that could become unrecoverable as a result of a restructuring of the electric utility industry and/or electricity market, or as a result of retail-turned-wholesale customers, or customers switching generation or Transmission Service suppliers.

Stranded Investment Recovery Charge: A charge established by a Transmission Owner to recover Strandable Costs.

Study Month: The calendar month for which the ISO calculates the Monthly Net Benefit Offer Floor, in accordance with Section 4.2.1.9 of the ISO Services Tariff and ISO Procedures.

Subzone: That portion of a Load Zone in a Transmission Owner's Transmission District.

Supplemental Event Interval: Any RTD interval in which there is a maximum generation pickup or a large event reserve pickup or which is one of the three RTD intervals following the termination of the maximum generation pickup or the large event reserve pickup.

Supplemental Resource Evaluation ("SRE"): A determination of the least cost selection of additional Generators, which are to be committed, to meet: (i) changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to meet the reliability requirements of the Transmission Owner's local system or to meet Load or reliability requirements of the ISO; or (ii) forecast Load and reserve requirements over the six-day period that follows the Dispatch Day.

Supplier: A Party that is supplying the Capacity, Demand Reduction, Energy and/or associated Ancillary Services to be made available under the ISO OATT or the ISO Services Tariff, including Generators, BTM:NG Resources, and Demand Side Resources that satisfy all applicable ISO requirements.

System Resource: A portfolio of Unforced Capacity provided by Resources located in a single ISO-defined Locality, the remainder of the NYCA, or any single External Control Area, that is owned by or under the control of a single entity, which is not the operator of the Control Area where such Resources are located, and that is made available, in whole or in part, to the ISO.

2.20 Definitions - T

Tangible Net Worth: The value, determined by the ISO, of all of a Customer's assets less both: (i) the amount of the Customer's liabilities and (ii) all of the Customer's intangible assets, including, but not limited to, patents, trademarks, franchises, intellectual property, and goodwill.

Testing Period: An ISO approved period of time during which a Generator is testing equipment and during which unstable operation prevents the unit from accurately following its base points.

Third Party Transmission Wheeling Agreements ("Third Party TWAs"): A Transmission Wheeling Agreement, as amended, between Transmission Owners or between a Transmission Owner and an entity that is not a Transmission Owner. Third Party TWAs are associated with the purchase (or sale) of Energy, Capacity, and/or Ancillary Services for the benefit of an entity that is not a Transmission Owner. All Third Party TWAs are listed in Table 1 A of Attachment L to the ISO OATT, and are designated in the "Treatment "column of Table 1A, as "Third Party TWA."

Total Transfer Capability ("TTC"): The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner**.**

Trading Hub: A virtual location in a given Load Zone, modeled as a Generator bus and/or Load bus, for scheduling Bilateral Transactions in which both the POI and POW are located within the NYCA.

Trading Hub Energy Owner: A Customer who buys energy in a Bilateral Transaction in which the POW is a Trading Hub, or who sells energy in a Bilateral Transaction in which the POI is a Trading Hub.

Transaction: The purchase and/or sale of Energy or Capacity, or the sale of Ancillary Services. A Transaction bid into the Energy market to sell or purchase Energy or to schedule a Bilateral Transaction includes a Point of Injection and a Point of Withdrawal.

Transfer Capability: The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission facilities (or paths) between those areas under specified system conditions.

Transmission Congestion Contract Component ("TCC Component"): A component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Transmission Congestion Contracts ("TCCs"): As defined in the ISO OATT.

Transmission Customer: Any entity (or its designated agent) that requests or receives Transmission Service pursuant to a Service Agreement and the terms of the ISO OATT.

Transmission District: The geographic area in which a Transmission Owner, including LIPA, is obligated to serve Load, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York.

Transmission Facilities Under ISO Operational Control: The transmission facilities of the Transmission Owners listed in Appendix A-1 of the ISO/TO Agreement ("Listing of Transmission Facilities Under ISO Operational Control") and listed in Appendix A-1 of an Operating Agreement ("NTO Transmission Faciilities Under ISO Operational Control") that are subject to the Operational Control of the ISO. This listing may be amended from time-to-time as specified in the ISO/TO Agreement and Operating Agreements.

Transmission Facilities Requiring ISO Notification: The transmission facilities of the Transmission Owners listed in Appendix A-2 of the ISO/TO Agreement ("Listing of Transmission Facilities Requiring ISO Notification") and listed in Appendix A-2 of an Operating Agreement ("NTO Transmission Facilities Requiring ISO Notification") whose status of operation must be provided to the ISO by the Transmission Owners (for the purposes stated in the ISO Tariffs and in accordance with the ISO Tariffs, ISO/TO Agreement, and/or Operating Agreements) prior to the Transmission Owners making operational changes to the state of these facilities. This listing may be amended from time-to-time as specified in the ISO/TO Agreement and Operating Agreements.

Transmission Facility Agreement ("TFA"): Agreements governing the use of specific or designated transmission facilities charges to cover all, or a portion, of the costs to install, own, operate, or maintain transmission facilities, to the customer under the agreement and that have provisions to provide Transmission Service utilizing said transmission facilities. All Transmission Facility Agreements are listed in Attachment L. Table 1A, and are designated in the "Treatment" column as "Facility Agmt. – MWA."

Transmission Fund ("T-Fund"): The mechanism used under the current NYPP Agreement to compensate the Member Systems for providing Transmission Service for economy Energy Transactions over their transmission systems. Each Member System is allocated a share of the economy Energy savings in dollars assigned to the fund that is based on the ratio of their investment in transmission facilities to the sum of investments in transmission and generation facilities.

Transmission Owner: The public utility or authority (or its designated agent) that owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff.

Transmission Owner's Monthly Transmission System Peak: The maximum hourly firm usage as measured in megawatts ("MW") of the Transmission Owner's transmission system in a calendar month.

Transmission Reliability Margin ("TRM"): The amount of TTC reserved by the ISO to ensure the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Transmission Service: Point-To-Point Network Integration or Retail Access Transmission Service provided under the ISO OATT.

Transmission Service Charge ("TSC"): A charge designed to ensure recovery of the embedded cost of a transmission system owned by a Member System.

Transmission Shortage Cost: A pricing mechanism utilized in determining the Shadow Price of a particular transmission Constraint that will be used in calculating LBMP in accordance with Section 17.1.4 of Attachment B of this ISO Services Tariff.

Transmission System: The facilities operated by the ISO that are used to provide Transmission Services under the ISO OATT.

Transmission Usage Charge ("TUC"): Payments made by the Transmission Customer to cover the cost of Marginal Losses and, during periods of time when the transmission system is constrained, the marginal cost of Congestion. The TUC is equal to the product of: (1) the LBMP at the POW minus the LBMP at the POI (in $/MWh); and (2) the scheduled or delivered Energy (in MWh).

Transmission Wheeling Agreement ("TWA"): The Agreements listed in Table 1A of Attachment L to the ISO OATT governing the use of specific or designated transmission facilities that are owned, controlled or operated by an entity for the transmission of Energy in interstate commerce. TWAs between Transmission Owners have been modified such that all TWAs between Transmission Owners are now MWAs.

2.21 Definitions - U

Unforced Capacity: The measure by which Installed Capacity Suppliers will be rated, in accordance with formulae set forth in the ISO Procedures, to quantify the extent of their contribution to satisfy the NYCA Installed Capacity Requirement, and which will be used to measure the portion of that NYCA Installed Capacity Requirement for which each LSE is responsible.

Unforced Capacity Deliverability Rights: Unforced Capacity Deliverability Rights ("UDRs") are rights, as measured in MWs, associated with (i) new incremental controllable transmission projects, and (ii) new projects to increase the capability of existing controllable transmission projects that have UDRs, that provide a transmission interface to a Locality. When combined with Unforced Capacity which is located in an External Control Area or non-constrained NYCA region either by contract or ownership, and which is deliverable to the NYCA interface in the Locality in which the UDR transmission facility is electrically located, UDRs allow such Unforced Capacity to be treated as if it were located in the Locality, thereby contributing to an LSE's Locational Minimum Installed Capacity Requirement. To the extent the NYCA interface is with an External Control Area the Unforced Capacity associated with UDRs must be deliverable to the Interconnection Point.

UCAP Component: A component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Unrated Customer: A Customer that does not currently have a senior long-term unsecured debt rating or issuer rating from Standard & Poor's, Moody's, Fitch, or Dominion, and that has not received an ISO Equivalency Rating.

Unsecured Credit: A basis for satisfying part of a Customer's Operating Requirement on the basis of the Customer's creditworthiness. The amount of a Customer's Unsecured Credit shall be determined in accordance with Section 26.5 of Attachment K to this Services Tariff.

2.22 Definitions - V

Variably Scheduled Proxy Generator Bus: A Proxy Generator Bus for which the ISO may schedule Transactions at 15 minute intervals in real time. Variably Scheduled Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

Verified Average Coincident Load ("Verified ACL"): The Average Coincident Load determined by the ISO with verification data provided by the RIP for SCRs enrolled with a Provisional Average Coincident Load, as calculated pursuant to Section 5.12.11.1.2 of this Services Tariff, or, beginning with the Summer 2014 Capability Period, for resources with a reported Incremental Average Coincident Load, as calculated pursuant to Section 5.12.11.1.5 of this Services Tariff. The Verified ACL shall be used to evaluate the SCR's event responses for performance and in the calculation of the SCR's performance factor and all associated performance factors, deficiencies and penalties.

Virtual Load: Any Bid to purchase Energy in the Day-Ahead Market submitted at a load bus specified for Virtual Transactions.

Virtual Supply: Any Bid to sell Energy in the Day-Ahead Market submitted at a load bus specified for Virtual Transactions.

Virtual Transaction: Any Bid to purchase or sell Energy in the Day-Ahead Market submitted at a load bus specified for Virtual Transactions.

Virtual Transaction Component: A component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

2.23 Definitions - W

West of Central-East ("West" or "Western"): An electrical area comprised of Load Zones A, B, C, D, and E, as identified in the ISO Procedures.

Wheels Through: Transmission Service, originating in another Control Area, that is wheeled through the NYCA to another Control Area.

Wheels Through Credit Requirement: A component of the External Transaction Component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Wholesale Market: The sum of purchases and sales of Energy and Capacity for resale along with Ancillary Services needed to maintain reliability and power quality at the transmission level coordinated together through the ISO and Power Exchanges. A party who purchases Energy, Capacity or Ancillary Services in the Wholesale Market to serve its own Load is considered to be a participant in the Wholesale Market.

Wholesale Transmission Services Charges ("WTSC"): Those charges calculated pursuant to Attachment H of the OATT, incurred or declared overdue by a Transmission Owner pursuant to Section 26.4.2 of Attachment K, after the effective date of these revisions; provided, however, that these provisions will not apply to pre-petition bankruptcy debts for a company that is currently in bankruptcy.

Wind Energy Forecast: The ISO's forecast of Energy that is expected to be supplied over a specified interval of time by an Intermittent Power Resource that depends on wind as its fuel and which is used in ISO's Energy market commitment and dispatch.

Wind Output Limit: A Base Point Signal calculated for an Intermittent Power Resource depending on wind as its fuel and which, when sent to the Intermittent Power Resource, shall include a separate flag indicating that the Base Point Signal directs the Intermittent Power Resource to reduce its output. All Intermittent Power Resources, other than those in commercial operation as of January 1, 2002 with name plate capacity of 12 MWs or fewer, shall be eligible to receive a Wind Output Limit.

WTSC Component: A component of the Operating Requirement, calculated in accordance with Section 26.4.2, of Attachment K to this Services Tariff.

2.24 Definitions - X

2.25 Definitions - Y

2.26 Definitions - Z

3 Term and Effectiveness

3.1 Effectiveness

The ISO Services Tariff shall become effective on the latest of: (i) Commission approval of: (a) the ISO OATT, (b) the ISO Services Tariff, (c) the ISO Agreement, (d) the NYSRC Agreement, (e) the ISO/NYSRC Agreement, and (f) the ISO/TO Agreement (collectively, the "ISO Tariffs" and "ISO Related Agreements"); (ii) the date on which both the Commission and the PSC grant all necessary approvals to the Transmission Owners to transfer Operational Control of any facilities to the ISO or otherwise dispose of any of their property, including, without limitation, those approvals required under Section 70 of the New York Public Service Law ("PSL") and Section 203 of the Federal Power Act ("FPA"); (iii) the last date that any other approval or authorization is received, to the extent such additional approval or authorization is necessary; (iv) execution of the ISO Related Agreements; or (v) such later date specified by the Commission.

3.2 Term and Termination

The ISO Services Tariff shall remain in effect until: (i) canceled by the ISO upon sixty (60) days prior written notice in accordance with applicable Commission regulations; or (ii) the effective date of any law, order, rule, regulation, or determination of a body of competent jurisdiction requiring termination or a material modification of the ISO Services Tariff and/or the Service Agreements executed pursuant to the terms of the Tariff (See Attachment A) that would be inconsistent with any material term or provision of the ISO/TO Agreement. Any Customer may withdraw from the Tariff on thirty (30) days prior notice to the ISO; provided, however, that an LSE is required to be a Customer and comply with applicable requirements of the Tariff as long as it continues to serve Load in the NYCA.

3.3 Regulations

The ISO Services Tariff and any related Service Agreement are made subject to all applicable federal, state and local laws, regulations and orders.

3.4 Access to Complete and Accurate Data

Customers under the Tariff shall provide to the ISO such information and data as the ISO reasonably deems necessary in order to perform its functions and fulfill its responsibilities under the Tariff and in accordance with the ISO Market Power Monitoring Program. Such information will be provided on a timely basis and in the formats prescribed in the ISO Procedures. The ISO shall establish metering specifications and standards for all metering that is used as a data source by the ISO (See Article 13). Customers shall install and maintain such metering at their own expense and deliver data to the ISO without charge.

3.5 ISO Procedures

The ISO shall develop, and modify as appropriate, procedures for the efficient and non-discriminatory operation of the ISO Administered Markets and for the safe and reliable operation of the NYCA in accordance with the terms and conditions of the Tariff. All such procedures must be consistent with Good Utility Practice.

3.5.1 Market Problems Reporting Procedure

Upon ISO discovery of a potential Market Problem, the ISO will immediately report the Market Problem to the Market Monitoring Unit and to the Commission’s Office of Enforcement.

The ISO will then report the Market Problem to Market Participants, subject to applicable confidentiality restrictions, unless it is determined in consultation with Commission staff that disclosure could lead to gaming or other harmful outcomes. The report will also be provided to Market Participants in an e-mail notice with this subject line: "Notice of a Market Problem."

The ISO will accomplish all three of the above steps as soon as possible, but in no event longer than five calendar days after discovery of the potential Market Problem.

In the event of a determination that disclosure of a Market Problem could lead to gaming or other harmful outcomes, ISO, unless otherwise directed by Commission staff, will provide notice to the Market Participants of the identification of a potential Market Problem and the conduct of a confidential investigation. Thereafter, the ISO shall consult with Market Participants as soon as practicable after resolution of the underlying issue pursuant to direction from the Commission.

In the event of an exigent circumstances filing of tariff amendments pursuant to Article 19 of the ISO Agreement, this consultation would include seeking concurrence on the Section 205 filing from the Management Committee.

If no exigent circumstances filing is made, the ISO will provide an opportunity for Market Participants to comment prior to a request to FERC for a tariff waiver or other remedy. In the ISO's reports to Market Participants, subject to applicable confidentiality restrictions, the NYISO will provide the following information:

- Description of the Market Problem and tariff implications as appropriate;
- Description of the time frame involved;
- Description of underlying cause of the Market Problem;
- Description of economic impacts; and
- Description of steps planned or taken to address the Market Problem including a proposed timetable for the developing necessary tariff revisions, if applicable, as developed in consultation with Market Participants. The ISO will also report when it determines a Market Problem investigation has concluded.

Except where a longer period of analysis is required, the ISO will provide an explanation to all Market Participants of its proposed steps to address the Market Problem as soon as reasonably possible, but in no event later than 30 calendar days of its initial notice to Market Participants and the ISO shall make staff available to discuss proposed remedy at the appropriate working group or committee with advance notice to all Market Participants. Where a longer period of analysis is required, the ISO will provide updates to Market Participants at least quarterly.

3.5.2 Provision of Data By Market Participants

Whenever requested by the ISO, each LSE shall provide the ISO with a forecast of the Loads for which it is responsible for the particular time period designated by the ISO. Customers shall inform the ISO, in accordance with the ISO Procedures, of the Availability of Generators within the NYCA subject to a Customer's control by Energy contract, ownership or otherwise. Additionally, the Transmission Owners will provide megawatt, megavar, voltage readings, transmission system data (facility ratings and impedance data), and maintenance schedules for all Transmission Facilities Under ISO Operational Control, and any person or entity that owns transmission facilities associated with an award of Incremental TCCs under Section 19.2.2 of Attachment M to the ISO OATT shall be responsible for providing the same data and schedules to the ISO. For Transmission Facilities Requiring ISO Notification, the Transmission Owners shall inform the ISO of all changes in the status of the designated transmission facilities. Transmission Owners and persons or entities that own transmission facilities associated with an award of Incremental TCCs shall provide such data and schedules pursuant to applicable provisions of the ISO Procedures. Suppliers will provide data on Generator status and output including maintenance schedules, Generator scheduled return dates (inclusive of return to service from maintenance, forced outages, partial unit outages or an increase in the forecasted Host Load of a Behind-the-Meter Net Generation Resource in real-time compared to the forecasted Host Load submitted as part of its Energy Bid in the Day-Ahead Market that resulted in a significant reduction in a generating unit's or a Behind-the-Meter Net Generation Resource's ability to produce Energy in any hour), and Generator machine data, in accordance with the ISO Procedures. These data shall also include Generator Incremental/Decremental Bids, operating limits, response rates, megawatt, megavar, and voltage readings.

3.6 Survival

Upon termination, expiration or cancellation of the ISO Services Tariff or any related Service Agreement, in accordance with their terms, the provisions of the Tariff, and any Service Agreement, shall remain in effect to the extent necessary to permit the conclusion of: (i) transactions previously initiated by the ISO hereunder; and (ii) billing, payment and accounting with respect to all matters arising hereunder or pursuant to a Service Agreement. Additionally, any provisions of the ISO Services Tariff or a Service Agreement which expressly survive termination or cancellation of the ISO Services Agreement or Services Tariff shall remain in effect in accordance with those provisions.

4 Market Services: Rights and Obligations

4.1 Market Services - General Rules

4.1.1 Overview

Market Services include all services and functions performed by the ISO under this Tariff related to the sale and purchase of Energy, Capacity or Demand Reductions, and the payment to Suppliers who provide Ancillary Services in the ISO Administered Markets.

4.1.2 Independent System Operator Authority

The ISO shall provide all Market Services in accordance with the terms of the ISO Services Tariff and the ISO Related Agreements. The ISO shall be the sole point of Application for all Market Services provided in the NYCA. Each Market Participant that sells or purchases Energy, including Demand Side Resources, Special Case Resources and Emergency Demand Response Program participants, sells or purchases Capacity, or provides Ancillary Services in the ISO Administered Markets utilizes Market Services and must take service as a Customer under this Tariff and enter into a Service Agreement under the Tariff, as set forth in Attachment A; each entity that withdraws Energy to supply Load within the NYCA or provides Installed Capacity to an LSE serving Load within the NYCA utilizes the Control Area Services provided by the ISO and benefits from the reliability achieved as a result of ISO Control Area Services, must take service as a Customer under this Tariff and enter into a Service Agreement under this Tariff, as set forth in Attachment A; and each entity that has its virtual bids accepted and thereby engages in Virtual Transactions and each entity that purchases Transmission Congestion Contracts, excluding Transmission Congestion Contracts that are created prior to January 1, 2010, utilizes Market Services and must take service as a Customer under this Tariff and enter into a Services Agreement under this Tariff, as set forth in Attachment A. Each Customer that utilizes Market Services also utilizes Transmission Service and shall obtain Transmission

Service under the ISO OATT.

4.1.3 Informational and Reporting Requirements

The ISO shall operate and maintain an OASIS, including a Bid/Post System that will facilitate the posting of Bids to supply Energy, Ancillary Services and Demand Reductions by Suppliers for use by the ISO and the posting of Locational Based Marginal Prices ("LBMP") and schedules for accepted Bids for Energy, Ancillary Services and Demand Reductions. The Bid/Post System will be used to post schedules for Bilateral Transactions. The Bid Post System also will provide historical data regarding Energy and Capacity market clearing prices in addition to Congestion Costs.

4.1.4 Scheduling Prerequisites

Pursuant to ISO Procedures, each Transaction offered in the Energy, Installed Capacity, Ancillary Services or Transmission Congestion Contract market shall be subject to a minimum size of one (1) megawatt ("MW"), provided however, Regulation Service may be offered in tenths of a MW and provided further, pursuant to ISO Procedures, Special Case Resources may offer a minimum of 100 kW of Unforced Capacity in the Installed Capacity Market. Each Transaction above one (1) megawatt may be scheduled in tenths of a megawatt provided, however, Bilateral Transactions and External Transactions in the LBMP Market must be bid and scheduled in increments of one (1) megawatt.

4.1.5 Communication Requirements for Market Services

Customers and Transmission Customers shall utilize Internet service providers to access the ISO's OASIS and bid/post system. Customers shall arrange for and maintain all communications facilities for the purpose of communication of commercial data to the ISO.

Each Customer shall be the customer of record for the telecommunications facilities and services its uses and shall assume all duties and responsibilities associated with the procurement, installation and maintenance of the subject equipment and software.

4.1.6 Customer Responsibilities

All purchasers in the Day-Ahead or Real-Time Markets who withdraw Energy within the NYCA or at an NYCA Interconnection with another Control Area must obtain Transmission Service under the ISO OATT. All Customers requesting service under the ISO Services Tariff to engage in Virtual Transactions must obtain Transmission Service under the ISO OATT.

All LSEs serving Load in the NYCA must comply with the Installed Capacity requirements set forth in Article 5 of this ISO Services Tariff.

All Customers taking service under the ISO Services Tariff must pay the Market Administration and Control Area Services Charge, as specified in Rate Schedule 1 of this ISO Services Tariff.

A Supplier with a Generator or Demand Side Resource with a real time physical operating problem that makes it impossible for it to operate in the bidding mode in which it was scheduled shall notify the NYISO.

4.1.7 Customer Compliance with Laws, Regulations and Orders

All Customers shall comply with all applicable federal, state and local laws, regulations and orders, including orders from the ISO.

4.1.7.1 Violations of FERC's orders, rules and regulations also violate this Section 4.1.7 of the ISO Services Tariff. In particular, if FERC or a court of competent jurisdiction determines there has been a violation of FERC's regulations related to electric energy market manipulation (see 18 C.F.R. Section

1c.2, or any successor provision thereto), such violation is also a violation of this ISO Services Tariff if such violation affects or is related to the ISO Administered Markets.

4.1.7.2 If the ISO becomes aware that a Customer may be engaging in, or might have engaged in, electric energy market manipulation, it shall promptly inform its Market Monitoring Unit.

4.1.7.3 This Section 4.1.7 of the ISO Services Tariff does not independently empower the ISO or its Market Monitoring Unit to impose penalties for, or to provide a remedy for, violations of FERC's prohibition against electric energy market manipulation, or for other violations of the ISO's Tariffs.

4.1.8 Commitment for Reliability

Suppliers with generating units committed by the ISO for service to ensure NYCA reliability or local system reliability, except for Behind-the-Meter Net Generation Resources, will recover startup and minimum generation costs that were not bid, that were not known before the close of the Real-Time Scheduling Window, and that were not recovered in the Dispatch Day, provided however, eligibility to recover such additional costs shall not be available for megawatts scheduled Day-Ahead. Payment for such costs shall be determined, as if bid, pursuant to the provisions of Attachment C of this Tariff. Payments for securing NYCA reliability and local system reliability shall be recovered by the ISO in accordance with Rate Schedule 1 of the ISO OATT.

Re-dispatching costs incurred as a result of reductions in Transfer Capability caused by Storm Watch ("Storm Watch Costs") shall be aggregated and recovered on a monthly basis by the ISO exclusively from Transmission Customers in Load Zone J. The ISO shall calculate

Storm Watch Costs by multiplying the real-time Shadow Price of any binding constraint associated with a Storm Watch, by the higher of (a) zero; or (b) the scheduled Day-Ahead flow across the constraint minus the actual real-time flow across the constraint.

4.1.9 Cost Recovery for Units Responding to Local Reliability Rules Addressing Loss of Generator Gas Supply

4.1.9.1 Eligibility for Cost Recovery

Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rule addressing the Loss of Generator Gas Supply for Generators located in New York City or the Local Reliability Rule addressing the Loss of Generator Gas Supply for Generators located on Long Island, as being required either to burn an alternate fuel at designated minimum levels, or to activate their auto-swap capability, based on forecast Load levels in Load Zones J and K (for purposes of this Section 4.1.9, "Eligible Units"), shall be eligible to recover costs associated with burning the required alternate fuel when one of the specified Local Reliability Rules is invoked. For purposes of this Section 4.1.9, the periods of time in which the Eligible Unit burns the alternate fuel only because one of the Local Reliability Rulesaddressing the loss of gas supply for Generators located in New York City or on Long Island has been invoked, including that period of time required for an Eligible Unit to move into and out of compliance with a Local Reliability Rule addressing the Loss of Generator Gas Supply, shall be referred to as the "Eligibility Period."

4.1.9.1.1 Obligation to Test Automatic Fuel Swap Capability and Eligibility to Recover Costs of Performing Fuel Swap Tests

Combined cycle Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rules addressing the Loss of Generator Gas Supply for Generators located in New York City, which have the ability to automatically swap from natural gas to a liquid fuel source in the event of the sudden interruption of gas fuel supply or loss of gas pressure or the unavailability of gas supply to the Generator, shall:

(a) develop test procedures that are consistent with the requirements of the applicable Local Reliability Rule and ISO Procedures; and

(b) successfully test to demonstrate that the designated combined cycle units are able to automatically swap from natural gas to a liquid fuel source each Capability Period.

The requirement to perform a test each Capability Period can be met by performing a real-time automatic fuel swap, if that fuel swap was successful and occurred during the relevant Capability Period. The scheduling of a test to demonstrate that a designated combined cycle unit is able to automatically swap from natural gas to a liquid fuel source in real-time operations shall be coordinated with the ISO and with the Transmission Owner in whose subzone the Generator is located, consistent with ISO Procedures.

The period during which combined cycle Eligible Units are performing scheduled automatic fuel swap testing, including that period of time required for an Eligible Unit to move into and out of compliance with a Local Reliability Rule addressing the Loss of Generator Gas Supply, is an “Eligibility Period.”

4.1.9.2 Variable Operating Cost Recovery

For Eligibility Periods, Eligible Units burning an alternate fuel that would not have been burned but for Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island being invoked and Eligible Units burning an alternate fuel because they activated their auto-swap capability and experienced a swap to the alternate fuel that would not have occurred but for the operation of the auto-swap capability in accordance with the implementation of the Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island shall recover costs that vary with the amount of alternate fuel burned ("variable operating costs") if: (i) such costs are not reflected in the reference level for that Eligible Unit for the hours included in the Eligibility Period, pursuant to ISO Procedures, and (ii) the hour is one for which the commodity cost of the alternate fuel including taxes and emission allowance costs is greater than the commodity cost for natural gas, including taxes and emission allowance costs, as determined by the ISO. These relative commodity cost determinations shall use the same indices used by the ISO to establish daily Reference Levels. Variable operating costs shall include the commodity cost, associated taxes and emission allowance costs, of the required alternate fuel burned during an Eligibility Period pursuant to Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island.

4.1.9.3 Additional Cost Recovery

An Eligible Unit that seeks to recover costs incurred in connection with its compliance with Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island, in addition to the commodity cost, associated taxes and emission allowance cost recovery specified in Section 4.1.9.2, shall negotiate an Implementation Agreement with the ISO. The Eligible Unit and the ISO shall consult with and consider the input of the New York State Public Service Commission, and the Transmission Owner designated by the applicable Local Reliability Rule addressing the loss of gas supply for Generators located in New York City or on Long Island. Such Implementation Agreements shall specify, among other terms and conditions, the facilities (or portions of facilities) used to meet obligations under the Local Reliability Rule addressing the loss of gas supply for Generators located in New York City or on Long Island. The Implementation Agreement shall indicate the rate to be charged during the period of the Implementation Agreement to recover such additional costs.

The Implementation Agreement may also include costs in addition to commodity cost, associated taxes and emission allowance costs of the alternate fuel incurred in connection with compliance with Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island that vary with the amount of alternate fuel burned because a Local Reliability Rule addressing the loss of gas supply was invoked. These variable costs shall be paid pursuant to Section 4.1.9.2 as variable operating costs so as to not duplicate payments.

Each such Implementation Agreement shall have a duration of one or more Capability Periods and shall commence at the beginning of a Capability Period unless another date is approved by the Commission. If the Eligible Unit and the ISO reach agreement on the terms and conditions of the Implementation Agreement, the ISO shall file it with the Commission for its review and acceptance.

In the event that the Eligible Unit and the ISO have not come to an agreement six months prior to the beginning of the Capability Period that the Implementation Agreement is intended to govern, then either one of them may request the assistance of the Commission's Dispute Resolution Service. If the Dispute Resolution Service agrees to provide its assistance the Eligible Unit and the ISO shall participate in whatever dispute resolution process the Dispute Resolution Service may recommend. The Commission's Dispute Resolution Service may include other stakeholders to the extent confidentiality protections are in place. If, however, there is no agreement four months prior to the beginning of the relevant Capability Period then the Eligible Unit and the ISO may each file an unexecuted Implementation Agreement for the Commission's review and acceptance.

In the event that any provisions of this Section 4.1.9 are modified prior to the termination date of any Commission-accepted Implementation Agreement, such Implementation Agreement will remain in full force and effect until it expires in accordance with its contractual terms and conditions.

Rules for establishing Eligibility Periods shall be specified in ISO Procedures.

4.1.9.4 Billing

Payments made by the ISO to the Eligible Unit to pay variable operating costs and to pay the rate established by the Implementation Agreement pursuant to this Section 4.1.9 shall be in addition to any LBMP, Ancillary Service or other revenues received as a result of the Eligible Unit's Day-Ahead or Real-Time dispatch for that day. Payment by the ISO of variable operating costs pursuant to Section 4.1.9.2 shall be based on the Eligibility Period, quantity of alternate fuel burned, and relative costs of alternate fuel compared to natural gas. Payment by the ISO of the rate established in the Implementation Agreement for costs incurred other than variable operating costs shall be made as part of the ISO billing cycle regardless of which Local Reliability Rule addressing the loss of gas supply an alternate fuel is burned pursuant to, and regardless of the relative cost of the alternate fuel compared to natural gas reflected in reference levels.

4.1.9.5 Other Provisions

The ISO shall make available for the Transmission Owner in whose subzone the Generator is located: (i) the identity of Generators determined by the ISO to be eligible to recover the costs associated with burning the required alternate fuel pursuant to the provisions of this Section 4.1.9; (ii) the start and stop hours for each claimed Eligibility Period and (iii) the amount of alternate fuel for which the Generator has sought to recover variable operating costs.

4.2 Day-Ahead Markets and Schedules

4.2.1 Day-Ahead Load Forecasts, Bids and Bilateral Schedules

4.2.1.1 General Customer Forecasting and Bidding Requirements

Subject to the two earlier submission deadlines set forth below, by 5 a.m. on the day prior to the Dispatch Day: (i) All LSEs serving Load in the NYCA shall provide the ISO with Load forecasts for the Dispatch Day and the day after the Dispatch Day; and (ii) Customers and Transmission Customers submitting Bids in the Day-Ahead Market shall provide the ISO, consistent with ISO Procedures:

a. Bids to supply Energy, including Bids to supply Energy in Virtual Transactions;

b. Bids to supply Ancillary Services;

c. Requests for Bilateral Transaction schedules;

d. Bids to purchase Energy, including Bids to purchase Energy in Virtual Transactions;

e. Demand Reduction Bids; and

f. For Behind-the-Meter Net Generation Resources, the forecasted Host Load for each hour of the Dispatch Day.

By 4:50 a.m. on the day prior to the Dispatch Day, all Customers or Transmission Customers shall submit Bids for External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line.

By 4:45 a.m. on the day prior to the Dispatch Day, all Customers or Transmission Customers shall submit Bids that include revised fuel type or fuel price information to the ISO's Market Information System.

In general, the information provided to the ISO shall include the following:

4.2.1.2 Load Forecasts

The Load forecast shall indicate the predicted level of Load in MW by Point of Withdrawal for each hour.

4.2.1.3 Bids by Suppliers Using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed Bid Modes to Supply Energy and/or Ancillary Services

4.2.1.3.1 General Rules

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes shall identify the Capacity, in MW, available for commitment in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Supplier will voluntarily enter into dispatch commitments. If the Supplier elects to participate in the Day-Ahead Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not consist solely of Station Power) at a single PTID, it can only participate in the Day-Ahead Market as a Behind-the-Meter Net Generation Resource. If the Supplier is a Behind-the-Meter Net Generation Resource, the ISO shall only consider price-MW pairs in excess of the forecasted Host Load for the Resource.

If the Supplier using the ISO-Committed Flexible or Self-Committed Flexible bid mode is eligible to provide Regulation Service or Operating Reserves under Rate Schedules 3 and 4 respectively of this ISO Services Tariff, the Supplier's Bid may specify the quantity of Regulation Capacity it is making available and shall specify an emergency response rate that determines the quantity of Operating Reserves that it is capable of providing. Offers to provide Regulation Service and Operating Reserves must comply with the rules set forth in Rate

Schedules 3 and 4 of this ISO Services Tariff. If a Supplier that is eligible to provide Operating Reserves does not submit a Day-Ahead Availability Bid for Operating Reserves, its Day-Ahead Bid shall be rejected in its entirety. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit that is dispatched as a single aggregate unit at a single PTID is not qualified to provide Regulation Service or Spinning Reserves. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new Bid is timely. See Section 4.2.1.9 for bidding requirements for Demand Side Resources offering Energy in the Day-Ahead Market.

Suppliers other than Demand Side Resources entering a Bid into the Day-Ahead Market may also enter Day-Ahead Bids for each of the next nine (9) Dispatch Days. If not subsequently modified or withdrawn, these offers for subsequent Dispatch Days may be used by the ISO as offers from these Suppliers in the Day-Ahead Market for these subsequent Dispatch Days. For Suppliers that are providing Unforced Capacity in the ISO-administered ICAP Market for the month in which the Dispatch Day and the nine-day advance bidding period are encompassed, the ISO may enter the eighth day offer as the Bid for that Supplier's ninth day, if there is, otherwise no ninth–day Bid.

4.2.1.3.2 Bid Parameters

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes may identify-variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, and other parameters described in ISO Procedures. Day-Ahead Bids from Demand Side Resources offering Operating Reserves or Regulation Service shall be ISO-Committed Flexible and shall have an Energy Bid price no lower than the Monthly Net Benefit Offer Floor. Day-Ahead offers by Intermittent Power Resources that depend on wind as their fuel shall be ISO-Committed Flexible and shall include a Minimum Generation Bid of zero megawatts and zero costs and a Start-Up Bid of zero cost.

Day-Ahead Bids by ISO-Committed Fixed and ISO-Committed Flexible Generators, other than bids from Intermittent Power Resources that depend on wind as their fuel, shall also include Minimum Generation Bids and hourly Start-Up Bids. Bids shall specify whether a Supplier is offering to be ISO-Committed Fixed, ISO-Committed Flexible, Self-Committed Fixed, or Self-Committed Flexible.

4.2.1.3.3 Upper Operating Limits and Response Rates

All Bids to supply Energy and Ancillary Services must specify a UOL_N and a UOL_E for each hour. A Resource's UOL_E may not be lower than its $UOL_{N.}$

Bids from Suppliers for Generators supplying Energy and Ancillary Services must specify a normal response rate and may provide up to three normal response rates provided the minimum normal response rate may be no less than one percent (1%) of the Generator's Operating Capacity per minute. All Bids from Suppliers for Generators supplying Energy and Ancillary Services must also specify an emergency response rate which shall be equal to or greater than the maximum normal response rate of the Generator.

Bids from Suppliers offering Operating Reserves or Regulation Service from Demand Side Resources must specify a normal response rate and an emergency response rate provided that the emergency response rate may not be lower than the normal response rate. For Demand Side Resources the minimum acceptable response rate is one percent (1%) of the quantity of Demand Reduction the Demand Side Resource produces per minute.

4.2.1.4 Offers to Supply Energy from Self-Committed Fixed Generators

Self-Committed Fixed Generators shall provide the ISO with a schedule of their expected Energy output for each hour. Self-Committed Fixed Generators are responsible for ensuring that any hourly changes in output are consistent with their response rates. Self-Committed Fixed Generators shall also submit UOL_Ns, UOL_Es and variable Energy Bids for possible use by the ISO in the event that RTD-CAM initiates a maximum generation pickup, as described in Section 4.4.3 of this ISO Services Tariff.

4.2.1.5 Bids to Supply Energy in Virtual Transactions

Customers submitting Bids to supply Energy in Virtual Transactions shall identify the Energy, in MW, available in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Customer will voluntarily make it available.

4.2.1.6 Bids to Purchase Energy in Virtual Transactions

Customers submitting bids to purchase Energy in Virtual Transactions shall identify the Energy, in MW, to be purchased in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Customer will voluntarily purchase it.

4.2.1.7 Bilateral Transactions

Transmission Customers requesting Bilateral Transaction schedules shall identify hourly Transaction quantities (in MW) by Point of Injection and Point of Withdrawal, minimum run times associated with Firm Point-to-Point Transmission Service, if any, and shall provide other information (as described in ISO Procedures).

4.2.1.8 Bids to Purchase LBMP Energy in the Day-Ahead Market

Each purchaser shall submit Bids indicating the hourly quantity of Energy, in MW, that it will purchase from the Day-Ahead Market for each hour of the following Dispatch Day. These Bids shall indicate the quantities to be purchased by Point of Withdrawal. The Bids may identify prices at which the purchaser will voluntarily enter into the Transaction.

4.2.1.9 Day-Ahead Bids from Demand Reduction Providers and DSASP Providers to Supply Energy from Demand Reductions

Demand Reduction Providers and DSASP Providers offering Energy from Demand Side Resources shall submit Bids: (i) identifying the amount of Demand Reduction, in MWs in accordance with Section 4.1.4, that is available for commitment in the Day-Ahead Market (for every hour of the dispatch day) and (ii) identifying the prices at which the Demand Reduction Provider or DSASP Provider will voluntarily enter into dispatch commitments to reduce demand; provided, however, the price at which the Demand Reduction Provider or DSASP Provider will voluntarily enter into dispatch commitments to reduce demand shall be no lower than the Monthly Net Benefit Offer Floor, as determined in accordance with this section. The Bids will identify the minimum period of time that the Demand Reduction Provider or DSASP Provider is willing to reduce demand, however the minimum period may not be less than one hour. The Bid may separately identify the Demand Reduction Provider's Curtailment Initiation Cost. Demand Reduction Bids from Demand Reduction Providers that are not accepted in the Day-Ahead Market shall expire at the close of the Day-Ahead Market.

The ISO shall perform the Net Benefits Test and post on its web site the Monthly Net Benefit Offer Floor for each month by the 15^{th} of the preceding month in accordance with ISO Procedures. The Net Benefits Test shall establish the threshold price below which the dispatch of Energy from Demand Side Resources is not cost-effective. The Net Benefits Test shall consist of the following steps: (1) the ISO shall compile hourly supply curves for the Reference Month; (2) the ISO shall develop the average supply curve for the Study Month by updating the Reference Month supply curves for retirements and new entrants, and adjusting offers for changes in fuel prices; (3) the ISO shall apply an appropriate mathematical formula to smooth the average supply curve; and (4) the ISO shall evaluate the smoothed average supply curve to determine the Monthly Net Benefit Floor for the Study Month. The ISO shall apply the Monthly Net Benefit Offer Floor, as so calculated, to Bids submitted by Demand Response Providers for all hours in the Study Month.

The ISO shall promptly post corrections, where necessary, to the Monthly Net Benefit Offer Floor. Corrections shall only apply to errors in conducting the calculations described above and/or in posting the properly calculated Monthly Net Benefit Offer Floor. Corrections shall not include recalculations based on changes in gas prices as set forth above. The ISO shall not use any correction to the Monthly Net Benefit Offer Floor to determine revised Day-Ahead Market clearing prices for periods prior to the imposition of the correction.

4.2.2 ISO Responsibility to Establish a Statewide Load Forecast

By 8 a.m., or as soon thereafter as is reasonably possible, the ISO will develop and publish its statewide Load forecast on the OASIS. The ISO will use this forecast to perform the SCUC for the Dispatch Day.

4.2.3 Security Constrained Unit Commitment ("SCUC")

Subject to ISO Procedures and Good Utility Practice, the ISO will develop a SCUC schedule over the Dispatch Day using a computer algorithm which simultaneously minimizes the total Bid Production Cost of: (i) supplying power or Demand Reductions to satisfy accepted purchasers' Bids to buy Energy from the Day-Ahead Market; (ii) providing sufficient Ancillary

Services to support Energy purchased from the Day-Ahead Market consistent with the Regulation Service Demand curve and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively of this ISO Services Tariff; (iii) committing sufficient Capacity to meet the ISO's Load forecast and provide associated Ancillary Services; and (iv) meeting Bilateral Transaction schedules submitted Day-Ahead excluding schedules of Bilateral Transactions with Trading Hubs as their POWs. The computer algorithm shall consider whether accepting Demand Reduction Bids will reduce the total Bid Production Cost.

The ISO shall compute all NYCA Interface Transfer Capabilities prior to scheduling Transmission Service Day-Ahead. The ISO shall run the SCUC utilizing the computed Transfer Capabilities, submitted Firm Point-to-Point Transmission Service requests, Load forecasts, and submitted Incremental Energy Bids, Decremental Bids and Sink Price Cap Bids.

The schedule will include commitment of sufficient Generators and/or Demand Side Resources to provide for the safe and reliable operation of the NYS Power System. SCUC will treat a Behind-the-Meter Net Generation Resource as already being committed and available to be scheduled. Pursuant to ISO Procedures, the ISO may schedule any Resource to run above its UOL_N up to the level of its UOL_E. In cases in which the sum of all Bilateral Schedules, excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load within the NYCA in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO will commit Resources in addition to the Operating Reserves it normally maintains to enable it to respond to contingencies. The purpose of these additional resources is to ensure that sufficient Capacity is available to the ISO in real-time to enable it to meet its Load forecast (including associated Ancillary Services). In considering which additional Resources to schedule to meet the ISO's Load forecast, the ISO will evaluate unscheduled Imports, and will not schedule those Transactions if its evaluation determines the cost of those Transactions would effectively exceed a Bid Price cap in the hours in which the Energy provided by those Transactions is required. In addition to all Reliability Rules, the ISO shall consider the following information when developing the SCUC schedule: (i) Load forecasts; (ii) Ancillary Service requirements as determined by the ISO given the Regulation Service Demand Curve and Operating Reserve Demand Curves referenced above; (iii) Bilateral Transaction schedules excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs; (iv) price Bids and operating Constraints submitted for Generators or for Demand Side Resources; (v) price Bids for Ancillary Services; (vi) Decremental Bids and Sink Price Cap Bids for External Transactions; and (vii) Bids to purchase or sell Energy from or to the Day-Ahead Market. External Transactions with minimum run times greater than one hour will only be scheduled at the requested Bid for the full minimum run time. External Transactions with identical Bids and minimum run times greater than one hour will not be prorated. The SCUC schedule shall list the hourly injections and withdrawals for: (a) each Customer whose Bid the ISO accepts for the Dispatch Day; and (b) each Bilateral Transaction scheduled Day-Ahead excluding Bilateral Transactions with Trading Hubs as their POWs.

In the development of its SCUC schedule, the ISO may commit and de-commit Generators and Demand Side Resources, based upon any flexible Bids, including Minimum Generation Bids, Start-Up Bids, Curtailment Initiation Cost Bids, Energy, and Incremental Energy Bids and Decremental Bids received by the ISO provided however that: (a) the ISO shall commit zero megawatts of Energy for Demand Side Resources committed to provide Operating Reserves and Regulation Service; and (b) for Behind-the-Meter Net Generation Resources, the

ISO will consider for dispatch only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

The ISO will select the least cost mix of Ancillary Services and Energy from Suppliers, Demand Side Resources, and Customers submitting Virtual Transactions bids. The ISO may substitute higher quality Ancillary Services (*i.e.*, shorter response time) for lower quality Ancillary Services when doing so would result in an overall least bid cost solution. For example, 10-Minute Non-Synchronized Reserve may be substituted for 30-Minute Reserve if doing so would reduce the total bid cost of providing Energy and Ancillary Services.

4.2.3.1 Reliability Forecast for the Dispatch Day

At the request of a Transmission Owner to meet the reliability of its local system, the ISO may incorporate into the ISO's Security Constrained Unit Commitment constraints specified by the Transmission Owner.

A Transmission Owner may request commitment of certain Generators for a Dispatch Day if it determines that certain Generators are needed to meet the reliability of its local system. Such request shall be made before the Day-Ahead Market for that Dispatch Day has closed if the Transmission Owner knows of the need to commit certain Generators before the Day-Ahead Market close. The ISO may commit one or more Generator(s) in the Day-Ahead Market for a Dispatch Day if it determines that the Generator(s) are needed to meet NYCA reliability requirements.

A Transmission Owner may request commitment of additional Generators for a Dispatch Day following the close of the Day-Ahead Market to meet changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to ensure the reliability of its local system. The ISO will use SRE to fulfill a Transmission Owner's request for additional units.

All Generator commitments made in the Day-Ahead Market pursuant to this Section 4.2.3.1 shall be posted on the ISO website following the close of the Day-Ahead Market, in accordance with ISO procedures. In addition, the ISO shall post on its website a non-binding, advisory notification of a request, or any modifications thereto, made pursuant to this Section 4.2.3.1 in the Day-Ahead Market by a Transmission Owner to commit a Generator that is located within a Constrained Area, as defined in Attachment H of this Services Tariff. The advisory notification shall be provided upon receipt of the request and in accordance with ISO procedures.

After the Day-Ahead schedule is published, the ISO shall evaluate any events, including, but not limited to, the loss of significant Generators or transmission facilities that may cause the Day-Ahead schedules to be inadequate to meet the Load or reliability requirements for the Dispatch Day.

In order to meet Load or reliability requirements in response to such changed conditions the ISO may: (i) commit additional Resources, beyond those committed Day-Ahead, using a SRE and considering (a) Bids submitted to the ISO that were not previously accepted but were designated by the bidder as continuing to be available; or (b) new Bids from all Suppliers, including neighboring systems; or (ii) take the following actions: (a) after providing notice, require all Resources to run above their UOL_Ns, up to the level of their UOL_Es (pursuant to ISO Procedures) and/or raise the UOL_Ns of Capacity Limited Resources and Energy Limited Resources to their UOL_E levels, or (b) cancel or reschedule transmission facility maintenance outages when possible. Actions taken by the ISO in performing supplemental commitments will not change any financial commitments that resulted from the Day-Ahead Market.

4.2.4 Reliability Forecast for the Six Days Following the Dispatch Day

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the ISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven (7)-day period that begins with the next Dispatch Day. The ISO will perform a Supplemental Resource Evaluation ("SRE") for days two (2) through seven (7) of the commitment cycle. If it is determined that a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) is needed for reliability, the ISO shall accept a Bid from the Generator and the Generator will begin its start-up sequence. During each day of the start-up sequence, the ISO will perform an SRE to determine if long start-up time Generators will still be needed as previously forecasted. If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start-up sequence.

The ISO will commit to long start-up time Generators to preserve reliability. However, the ISO will not commit resources with long start-up times to reduce the cost of meeting Loads that it expects to occur in days following the next Dispatch Day.

A Supplier that bids on behalf of a long start-up time Generator, including one that is committed and whose start is subsequently aborted by the ISO as described in this Section 4.2.4, may be eligible for a Bid Production Cost Guarantee pursuant to the provisions of Section 4.6.6 and Attachment C of this ISO Services Tariff. The costs of such a Bid Production Cost guarantee will be recovered by the ISO under Rate Schedule 1 of the ISO OATT.

The ISO shall perform the SRE as follows: (1) The ISO shall develop a forecast of daily system peak Load for days two (2) through seven (7) in this seven (7)-day period and add the appropriate reserve margin; (2) the ISO shall then forecast its available Generators for the day in question by summing the Operating Capacity for all Generators currently in operation that are available for the commitment cycle, the Operating Capacity of all other Generators capable of starting on subsequent days to be available on the day in question, and an estimate of the net Imports from External Bilateral Transactions; (3) if the forecasted peak Load plus reserves exceeds the ISO's forecast of available Generators for the day in question, then the ISO shall commit additional Generators capable of starting prior to the day in question (*e.g.*, start-up period of two (2) days when looking at day three (3)) to assure system reliability; (4) in choosing among Generators with comparable start-up periods, the ISO shall schedule Generators to minimize Minimum Generation Bid and Start-Up Bid costs of meeting forecasted peak Load plus Ancillary Services consistent with the Reliability Rules; (5) in determining the appropriate reserve margin for days two (2) through seven (7), the ISO will supplement the normal reserve requirements to allow for forced outages of the short start-up period units (*e.g.*, gas turbines) assumed to be operating at maximum output in the unit commitment analysis for reliability.

Energy Bids are binding for day one (1) only for units in operation or with start-up periods less than one (1) day. Minimum Generation Bids for Generators with start-up periods greater than one (1) day will be binding only for units that are committed by the ISO and only for the first day in which those units could produce Energy given their start-up periods. For example, Minimum Generation Bids for a Generator with a start-up period of two (2) days would be binding only for day three (3) because, if that unit begins to start up at any time during day one (1), it would begin to produce Energy forty-eight (48) hours later on day three (3). Similarly, the Minimum Generation Bids for a Generator with a start-up period of three (3) days would be binding only for day four (4).

4.2.5 Post the Day-Ahead Schedule

By 11 a.m. on the day prior to the Dispatch Day, the ISO shall close the Day-Ahead scheduling process and post on the Bid/Post System the Day-Ahead schedule for each entity that submits a Bid or Bilateral Transaction schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the statewide aggregate resources (Day-Ahead Energy schedules and total operating capability forecast), Day-Ahead scheduled Load, forecast Load for each Load Zone, and the Day-Ahead LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone in each hour of the upcoming Dispatch Day. The ISO shall conduct the Day-Ahead Settlement based upon the Day-Ahead schedule determined in accordance with this section and Attachment B to this Services Tariff. The ISO will provide the Transmission Owner with the Load forecast (for seven (7) days) as well as the ISO security evaluation data to enable local area reliability to be assessed.

4.2.6 Day-Ahead LBMP Market Settlements

The ISO shall calculate the Day-Ahead LBMPs for each Load Zone and at each Generator bus and Demand Reduction Bus as described in Attachment B. Each Supplier that bids a Generator into the ISO Day-Ahead Market and is scheduled in the SCUC to sell Energy in the Day-Ahead Market will be paid the product of: (a) the Day-Ahead hourly LBMP at the applicable Generator bus; and (b) the hourly Energy schedule. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to sell Energy into the Day-Ahead LBMP Market will be paid the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. For each

Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in SCUC to provide Energy from the Demand Reduction, the LSE providing Energy service to the Demand Side Resource that accounts for the Demand Reduction shall be paid the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction Bus; and (b) the hourly demand reduction scheduled Day-Ahead (in MW). In addition, each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in the SCUC to provide Energy through Demand Reduction shall receive a Demand Reduction Incentive Payment from the ISO equal to the product of: (a) the Day-Ahead hourly LBMP at the Demand Reduction bus; and (b) the lesser of the verified actual hourly Demand Reduction or the scheduled hourly Demand Reduction (in MW). Each Customer that bids into the Day-Ahead Market, including each Customer that submits a Bid for a Virtual Transaction, and has a schedule accepted by the ISO to purchase Energy in the Day-Ahead Market will pay the product of: (a) the Day-Ahead hourly Zonal LBMP at each Point of Withdrawal; and (b) the scheduled Energy at each Point of Withdrawal. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to buy Energy from the Day-Ahead LBMP Market will pay the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. Each Customer that submits a Virtual Transaction bid into the ISO Day-Ahead Market and has a schedule accepted by the ISO to sell Energy in a Load Zone in the Day-Ahead Market will receive a payment equal to the product of (a) the Day-Ahead hourly zonal LBMP for that Load Zone; and (b) the hourly scheduled Energy for the Customer in that Load Zone. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POI and has its schedule accepted by the ISO will pay the product of: (a) the Day-Ahead hourly zonal LBMP for the

Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POW and has its schedule accepted by the ISO will be paid the product of: (a) the Day-Ahead hourly zonal LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

The ISO shall publish the Day-Ahead Settlement Load Zone LBMPs for each hour in the Dispatch Day.

4.3 In-Day Scheduling Changes

After the Day-Ahead schedule is published, the ISO shall normally grant requests by Capacity Limited Resources and Energy Limited Resources for reductions from Day-Ahead schedules to their UOL_Ns for any hour(s) in which they are scheduled above their UOL_Ns. However, the ISO may schedule such Resources to provide Energy in the Real-Time Market in an amount up to its Day-Ahead schedule during the relevant hour(s) at a price no higher than the relevant Day-Ahead offer price when it is needed to prevent or to address an Emergency.

The ISO will not recall Energy produced by a Generator serving External Load to the extent that the Generator is not providing Installed Capacity (and has not indicated that it wishes to qualify as a provider of Installed Capacity) in the NYCA. The ISO shall take action, including manual intervention, to schedule Export Transactions from Generators that have Available Generating Capacity and that have supplied installed Capacity to entities serving Load located in an External Control Area when the External Control Area issues a notification requiring such Generators to supply Energy, provided however, that any Transaction may be Curtailed in response to the invocation of Transmission Loading Relief procedures by the ISO or by operators of other Control Areas. Energy from non-Installed Capacity providers in New York which is being Supplied outside the NYCA could be purchased by the ISO, pursuant to ISO Procedures, should an emergency exist in the NYCA, provided however that Energy from Generators that have supplied installed Capacity to entities serving Load located in an External Control Area that are responding to a notification by the External Control Area that requires such Generators to supply Energy, may not be purchased by the ISO should a capacity resource emergency exist in the NYCA.

4.4 Real-Time Markets and Schedules

4.4.1 Real-Time Commitment ("RTC")

4.4.1.1 Overview

RTC will make binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of Resources that can respond in ten minutes) and thirty minutes (in the case of Resources that can respond in thirty minutes) after the scheduled posting time of each RTC run, will provide advisory commitment information for the remainder of the two and a half hour optimization period, and will produce binding schedules for External Transactions to begin at the start of each quarter hour. RTC will treat a Behind-the-Meter Net Generation Resource as already being committed and available to be scheduled. RTC will co-optimize to solve simultaneously for all Load, Operating Reserves and Regulation Service and to minimize the total as-bid production costs over its optimization timeframe. RTC will consider SCUC's Resource commitment for the day, load forecasts that RTC itself will produce each quarter hour, binding transmission constraints, and all Real-Time Bids and Bid parameters submitted pursuant to Section 4.4.1.2 below.

4.4.1.2 Bids and Other Requests

After the Day-Ahead schedule is published and before the close of the Real-Time Scheduling Window for each hour, Customers may submit Real-Time Bids into the Real-Time Market for real-time evaluation by providing all information required to permit real-time evaluation pursuant to ISO Procedures. If the Supplier elects to participate in the Real-Time Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not exclusively consist of Station Power) at a single PTID, it can only participate in the Real-Time Market as a Behind-the-Meter Net

Generation Resource. If a Behind-the-Meter Net Generation Resource submits Bids into the Real-Time Market for real-time evaluation, such Bids shall provide the forecasted Host Load for each hour for which Bids are submitted.

4.4.1.2.1 Real-Time Bids to Supply Energy and Ancillary Services, other than External Transactions

Intermittent Power Resources that depend on wind as their fuel submitting new or revised offers to supply Energy shall bid as ISO-Committed Flexible and shall submit a Minimum Generation Bid of zero MW and zero cost and a Start-Up Bid at zero cost. Eligible Customers may submit new or revised Bids to supply Energy, Operating Reserves and/or Regulation Service. Customers that submit such Bids may specify different Bid parameters in real-time than they did Day-Ahead. Incremental Energy Bids, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, and/or Start-Up Bids may be submitted by Suppliers bidding Resources using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the Incremental Energy Bids or Start-Up Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids or Start-Up Bids where appropriate, if not otherwise prohibited pursuant to other provisions of the tariff. Minimum Generation Bids or Regulation Service Bids for any hour in which such Resources received a Day-Ahead Energy schedule or a Regulation Service schedule, as appropriate, may not exceed the Minimum Generation Bids or Regulation Service Bids, as appropriate, submitted for those Resources in the Day-Ahead Market. Additionally, Real-Time Minimum Run Qualified Gas Turbine Customers shall not increase their previously submitted Real-Time Incremental Energy Bids, Minimum Generation Bids, or Start-Up Bids within 135 minutes of the dispatch hour. Bids to supply Energy or Ancillary Services shall be subject to the rules set forth in Section 4.2.1 of this ISO Services Tariff. For Behind-the-Meter Net Generation

Resources, the ISO will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

Suppliers bidding on behalf of Generators that did not receive a Day-Ahead schedule for a given hour may offer their Generators, for those hours, using the ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed bid mode or, with ISO approval, the ISO-Committed Fixed bid modes in real-time. For Behind-the-Meter Net Generation Resources, the ISO will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit. Suppliers bidding on behalf of Demand Side Resources that did not receive a Day-Ahead schedule to provide Operating Reserves or Regulation Service for a given hour may offer to provide Operating Reserves or Regulation Service using the ISO-Committed Flexible bid mode for that hour in the Real-Time Market provided, however, that the Demand Side Resource shall have an Energy price Bid no lower than $75/MW hour. A Supplier bidding on behalf of a Generator that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator for the Real-Time Market for that hour provided, however, that Generators that were scheduled Day-Ahead in Self-Committed Fixed mode may switch, with ISO approval, to ISO-Committed Fixed bidding mode in real-time. Generators that were scheduled Day-Ahead in ISO-Committed Fixed mode will be scheduled as Self-Committed Fixed in the Real-Time Market unless, with ISO approval, they change their bidding mode to ISO-Committed Fixed.

A Generator with a real time physical operating problem that makes it impossible for it to operate in the bidding mode in which it was scheduled Day-Ahead should notify the NYISO. Additionally, if the Host Load of a Behind-the-Meter Net Generation Resource is greater in real-time than was forecasted Day-Ahead such that it cannot meet its Day-Ahead schedule, it must notify the NYISO.

Generators and Demand Side Resources may not submit separate Operating Reserves Availability Bids in real-time and will instead automatically be assigned a real-time Operating Reserves Availability Bid of zero for the amount of Operating Reserves they are capable of providing in light of their response rate (as determined under Rate Schedule 4).

4.4.1.2.2 Real-Time Bids Associated with Internal and External Bilateral Transactions

Customers may use Real-Time Bids to seek to modify Bilateral Transactions that were previously scheduled Day-Ahead or propose new Bilateral Transactions, including External Transactions, for economic evaluation by RTC, provided however, that Bilateral Transactions with Trading Hubs as their POWs that were previously scheduled Day-Ahead may not be modified. Bids associated with Internal Bilateral Transactions shall be subject to the rules set forth above in Section 4.2.1.7.

Except as provided in this section, External Transaction Bids may not vary over the course of an hour. Each such Bid must offer to import, export or wheel the same amount of Energy at the same price at each point in time within that hour. At Variably Scheduled Proxy Generator Buses the ISO shall permit the submission of Bids to import or export Energy that vary the amount of Energy, and vary the price, for each quarter hour evaluation period.

The ISO may vary External Transaction Schedules at Proxy Generator Buses that are authorized to schedule transactions on an intra-hour basis if the party submitting the Bid for such a Transaction elects to permit variable scheduling. The ISO may also vary External Transaction Schedules at CTS Enabled Proxy Generator Buses. External Transaction Bids submitted to import Energy from, or export Energy to Proxy Generator Buses that are authorized to schedule transactions on either an intra-hour or hourly basis shall indicate whether the ISO may vary schedules associated with those Bids within each hour. Transmission Customers scheduling External Bilateral Transactions shall also be subject to the provisions of Section 16, Attachment J of the ISO OATT.

4.4.1.2.3 Self-Commitment Requests

Self-Committed Flexible Resources must provide the ISO with schedules of their expected minimum operating points in quarter hour increments. Self-Committed Fixed Resources must provide their expected actual operating points in quarter hour increments or, with ISO approval, bid as an ISO-Committed Fixed Generator.

4.4.1.2.4 ISO-Committed Fixed

The ability to use the ISO-Committed Fixed bidding mode in the Real-Time Market shall be subject to ISO approval pursuant to procedures, which shall be published by the ISO. Generators that have exclusively used the Self-Committed Fixed or ISO-Committed Fixed bid modes in the Day-Ahead Market or that do not have the communications systems, operational control mechanisms or hardware to be able to respond to five-minute dispatch basepoints are eligible to bid using the ISO-Committed Fixed bid mode in the Real-Time Market. Real-Time Bids by Generators using the ISO-Committed Fixed bid mode in the Real-Time Market shall provide variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, Minimum Generation Bids, hourly Start-Up Bids and other information pursuant to ISO Procedures.

RTC shall schedule ISO-Committed Fixed Generators.

4.4.1.3 External Transaction Scheduling

RTC15 will schedule External Transactions on an hourly basis as part of its development of a co-optimized least-bid cost Real-Time Commitment. For External Transactions that are scheduled on a 15 minute basis, the amount of Energy scheduled to be imported, exported or wheeled in association with that External Transaction may change on the quarter hour. All RTC runs will schedule intra-hour External Transactions on a 15 minute basis at Variably Scheduled Proxy Generator Buses. RTC will alert the ISO when it appears that scheduled External Transactions need to be reduced for reliability reasons but will not automatically Curtail them. Curtailment decisions will be made by the ISO, guided by the information that RTC provides, pursuant to the rules established by Attachment B of this ISO Services Tariff and the ISO Procedures. External Bilateral Transaction schedules are also governed by the provisions of Section 16, Attachment J of the OATT.

4.4.1.4 Posting Commitment/De-Commitment and External Transaction Scheduling Decisions

Except as specifically noted in Section 4.4.2, 4.4.3 and 4.4.4 of this ISO Services Tariff, RTC will make all Resource commitment and de-commitment decisions. RTC will make all economic commitment/de-commitment decisions based upon available offers assuming Suppliers internal to the NYCA have a one-hour minimum run time; provided however, Real-Time Minimum Run Qualified Gas Turbines shall be assumed to have a two-hour minimum run time. For Behind-the-Meter Net Generation Resources, RTC will consider only those segments of the Resource’s Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

RTC will produce advisory commitment information and advisory real-time prices. RTC will make decisions and post information in a series of fifteen-minute "runs" which are described below.

RTC_{15} will begin at the start of the first hour of the RTC co-optimization period and will post its commitment, de-commitment, and External Transaction scheduling decisions no later than fifteen minutes after the start of that hour. During the RTC_{15} run, RTC will:

(i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;

(ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;

(iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time;

(iv) Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information;

(v) Schedule economic hourly External Transactions for the next hour;

(vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;

(vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and

(viii) Schedule ISO-Committed Fixed Resources.

All subsequent RTC runs in the hour, *i.e.*, RTC_{30}, RTC_{45}, and RTC_{00} will begin executing at fifteen minutes before their designated posting times (for example, RTC_{30} will begin in the fifteenth minute of the hour), and will take the following steps:

(i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at that time;

(ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at that time;

(iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected at that time;

(iv) Issue advisory commitment, de-commitment, and dispatching guidance for the period from thirty minutes in the future until the end of the RTC co-optimization period;

(v) Either reaffirm that the External Transactions scheduled by previous RTC runs should continue to flow in the next hour, or inform the ISO that External Transactions may need to be reduced;

(vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;

(vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and

(viii) Schedule ISO-Committed Fixed Resources.

4.4.1.5 External Transaction Settlements

Settlements for External Transactions in the LBMP Market are described in Sections 4.2.6 and 4.5 of this ISO Services Tariff. Settlements for External Bilateral Transactions are also described in Section 16, Attachment J and Rate Schedules 7 and 8 of the OATT.

The calculation of Real-Time LBMPs at Proxy Generator Buses and CTS Enabled Interfaces is described in Section 17, Attachment B to this ISO Services Tariff.

4.4.2 Real-Time Dispatch

4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and Demand Side Resources, produce schedules for intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Real-Time Market Prices for Regulation Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions, except as specifically provided in Section 4.4.2.4 below. Each Real-Time Dispatch run will co-optimize to solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon (which may be fifty, fifty-five, or sixty minutes long depending on where the run falls in the hour.) In addition to producing a binding schedule for the next five minutes, each Real-Time Dispatch run will produce advisory schedules for the remaining four time steps of its bid-optimization horizon (which may be five, ten, or fifteen minutes long depending on where the run falls in the hour). An advisory schedule may become binding in the absence of a subsequent Real-Time Dispatch run. RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

4.4.2.2 External Transaction Scheduling

All RTD runs will schedule External Transactions on a 5 minute basis at Dynamically Scheduled Proxy Generator Buses. For External Transactions that are scheduled on a 5 minute basis, the amount of Energy scheduled to be imported, exported or wheeled in association with that External Transaction may change every 5 minutes. External Bilateral Transaction Schedules are also governed by the provisions of Attachment J of the OATT.

4.4.2.3 Calculating Real-Time Market LBMPs and Advisory Prices

RTD shall calculate *ex ante* Real-Time LBMPs at each Generator bus, and for each Load Zone in each RTD cycle, in accordance with the procedures set forth in Attachment B to this ISO Services Tariff. RTD will also calculate and post advisory Real-Time LBMPs for the next four quarter hours in accordance with the procedures set forth in Attachment B.

4.4.2.4 Real-Time Pricing Rules for Scheduling Ten Minute Resources

RTD may commit and dispatch, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting within ten minutes (“eligible Resources”) when necessary to meet load. Eligible Resources committed and dispatched by RTD for pricing purposes may be physically started through normal ISO operating processes. In the RTD cycle in which RTD commits and dispatches an eligible Resource, RTD will consider the Resource's start-up and incremental energy costs and will assume the Resource has a zero downward response rate for purposes of calculating *ex ante* Real-Time LBMPs pursuant to Section 17, Attachment B to this ISO Services Tariff.

4.4.2.5 Converting to Demand Reduction, Special Case Resource Capacity scheduled as Operating Reserves, Regulation or Energy in the Real-Time Market

The ISO shall convert to Demand Reductions, in hours in which the ISO requests that Responsible Interface Parties notify their Special Case Resources to reduce their demand pursuant to ISO Procedures, any Operating Reserves, Regulation Service or Energy scheduled in the Day-Ahead Market from Demand Side Resources that are also providing Special Case Resource Capacity. The ISO shall settle the Demand Reduction provided by that portion of the Special Case Resource Capacity that was scheduled Day-Ahead as Operating Reserves, Regulation Service or Energy as being provided by a Supplier of Operating Reserves, Regulation Service or Energy as appropriate. The ISO shall settle any remaining Demand Reductions provided beyond Capacity that was scheduled Day-Ahead as Ancillary Services or Energy as being provided by a Special Case Resource, provided such Demand Reduction is otherwise payable as a reduction by a Special Case Resource.

Operating Reserves or Regulation Service scheduled Day-Ahead and converted to Energy in real time pursuant to this Section 4.4.2.4, will be eligible for a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

Special Case Resource Capacity that has been scheduled in the Day-Ahead Market to provide Operating Reserves, Regulation Service or Energy and that has been instructed as a Special Case Resource to reduce demand shall be considered, for the purpose of determining a Scarcity Reserve Requirement pursuant to Rate Schedule 4 of this ISO Services Tariff, to be a Special Case Resource.

The ISO shall not accept offers of Operating Reserves or Regulation Service in the Real-Time Market from Demand Side Resources that are also providing Special Case Resource Capacity for any hour in which the ISO has requested Special Case Resources to reduce demand.

4.4.2.6 Converting to Demand Reduction Curtailment Services Provider Capacity scheduled as Operating Reserves, Regulation or Energy in the Real-Time Market

The ISO shall convert to Demand Reductions, in hours in which the ISO requests Demand Reductions from the Emergency Demand Response Program pursuant to ISO Procedures, any Operating Reserves, Regulation Service or Energy scheduled in the Day-Ahead Market by Demand Side Resources that are also providing Curtailment Services Provider Capacity. The ISO shall settle the Demand Reduction provided by that portion of the Curtailment Services Provider Capacity that was scheduled Day-Ahead as Operating Reserves, Regulation Service or Energy as being provided by a Supplier of Operating Reserves, Regulation Service or Energy as appropriate. The ISO shall settle Demand Reductions provided beyond Capacity that was scheduled Day-Ahead as ancillary services or Energy as being provided by a Curtailment Services Provider.

Operating Reserves or Regulation Service scheduled Day-Ahead and converted to Energy in real time pursuant to this Section 4.4.2.5, will be eligible for a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

Curtailment Services Provider Capacity that has been scheduled in the Day-Ahead Market as Operating Reserves, Regulation Service or Energy and that has been instructed to reduce demand shall be considered, for the purpose of determining a Scarcity Reserve Requirement pursuant to Rate Schedule 4 of this ISO Services Tariff, to be a Emergency Demand Response Program Resource.

The ISO shall not accept offers of Operating Reserves and Regulation Service in the Real-Time Market from Demand Side Resources that are also providing Curtailment Services Provider Capacity for any hour in which the ISO has requested participants in the Emergency Demand Response Program pursuant to ISO Procedures to reduce demand.

4.4.2.7 Post the Real-Time Schedule

Subsequent to the close of the Real-Time Scheduling Window, the ISO shall post the real-time schedule for each entity that submits a Bid or Bilateral Transaction schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer, Transmission Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the real-time Load for each Load Zone, and the Real-Time LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone for each hour of the Dispatch Day. The ISO shall conduct the real-time settlement based upon the real-time schedule determined in accordance with this Section.

4.4.3 Real-Time Dispatch - Corrective Action Mode

When the ISO needs to respond to system conditions that were not anticipated by RTC or the regular Real-Time Dispatch, *e.g.,* the unexpected loss of a major Generator or Transmission line, it will activate the specialized RTD-CAM program. RTD-CAM runs will be nominally either five or ten minutes long, as is described below. Unlike the Real-Time Dispatch, RTD-CAM will have the ability to commit certain Resources, and schedule intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses. When RTD-CAM is activated, the ISO will have discretion to implement various measures to restore normal operating conditions. These RTD-CAM measures are described below.

The ISO shall have discretion to determine which specific RTD-CAM mode should be activated in particular situations. In addition, RTD-CAM may require Resources to run above their UOL_Ns, up to the level of their UOL_Es as is described in the ISO Procedures. Self-Committed Fixed Resources will not be expected to move in response to RTD-CAM Base Point Signals except when a maximum generation pickup is activated.

Except as expressly noted in this section, RTD-CAM will dispatch the system in the same manner as the normal Real-Time Dispatch.

4.4.3.1 RTD-CAM Modes

4.4.3.1.1 Reserve Pickup

The ISO will enter this RTD-CAM mode when necessary to re-establish schedules when large area control errors occur. When in this mode, RTD-CAM will send 10-minute Base Point Signals and produce schedules for the next ten minutes. RTD-CAM may also commit, or if necessary de-commit, Resources capable of starting or stopping within 10-minutes. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements and Scarcity Reserve Requirements, but will set all Regulation Service schedules to zero. If Resources are committed or de-committed in this RTD-CAM mode the schedules for them will be passed to RTC and the Real-Time Dispatch for their next execution.

The ISO will have discretion to classify a reserve pickup as a "large event" or a "small event." In a small event the ISO will have discretion to reduce Base Point Signals in order to reduce transmission line loadings. The ISO will not have this discretion in large events. The distinction also has significance with respect to a Supplier's eligibility to receive Bid Production Cost guarantee payment in accordance with Section 4.6.6 and Attachment C of this ISO Services Tariff.

4.4.3.1.2 Maximum Generation Pickup

The ISO will enter this RTD-CAM mode when an Emergency makes it necessary to maximize Energy production in one or more location(s), i.e., Long Island, New York City, Southeastern New York, East of Central East and/or NYCA-wide. RTD-CAM will produce schedules directing all Generators located in a targeted location to increase production at their emergency response rate up to their UOL_E level and to stay at that level until instructed otherwise. Security constraints will be obeyed to the extent possible. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements and Scarcity Reserve Requirements, but will set all Regulation Service schedules to zero.

4.4.3.1.3 Base Points ASAP -- No Commitments

The ISO will enter this RTD-CAM mode when changed circumstances make it necessary to issue an updated set of Base Point Signals. Examples of changed circumstances that could necessitate taking this step include correcting line, contingency, or transfer overloads and/or voltage problems caused by unexpected system events. When operating in this mode, RTD-CAM will produce schedules and Base Point Signals for the next five minutes but will only redispatch Generators that are capable of responding within five minutes. RTD-CAM will not commit or de-commit Resources in this mode.

4.4.3.1.4 Base Points ASAP -- Commit As Needed

This operating mode is identical to Base Points ASAP – No Commitments, except that it also allows the ISO to commit Generators that are capable of starting within 10 minutes when doing so is necessary to respond to changed system conditions.

4.4.3.1.5 Re-Sequencing Mode

When the ISO is ready to de-activate RTD-CAM, it will often need to transition back to normal Real-Time Dispatch operation. In this mode, RTD-CAM will calculate normal five-minute Base Point Signals and establish five minute schedules. Unlike the normal RTD-Dispatch, however, RTD-CAM will only look ahead 10-minutes. RTD-CAM re-sequencing will terminate as soon as the normal Real-Time Dispatch software is reactivated and is ready to produce Base Point signals for its entire optimization period.

4.4.3.2 Calculating Real-Time LBMPs

When RTD-CAM is activated, RTD shall calculate *ex ante* Real-Time LBMPs at each Generator bus, and for each Load Zone in accordance with the procedures set forth in Section 17, Attachment B of this ISO Services Tariff.

4.4.4 Identifying the Pricing and Scheduling Rules That Apply to External Transactions

LBMPs will be determined and External Transactions will be scheduled at external Proxy Generator Buses consistent with the table below.

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	Non-Competitive	CTS Enabled Proxy Generator Bus		Scheduling Frequencies		
					Requires CTS Bids	Permits CTS Bids	Hourly Scheduled	Variably Scheduled	Dynamically Scheduled (Not Presently Available)
Hydro Quebec									
HQ_GEN_IMPORT	323601			✓			✓	✓	
HQ_LOAD_EXPORT	355639			✓			✓	✓	
HQ_GEN_CEDARS_PROXY	323590	Dennison Scheduled Line		✓			✓		
HQ_LOAD_CEDARS_PROXY	355586	Dennison Scheduled Line		✓			✓		
HQ_GEN_WHEEL	23651			✓			✓		
HQ_LOAD_WHEEL	55856			✓			✓		
PJM									
PJM_GEN_KEYSTONE	24065					✓	✓* (See Notes)	✓	
PJM_LOAD_KEYSTONE	55857					✓	✓* (See Notes)	✓	
PJM_GEN_NEPTUNE_PROXY	323594	Neptune Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_LOAD_NEPTUNE_PROXY	355615	Neptune Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_GEN_VFT_PROXY	323633	Linden VFT Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_LOAD_VFT_PROXY	355723	Linden VFT Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_HTP_GEN	323702	HTP Scheduled Line	✓			✓	✓* (See Notes)	✓	
HUDSONTP_345KV_HTP_LOAD	355839	HTP Scheduled Line	✓			✓	✓* (See Notes)	✓	

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	Non-Competitive	CTS Enabled Proxy Generator Bus		Scheduling Frequencies		
					Requires CTS Bids	Permits CTS Bids	Hourly Scheduled	Variably Scheduled	Dynamically Scheduled (Not Presently Available)
ISO New England									
N.E._GEN_SANDY_POND	24062				✓		✓** (See Notes)	✓	
NE_LOAD_SANDY_PD	55858				✓		✓** (See Notes)	✓	
NPX_GEN_CSC	323557	Cross Sound Scheduled Line	✓				✓		
NPX_LOAD_CSC	355535	Cross Sound Scheduled Line	✓				✓		
NPX_GEN_1385_PROXY	323591	Northport Norwalk Scheduled Line					✓		
NPX_LOAD_1385_PROXY	355589	Northport Norwalk Scheduled Line					✓		
Ontario									
O.H._GEN_BRUCE	24063						✓		
OH_LOAD_BRUCE	55859						✓		

Notes:
* At specifically identified Proxy Generator Buses (“* See Notes”), only Wheels Through (the NYCA) are scheduled on an hourly basis.
** At specifically identified Proxy Generator Buses (“** See Notes”), only wheels through the NYCA or a neighboring Control Area are scheduled on an hourly basis.

Pricing rules for Proxy Generator Buses are set forth in Section 17 of the Services Tariff.

The ISO may offer a more frequent scheduling option at a Proxy Generator Bus identified on the table. The ISO shall inform its Market Participants of the availability of such an option by providing notice at least two weeks in advance of the implementation of any such change. At the same time, the ISO shall update the above table to reflect the change in scheduling options by submitting a compliance filing in FERC Docket No. ER11-2547. Unless FERC acts on the ISO's compliance filing, the ISO shall effectuate the change in scheduling capability on the date it proposed in its compliance filing. The addition of new Proxy Generator Buses to the table, or changing the pricing rules that apply at a Proxy Generator Bus, may not be accomplished by submitting a compliance filing in Docket No. ER11-2547. The ISO may revert to establishing hourly Import and Export schedules using all available External Transaction Bids at a Proxy Generator Bus that is identified as a Dynamically or Variably Scheduled Proxy Generator Bus when the ISO or a neighboring Balancing Authority is not able to implement schedules as expected, or when necessary to ensure or preserve system reliability. When it reverts to hourly Import and Export schedules at a Dynamically or Variably Scheduled Proxy Generator Bus, the ISO shall apply the pricing rules for a corresponding Proxy Generator Bus that is not Dynamically Scheduled or Variably Scheduled. The ISO may cease evaluating CTS Interface Bids at CTS Enabled Proxy Generator Buses when the ISO or a neighboring Balancing Authority is not able to implement schedules as expected, or when necessary to ensure or preserve system reliability.

4.5 Real-Time Market Settlements

Transmission Customers and Customers taking service under this ISO Services Tariff or the ISO OATT, shall be subject to the Real-Time Market Settlement. All withdrawals and injections not scheduled on a Day-Ahead basis, including Real-Time deviations from any Day-Ahead External Transaction schedules, shall be subject to the Real-Time Market Settlement. Transmission Customers not taking service under this Tariff shall be subject to balancing charges as provided for under the ISO OATT. Settlements with Suppliers scheduling service from External Suppliers to the LBMP Market or to External Loads from the LBMP Market will be based upon scheduled withdrawals or injections. Real-Time Market Settlements for injections by Resources supplying Regulation Service or Operating Reserves shall follow the rules which are described in Rate Schedules 15.3 and 15.4, respectively.

For the purposes of this section, the scheduled output of each of the following Generators in each RTD interval in which it has offered Energy shall retroactively be set equal to its actual output in that RTD interval:

(i) Generators, except for the Generator of a Behind-the-Meter Net Generation Resource, providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999 who have not provided telemetering to their local TO and historically have not been eligible to participate in the NYPP market, which will continue to be treated as TO Load modifiers under the ISO-administered markets;

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 523 MW of such units.

This procedure shall not apply to Behind-the-Meter Net Generation Resources or a Generator for those hours it has used the ISO-Committed Flexible or Self-Committed Flexible bid mode.

In Sections 4.5.1, 4.5.2, 4.5.3, 4.5.4, 4.5.5 and 4.5.6 of this Tariff, references to “scheduled” Energy injections and withdrawals shall encompass injections and withdrawals that are scheduled Day-Ahead, as well as injections and withdrawals that occur in connection with real-time Bilateral Transactions. In Sections 4.5.1, 4.5.3, 4.5.4 and 4.5.6 of this Tariff, references to Energy Withdrawals and Energy Injections shall not include Energy Withdrawals or Energy Injections in Virtual Transactions, or Energy Withdrawals or Energy Injections at Trading Hubs. Generators, including Limited Energy Storage Resources, that are providing Regulation Service shall not be subject to the real-time Energy market settlement provisions set forth in this Section, but shall instead be subject to the Energy settlement rules set forth in Rate Schedule 15.3 of this ISO Services Tariff.

4.5.1 Settlement When Actual Energy Withdrawals Exceed Scheduled Energy Withdrawals Other Than Scheduled or Actual Withdrawals in Virtual Transactions

When the Actual Energy Withdrawals by a Customer over an RTD interval exceed the Energy withdrawals scheduled over that RTD interval, the ISO shall charge the Real-Time LBMP for Energy equal to the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the Actual Energy Withdrawals and the scheduled Energy withdrawals at that Load Zone.

If the Generator of a Behind-the-Meter Net Generation Resource is not able to serve the Resource's Host Load at any time, any resulting Actual Energy Withdrawals that serve the Host Load will be charged to the Load Serving Entity responsible for serving the Behind-the-Meter Net Generation Resource.

4.5.2 Settlement for Customers Scheduled To Sell Energy in Virtual Transactions in Load Zones

The Actual Energy Injection in a Load Zone by a Customer scheduled Day-Ahead to sell Energy in a Virtual Transaction is zero and the Customer shall pay a charge for the Energy imbalance equal to the product of: (a) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Injection of the Customer for that Hour in that Load Zone.

4.5.3 Settlement When Actual Energy Injections are Less Than Scheduled Energy Injections or Actual Demand Reductions are Less Than Scheduled Demand Reductions

4.5.3.1 General Rule

When the Actual Energy Injections by a Supplier over an RTD interval are less than the Energy injections scheduled Day-Ahead over that RTD interval, the Supplier shall pay a charge for the Energy imbalance equal to the product of: (a) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus; and (b) the difference between the scheduled Day-Ahead Energy injections and the lesser of: (i) the Actual Energy Injections at that bus; or (ii) the Supplier's Real-Time Scheduled Energy Injection plus any Compensable Overgeneration. If the Energy injections by a Supplier over an RTD interval are less than the Energy injections scheduled for the Supplier Day-Ahead, and if the Supplier reduced its Energy injections in response to instructions by the ISO or a Transmission Owner that were issued in order to maintain a secure and reliable dispatch, the Supplier may be entitled to a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

4.5.3.2 Failed Transactions

If an Energy injection scheduled by RTC at a Proxy Generator Bus fails in the ISO's checkout process, the Supplier or Transmission Customer that was scheduled to make the injection will pay the Energy imbalance charge described above in Section 4.5.3.1. In addition, if the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Mitigation and Analysis Department will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy injection at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy injection from the amount of the Import scheduled by RTC; multiplied by (ii) the greater of the Real-Time Market Congestion Component of the LBMP in the relevant interval, or zero.

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this section and the Financial Impact Charge described below in Section 4.5.4.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 1 of this ISO Services Tariff. In the event that the Energy injections for an Import scheduled by RTC or RTD, at a Proxy Generator Bus is Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible to receive an Import Curtailment Guarantee Payment for its curtailed Import pursuant to Attachment J of this ISO Services Tariff.

4.5.3.3 Capacity Limited Resources and Energy Limited Resources

For any hour in which: (i) a Capacity Limited Resource is scheduled to supply Energy, Operating Reserves, or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in upper operating limit; (iii) the Capacity Limited Resource requests a reduction for Capacity limitation reasons; and (iv) the ISO reduces the Capacity Limited Resource's upper operating limit to a level equal to, or greater than, its bid-in upper operating limit; the imbalance charge for Energy, Operating Reserve Service or Regulation Service imposed on that Capacity Limited Resource for that hour for its Day-Ahead Market obligations above its Capacity limited upper operating limit shall be equal to the product of: (a) the Real-Time price for Energy, Operating Reserve Service and Regulation Capacity; and (b) the Capacity Limited Resource's Day-Ahead schedule for each of these services minus the amount of these services that it has an obligation to supply pursuant to its ISO-approved schedule. When a Capacity Limited Resource's Day-Ahead obligation above its Capacity limited upper operating limit is balanced as described above, any real-time variation from its obligation pursuant to its Capacity limited schedules shall be settled pursuant to the methodology set forth in Section 4.5.3.1.

For any day in which: (i) an Energy Limited Resource is scheduled to supply Energy, Operating Reserves or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in Normal Upper Operating Limit; (iii) the Energy Limited Resource requests a reduction for Energy limitation reasons; and (iv) the ISO reduces the Energy Limited Resource's Day-Ahead Emergency Upper Operating Limit to a limit no lower than the Normal Upper Operating Limit; the Resource may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

4.5.3.4 Demand Reductions

When the verified actual Demand Reduction over an hour from a Demand Reduction Provider that is also the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled for that hour, that-LSE shall pay a Demand Reduction imbalance charge consisting of the product of: (a) the greater of the Day-Ahead LBMP or the Real-Time LBMP for that hour and (b) the difference between the scheduled Demand Reduction and the verified actual Demand Reduction in that hour.

When the verified actual Demand Reduction over an hour from a Demand Reduction Provider that is not the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled over that hour, then (1) the LSE providing Energy service to the Demand Reduction Provider's Demand Side Resource(s) shall pay a Demand Reduction imbalance charge equal to the product of (a) the Day-Ahead LBMP calculated for that hour for the applicable Load bus and (b) the difference between the scheduled Demand Reduction and the verified actual Demand Reduction at that bus in that hour, and (2) the Demand Reduction Provider will pay an amount equal to (a) the product of (i) the higher of the Day-Ahead LBMP or the Real-Time LBMP calculated for that hour for the applicable Load bus, and (ii) the difference between the scheduled Demand Reduction and the verified actual Demand Reduction at that bus in that hour, and (b) minus the amount paid by the LSE providing service to the Demand Reduction Provider's Demand Side Resource(s) under (1), above.

4.5.4 Settlement When Actual Energy Withdrawals are Less Than Scheduled Energy Withdrawals Other Than Actual or Scheduled Withdrawals in Virtual Transactions

4.5.4.1 General Rules

When a Customer's Actual Energy Withdrawals over an RTD interval are less than its Energy withdrawals scheduled Day-Ahead over that RTD interval, the Customer shall be paid the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the scheduled Energy withdrawals and the Actual Energy Withdrawals in that Load Zone. In addition, a Customer LSE providing Energy service to a Demand Reduction Provider's Demand Side Resource in a Load Zone shall be charged the product of: (a) the Real-Time hourly LBMP for that Load Zone; and (b) the actual Demand Reduction at the Demand Reduction Bus in that Load Zone.

4.5.4.2 Failed Transactions

If an Energy withdrawal at a Proxy Generator Bus scheduled by RTC fails in the ISO's checkout process, the Supplier or Transmission Customer that was scheduled to make the withdrawal will pay or be paid the energy imbalance charge described above in Section 4.5.4.1. In addition, if the checkout failure occurred for the reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Mitigation and Analysis Department will determine whether the Transaction associated with a withdrawal failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy withdrawal at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy withdrawal from the amount of the Export scheduled by RTC; multiplied by (ii) the product of negative one and the lesser of the Real-Time Market Congestion Component of the LBMP in the relevant interval, or zero.

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this subsection and the Financial Impact Charge described above in Section 4.5.3.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 15.1 of this ISO Services Tariff.

4.5.5 Settlement for Customers Scheduled To Purchase Energy in Virtual Transactions in Load Zones

The Actual Energy Withdrawal in a Load Zone by a Customer scheduled Day-Ahead to purchase Energy in a Virtual Transaction is zero and the Customer shall be paid the product of: (1) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Withdrawal of the Customer for that Hour in that Load Zone.

4.5.6 Settlement When Actual Energy Injections Exceed Scheduled Energy Injections

When Actual Energy Injections from a Generator over an RTD interval exceed the Energy injections scheduled Day-Ahead over the RTD interval the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the lesser of (i) the Supplier's Actual Energy Injection or (ii) its Real-Time Scheduled Energy Injection for that RTD interval, plus any Compensable Overgeneration and the Supplier's Day-Ahead scheduled Energy injection over the RTD interval, unless the payment that the Supplier would receive for such injections would be negative (i.e., unless the LBMP calculated in that RTD interval at the applicable Generator's bus is negative) in which case the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the Supplier's Actual Energy Injection for that RTD interval and the Supplier's Day-Ahead scheduled Energy injection over that RTD interval. A Generator that is not following Base Point Signals shall not be compensated for Energy in excess of its Real-Time Scheduled Energy Injection if its applicable upper operating limit has been reduced below its bid-in upper operating limit by the ISO in order to reconcile the ISO's dispatch with the Generator's actual output, or to address reliability concerns. Suppliers shall not be compensated for Energy in excess of their Real-Time Scheduled Energy Injections, except: (i) for Compensable Overgeneration; (ii) when the ISO initiates a large event reserve pickup or a maximum generation pickup under RTD-CAM; or (iii) when a Transmission Owner initiates a reserve pickup in accordance with a Reliability Rule, including a Local Reliability Rule. When there is no large event reserve pickup or maximum generation pickup, or when there is such an instruction but a Supplier is not located in the area affected by the maximum generation pickup, that Supplier shall not be compensated for Energy in excess of its Real-Time Scheduled Energy Injection plus any Compensable Overgeneration. When there is a reserve pickup, or when there is a maximum generation pickup and a Supplier is located in the area affected by it, and the Supplier was either scheduled to operate in RTD or subsequently was directed to operate by the ISO, that Supplier shall be paid based on the product of: (1) the Real-Time LBMP calculated in that RTD Interval for the applicable Generator bus; and (2) the Actual Energy Injection minus the Energy injection scheduled Day-Ahead.

4.5.7 Settlement for Trading Hub Energy Owner when POI is a Trading Hub

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Real-Time Market with a Trading Hub as its POI and has its schedule accepted by the ISO will pay the product of: (a) the hourly integrated Real-Time LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

4.5.8 Settlement for Trading Hub Energy Owner when POW is a Trading Hub

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Real-Time Market with a Trading Hub as its POW and has its schedule accepted by the ISO will be paid the product of: (a) the hourly integrated Real-Time LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

4.5.9 Performance Tracking

The ISO shall use a Performance Tracking System to compute the difference between the Energy actually supplied and the Energy scheduled by the ISO for all Suppliers located within the NYCA and shall use it to measure compliance with criteria associated with the provision of Energy and Ancillary Services as set forth in the ISO Procedures. The Performance Tracking System shall also be used to report metrics for Loads.

4.6 Payments

4.6.1 Payments to Suppliers of Regulation Service

Suppliers of Regulation Service shall receive a payment that is calculated pursuant to Rate Schedule 15.3 of this ISO Services Tariff

4.6.2 Payments to Suppliers of Reactive Supply and Voltage Support Service ("Voltage Support Service")

Suppliers of Voltage Support Service shall receive a Voltage Support Service payment in accordance with the criteria and formula in Rate Schedule 15.2.

4.6.3 Payments to Suppliers for Operating Reserves

Suppliers of each type of Operating Reserve will receive payments for each MW of Operating Reserve that they provide, as requested by the ISO, pursuant to Rate Schedule 15.4.

Additionally, Generators providing Operating Reserves shall receive a payment for Energy when the ISO requests Energy under a reserve activation. The Energy payment shall be calculated as the product of: (a) the Energy provided; and (b) the Real-Time Market LBMP.

4.6.4 Payments to Generators for Black Start Capability

Black Start Capability providers shall receive a payment for Black Start Capability as set forth in Rate Schedule 15.5.

4.6.5 Day-Ahead Margin Assurance Payments

A Supplier that is scheduled in the Day-Ahead Market to provide Energy, Regulation Service, or Operating Reserves may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

4.6.6 Bid Production Cost Guarantee Payments

4.6.6.1 Day-Ahead BPCG for Generators

The ISO shall determine if a Supplier eligible under Section 18.2.1 of Attachment C of this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment will not recover its Day-Ahead Regulation Capacity Bid, Operating Reserves Bid, or its Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid to produce Energy in the Day-Ahead Market, including Energy provided by the capacity scheduled for Regulation Service, through Day-Ahead LBMP revenue, Day-Ahead Imputed LBMP Revenue and net Day-Ahead Ancillary Services revenues for Voltage Support Service, Regulation Service, and synchronized Operating Reserves. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Generator. On the basis of such determination (and subject to any mitigation that may apply) the ISO shall pay a Day-Ahead BPCG to the Supplier pursuant to Section 18.2 of Attachment C to this ISO Services Tariff.

4.6.6.2 Day-Ahead BPCG for Imports

The ISO shall determine if a Supplier supplying an Import and eligible under Section 18.3.1 of Attachment C of this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment will not recover its Day-Ahead Decremental Bid through Day-Ahead LBMP revenue and Day-Ahead Imputed LBMP Revenue. Such determination shall be made for an entire Day-Ahead Market day and such determination shall be made separately for each Import transaction. On the basis of such determination, the ISO shall pay a Day-Ahead Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.3 of Attachment C of this ISO Services Tariff.

4.6.6.3 Real-Time BPCG for Generators in RTD Intervals Other than Supplemental Event Intervals

The ISO shall determine if a Supplier eligible under Section 18.4.1 of Attachment C of this ISO Services Tariff for a real-time Bid Production Cost guarantee payment will not recover its real-time Regulation Capacity Bid, Regulation Movement Bid, Operating Reserves Bid, or its Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid to produce Energy that was not scheduled in the Day-Ahead Market, including Energy provided by the capacity scheduled for Regulation Service, through real-time LBMP revenue, real-time Imputed LBMP Revenue and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and synchronized Operating Reserves. Such determination shall be made for an entire Dispatch Day (except for Supplemental Event Intervals). Such determination shall be made separately for each Generator. On the basis of such determination, and subject to any mitigation that may apply, the ISO shall pay a real-time Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.4 of Attachment C to this ISO Services Tariff and, as applicable, Section 15.3.

Suppliers bidding on behalf of Resources that were not committed by the ISO to operate in a given Dispatch Day, but which continue to operate due to minimum run time Constraints, shall not receive such a supplemental payment.

4.6.6.4 BPCG for Generators for Supplemental Event Intervals

The ISO shall determine if a Supplier eligible under Section 18.5.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for a Supplemental Event Interval will not recover its real-time Regulation Capacity Bid, Regulation Movement Bid, Operating Reserves Bid, or its Minimum Generation Bid and Incremental Energy Bid to produce Energy that was not scheduled Day-Ahead, including Energy provided by the capacity scheduled for Regulation Service, through real-time LBMP revenue, real-time Imputed LBMP Revenue and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and Operating Reserves in that interval. Such determination shall be made separately for each Supplemental Event Interval, and such determination shall be made separately for each Generator. On the basis of such determination, the ISO shall pay a Bid Production Cost guarantee payment to the Supplier for a Supplemental Event Interval pursuant to Section 18.5 of Attachment C of this ISO Services Tariff.

4.6.6.5 Real-Time BPCG for External Transactions

External Transactions are not eligible to receive Bid Production Cost guarantee payments in the Real-Time Market pursuant to Section 18.6 of Attachment C of this ISO Services Tariff.

4.6.6.6 BPCG for Long Start-Up Time Generators Whose Starts Are Aborted by the ISO Prior to their Dispatch

The ISO shall pay a Supplier eligible under Section 18.7.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) whose start is aborted by the ISO prior to its dispatch for that portion of its Start-Up Bid that corresponds to that portion of its start-up sequence that it completed prior to being aborted. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each long start-up time Generator. On the basis of such determination, the ISO shall pay a Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.7 of Attachment C of this ISO Services Tariff.

4.6.6.7 BPCG for Demand Reduction in the Day-Ahead Market

The ISO shall determine if a Demand Reduction Provider eligible under Section 18.8.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for Demand Reduction in the Day-Ahead Market will not recover its Day-Ahead Curtailment Initiation Cost and its Day-Ahead Demand Reduction Bid through Day-Ahead LBMP revenues. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall pay a Bid Production Cost guarantee payment to the Demand Reduction Provider pursuant to Section 18.8 of Attachment C of this ISO Services Tariff.

4.6.6.8 BPCG for Special Case Resources

The ISO shall determine if a Supplier eligible under Section 18.9.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for a Special Case Resource will not recover its Minimum Payment Nomination through real-time LBMP revenues. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each Special Case Resource. On the basis of such determination, the ISO shall make a Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.9 of Attachment C of this ISO Services Tariff.

4.6.6.9 Day-Ahead BPCG for Demand Side Resources Scheduled to Provide Synchronized Operating Reserves and/ or Regulation Service

The ISO shall determine if a Supplier that bids Demand Side Resources committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service in the Day-Ahead Market will not recover its Day-Ahead synchronized Operating Reserves Bid to provide the amount of synchronized Operating Reserves that it was scheduled to provide, and/or its Day-

Ahead Regulation Capacity Bid to provide the amount of Regulation Capacity that it was scheduled to provide. Such supplier shall be eligible under Section 18.10.1 of Attachment C to this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall make a Bid Production Cost guarantee payment to the Customer pursuant to Section 18.10 of Attachment C of this ISO Services Tariff.

4.6.6.10 Real-Time BPCG for Demand Side Resources Scheduled to Provide Synchronized Operating Reserves and/ or Regulation Service

The ISO shall determine if a Supplier that bids Demand Side Resources committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service will not recover its real-time synchronized Operating Reserves Bid to provide the amount of synchronized Operating Reserves that it was scheduled to provide, and/or its real-time Regulation Capacity and Regulation Bids to provide Regulation Service. Such Supplier shall be eligible under Section 18.11.1 of Attachment C to this ISO Services Tariff for a real-time Bid Production Cost guarantee payment. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall make a Bid Production Cost guarantee payment to the Customer pursuant to Section 18.11 of Attachment C of this ISO Services Tariff.

4.7 Procurement of Station Power

A Generator may self-supply Station Power in accordance with the following provisions.

4.7.1 A Generator may self supply Station Power during any calendar month when either:

4.7.1.1 Its net output for that month is positive; or

4.7.1.2 Its net output for that month is negative and the Generator, during the same month, has available at other Generators owned by the same entity that owns the Generator positive net output in an amount at least sufficient to offset fully such negative net output (hereinafter referred to as "remote self-supply of Station Power"). A Generator may not remotely self-supply Station Power from Generators that are owned by its owner's corporate affiliates.

4.7.1.2.1 If an entity owns a portion of a jointly owned Generator it may remotely self-supply its other Generators up to the amount of its entitlement to Energy from the jointly-owned Generator provided that: (A) the entity has the right to call upon that Energy for its own use; and (B) the Energy entitlement is not characterized as a sale from the jointly owned Generator to any of its joint owners.

4.7.2 A Generator's net output for the month may be positive because either:

4.7.2.1 The Generator is physically supplying Energy for its Station Power needs, using its own facilities, and without using facilities that are owned by any Transmission Owner; or

4.7.2.2 The Generator's Station Power requirements for the month, including all Energy received for use as Station Power, regardless of its voltage or the metering point of receipt, are less than the amount of Energy that the Generator injects into the New York State Power System for the month.

4.7.3 The determination of net output under this Section 4.7 shall apply only to determine whether the Generator self-supplied Station Power during the month and will not affect the price of Energy sold or consumed by the Generator at any bus during any hour during the month.

4.7.4 When a Generator has positive net output for an interval and is delivering Energy into the New York State Power System, it will be paid the Real-Time or Day-Ahead LBMP at its bus, as appropriate, for all of the Energy delivered pursuant to the ISO Services Tariff. Conversely, when a Generator has negative net output for an interval and is self-supplying Station Power from the New York State Power System under Section 4.7.1.1 or 4.7.1.2, it will pay the Real-Time or Day-Ahead LBMP, as appropriate, for all of the Energy consumed, pursuant to the ISO Services Tariff.

4.7.5 The ISO will determine the extent to which each affected generator self-supplied its Station Power requirements or obtained Station Power from third-party providers (including corporate affiliates) during the Billing Period and will incorporate that determination in its accounting and billing. To the extent that Station Power deliveries from third parties, including corporate affiliates of a Generator's owner, involve an unbundled Transmission Service component, the Generator shall take Transmission Service under Part 5 of the ISO OATT unless the Generator has made other arrangements with the local Transmission Owner under the Transmission Owner's retail access tariff.

4.7.6 When a Generator self-supplies Station Power during any month according to Section 4.7.1.1, above, the Generator will not incur any charges for Transmission Service. When a Generator remotely self-supplies Station Power according to Section 4.7.1.2 above, the Generator shall, to the extent that Transmission Service is involved, pay for Transmission Service for the quantity of Energy that the Generator remotely self-supplies. Such Transmission Service shall be provided under Part 3 of the ISO OATT and shall be charged the hourly rate under Schedule 6.7 of the ISO OATT for Firm Point-to-Point Transmission Service, provided however, that the terms and charges under Schedules 6.1 through 6.3, 6.5, 6.6, 6.8 and 6.9 of the ISO OATT shall not apply to such service. The amount of Energy that a Generator transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of Capacity or Energy by or for such Generator under any other provisions of the ISO OATT or ISO Services Tariff.

4.7.7 A Generator may remotely self-supply Station Power from an External Generator owned by the same entity that owns the Generator only if the External Generator has positive net output during the month and if the Generator has scheduled Imports into the NYCA from the External Generator during the month in an amount at least sufficient to offset fully its negative net output for the month.

5 CONTROL AREA SERVICES: RIGHTS AND OBLIGATIONS

5.1 Control Area Services

The ISO will provide Control Area Services in accordance with the standards and criteria of NERC and NPCC, the Reliability Rules of the NYSRC, and Good Utility Practice. The Control Area Services provided by the ISO include, but are not limited to, the following:

(a) Developing and implementing procedures to maintain the reliability of NYS Power System;

(b) Coordinating operations with other Control Area operators;

(c) Arranging for reserve sharing agreements with other ISOs and other Control Areas to enhance reliability during abnormal operating conditions;

(d) Coordinating the outage schedules for generating units within the NYCA to maintain system reliability;

(e) Committing adequate generation resources to ensure the reliability of the NYS Power System;

(f) Taking command and control of the NYCA resources during Emergency conditions and coordinating operations with Transmission Owners;

(g) Maintaining and Operating a central control center and performing the functions of the NERC security control center for the NYCA under Emergency operating conditions;

(h) Defining the Installed Capacity requirements for LSEs, inclusive of individual customers taking services directly from the ISO, within the NYCA;

(i) Determining Locational Installed Capacity requirements for LSEs to ensure the reliable operation of the NYCA;

(j) Administering of an Installed Capacity Market;

(k) Training the operating personnel of the ISO and Transmission Owner control rooms; and

(l) Administering the mandatory NERC reliability compliance process.

5.1.1 Customer Compliance with Reliability Standards; Penalties

5.1.1.1 Customer Compliance with Reliability Standards:

In accordance with applicable requirements in this Tariff and the ISO Procedures, all Customers shall conform to all applicable reliability criteria, policies, standards, rules, regulations and other requirements of NERC, NPCC, NYSRC, any applicable regional council, or their successors, the ISO's specific reliability requirements and ISO Procedures, and applicable operating guidelines and all applicable requirements of federal and state regulatory authorities. Failure to conform to these requirements may subject a Customer to direct assignment of penalties assessed against the ISO by FERC, NERC, NPCC or any other federal or state regulatory authority as a result of such Customer's failure to conform.

5.1.1.2 Direct Assignment of Penalty Costs:

The ISO's compliance with applicable reliability criteria, policies, standards, rules, regulations and other requirements is sometimes dependent on timely, accurate and adequate information and/or action on the part of a Customer. If the ISO is found to be non-compliant with respect to any applicable reliability criteria, policies, standards, rules, regulations and other requirements as a result of a Customer's actions or failure to act in violation of an obligation imposed by the ISO Tariffs, ISO Procedures, or ISO Related Agreements, the ISO may seek to directly assign to the Customer the cost of a penalty imposed on the ISO as a consequence of its non-compliance. If the Customer is found to be non-compliant with respect to any applicable reliability criteria, policies, standards, rules, regulations and other requirements as a result of the

ISO's actions or failure to act in violation of an obligation imposed by the ISO Tariffs, ISO Procedures, or ISO Related Agreements, the Customer may seek to directly assign to the ISO the cost of a penalty imposed on the Customer as a consequence of the ISO's non-compliance. Any direct assignment of penalty costs must first be approved by FERC, as provided in Schedule 6.11 of the OATT.

5.1.1.3 ISO's Recovery of Penalty Costs Through Schedule 11:

If direct assignment to a particular Customer is not possible or if the ISO is directly responsible for a violation because of its own action or inaction, the ISO may seek to recover such penalty costs in Schedule 6.11 Section 6.11.3 of the ISO OATT. Any inclusion of penalty costs in Schedule 6.11 must first be approved by FERC on a case-by-case basis, as provided in Schedule 6.11 of the ISO OATT. Prior to seeking FERC authorization for recovery of a penalty in Schedule 6.11 Section 6.11.3 of the ISO OATT, the ISO shall consult with the Management Committee and any appropriate subcommittee or working groups designated by the Management Committee, regarding the recovery and allocation of such penalty before filing at FERC. Any recommendation by the Management Committee regarding a proposed penalty recovery shall be reported by the ISO to FERC in any ISO filing seeking penalty recovery.

5.1.2 Incorporation of Certain Business Practice Standards

(a) Pursuant to Commission Order No. 676-H, the ISO incorporates by reference the following business practice standards developed by the North American Energy Standards Board's Wholesale Electric Quadrant:

WEQ-000, Abbreviations, Acronyms, and Definition of Terms, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Oct. 4, 2012, Nov. 28, 2012 and Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);

WEQ-001, Open Access Same-Time Information Systems (OASIS), OASIS Version 2.0 ,WEQ Version 003, July 31, 2012 as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied November 26, 2013) excluding Standards WEQ-001-9.5, WEQ-001-10.5, WEQ-001-14.1.3, WEQ-001-15.1.2 and WEQ-001-106.2.5, except as provided below;

WEQ-004, Coordinate Interchange, WEQ Version 003, July 31, 2012 (with Final Action ratified on December 28, 2012), except as provided below;

WEQ-005, Area Control Error (ACE) Equation Special Cases, WEQ Version 003, July 31, 2012

WEQ-006, Manual Time Error Correction, WEQ Version 003, July 31, 2012;

WEQ-007, Inadvertent Interchange Payback, WEQ Version 003, July 31, 2012;

WEQ-008, Transmission Loading Relief - Eastern Interconnection, WEQ Version 003, July 31, 2012 (with minor corrections applied November 28, 2012);

WEQ-011, Gas/Electric Coordination, WEQ Version 003, July 31, 2012;

WEQ-012, Public Key Infrastructure (PKI), WEQ Version 003, July 31, 2012, (as modified by NAESB final actions ratified on Oct. 4, 2012), except as provided below (NYISO compliance to begin May 15, 2017, pursuant to *New York Independent System Operator, Inc.*, FERC Docket No. ER15-550-000, Notice Granting Extension (April 15, 2015);

WEQ-015, Measurement and Verification of Wholesale Electricity Demand Response, WEQ Version 003, July 31, 2012 (with minor corrections applied November 26, 2013); and

WEQ-021, Measurement and Verification of Energy Efficiency Products, WEQ Version 003, July 31, 2012.

(b) The ISO is not required to comply with the following Standards:

WEQ-001, Open Access Same-Time Information Systems (OASIS), OASIS Version 2.0, WEQ Version 003, July 31, 2012 (with minor corrections applied November 26, 2013): Standards 001-2,001-3, 001-4, 001-5, 001-6, 001-7, 001-8, 001-9, 001-10, 001-011, 001-012, 001-13.1.2, 001-13.1.3(b) and (c), 001-014, 001-015, 001-016, 001-017, 001-018, 001-019, 001-020, 001-021, 001-022, 001-23, 001-101 through 001-107.3.1, 001-Appendix A, 001-Appendix B, and 001-Appendix D, pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015);

WEQ-002, Open Access Same-Time Information Systems (OASIS) Business Practice Standards & Communication Protocols (S&CP), OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Nov. 28, 2012 and Dec. 28, 2012(with minor corrections applied November 26, 2013), pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015);

WEQ-003, Open Access Same-Time Information Systems (OASIS) Data Dictionary Business Practice Standards, OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Nov. 28, 2012 and Dec. 28, 2012 (with minor corrections applied November 26, 2013), pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015);

WEQ-004, Coordinate Interchange, WEQ Version 003, July 31, 2012 (with Final Action ratified on December 28, 2012): Standards 004-3, 004-18, and 004-Appendix A and 004-Appendix C, pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015); and

WEQ-013, Open Access Same-Time Information Systems (OASIS) Implementation Guide, OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied November 26, 2013), pursuant to *New York Independent System Operator, Inc.*, 151 FERC ¶ 61,157 (May 19, 2015).

5.2 Independent System Operator Authority

The ISO will act as the Control Area operator, as defined by NERC, for the NYCA. The ISO will provide all Control Area Services in the NYCA. Control Area Services provided by the ISO will be in accordance with the terms of the ISO Services Tariff, the Reliability Rules, the ISO Related Agreements and Good Utility Practice. The ISO will act with other Control Area operators as required to modify External Transactions pursuant to this Tariff and to ensure the effective and reliable coordination with the interconnected Control Areas. In acting as the Control Area operator, the ISO will be responsible for maintaining the safety and the short-term reliability of the NYCA and for the implementation of reliability standards promulgated by NERC and NPCC and for the Reliability Rules promulgated by the NYSRC. To be included within NYCA, a Market Participant must meet the requirements of Section 5.6. Each Market Participant that (1) withdraws Energy to supply Load within the NYCA; or (2) provides installed Capacity to an LSE serving Load within the NYCA, benefits from the Control Area Services provided by the ISO and from the reliability achieved as a result of ISO Control Area Services and therefore must take service as a Customer under the Tariff. To be included within NYCA, a Market Participant must meet the requirements of Section 5.6. A Market Participant that is not included within the NYCA may take service as a Customer under the Tariff, provided that it meets the requirements of Section 5.7.

5.2.1 Suspension of Virtual Transactions

The ISO may temporarily suspend Virtual Transactions if it determines that:

5.2.1.1 The financial exposure of customers engaged in Virtual Transactions cannot be determined with a reasonable degree of accuracy or to factors such as software or system failures;

5.2.1.2 A market aberration associated with Virtual Transactions substantially impairs the functioning of the ISO-administered markets; or

5.2.1.3 Virtual Transactions substantially impair the ability of the ISO to maintain the reliability of the electric system.

As soon as reasonably practicable, the ISO shall notify the Commission and Market Participants of the reason(s) for any suspension of Virtual Transactions, the action(s) necessary to restore Virtual Transactions, and the estimated time required to restore Virtual Transactions.

5.2.2 Suspension of the Ability of Generators to Increase Their Bids in Real-Time

The ISO may temporarily suspend the ability to submit Incremental Energy Bids in the real-time market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate for the portions of Generators' Capacity that were scheduled in the Day-Ahead Market, if the ISO determines that:

5.2.2.1 a market aberration associated with Incremental Energy Bids submitted in the real-time market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market for the portions of Generators' Capacity that were scheduled in the Day-Ahead Market substantially impairs the functioning of the ISO-administered markets; or

5.2.2.2 Permitting Incremental Energy Bids submitted in the real-time market to exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of Generators' Capacity that were scheduled in the Day-Ahead Market substantially impairs the ability of the ISO to maintain the reliability of the electric system.

As soon as reasonably practicable, the ISO shall notify the Commission and Market Participants of the reason(s) for any suspension of the ability for Incremental Energy Bids submitted in the real-time market to exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of Generators' Capacity that were scheduled in the Day-Ahead Market; the action(s) necessary to restore this feature to the ISO-Administered Markets; and the estimated time required to restore this feature to the ISO-Administered Markets.

5.3 Control Center Operation

The ISO will maintain and operate a control center in order to monitor the power flows on and across the NYCA, coordinate the flow of electricity within the NYCA, respond to Emergency situations, monitor power flows between the NYCA and neighboring Control Areas and maintain reliability.

5.3.1 Back-Up Operation

The ISO shall develop Back-Up Operation procedures that will carry out the intent and purposes of this ISO Services Tariff, to the extent practical, in circumstances under which the normal communications or computer systems of the ISO are not fully functional. Such procedures shall include testing requirements and training for the ISO staff, Transmission Owner staff, and Market Participants. If a communication or computer system malfunction results in the ISO's inability to operate the NYCA in accordance with ISO Procedures or under approved testing procedures, the ISO will direct the Transmission Owners to assume the responsibility to operate their respective systems in accordance with Good Utility Practice to facilitate the operation of the NYCA in a safe and reliable manner. The Transmission Owners will continue to operate their respective systems until such time that the ISO is ready to resume control. During Back-Up Operation, the Transmission Owner control centers will operate to maintain the Desired Net Interchange ("DNI") within each Transmission District. Generator Bid curves will be provided by the ISO to the individual Transmission Owners in order to permit dispatch by the Transmission Owners subject to the Transmission Owner code of conduct. Normal Day-Ahead Market and Real-Time Market operations may be halted, if required.

5.3.2 Market Participant and Customer Obligations

During Back-Up Operation, Customers and other Market Participants shall comply with any and all instructions and orders issued by the ISO or the Transmission Owners.

5.3.3 Billing and Settlement

In the event that Back-Up Operation is implemented, the billing and settlement procedures contained in Article 7 of this ISO Services Tariff shall apply only to the extent they can be implemented under the Back-Up Operation procedures. The ISO will follow specific billing and settlement procedures for use under the~~se~~ specific circumstances that required Back-Up Operation. The ISO shall gather necessary information, manually reconstruct the billing information as soon as practical, and submit invoices to Customers. The ISO shall be under no obligation to comply with the billing procedure time limits specified in Article 7. Neither the ISO nor the Transmission Owners shall be liable, under any circumstances, for any economic losses suffered by any Customer, Market Participant, or third party, resulting from the implementation by the ISO of Back-Up Operation, or from compliance with orders issued by the ISO or Transmission Owners that were necessary to operate the NYCA in a safe and reliable manner. Such orders may include, without limitation, instructions to generation facilities to increase or decrease output, and instructions to Load to reduce or interrupt service.

5.4 Operation Under Adverse Conditions

The ISO shall operate the NYS Power System during Adverse Conditions, including, but not limited to, thunder storms, hurricanes, tornadoes, solar magnetic flares and threat of terrorist activities, in accordance with the Reliability Rules, inclusive of Local Reliability Rules and related PSC orders. Consistent with such Reliability Rules, the ISO shall maintain reliability of the NYS Power System by directing the adjustment of the Generator output levels and controllable transmission devices in certain areas of the system to reduce power flows across transmission lines vulnerable to outages due to these Adverse Conditions, thereby reducing the likelihood of major power system disturbances.

The ISO shall have the sole authority to declare that Adverse Conditions are imminent or present and invoke the appropriate operating procedure(s) affecting the NYS Power System in response to those conditions. Activation of a procedure in compliance with a Local Reliability Rule shall involve a two (2) step process. The Transmission Owner directly involved with such Local Reliability Rule, such as Storm Watch, shall advise the ISO that Adverse Conditions are imminent or present and recommend to the ISO the activation of procedures in support of that Local Reliability Rule. Consistent with the Local Reliability Rule, the ISO shall declare the activation of the appropriate procedures.

The Transmission Owner and the ISO shall coordinate the implementation of the applicable procedures to the extent that Transmission Facilities under ISO Operational Control are impacted. Records pertaining to the activation of such procedures and the response in accordance with those procedures shall be maintained and made available upon request.

The Real-Time LBMPs shall be based on adjusted Generator levels set in response to activation of these procedures. Revenue shortfalls may occur if the redispatch of the system

Curtails Energy scheduled Day-Ahead and more expensive Energy is dispatched subsequent to the Day-Ahead Settlement. These revenue shortfalls shall be recovered by the ISO through the Rate Schedule 1 charge under the ISO OATT.

5.5 Major Emergency State

In the event of, or in order to prevent, a Major Emergency State, Customers shall comply with all ISO Procedures and Reliability Rules applicable to a Major Emergency State.

5.6 Requirements For Inclusion Within The New York Control Area

To be included within the NYCA a Supplier or a Load must meet the following requirements:

(a) Its facilities must be included within the NYCA.

(b) It must accept and comply with NYCA standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the ISO Procedures so that sufficient electrical equipment control capability, information and communication are available to the ISO for planning and operation of the NYCA.

(c) Its facilities must be able to respond to command and control instructions from the ISO.

(d) It must have compatible operational communication mechanisms, maintained at its expense, to interact with the ISO and for Internal requirements.

(e) It must ensure the continued compatibility of its local Energy management system, system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the ISO as the ISO directs the operation of the NYCA.

5.7 Requirements For Entities Not Located Within The New York Control Area

In order for a Supplier or a Load that is not included within the NYCA to take services under the Tariff, it must be contained, in whole or in part, within a separate Control Area that meets all of the requirements for a Control Area defined by NERC, NPCC and any succeeding organizations. An entity that is contained in a Control Area other than the NYCA may take services under the ISO Services Tariff for the purpose of engaging in Control Area to Control Area Capacity and Energy Transactions with the ISO. In order for a Supplier or a Load not contained in the NYCA to take services under the ISO Services Tariff, an inter-Control Area agreement between the Control Area in which the entity is located and the ISO, that satisfies the reasonable requirements of both Control Area operators, must be in place.

5.8 Communication and Metering Requirements for Control Area Services

The ISO shall arrange for and maintain reliable communications and metering facilities between the ISO and the Transmission Owners in the NYCA and the Control Area operators of all neighboring interconnected Control Areas. Such facilities may consist of data circuits, voice lines, meters and other facilities deemed necessary by the ISO to maintain reliable communication links for the sole purpose of transmitting operations and reliability data and instructions. The ISO shall be responsible for the specification, installation and maintenance of the required facilities according to ISO Procedures. The costs incurred by the ISO to establish communications facilities between the ISO and a Security Coordinators of a neighboring Control Area shall be borne by the Control Area that requested the establishment of the communications facilities unless a different arrangement is agreed to by both Control Areas. The total cost of the communications facilities between the ISO and the Transmission Owners and the portion of the cost of inter-Control Area communication facilities assigned to the ISO shall be collected from all Customers in accordance with Rate Schedule 15.1 of the ISO Services Tariff. Transmission Owners with communications requirements which exceed those required by the ISO shall procure and maintain such additional facilities at their own expense.

Generators, Suppliers and Loads are required to exchange certain operating and reliability data with the ISO and the Transmission Owners' Control Centers in accordance with the ISO Agreement and the ISO/TO Agreement, applicable ISO operating and reliability requirements, and in conjunction with any requirements for interconnection with the Transmission Owner.

In addition, Suppliers wishing to submit Bids in the RTC for Energy or Regulation Service must make provision to receive command and control information from the ISO. Those Generators or Suppliers currently providing this capability via a Transmission Owner may continue to do so. Those requiring installation of this capability must contract with the ISO or with the interconnected Transmission Owner and must comply with applicable ISO or Transmission Owner data and other technical requirements.

Suppliers with multiple units at a single location must maintain a consistent representation of the plant with the ISO with respect to aggregation of units for purposes of bidding. If an aggregate Bid is to be provided for a group of units and those units are bidding in the RTC, or providing Regulation Service, then the ISO shall model those units as a group for purposes of dispatch, control and security modeling. The ISO will provide a single aggregate Base Point Signal and unit control error. If, however, the Supplier wishes to dispatch units individually, then it must configure both its bidding and data interfaces accordingly. Each Supplier must initially specify the configuration of the plant for purposes of bidding aggregation and must then maintain bidding and data interfaces consistent with that configuration. Similar modeling, control and bidding Constraints apply to an LSE that bids Load that is dispatchable by the ISO.

5.8.1 Collection and Communication of Energy Forecasting Data by Intermittent Power Resources that Depend on Wind as Their Fuel

Pursuant to ISO Procedures, Intermittent Power Resources that depend on wind as their fuel shall maintain in good working order equipment to collect wind speed and wind direction data at their site and shall provide the ISO, or its agent, with wind speed, wind direction and maximum available megawatt data in the manner identified by the ISO, provided however this requirement shall not apply to any Intermittent Power Resource in commercial operation as of January 1, 2002 with nameplate capacity of 12 MWs or fewer. Maximum available megawatts shall be the sum of the individual nameplate capacities for all turbines that are online and currently capable of producing power (including those turbines that are not producing any power due to low wind speeds); this value should exclude those turbines that are not producing power due to a fault condition or a network communication failure condition or that are offline for service. Each Intermittent Power Resource that depends on wind as its fuel shall be responsible for the cost of installing and maintaining such equipment at its site and shall share in funding the ISO's cost of wind forecasting function pursuant to this Services Tariff.

The ISO may impose financial sanctions for failure to provide wind speed and wind direction data pursuant to ISO Procedures.

Upon a determination of failure to provide wind speed and wind direction data pursuant to ISO Procedures, the ISO shall take the following actions. The ISO shall notify the Intermittent Power Resource that depends on wind as its fuel by written notice of its determination of failure to provide wind speed and wind direction data and that the ISO may impose financial sanctions if the failure is not corrected. The ISO shall offer a reasonable opportunity to correct the failure to provide wind speed and wind direction data pursuant to ISO Procedures. If, following such reasonable opportunity to cure, such failure is not cured, the ISO may impose daily sanctions of the greater of $500 or $20/MW of nameplate capacity until such failure is cured. The ISO shall offer the Intermittent Power Resource an opportunity to be heard by senior officers of the ISO prior to imposing sanctions.

5.9 Installed Capacity and Locational Export Capacity

5.9.1 Sections 5.10 through 5.17 of this Tariff, implementing the Installed Capacity market design, shall govern LSE Unforced Capacity Obligations, the qualification of Installed Capacity Suppliers, and the ISO's administration of Installed Capacity auctions.

5.9.2 Provisions applicable to Locational Export Capacity. Nothing in this Section alters the requirements in the ISO Tariffs or ISO Procedures generally applicable to Installed Capacity Suppliers and Generators.

5.9.2.2 Eligibility. In order to be eligible to export capacity from an Import Constrained Locality for an Obligation Procurement Period, the Market Participant for a Generator must:

5.9.2.2.1 Notify the ISO on or before the first business day of the month prior to the month of the export, specify the quantity of MW in ICAP, and the Control Area that will be entitled to the exported capacity, such notice in accordance with ISO Procedures; and

5.9.2.2.2 Provide all data and other information to the ISO required in accordance with Services Tariff Section 23.4.5.

5.9.2.3 During any month a Generator has Locational Export Capacity, the Market Participant for it shall Bid the Locational Export Capacity into the in-day market when the ISO issues a Supplemental Resource Evaluation request (an SRE), unless the entity has a bid pending in the Real-Time Market when the SRE request is made or is unable to bid in response to the SRE request due to an outage as defined in the ISO Procedures, or due to other operational issues, or due to temperature related deratings.

5.10 NYCA Minimum Installed Capacity Requirement

The NYCA Minimum Installed Capacity Requirement is derived from the NYCA Installed Reserve Margin, which is established each year by the NYSRC. The NYCA Minimum Installed Capacity Requirement for the Capability Year beginning each May 1 will be established by multiplying the NYCA peak Load forecasted by the ISO by the quantity of one plus the NYCA Installed Reserve Margin. The ISO shall translate the NYCA Installed Reserve Margin, and thus the NYCA Minimum Installed Capacity Requirement, into a NYCA Minimum Unforced Capacity Requirement. For each Capability Period, the NYCA Minimum Unforced Capacity Requirement shall equal the product of the NYCA Minimum Installed Capacity Requirement and the ratio of (1) the total amount of Unforced Capacity that the specified Resources are qualified to provide during such Capability Period, as of the time the NYCA Minimum Unforced Capacity Requirement is determined as specified in ISO Procedures, to (2) the sum of the DMNCs used to determine the Unforced Capacities of such Resources for such Capability Period. The foregoing calculation shall be determined using the Resources in the NYCA in the most recent final version of the ISO's annual Load and Capacity Data Report, with the addition of Resources commencing commercial operation since completion of that report and the deletion of Resources with scheduled or planned retirement dates before or during such Capability Period.

The NYCA Minimum Unforced Capacity Requirement represents a minimum level of Unforced Capacity that must be secured by LSEs in the NYCA for each Obligation Procurement Period. Under the provisions of this Services Tariff and the ISO Procedures, each LSE will be obligated to procure its LSE Unforced Capacity Obligation. The LSE Unforced Capacity Obligation will be determined for each Obligation Procurement Period by the ICAP Spot Market

Auction, in accordance with ISO Procedures. Qualified Resources will have the opportunity to supply amounts of Unforced Capacity to meet the LSE Unforced Capacity Obligation as established by the ICAP Spot Market Auction.

The ISO will calculate a NYCA peak Load each year by applying regional Load growth factors to the prior calendar year's Adjusted Actual Peak Load. Regional Load growth factors shall be proposed by the Transmission Owners and reviewed by the ISO pursuant to procedures agreed to by Market Participants and described in the ISO Procedures. Disputes concerning the development of regional Load growth factors shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

The ISO shall determine the amount of Unforced Capacity that must be sited within the NYCA, and within each Locality, and the amount of Unforced Capacity that may be procured from areas External to the NYCA, in a manner consistent with the Reliability Rules. New Transmission projects to which the NYISO has granted UDRs will not affect the determination by the NYISO of the amount of Unforced Capacity that must be located within the NYCA or within each Locality of the NYCA.

5.11 Requirements Applicable to LSEs

5.11.1 Allocation of the NYCA Minimum Unforced Capacity Requirement

Each Transmission Owner and each municipal electric utility will submit to the ISO, for its review pursuant to mutually agreed upon procedures which shall be described in the ISO Procedures, the weather-adjusted Load within its Transmission District during the hour in which actual Load in the NYCA was highest (the "NYCA peak Load") for the current Capability Year. (Municipal electric utilities may elect not to submit weather-adjusted data, in which case, weather adjustments shall be performed per ISO procedures. The ISO shall use these data to determine the Adjusted Actual Load at the time of the NYCA peak Load for each Transmission District and municipal electric utility pursuant to ISO Procedures, which shall ensure that transmission losses and the effects of demand reduction programs and the other elements of Adjusted Actual Load are treated in a consistent manner and that all weather normalization procedures meet a minimum criterion described in the ISO Procedures. Each Transmission District or municipal electric utility Load forecast coincident with the NYCA peak shall be the product of that Transmission District or municipal electric utility's Adjusted Actual Load at the time of the NYCA peak Load multiplied by one plus the regional Load growth factor for that Transmission District or municipal electric utility developed pursuant to Section 5.10 of this Tariff. After calculating each Transmission District or municipal electric utility Load forecast, if the ISO determines that an Adjusted Actual Load determined for a Transmission District or municipal electric utility does not reflect reasonable expectations of what Load might reasonably have been expected to occur in that Transmission District or area served by that municipal electric utility in that Capability Year, after taking into consideration the adjustments to account for weather normalization, transmission losses and demand response programs and other elements of Adjusted Actual Load that are described in the ISO Procedures, the ISO Procedures shall also authorize the ISO to substitute its own measures of Adjusted Actual Load for that Transmission District or area serviced by that municipal electric utility in this calculation, subject to the outcome of dispute resolution procedures if invoked. The ISO's measure of Adjusted Actual Load shall be binding unless otherwise determined as the result of dispute resolution procedures that may be invoked. Each Transmission Owner must also submit aggregate Adjusted Load data, coincident with the NYCA peak hour, for all customers served by each LSE active within its Transmission District. The aggregate Load data may be derived from direct meters or Load profiles of the customers served. Each Transmission Owner shall be required to submit such forecasts and aggregate peak Load data in accordance with the ISO Procedures. Each municipal electric utility may choose to submit its peak Load forecast based on the Transmission District's peak Load forecast provided by a Transmission Owner or to provide its own. Any disputes arising out of the submittals required in this paragraph shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

All aggregate Load data submitted by a Transmission Owner must be accompanied by documentation indicating that each affected LSE has been provided the data regarding the assignment of customers to the affected LSE. Any disputes between LSEs and Transmission Owners regarding such data or assignments shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

The ISO shall allocate the NYCA Minimum Unforced Capacity Requirement among all LSEs serving Load in the NYCA prior to the beginning of each Capability Year. It shall then adjust the NYCA Minimum Unforced Capacity Requirement and reallocate it among LSEs before each Winter Capability Period as necessary to reflect changes in the factors used to translate ICAP requirements into Unforced Capacity requirements. Each LSE's share of the NYCA Minimum Unforced Capacity Requirement will equal the product of: (i) the NYCA Minimum Installed Capacity Requirement as translated into a NYCA Minimum Unforced Capacity Requirement; and (ii) the ratio of the sum of the Load forecasts coincident with the NYCA peak Load for that LSE's customers in each Transmission District to the NYCA peak Load forecast.

Each LSE Unforced Capacity Obligation will equal the product of (i) the ratio of that LSE's share of the NYCA Minimum Unforced Capacity Requirement to the total NYCA Minimum Unforced Capacity Requirement and (ii) the total of all of the LSE Unforced Capacity Obligations for the NYCA established by the ICAP Spot Market Auction. The LSE Unforced Capacity Obligation will be determined in each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures. Each LSE will be responsible for acquiring sufficient Unforced Capacity to satisfy its LSE Unforced Capacity Obligations. LSEs with Load in more than one Locality will have an LSE Unforced Capacity Obligation for each Locality.

Prior to the beginning of each Capability Period, Transmission Owners shall submit the required Load-shifting information to the ISO and to each LSE affected by the Load-shifting, in accordance with the ISO Procedures. In the event that there is a pending dispute regarding a Transmission Owner's forecast, the ISO shall nevertheless establish each LSE's portion of the NYCA Minimum Unforced Capacity Requirement applicable at the beginning of each Capability Period in accordance with the schedule established in the ISO Procedures, subject to possible adjustments that may be required as a result of resolution of the dispute through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

Each month, as Transmission Owners report customers gained and lost by LSEs through Load-shifting, the ISO will adjust each LSE's portion of the NYCA Minimum Unforced Capacity Requirement such that (i) the total Transmission District Installed Capacity requirement remains constant and (ii) an individual LSE's allocated portion reflects the gains and losses. If an LSE loses a customer as a result of that customer leaving the Transmission District, the Load-losing LSE shall be relieved of its obligation to procure Unforced Capacity to cover the Load associated with the departing customer as of the date that the customer's departure is accepted by the ISO and shall be free to sell any excess Unforced Capacity. In addition, when a customer leaves the Transmission District, the ISO will adjust each LSE's portion of the NYCA Minimum Unforced Capacity Requirement so that the total Transmission District's share of the NYCA Minimum Unforced Capacity Requirement remains constant.

5.11.2 LSE Obligations

Each LSE must procure Unforced Capacity in an amount equal to its LSE Unforced Capacity Obligation from any Installed Capacity Supplier through Bilateral Transactions with purchases in ISO-administered Installed Capacity auctions, by self-supply from qualified sources, or by a combination of these methods. Each LSE must certify the amount of Unforced Capacity it has or has obtained prior to the beginning of each Obligation Procurement Period by submitting completed Installed Capacity certification forms to the ISO by the date specified in the ISO Procedures. The Installed Capacity certification forms submitted by the LSEs shall be in the format and include all the information prescribed by the ISO Procedures.

All LSEs shall participate in the ICAP Spot Market Auction pursuant to Section 5.14.1 of this Tariff.

5.11.3 Load-Shifting Adjustments

The ISO shall account for Load-shifting among LSEs each month using the best available information provided to it and the affected LSEs by the individual Transmission Owners**.** The ISO shall, upon notice of Load-shifting by a Transmission Owner and verification by the relevant Load-losing LSE, increase the Load-gaining LSE's LSE Unforced Capacity Obligation, as applicable, and decrease the Load-losing LSE's LSE Unforced Capacity Obligation, as applicable, to reflect the Load-shifting.

The Load-gaining LSE shall pay the Load-losing LSE an amount, pro-rated on a daily basis, based on the Market-Clearing Price of Unforced Capacity determined in the most recent previous applicable ICAP Spot Market Auction until the first day of the month after the nearest following Monthly Installed Capacity Auction is held. The amount paid by a Load-gaining LSE shall reflect any portion of the Load-losing LSE's LSE Unforced Capacity Obligation that is attributable to the shifting Load for the applicable Obligation Procurement Period, in accordance with the ISO Procedures. In addition, the amount paid by a Load-gaining LSE shall be reduced by the Load-losing LSE's share of any rebate associated with the lost Load paid pursuant to Section 5.15 of this Tariff.

Each Transmission Owner shall report to the ISO and to each LSE serving Load in its Transmission District the updated, aggregated LSE Loads with documentation in accordance with and by the date set forth in the ISO Procedures. The ISO shall reallocate a portion of the NYCA Minimum Unforced Capacity Requirement and the Locational Minimum Unforced Capacity Requirement, as applicable, to each LSE for the following Obligation Procurement

Period, which shall reflect all documented Load-shifts as of the end of the current Obligation Procurement Period. Any disputes among Market Participants concerning Load-shifting shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable. In the event of a pending dispute concerning a Load-shift, the ISO shall make its Obligation Procurement Period Installed Capacity adjustments as if the Load-shift reported by the Transmission Owners had occurred, or if the dispute pertains to the timing of a Load-shift, as if the Load-shift occurred on the effective date reported by the Transmission Owner, but will retroactively modify these allocations, as necessary, based on determinations made pursuant to the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

5.11.4 LSE Locational Minimum Installed Capacity Requirements

The ISO will determine the Locational Minimum Installed Capacity Requirements, stated as a percentage of the Locality's forecasted Capability Year peak Load and expressed in Unforced Capacity terms, that shall be uniformly applicable to each LSE serving Load within a Locality. In establishing Locational Minimum Installed Capacity Requirements, the ISO will take into account all relevant considerations, including the total NYCA Minimum Installed Capacity Requirement, the NYS Power System transmission Interface Transfer Capability, the election by the holder of rights to UDRs that can provide Capacity from an External Control Area with a capability year start date that is different than the corresponding ISO Capability Year start date ("dissimilar capability year"), the Reliability Rules and any other FERC-approved Locational Minimum Installed Capacity Requirements.

The Installed Capacity Supplier holding rights to UDRs from an External Control Area with a dissimilar capability year shall have one opportunity for a Capability Year in which the Scheduled Line will first be used to offer Capacity associated with the UDRs, to elect that the ISO determine Locational Minimum Installed Capacity Requirements without a quantity of MW from the UDRs for the first month in the Capability Year, and with the same quantity of MW as Unforced Capacity for the remaining months, in each case (a) consistent with and as demonstrated by a contractual arrangement to utilize the UDRs to import the quantity of MW of Capacity into a Locality, and (b) in accordance with ISO Procedures (a "capability year adjustment election"). If there is more than one Installed Capacity Supplier holding rights to UDRs concurrently, an Installed Capacity Supplier's election pursuant to the preceding sentence (x) shall be binding on the entity to which the NYISO granted the UDRs up to the quantity of MW to which the Installed Capacity Supplier holds rights, and a subsequent assignment of these UDRs to another rights holder will not create the option for another one-time election by the new UDR rights holder, and (y) shall not affect the right another Installed Capacity Supplier may have to make an election. The right to make an election shall remain unless and until an election has been made by one or more holders of rights to the total quantity of MW corresponding to the UDRs. Absent this one-time election, the UDRs shall be modeled consistently for all months in each Capability Year as elected by the UDR rights holder in its notification to the ISO in accordance with ISO Procedures. Upon such an election, the ISO shall determine the Locational Minimum Unforced Capacity Requirement (i) for the first month of the Capability Year without the quantity of MW of Capacity associated with the UDRs, and (ii) for the remaining eleven months as Unforced Capacity. After the Installed Capacity Supplier has made its one-time election for a quantity of MW, the quantity of MW associated with the UDRs held by the

Installed Capacity Supplier shall be modeled consistently for all months in any future Capability Period.

The Locational Minimum Unforced Capacity Requirement represents a minimum level of Unforced Capacity that must be secured by LSEs in each Locality in which it has Load for each Obligation Procurement Period. The Locational Minimum Unforced Capacity Requirement for each Locality shall equal the product of the Locational Minimum Installed Capacity Requirement for a given Locality ((A) with or without the UDRs if there is a capability year adjustment election by a rights holder and (B) without the Locality Exchange MW) and the ratio of (1) the total amount of Unforced Capacity that the specified Resources are qualified to provide (with or without the UDRs associated with dissimilar capability periods, as so elected by the rights holder) during each month in the Capability Period, as of the time the Locational Minimum Unforced Capacity Requirement is determined as specified in ISO Procedures, to (2) the sum of the DMNCs used to determine the Unforced Capacities of such Resources for such Capability Period (with or without the DMNCs associated with the UDRs, as so elected by the rights holder).

The foregoing calculation shall be determined using the Resources in the given Locality in the most recent final version of the ISO's annual Load and Capacity Data Report, with the addition of Resources commencing commercial operation since completion of that report and the deletion of Resources with scheduled or planned retirement dates before or during such Capability Period. The ISO will apply the Locality Exchange Factor for the applicable External Control Area to the MW of Locational Export Capacity that are the lesser of (i) the lesser of the Generator's CRIS and its most recent DMNC, and (ii) the MW pursuant to the notice provided pursuant to Section 5.9.2.2.1 of this Services Tariff.

Under the provisions of this Services Tariff and the ISO Procedures, each LSE will be obligated to procure its LSE Unforced Capacity Obligation. The LSE Unforced Capacity Obligation will be determined for each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures.

Qualified Resources will have the opportunity to supply amounts of Unforced Capacity to meet the LSE Unforced Capacity Obligation as established by the ICAP Spot Market Auction.

To be counted towards the locational component of the LSE Unforced Capacity Obligation, Unforced Capacity owned by the holder of UDRs or contractually combined with UDRs must be deliverable to the NYCA interface with the UDR transmission facility pursuant to NYISO requirements and consistent with the election of the holder of the rights to the UDRs set forth in this Section.

In addition, any Customer that purchases Unforced Capacity associated with any generation that is subject to capacity market mitigation measures in an ISO-administered auction may not resell that Unforced Capacity in a subsequent auction at a price greater than the annual mitigated price cap, as applied in accordance with the ISO Procedures in accordance with Sections 5.13.2, 5.13.3, and 5.14.1 of this Tariff. The ISO shall inform Customers that purchase Unforced Capacity in an ISO-administered auction of the amount of Unforced Capacity they have purchased that is subject to capacity market mitigation measures.

The ISO shall have the right to audit all executed Installed Capacity contracts and related documentation of arrangements by an LSE to use its own generation to meet its Locational Minimum Installed Capacity Requirement for an upcoming Obligation Procurement Period.

5.11.4.1 Determination of Locality Exchange Factor:

No later than January 31 each year, the ISO shall determine the Locality Exchange Factor for each Import Constrained Locality relative to each neighboring Control Area.

The ISO shall make each such determination by performing a power flow based analysis according to applicable transmission system planning practices for the determination of interface transfer limits used for the resource adequacy topology. Base case data from the most recent reliability planning process will be incorporated. The Locality Exchange Factor is the ratio of the shift factor on the applicable NYCA interface of a transfer from the Import Constrained Locality to the respective neighboring Control Area, to the shift factor of a transfer from Rest of State to the Import Constrained Locality, calculated in accordance with ISO Procedures. Only the AC circuits comprising the respective neighboring Control Area's interface with the NYCA will participate in the shift. The ISO shall post its Locality Exchange Factors on its website prior to the opening of the Summer Capability Period Auction, and notify the New York State Reliability Council.

5.12 Requirements Applicable to Installed Capacity Suppliers

5.12.1 Installed Capacity Supplier Qualification Requirements

In order to qualify as an Installed Capacity Supplier, Generators and controllable transmission projects electrically located in the NYCA must have obtained Capacity Resource Interconnection Service ("CRIS") pursuant to the applicable provisions of Attachment S to the ISO OATT, and controllable transmission projects must also have obtained Unforced Capacity Deliverability Rights. Even if a Generator has otherwise satisfied the requirements to participate in the ISO's Installed Capacity market, a Generator in Inactive Reserves, an ICAP Ineligible Forced Outage, a Mothball Outage, or that is Retired is ineligible to participate in the ISO's Installed Capacity market. A Generator that elects to participate in the ICAP Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not consist solely of Station Power) at a single PTID can only participate in the Installed Capacity market as a Behind-the-Meter Net Generation Resource.

In addition, to qualify as an Installed Capacity Supplier in the NYCA, Energy Limited Resources, Generators, Installed Capacity Marketers, Intermittent Power Resources, Behind-the-Meter Net Generation Resources, Limited Control Run-of-River Hydro Resources and System Resources rated 1 MW or greater, other than External System Resources and Control Area System Resources which have agreed to certain Curtailment conditions as set forth in the last paragraph of Section 5.12.1 below, Responsible Interface Parties, existing municipally-owned generation, Energy Limited Resources, and Intermittent Power Resources, to the extent those entities are subject to the requirements of Section 5.12.11 of this Tariff, shall:

5.12.1.1 provide information reasonably requested by the ISO including the name and location of Generators, and System Resources;

5.12.1.2 in accordance with the ISO Procedures, perform DMNC or DMGC tests and submit the results to the ISO, or provide to the ISO appropriate historical production data;

5.12.1.3 abide by the ISO Generator maintenance coordination procedures;

5.12.1.4 provide the expected return date from any outages (including partial outages) to the ISO;

5.12.1.5 in accordance with the ISO Procedures,

5.12.1.5.1 provide documentation demonstrating that it will not use the same Unforced Capacity for more than one (1) buyer at the same time, and

5.12.1.5.2 in the event that the Installed Capacity Supplier supplies more Unforced Capacity than it is qualified to supply in any specific month (*i.e.*, is short on Capacity), documentation that it has procured sufficient Unforced Capacity to cover this shortfall.

5.12.1.6 except for Installed Capacity Marketers and Intermittent Power Resources that depend upon wind or solar as their fuel, Bid into the Day-Ahead Market, unless the Energy Limited Resource, Generator, Limited Control Run-of-River Hydro Resource or System Resource is unable to do so due to an outage as defined in the ISO Procedures or due to temperature related de-ratings. Generators may also enter into the MIS an upper operating limit that would define the operating limit under normal system conditions. The circumstances under which the ISO will direct a Generator to exceed its upper operating limit are described in the ISO Procedures;

5.12.1.7 provide Operating Data in accordance with Section 5.12.5 of this Tariff;

5.12.1.8 provide notice to the ISO of any proposed transfers of deliverability rights to be carried out pursuant to Sections 25.9.4 - 25.9.6 of Attachment S to the ISO OATT, on the Class Year Start Date if a request to transfer CRIS at a different location, and upon the submission of the request if it is a request to transfer CRIS at the same location.

5.12.1.9 comply with the ISO Procedures;

5.12.1.10 when the ISO issues a Supplemental Resource Evaluation request (an SRE), Bid into the in-day market unless the entity has a bid pending in the Real-Time Market when the SRE request is made or is unable to bid in response to the SRE request due to an outage as defined in the ISO Procedures, or due to other operational issues, or due to temperature related deratings; and

5.12.1.11 Installed Capacity Suppliers located East of Central-East shall Bid in the Day-Ahead and Real-Time Markets all Capacity available for supplying 10-Minute Non-Synchronized Reserve (unless the Generator is unable to meet its commitment because of an outage as defined in the ISO Procedures), except for the Generators described in Subsections 5.12.1.11.1, 5.12.1.11.2 and 5.12.1.11.3 below:

5.12.1.11.1 Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchasers do not control the operation of the supply source but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999, who have not provided telemetering to their local TO and historically have not been eligible to participate in the NYPP market, which will continue to be treated as TO Load modifiers under the ISO-administered markets;

5.12.1.11.2 Existing topping turbine Generators and extraction turbine Generators producing Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators used in replacing or repowering steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 523 MW of such units; and

5.12.1.11.3 Units that have demonstrated to the ISO that they are subject to environmental, contractual or other legal or physical requirements that would otherwise preclude them from providing 10-Minute NSR.

5.12.1.12 A Resource that was determined by the ISO to be qualified as a Behind-the-Meter Net Generation Resource and for which Net Unforced Capacity was calculated by the ISO for a Capability Year can annually, by written notice received by the NYISO prior to August 1, elect not to participate in the ISO Administered Markets as a Behind-the-Meter Net Generation Resource. Such notice shall be in accordance with ISO Procedures. A Resource that makes such an election cannot participate as a Behind-the-Meter Net Generation Resource for the entire Capability Year for which it made the election, but can, however, prior to August 1 of any subsequent Capability Year, provide all required information in order to seek to re-qualify as a Behind-the-Meter Net Generation Resource.

The ISO shall inform each potential Installed Capacity Supplier that the ISO must receive and approve DMNC or DMGC data, as applicable of its approved DMNC or DMGC ratings for the Summer Capability Period and the Winter Capability Period in accordance with the ISO Procedures.

Requirements to qualify as Installed Capacity Suppliers for External System Resources and Control Area System Resources located in External Control Areas that have agreed not to Curtail the Energy associated with such Installed Capacity or to afford it the same Curtailment priority that it affords its own Control Area Load shall be established in the ISO Procedures.

External Installed Capacity not associated with UDRs, including capacity associated with External CRIS Rights, Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual, the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT, Import Rights, and External System Resources, is only qualified to satisfy a NYCA Minimum Unforced Capacity Requirement and is not eligible to satisfy a Locational Minimum Installed Capacity Requirement.

Not later than 30 days prior to each ICAP Spot Market Auction, each Market Participant that may make offers to sell Unforced Capacity in such auction shall submit information to the ISO, in accordance with ISO Procedures and in the format specified by the ISO that identifies each Affiliated Entity, as that term is defined in Section 23.2.1 of Attachment H of the Services Tariff, of the Market Party or with which the Market Party is an Affiliated Entity. The names of entities that are Affiliated Entities shall not be treated as Confidential Information, but such treatment may be requested for the existence of an Affiliated Entity relationship. The information submitted to the ISO shall identify the nature of the Affiliated Entity relationship by the applicable category specified in the definition of "Affiliated Entity" in Section 23.2.1 of Attachment H of the Services Tariff.

5.12.2 Additional Provisions Applicable to External Installed Capacity Suppliers

Terms in this Section 5.12.2 not defined in the Services Tariff have the meaning set forth in the OATT.

5.12.2.1 Provisions Addressing the Applicable External Control Area

External Generators, External System Resources, and Control Area System Resources qualify as Installed Capacity Suppliers if they demonstrate to the satisfaction of the NYISO that the Installed Capacity Equivalent of their Unforced Capacity is deliverable to the NYCA or, in the case of an entity using a UDR to meet a Locational Minimum Installed Capacity Requirement, to the NYCA interface associated with that UDR transmission facility and will not be recalled or curtailed by an External Control Area to satisfy its own Control Area Loads, or, in the case of Control Area System Resources, if they demonstrate that the External Control Area will afford the NYCA Load the same curtailment priority that they afford their own Control Area Native Load Customers. The amount of Unforced Capacity that may be supplied by such entities qualifying pursuant to the alternative criteria may be reduced by the ISO, pursuant to ISO Procedures, to reflect the possibility of curtailment. External Installed Capacity associated with Import Rights or UDRs is subject to the same deliverability requirements applied to Internal Installed Capacity Suppliers associated with UDRs.

5.12.2.2 Additional Provisions Addressing Internal Deliverability and Import Rights

In addition to the provisions contained in Section 5.12.2.1 above, External Installed Capacity not associated with UDRs or External CRIS Rights will be subject to the deliverability test in Section 25.7.8 and 25.7.9 of Attachment S to the ISO OATT. The deliverability of External Installed Capacity not associated with UDRs or External CRIS Rights will be evaluated annually as a part of the process that sets import rights for the upcoming Capability Year, to determine the amount of External Installed Capacity that can be imported to the New York Control Area across any individual External Interface and across all of those External Interfaces, taken together. The External Installed Capacity deliverability test will be performed using the ISO's forecast, for the upcoming Capability Year, of New York Control Area CRIS resources, transmission facilities, and load. Under this process (i) Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual, and (ii) the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT, will be considered deliverable within the Rest of State. Additionally, 1090 MW of imports made over the Quebec (via Chateauguay) Interface will be considered to be deliverable until the end of the 2010 Summer Capability Period.

The import limit set for External Installed Capacity not associated with UDRs or External CRIS Rights will be set no higher than the amount of imports deliverable into Rest of State that (i) would not increase the LOLE as determined in the upcoming Capability Year IRM consistent with Section 2.7 of the NYISO Installed Capacity Manual, "Limitations on Unforced Capacity Flow in External Control Areas," (ii) are deliverable within the Rest of State Capacity Region when evaluated with the New York Control Area CRIS resources and External CRIS Rights forecast for the upcoming Capability Year, and (iii) would not degrade the transfer capability of any Other Interface by more than the threshold identified in Section 25.7.9 of Attachment S to the ISO OATT. Import limits set for External Installed Capacity will reflect the modeling of awarded External CRIS rights, but the awarded External CRIS rights will not be adjusted as part of import limit-setting process. Procedures for qualifying selling, and delivery of External Installed Capacity are detailed in the Installed Capacity Manual.

Until the grandfathered import rights over the Quebec (via Chateauguay) Interface expire at the end of the 2010 Summer Capability Period, the 1090 MW of grandfathered import rights will be made available on a first-come, first-served basis pursuant to ISO Procedures. Any of the grandfathered import rights over the Quebec (via Chateauguay) Interface not utilized for a Capability Period will be made available to other external resources for that Capability Period, pursuant to ISO Procedures, to the extent the unutilized amount is determined to be deliverable.

Additionally, any of the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation not utilized by New York State Electric & Gas Corporation for a Capability Period will be made available to other external resources for that Capability Period, pursuant to ISO procedures, to the extent the unutilized amount is determined to be deliverable within the Rest of State Capacity Region.

LSEs with External Installed Capacity as of the effective date of this Tariff will be entitled to designate External Installed Capacity at the same NYCA Interface with another Control Area, in the same amounts in effect on the effective date of this Tariff. To the extent such External Installed Capacity corresponds to Existing Transmission Capacity for Native Load as reflected in Table 3 of Attachment L to the ISO OATT, these External Installed Capacity rights will continue without term and shall be allocated to the LSE's retail access customers in accordance with the LSE's retail access program on file with the PSC and subject to any necessary filings with the Commission. External Installed Capacity rights existing as of September 17, 1999 that do not correspond to Table 3 of Attachment L to the ISO OATT shall survive for the term of the relevant External Installed Capacity contract or until the relevant External Generator is retired.

5.12.2.3 One-Time Conversion of Grandfathered Quebec (via Chateauguay) Interface Rights.

An entity can request to convert a specified number of MW, up to 1090 MW over the Quebec External Interface (via Chateauguay), into External CRIS Rights by making either a Contract Commitment or Non-Contract Commitment that satisfies the requirements of Section 25.7.11.1 of Attachment S to the ISO OATT. The converted number of MW will not be subject to further evaluation for deliverability within a Class Year Deliverability Study under Attachment S to the ISO OATT, as long as the External CRIS Rights are in effect.

5.12.2.3.1 The External CRIS Rights awarded under this conversion process will first become effective for the 2010-2011 Winter Capability Period.

5.12.2.3.2 Requests to convert these grandfathered rights must be received by the NYISO on or before 5:00 pm Eastern Time on February 1, 2010, with the following information: (a) a statement that the entity is electing to convert by satisfying the requirements of a Contract Commitment or a Non-Contract Commitment in accordance with Section 25.7.11.1 of Attachment S to the ISO OATT; (b) the length of the commitment in years; (c) for the Summer Capability Period, the requested number of MW; (d) for the Winter Capability Period, the Specified Winter Months, if any, and the requested number of MW; and (e) a minimum number of MW the entity will accept if granted (“Specified Minimum”) for the Summer Capability Period and for all Specified Winter Months, if any.

5.12.2.3.3 An entity cannot submit one or more requests to convert in the aggregate more than 1090 MW in any single month.

5.12.2.3.4 If requests to convert that satisfy all other requirements stated herein are equal to or less than the 1090 MW limit, all requesting entities will be awarded the requested number of MW of External CRIS Rights. If conversion requests exceed the 1090 MW limit, the NYISO will prorate the allocation based on the weighted average of the requested MW times the length of the contract/commitment (*i.e.*, number of Summer Capability Periods) in accordance with the following formula:

$$Rights\ allocated\ to\ entity\ i = 1090 * (MW_i * contract/commitment\ length_i) / \sum_j \left(MW_j * contract/commitment\ length_j\right)$$

j = l,…# entities requesting import rights

In the formula, contract/commitment length means the lesser of the requested contract/commitment length and twenty (20) years. The NYISO will perform separate calculations for the Summer and Winter Capability Periods. The NYISO will determine whether the prorated allocated number of MW for any requesting entity is less than the entity's Specified Minimum. If any allocation is less, the NYISO will remove such request(s) and recalculate the prorated allocations among the remaining requesting entities using the above formula. This process will continue until the prorated allocation meets or exceeds the specified minimum for all remaining requests.

5.12.2.3.5 Any portion of the previously grandfathered 1090 MW not converted through this process will no longer be grandfathered from deliverability.

Previously grandfathered rights converted to External CRIS Rights but then terminated will no longer be grandfathered from deliverability.

5.12.2.4 Offer Cap Applicable to Certain External CRIS Rights

Notwithstanding any other capacity mitigation measures or obligations that may apply, the offers of External Installed Capacity submitted pursuant to a Non-Contract Commitment, as described in Section 25.7.11.1.2 of Attachment S of the ISO OATT, will be subject to an offer cap in each month of the Summer Capability Period and for all Specified Winter Months. This offer cap will be determined as the higher of:

5.12.2.4.1 1.1 times the price corresponding to all available Unforced Capacity determined from the NYCA ICAP Demand Curve for that Period; and

5.12.2.4.2 The most recent auction clearing price (a) in the External market supplying the External Installed Capacity, if any, and if none, then the most recent auction clearing price in an External market to which the capacity may be wheeled, less (b) any transmission reservation costs in the External market associated with providing the Installed Capacity, in accordance with ISO Procedures.

5.12.3 Installed Capacity Supplier Outage Scheduling Requirements

All Installed Capacity Suppliers, except for Control Area System Resources and Responsible Interface Parties, that intend to supply Unforced Capacity to the NYCA shall submit a confidential notification to the ISO of their proposed outage schedules in accordance with the ISO Procedures. Transmission Owners will be notified of these and subsequently revised outage schedules. Based upon a reliability assessment, if Operating Reserve deficiencies are projected to occur in certain weeks for the upcoming calendar year, the ISO will request voluntary rescheduling of outages. In the case of Generators actually supplying Unforced Capacity to the NYCA, if voluntary rescheduling is ineffective, the ISO will invoke forced rescheduling of their outages to ensure that projected Operating Reserves over the upcoming year are adequate.

A Generator that refuses a forced rescheduling of its outages for any unit shall be prevented from supplying Unforced Capacity in the NYCA with that unit during any month where it undertakes such outages. The rescheduling process is described in the ISO Procedures.

A Generator that intends to supply Unforced Capacity in a given month that did not qualify as an Installed Capacity Supplier prior to the beginning of the Capability Period must notify the ISO in accordance with the ISO Procedures so that it may be subject to forced rescheduling of its proposed outages in order to qualify as an Installed Capacity Supplier. A Supplier that refuses the ISO's forced rescheduling of its proposed outages shall not qualify as an Installed Capacity Supplier for that unit for any month during which it schedules or conducts an outage.

Outage schedules for External System Resources and Control Area System Resources shall be coordinated by the External Control Area and the ISO in accordance with the ISO Procedures.

5.12.4 Required Certification for Installed Capacity

(a) Each Installed Capacity Supplier must confirm to the ISO, in accordance with ISO Procedures that the Unforced Capacity it has certified has not been sold for use in an External Control Area.

(b) Each Installed Capacity Supplier holding rights to UDRs from an External Control Area must confirm to the ISO, in accordance with ISO Procedures, that it will not use as self-supply or offer, and has not sold, Installed Capacity associated with the quantity of MW for which it has not made its one time capability adjustment year election pursuant to Section 5.11.4.

(c) On and after the execution of an RMR Agreement, and for the duration of its term, an RMR Generator shall not enter into any new agreement or extend any other agreement that impairs or otherwise diminishes its ability to comply with its obligation under an RMR Agreement, or that limits its ability to provide Energy, Capacity, or Ancillary Services directly to the ISO Administered Markets. An Interim Service Provider shall not enter into any new agreement or extend any other agreement that limits its ability to provide Energy, Capacity, or Ancillary Services directly to the ISO Administered Markets or otherwise meet its obligations as an Interim Service Provider.

5.12.5 Operating Data Reporting Requirements

To qualify as Installed Capacity Suppliers in the NYCA, Resources shall submit to the ISO Operating Data in accordance with this Section 5.12.5 and the ISO Procedures. Resources that do not submit Operating Data in accordance with the following subsections and the ISO Procedures may be subject to the sanctions provided in Section 5.12.12.1 of this Tariff.

Resources that were not in operation on January 1, 2000 shall submit Operating Data to the ISO no later than one month after such Resources commence commercial operation, and in accordance with the ISO Procedures and the following subsections as applicable.

5.12.5.1 Generators, System Resources, Energy Limited Resources, Responsible Interface Parties, Intermittent Power Resources, Limited Control Run-of-River Hydro Resources and Municipally Owned Generation

To qualify as Installed Capacity Suppliers in the NYCA, Generators, External Generators, System Resources, External System Resources, Energy Limited Resources, Responsible Interface Parties, Intermittent Power Resources, Limited Control Run-of-River Hydro Resources, and municipally owned generation or the purchasers of Unforced Capacity associated with those Resources shall submit GADS Data, data equivalent to GADS Data, or other Operating Data to the ISO in accordance with the ISO Procedures. Prior to the successful implementation of a software modification that allows gas turbines to submit multiple bid points, these units shall not be considered to be forced out for any hours that the unit was available at its base load capability in accordance with the ISO Procedures. This section shall also apply to any Installed Capacity Supplier, External or Internal, using UDRs to meet Locational Minimum Installed Capacity Requirements.

5.12.5.2 Control Area System Resources

To qualify as Installed Capacity Suppliers in the NYCA, Control Area System Resources, or the purchasers of Unforced Capacity associated with those Resources, shall submit CARL Data and actual system failure occurrences data to the ISO each month in accordance with the ISO Procedures.

5.12.5.3 Transmission Projects Granted Unforced Capacity Deliverability Rights

An owner of a transmission project that receives UDRs must, among other obligations, submit outage data or other operational information in accordance with the ISO procedures to allow the ISO to determine the number of UDRs associated with the transmission facility.

5.12.6 Capacity Calculations, Operating Data Default, Value and Collection

5.12.6.1 ICAP Calculation for Behind-the-Meter Net Generation Resources

The ISO shall calculate the amount of Net-ICAP for each Behind-the-Meter Net Generation Resource as the Adjusted DMGC of the Generator of the Behind-the-Meter Net

Generation Resource minus the Resource's Adjusted Host Load in accordance with this Tariff and ISO Procedures.

5.12.6.1.1 Adjusted DMGC

The ISO's calculation of the Adjusted DMGC of a Behind-the-Meter Net Generation Resource shall be the least of: (i) its DMGC for the Capability Period; (ii) its Adjusted Host Load plus its applicable Injection Limit; and (iii) its Adjusted Host Load plus the number of MW of CRIS it has obtained, as determined in accordance with OATT Section 25 (OATT Attachment S) and ISO Procedures.

If the Station Power of a Behind-the-Meter Net Generation Resource is separately metered from all other Load of the Resource, such that the Station Power Load can be independently measured and verified, the Generator of a Behind-the-Meter Net Generation Resource may elect to perform a DMNC Test instead of a DMGC Test pursuant to ISO Procedures. Such election must be made in writing to the ISO prior to the start of the DMNC Test Period.

If a Behind-the-Meter Net Generation Resource elects to take a DMNC Test, the Station Power measured during such DMNC Test shall not be included in the Resource's Host Load. A Behind-the-Meter Net Generation Resource's DMNC value for the Capability Period shall be used in lieu of a DMGC value in the calculation of the Resource's Adjusted DMGC for the purposes of Sections 5.12.6.1 and 5.12.6.2 of this Services Tariff.

5.12.6.1.2 Adjusted Host Load

A Behind-the-Meter Net Generation Resource's Adjusted Host Load shall be equal to the product of the Average Coincident Host Load multiplied by one plus the Installed Reserve Margin.

The Adjusted Host Load shall be calculated by the ISO on an annual basis prior to the start of the Summer Capability Period and in accordance with ISO Procedures, based upon the Behind-the-Meter Net Generation Resource's Average Coincident Host Load for the prior Summer Capability Period and the Winter Capability Period before that.

5.12.6.1.2.1 Average Coincident Host Load

The ISO must receive the Behind-the-Meter Net Generation Resource's applicable metered Load data required to calculate an Average Coincident Host Load in accordance with ISO Procedures. The ISO shall compute the Average Coincident Host Load for each Capability Year (i) using the metered Host Load data for the applicable NYCA peak Load hours, except as provided below in this Section, and (ii) adjusted for weather normalization and Load growth as determined by the ISO in relation to developing the NYCA Minimum Installed Capacity Requirement in accordance with ISO Procedures.

For each Capability Year, the NYISO shall use the average of the highest twenty (20) one-hour peak Loads of the Host Load of the Behind-the-Meter Net Generation Resource that occur during the top forty (40) NYCA peak Load hours of the prior Summer Capability Period and the Winter Capability Period before that to calculate the Average Coincident Host Load.

If a facility meets the criteria to be, and has not previously been, a Behind-the-Meter Net Generation Resource, but does not have all of the appropriate meter data, its Average Coincident Host Load shall be a value forecasted by the Behind-the-Meter Net Generation Resource. The Behind-the-Meter Net Generation Resource's forecast shall be based on actual meter data, or if not available, billing data or other business data of the Host Load. An estimated Average Coincident Host Load can only be applicable to a Behind-the-Meter Net Generation Resource until actual data becomes available, but in any event no longer than three (3) consecutive Capability Years beginning with the Capability Year it is first an Installed Capacity Supplier.

5.12.6.1.2.2 Determination of Adjusted Host Load

After the ISO has calculated a Behind-the-Meter Net Generation Resource's Average Coincident Host Load, it shall then apply the NYCA Installed Reserve Margin. The Behind-the-Meter Net Generation Resource's Adjusted Host Load will be established by multiplying the Resource's Average Coincident Host Load for the Capability Year by the quantity of one plus the NYCA Installed Reserve Margin.

5.12.6.2 UCAP Calculations

The ISO shall calculate for each Resource the amount of Unforced Capacity that each Installed Capacity Supplier is qualified to supply in the NYCA in accordance with formulae provided in the ISO Procedures.

The amount of Unforced Capacity that each Generator, except for the Generator of a Behind-the-Meter Net Generation Resource, System Resource, Energy Limited Resource, Special Case Resource, and municipally-owned generation is authorized to supply in the NYCA shall be based on the ISO's calculations of individual Equivalent Demand Forced Outage Rates. The amount of Unforced Capacity that each Control Area System Resource is authorized to supply in the NYCA shall be based on the ISO's calculation of each Control Area System Resource's availability. The amount of Unforced Capacity that each Intermittent Power Resource is authorized to supply in the NYCA shall be based on the NYISO's calculation of the amount of capacity that the Intermittent Power Resource can reliably provide during system peak Load hours in accordance with ISO Procedures. Except as provided in Section 5.12.6.2.1 of this Services Tariff, this calculation shall not include hours in any month that the Intermittent Power

Resource was in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market. The amount of Unforced Capacity that each Limited Control Run-of-River Hydro Resource is authorized to provide in the NYCA shall be determined separately for Summer and Winter Capability Periods as the rolling average of the hourly net Energy provided by each such Resource during the 20 highest NYCA integrated real-time load hours in each of the five previous Summer or Winter Capability Periods, as appropriate, stated in megawatts. Except as provided in Section 5.12.6.2.1 of this Services Tariff, for a Limited Control Run-of-River Hydro Resource in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market during one of the 20 highest NYCA integrated real-time load hours in any one of the five previous Summer or Winter Capability Periods, the ISO shall replace that Winter or Summer Capability Period, as appropriate, with the next most recent Winter or Summer Capability Period such that the rolling average of the hourly net Energy provided by each such Resource shall be calculated from the 20 highest NYCA integrated real-time load hours in the five most recent prior Summer or Winter Capability Periods in which the Resource was not in an outage state that precluded its eligibility to participate in the Installed Capacity market on one of the 20 highest NYCA integrated real-time load hours in that Capability Period.

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for each Generator, System Resource, Special Case Resource, Energy Limited Resource, and municipally owned generation and update them periodically using a twelve-month calculation in accordance with formulae provided in the ISO Procedures; provided**,** however, except as provided in Section 5.12.6.2.1 of this Services Tariff, for a Generator in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed

Capacity market at any time during any month from which GADS or other operating data would otherwise be used to calculate an individual Equivalent Demand Forced Outage Rate, the ISO shall replace such month's GADS or other operating data with GADS or other operating data from the most recent prior month in which the Generator was not in an outage state that precluded its eligibility to participate in the Installed Capacity market.

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for Intermittent Power Resources and update them seasonally as described in ISO Procedures.

The amount of Unforced Capacity that each Behind-the-Meter Net Generation Resource is authorized to supply in the NYCA shall be its Net-UCAP. Net-UCAP is the lesser of (i) the ISO's calculation of the Generator of the Behind-the-Meter Net Generation Resource Adjusted DMGC multiplied by one minus its Equivalent Demand Forced Outage Rate, and then decreased by its Adjusted Host Load translated into Unforced Capacity terms consistent with Section 5.11.1 of this Tariff, and (ii) the Resource's Net-ICAP.

5.12.6.2.1 Exceptions

A Generator returning to the Energy market after taking an outage that precluded its participation in the Installed Capacity market and which returns with modifications to its operating characteristics determined by the ISO to be material and which, therefore, requires the submission of a new Interconnection Request will receive, as the initial derating factor for calculation of the Generator's Unforced Capacity upon its return to service, the derating factor it would have received as a newly connecting unit in lieu of a derating factor developed from unit-specific data. A Generator returning to the Energy market after taking an outage that precluded its participation in the Installed Capacity market and which, upon its return, uses as its primary fuel a fuel not previously used at the facility for any purpose other than for ignition purposes will receive, as the initial derating factor for calculation of the Generator's Unforced Capacity upon its return to service, the NERC class average derating factor in lieu of a derating factor developed from unit-specific data even if the modifications to allow use of a new primary fuel are not material and do not require the submission of a new Interconnection Request.

This Section 5.12.6.2.1 shall apply to a Generator returning to the Energy market after taking an outage that started on or after May 1, 2015 and that precluded its participation in the Installed Capacity market.

5.12.6.3 Default Unforced Capacity

In its calculation of Unforced Capacity, the ISO shall deem a Resource to be completely forced out for each month for which the Resource has not submitted its Operating Data in accordance with Section 5.12.5 of this Tariff and the ISO Procedures. A Resource that has been deemed completely forced out for a particular month may submit new Operating Data, for that month, to the ISO at any time. The ISO will use such new Operating Data when calculating, in a timely manner in accordance with the ISO Procedures, a Unforced Capacity value for the Resource.

Upon a showing of extraordinary circumstances, the ISO retains the discretion to accept at any time Operating Data which have not been submitted in a timely manner, or which do not fully conform with the ISO Procedures.

5.12.6.4 Exception for Certain Equipment Failures

When a Generator, Special Case Resource, Energy Limited Resource, or System Resource is forced into an outage by an equipment failure that involves equipment located on the high voltage side of the electric network beyond the step-up transformer, and including such step-up transformer, the outage will not be counted for purposes of calculating that Resource's Equivalent Demand Forced Outage Rate.

5.12.7 Availability Requirements

Subsequent to qualifying, each Installed Capacity Supplier shall, except as noted in Section 5.12.11 of this Tariff, on a daily basis: (i) schedule a Bilateral Transaction; (ii) Bid Energy in each hour of the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (iii) notify the ISO of any outages. An RMR Generator can only schedule a Bilateral Transaction to the extent expressly authorized in its RMR Agreement. The total amount of Energy that an Installed Capacity Supplier schedules, bids, or declares to be unavailable on a given day must equal or exceed the Installed Capacity Equivalent of the Unforced Capacity it supplies.

5.12.8 Unforced Capacity Sales

Each Installed Capacity Supplier will, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, be authorized to supply an amount of Unforced Capacity during each Obligation Procurement Period, based on separate seasonal Unforced Capacity calculations performed by the ISO for the Summer and Winter Capability Periods. Unforced Capacity may be sold in six-month strips, or in monthly, or multi-monthly segments.

External Unforced Capacity (except External Installed Capacity associated with UDRs) may only be offered into Capability Period Auctions or Monthly Auctions for the Rest of State, and ICAP Spot Market Auctions for the NYCA, and may not be offered into a Locality for an ICAP Auction. Bilateral Transactions which certify External Unforced Capacity using Import Rights may not be used to satisfy a Locational Minimum Unforced Capacity Requirement.

UCAP from an RMR Generator may only be offered into the ICAP Spot Market Auction, except and only to the extent that the RMR Agreement expressly permits the RMR Generator's UCAP to be certified in a Bilateral Transaction.

If an Energy Limited Resource's, Generator's, System Resource's or Control Area System Resource's DMNC rating, or the DMGC rating of a Generator of a Behind-the-Meter Net Generation Resource, if applicable, is determined to have increased during an Obligation Procurement Period, pursuant to testing procedures described in the ISO Procedures, the amount of Unforced Capacity that it shall be authorized to supply in that or future Obligation Procurement Periods shall also be increased on a prospective basis in accordance with the schedule set forth in the ISO Procedures provided that it first has satisfied the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT.

New Generators and Generators that have increased their Capacity since the previous Summer Capability Period due to changes in their generating equipment may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Summer Capability Period based upon a DMNC test, or the DMGC test of a Generator of a Behind-the-Meter Net Generation Resource, that is performed and reported to the ISO after March 1 and prior to the beginning of the Summer Capability Period DMNC Test Period. The Generator will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Summer DMNC Test Period. Any shortfall between the amount of Unforced Capacity supplied by the Generator for the Summer Capability Period and the amount verified during the Summer DMNC Test Period will be subject to deficiency charges pursuant to Section 5.14.2 of this Tariff. The deficiency charges will be applied to no more than the difference between the Generator's previous Summer Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Generator supplied for the Summer Capability Period.

New Generators and Generators that have increased their Capacity since the previous Winter Capability Period due to changes in their generating equipment may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Winter Capability Period based upon a DMNC test, or the DMGC test of a Generator of a Behind-the-Meter Net Generation Resource, that is performed and reported to the ISO after September 1 and prior to the beginning of the Winter Capability Period DMNC Test Period. The Generator will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Winter Capability Period DMNC Test Period. Any shortfall between the amount of Unforced Capacity certified by the Generator for the Winter Capability Period and the amount verified during the Winter Capability Period DMNC Test Period will be subject to deficiency charges pursuant to Section 5.14.2 of this Tariff. The deficiency charges will be applied to no more than the difference between the Generator's previous Winter Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Generator supplied for the Winter Capability Period.

Any Installed Capacity Supplier, except as noted in Section 5.12.11 of this ISO Services Tariff, which fails on a daily basis to schedule, Bid, or declare to be unavailable in the Day-Ahead Market an amount of Unforced Capacity, expressed in terms of Installed Capacity Equivalent, that it certified for that day, rounded down to the nearest whole MW, is subject to sanctions pursuant to Section 5.12.12.2 of this Tariff. If an entity other than the owner of an Energy Limited Resource, Generator, System Resource, Behind-the-Meter Net Generation Resource, or Control Area System Resource that is providing Unforced Capacity is responsible for fulfilling bidding, scheduling, and notification requirements, the owner and that entity must designate to the ISO which of them will be responsible for complying with the scheduling, bidding, and notification requirements. The designated bidding and scheduling entity shall be subject to sanctions pursuant to Section 5.12.12.2 of this ISO Services Tariff.

5.12.9 Sales of Unforced Capacity by System Resources

Installed Capacity Suppliers offering to supply Unforced Capacity associated with Internal System Resources shall submit for each of their Resources the Operating Data and DMNC testing data or historical data described in Sections 5.12.1 and 5.12.5 of this ISO Services Tariff in accordance with the ISO Procedures. Such Installed Capacity Suppliers will be allowed to supply the amount of Unforced Capacity that the ISO determines pursuant to the ISO Procedures to reflect the appropriate Equivalent Demand Forced Outage Rate. Installed Capacity Suppliers offering to sell the Unforced Capacity associated with System Resources may only aggregate Resources in accordance with the ISO Procedures.

5.12.10 Curtailment of External Transactions In-Hour

All Unforced Capacity that is not out of service, or scheduled to serve the Internal NYCA Load in the Day-Ahead Market may be scheduled to supply Energy for use in External Transactions provided, however, that such External Transactions shall be subject to Curtailment within the hour, consistent with ISO Procedures. Such Curtailment shall not exceed the Installed Capacity Equivalent committed to the NYCA.

5.12.11 Responsible Interface Parties, Municipally-Owned Generation, Energy Limited Resources and Intermittent Power Resources

5.12.11.1 Responsible Interface Parties

Responsible Interface Parties may qualify as Installed Capacity Suppliers, without having to comply with the daily bidding, scheduling, and notification requirements set forth in Section 5.12.7 of this Tariff, if their Special Case Resources are available to operate at the direction of the ISO in order to reduce Load from the NYS Transmission System and/or the distribution system for a minimum of four (4) consecutive hours each day, except for those subject to operating limitations established by environmental permits, which will not be required to operate in excess of two (2) hours and which will be derated by the ISO pursuant to ISO Procedures to account for the Load serving equivalence of the hours actually available, following notice of the potential need to operate twenty-one (21) hours in advance if notification is provided by 3:00 P.M. ET, or twenty-four (24) hours in advance otherwise, and a notification to operate two (2) hours ahead. In order for a Responsible Interface Party to enroll an SCR that uses an eligible Local Generator, any amount of generation that can reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO that was produced by the Local Generator during the hour coincident with the NYCA or Locality peaks, upon which the LSE Unforced Capacity Obligation of the LSE that serves that SCR is based, must be accounted for when the LSE's Unforced Capacity Obligation for the upcoming Capability Year is established. Responsible Interface Parties must provide this generator data in accordance with ISO Procedures so that the ISO can adjust upwards the LSE Unforced Capacity Obligation to prevent double-counting.

Responsible Interface Parties supplying Unforced Capacity cannot offer the Demand Reduction associated with such Unforced Capacity in the Emergency Demand Response

Program. A Resource with sufficient metering to distinguish MWs of Demand Reduction may participate as a Special Case Resource and in the Emergency Demand Response Program provided that the same MWs are not committed both as Unforced Capacity and to the Emergency Demand Response Program.

The ISO will have discretion, pursuant to ISO Procedures, to exempt Local Generators that are incapable of starting in two (2) hours from the requirement to operate on two (2) hours notification. Local Generators that can be operated to reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO and Loads capable of being interrupted upon demand, that are not available on certain hours or days will be derated by the ISO, pursuant to ISO Procedures, to reflect the Load serving equivalence of the hours they are actually available.

Responsible Interface Parties must submit a Minimum Payment Nomination, in accordance with ISO Procedures. The ISO may request Special Case Resource performance from less than the total number of Special Case Resources within the NYCA or a Load Zone in accordance with ISO Procedures.

Local Generators that can be operated to reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO and Loads capable of being interrupted upon demand will be required to comply with verification and validation procedures set forth in the ISO Procedures. Such procedures will not require metering other than interval billing meters on customer Load or testing other than DMNC or sustained disconnect, as appropriate, unless agreed to by the customer, except that Special Case Resources not called to supply Energy in a Capability Period will be required to run a test once every Capability Period in accordance with the ISO Procedures.

Unforced Capacity supplied in a Bilateral Transaction by a Special Case Resource pursuant to this subsection may only be resold if the purchasing entity or the Installed Capacity Marketer has agreed to become a Responsible Interface Party and comply with the ISO notification requirements for Special Case Resources. LSEs and Installed Capacity Marketers may become Responsible Interface Parties and aggregate Special Case Resources and sell the Unforced Capacity associated with them in an ISO-administered auction if they comply with ISO notification requirements for Special Case Resources.

Responsible Interface Parties that were requested to reduce Load in any month shall submit performance data to the NYISO, within 75 days of each called event or test, in accordance with ISO Procedures. Failure by a Responsible Interface Party to submit performance data for any Special Case Resources required to respond to the event or test within the 75-day limit will result in zero performance attributed to those Special Case Resources for purposes of satisfying the Special Case Resource's capacity obligation as well as for determining energy payments. All performance data are subject to audit by the NYISO and its market monitoring unit. If the ISO determines that it has made an erroneous payment to a Responsible Interface Party, the ISO shall have the right to recover it either by reducing other payments to that Responsible Interface Parties or by resolving the issue pursuant to other provisions of this Services Tariff or other lawful means.

Provided the Responsible Interface Party supplies evidence of such reductions in 75 days, the ISO shall pay the Responsible Interface Party that, through their Special Case Resources, caused a verified Load reduction in response to (i) an ISO request to perform due to a forecast reserve shortage (ii) an ISO declared Major Emergency State, (iii) an ISO request to perform made in response to a request for assistance for Load relief purposes or as a result of a Local

Reliability Rule, or (iv) a test called by the ISO, for such Load reduction, in accordance with ISO Procedures. Subject to performance evidence and verification, in the case of a response pursuant to clauses (i), (ii), of (iii) of this subsection, Suppliers that schedule Responsible Interface Parties shall be paid the zonal Real-Time LBMP for the period of requested performance or four (4) hours, whichever is greater, in accordance with ISO Procedures; provided, however, Special Case Resource Capacity shall settle Demand Reductions, in the interval and for the capacity for which Special Case Resource Capacity has been scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy, as being provided by a Supplier of Operating Reserves, Regulation Service or Energy.

In the event that a Responsible Interface Party's Minimum Payment Nomination for a Special Case Resource, for the number of hours of requested performance or the minimum four (4) hour period, whichever is greater, exceeds the LBMP revenue received, the Special Case Resource will be eligible for a Bid Production Cost Guarantee to make up the difference, in accordance with Section 4.23 of this Services Tariff and ISO Procedures; provided, however, the ISO shall set to zero the Minimum Payment Nomination for Special Case Resource Capacity in each interval in which such Capacity was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy. Subject to performance evidence and verification, in the case of a response pursuant to clause (iv) of this subsection, payment for participation in tests called by the ISO shall be equal to the zonal Real Time LBMP for the MWh of Energy reduced within the test period.

Transmission Owners that require assistance from enrolled Local Generators larger than 100 kW and Loads capable of being interrupted upon demand for Load relief purposes or as a result of a Local Reliability Rule, shall direct their requests for assistance to the ISO for implementation consistent with the terms of this section. Within Load Zone J, participation in response to an ISO request to perform made as a result of a request for assistance from a Transmission Owner for less than the total number of Special Case Resources, for Load relief purposes or as a result of a Local Reliability Rule, in accordance with ISO Procedures, shall be voluntary and the responsiveness of the Special Case Resource shall not be taken into account for performance measurement.

5.12.11.1.1 Special Case Resource Average Coincident Load

The ISO must receive from the Responsible Interface Party that enrolls a Special Case Resource, the applicable metered Load data required to calculate an ACL for that SCR as provided below and in accordance with ISO Procedures. The ACL shall be computed using the metered Load for the applicable Capability Period SCR Load Zone Peak Hours that indicates the Load consumed by each SCR that is supplied by the NYS Transmission System and/or distribution system and is exclusive of any generation produced by a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter, that served some of the SCR's Load.

Beginning with the Winter 2011-2012 Capability Period and thereafter, the ISO shall use the average of the highest twenty (20) one-hour peak Loads of the SCR taken from the Load data reported for the Capability Period SCR Load Zone Peak Hours during the Prior Equivalent Capability Period, and taking into account the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours, to create a SCR ACL baseline. In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours will be taken into account when creating the SCR ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence. The ISO will post to its website the Capability Period SCR Load Zone Peak Hours for each zone ninety (90) days prior to the beginning of the Capability Period for which the ACL will be in effect.

In the SCR enrollment file uploaded by the RIP each month within the Capability Period, among other required information, the RIP shall provide the SCR’s metered Load values for the applicable Capability Period SCR Load Zone Peak Hours necessary to compute the ACL for each SCR.

The exception to this requirement to report the required metered Load data for the ACL, when enrolling a SCR prior to the Summer 2014 Capability Period, is if (i) the SCR has not previously been enrolled with the ISO and (ii) never had interval metering Load data for each month in the Prior Equivalent Capability Period needed to compute the SCR's ACL. Beginning with the Summer 2014 Capability Period, the exception to this requirement to report the required metered Load data for the ACL, is dependent upon one or more of the eligibility conditions for SCR enrollment with a Provisional ACL provided in Section 5.12.11.1.2 of this Services Tariff and ISO Procedures. For SCRs that meet the criteria to enroll with a Provisional ACL, the ISO must receive from the RIP a Provisional ACL as provided in Section 5.12.11.1.2 of this Services Tariff and in accordance with ISO Procedures.

Beginning with the Summer 2014 Capability Period, in addition to the requirement for RIPs to report each SCR's metered Load values that occurred during the Capability Period SCR Load Zone Peak Hours, in accordance with this Services Tariff and ISO Procedures during the enrollment process, any qualifying increase in a SCR's Load that will be supplied by the NYS Transmission System and/or distribution system may be reported as an Incremental ACL, subject to the limitations and verification reporting requirements provided in Section 5.12.11.1.5 of this Services Tariff and in accordance with ISO Procedures. Incremental ACL values must be reported using the required enrollment file that may be uploaded by the RIP during each month's enrollment period. RIPs may not report Incremental ACL values for any SCRs that are enrolled in the Capability Period with a Provisional ACL.

A reduction in a SCR's Load that is supplied by the NYS Transmission System and/or distribution system and meets the criteria for a SCR Change of Status must be reported as a SCR

Change of Status as provided by Section 5.12.11.1.3 of this Services Tariff and in accordance with ISO Procedures.

The ACL is the basis for the upper limit of ICAP, except in circumstances when the SCR has reported a SCR Change of Status or reported an Incremental ACL pursuant to Sections 5.12.11.1.3 and 5.12.11.1.5 of this Services Tariff. The basis for the upper limit of ICAP for a SCR that has experienced a SCR Change of Status or reported an Incremental ACL shall be the Net ACL.

5.12.11.1.2 Use of a Provisional Average Coincident Load

Prior to the Summer 2014 Capability Period, as provided in Section 5.12.11.1.1 of this Services Tariff, if a new Special Case Resource has not previously been enrolled with the ISO and never had interval billing meter data from the Prior Equivalent Capability Period, its Installed Capacity value shall be its Provisional Average Coincident Load for the Capability Period for which the new SCR is enrolled. The Provisional ACL may be applicable to a new SCR for a maximum of three (3) consecutive Capability Periods, beginning with the Capability Period in which the SCR is first enrolled.

Beginning with the Summer 2014 Capability Period, a SCR may be enrolled using a Provisional ACL in lieu of an ACL when one of the following conditions has been determined by the ISO to apply: (i) the SCR has not previously been enrolled with the ISO for the seasonal Capability Period for which the SCR enrollment with a Provisional ACL is intended, (ii) the SCR was enrolled with a Provisional ACL in the Prior Equivalent Capability Period and was required to report fewer than twenty (20) hours of metered Load verification data that correspond with the Capability Period SCR Load Zone Peak Hours based on the meter installation date of the SCR, (iii) the RIP attempting to enroll the SCR with a Provisional ACL is not the same RIP that enrolled the SCR in the Prior Equivalent Capability Period and interval billing meter data for the SCR from the Prior Equivalent Capability Period is not obtainable by the enrolling RIP and not available to be provided to the enrolling RIP by the ISO. The Provisional ACL may be applicable to a SCR for a maximum of three (3) consecutive Capability Periods when enrolled with the same RIP, beginning with the Capability Period in which the SCR is first enrolled by the RIP.

A SCR enrolled in the Capability Period with a Provisional ACL may not be enrolled by another RIP for the remainder of the Capability Period and the Provisional ACL value shall apply to the resource for the entire Capability Period for which the value is established.

The Provisional ACL is the RIP's forecast of the SCR's ACL and shall be the basis for the upper limit of ICAP for which the RIP may enroll the SCR during the Capability Period.

Any SCR enrolled with a Provisional ACL shall be subject to actual in-period verification. A Verified ACL shall be calculated by the ISO using the top twenty (20) one-hour peak Loads reported for the SCR from the Capability Period SCR Load Zone Peak Hours that are applicable to verify the Provisional ACL in accordance with ISO Procedures and taking into account the resource's reported verified Load reductions in a Transmission Owner's demand response program that are coincident with any of the applicable Capability Period SCR Load Zone Peak Hours. In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours will be taken into account when creating the SCR Verified ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the Verified ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence.

Following the Capability Period for which a resource with a Provisional ACL was enrolled, the RIP shall provide to the ISO the metered Load data required to compute the Verified ACL of the resource. The ISO shall compare the Provisional ACL to the Verified ACL to determine, after applying the applicable performance factor, whether the UCAP of the SCR had been oversold and whether a shortfall has occurred as provided under Section 5.14.2 of this Services Tariff. If the RIP fails to provide verification data required to compute the Verified ACL of the resource enrolled with a Provisional ACL by the deadline: (a) the Verified ACL of the resource shall be set to zero for each Capability Period in which the resource with a Provisional ACL was enrolled and verification data was not reported, and (b) the RIP may be subject to penalties in accordance with this Services Tariff.

5.12.11.1.3 Reporting a SCR Change of Load or SCR Change of Status

5.12.11.1.3.1 SCR Change of Load

The Responsible Interface Party shall report any SCR Change of Load in accordance with ISO Procedures. The RIP is required to document the SCR Change of Load and when the total Load reduction for SCRs that have a SCR Change of Load within the same Load Zone is greater than or equal to 5 MWs, the RIP shall report the SCR Change of Load for each SCR in accordance with ISO Procedures.

5.12.11.1.3.2 SCR Change of Status

The Responsible Interface Party shall report any SCR Change of Status in accordance with ISO Procedures. The ISO shall adjust the reported ACL of the SCR for a reported SCR Change of Status to the Net ACL, for all prospective months to which the SCR Change of Status is applicable. When a SCR Change of Status is reported under clause (i), (ii) or (iii) within the definition of a Qualified Change of Status Condition and the SCR has sold capacity, the SCR shall be evaluated for a potential shortfall under Section 5.14.2 of this Services Tariff. Failure by the RIP to report a SCR Change of Status shall be evaluated as a potential shortfall under Section 5.14.2 of this Service Tariff and evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

Beginning with the Summer 2014 Capability Period, SCRs that were required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and that subsequently report or change a reported SCR Change of Status value after the first performance test in the Capability Period shall be required to demonstrate the performance of the resource against the Net ACL value in the second performance test in the Capability Period. The exceptions to this provision occur when a SCR's eligible Installed Capacity is set to zero throughout the period of the SCR Change of Status, when a SCR's eligible Installed Capacity is decreased by at least the same kW value as the reported SCR Change of Status, or if a SCR Change of Status is reported, and prior to the second performance test, the SCR returns to the full applicable ACL enrolled prior to the SCR Change of Status. Performance in both performance tests shall be used in calculation of the resource's performance factors and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a resource that was required to perform in the second performance test in the Capability Period: (a) the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

5.12.11.1.4 Average Coincident Load of an SCR Aggregation

The ISO shall compute the Average Coincident Load of an SCR Aggregation each month in accordance with ISO Procedures.

5.12.11.1.5 Use of an Incremental Average Coincident Load

Beginning with the Summer 2014 Capability Period, a Responsible Interface Party may report any qualifying increase to a Special Case Resource's Average Coincident Load as Incremental Average Coincident Load in the RIP enrollment file upload and in accordance with this Services Tariff and ISO Procedures.

For SCRs with a total Load increase equal to or greater than twenty (20) percent and less than thirty (30) percent of the applicable ACL, the RIP may enroll the SCR with an Incremental ACL provided that the eligible Installed Capacity does not increase from the prior enrollment months within the same Capability Period and prior to enrollment with an Incremental ACL. If the SCR is enrolled with an Incremental ACL and it is the first month of the SCR's enrollment in the applicable Capability Period, the enrolled eligible Installed Capacity value shall not exceed the maximum eligible Installed Capacity of the SCR from the Prior Equivalent Capability Period. When no enrollment exists for the SCR in the Prior Equivalent Capability Period and it is the first month of the SCR's enrollment in the applicable Capability Period, the enrolled eligible Installed Capacity of the SCR shall not exceed the ACL calculated from the Capability Period SCR Load Zone Peak Hours. For SCRs with a total Load increase equal to or greater than thirty (30) percent of the applicable ACL, the RIP may enroll the SCR with an Incremental ACL and an increase to the SCR's eligible Installed Capacity and is required to test as described in this section of the Service Tariff.

The ISO shall adjust the ACL of the SCR for an Incremental ACL for all months for which the Incremental ACL is reported by the RIP. For resources reporting an Incremental ACL, the Net ACL shall equal the enrolled ACL plus the reported Incremental ACL less any applicable SCR Change of Status and shall be the basis for the upper limit of ICAP for which the RIP may enroll the SCR during the Capability Period.

An Incremental ACL is a discrete change to the SCR operations that is expected to result in an increase to the Load that the SCR will consume from the NYS Transmission System and/or distribution system. It is not available to account for random fluctuations in Load, such as those caused by weather or other seasonal Load variations. Therefore, the ACL of a SCR may only be increased once per Capability Period and the amount of the increase enrolled must remain the same for all months for which the Incremental ACL is reported. A SCR enrolled in the Capability Period with an Incremental ACL may not be enrolled by another RIP for the remainder of the Capability Period. A SCR enrolled in the Capability Period with a Provisional ACL is not eligible to enroll with an Incremental ACL.

Following the Capability Period for which a SCR has been enrolled with an Incremental ACL, the RIP shall provide the hourly metered Load verification data that corresponds to the Monthly SCR Load Zone Peak Hours identified by the ISO for all months in which an Incremental ACL value was reported for the SCR. For each month for which verification data was required to be reported, the ISO shall calculate a Monthly ACL that will be used in the calculation of a Verified ACL. The Monthly ACL shall equal the average of the SCR’s top twenty (20) one-hour metered Load values that correspond with the applicable Monthly SCR Load Zone Peak Hours, and taking into account (i) the resource’s reported verified Load reduction in a Transmission Owner’s demand response program in hours coincident with any of these hours and (ii) the resource’s verified Load reduction in either of the ISO’s economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of these hours. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Monthly SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the Monthly ACL for each hour during the Monthly SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Monthly SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Monthly SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Monthly SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Monthly SCR Load Zone Peak Hour, in accordance with the preceding sentence. The Verified ACL shall be the average of the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period.

For any month in which verification data for the Incremental ACL is required but not timely submitted to the ISO in accordance with ISO procedures, the ISO shall set the metered Load values to zero. When a Monthly ACL is set to zero, the Verified ACL will be calculated as the average of: a) the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period; plus b) the Monthly ACLs for all months in which the SCR was enrolled within the same Capability Period with an Incremental ACL in the Capability Period in which the RIP failed to provide the minimum verification data required. In addition, a RIP may be subject to a penalty for each month for which verification data was required and not reported in accordance with this Services Tariff.

For each SCR that is enrolled with an Incremental ACL, the ISO shall compare the Net ACL calculated from the resource enrollment (ACL plus Incremental ACL less any applicable SCR Change of Status) to the Verified ACL calculated for the SCR to determine if the RIP’s use of an Incremental ACL may have resulted in a shortfall pursuant to Section 5.14.2.

A Special Case Resource that was required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and was subsequently enrolled using an Incremental ACL and an increase in the amount of Installed Capacity that the SCR is eligible to sell, shall be required to demonstrate performance against the maximum amount of eligible

Installed Capacity reported for the SCR in the second performance test in the Capability Period. Performance in this test shall be measured from the Net ACL. Performance in both performance tests shall be used in calculation of the resource's performance factor and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a resource that was required to perform in the second performance test in the Capability Period: (a) the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

5.12.11.2 Existing Municipally-Owned Generation

A municipal utility that owns existing generation in excess of its Unforced Capacity requirement, net of NYPA-provided Capacity may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, offer the excess Capacity for sale as Installed Capacity provided that it is willing to operate the generation at the ISO's request, and provided that the Energy produced is deliverable to the New York State Power System. Such a municipal utility shall not be required to comply with the requirement of Section 5.12.7 of this Tariff that an Installed Capacity Supplier bid into the Energy market or enter into Bilateral Transactions. Municipal utilities shall, however, be required to submit their typical physical operating parameters, such as their start-up times, to the ISO. This subsection is only applicable to municipally-owned generation in service or under construction as of December 31, 1999.

5.12.11.3 Energy Limited Resources

An Energy Limited Resource may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, qualify as an Installed Capacity Supplier if it Bids its Installed Capacity Equivalent into the Day-Ahead Market each day and if it is able to provide the Energy equivalent of the Unforced Capacity for at least four (4) consecutive hours each day. Energy Limited Resources shall also Bid a Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, designating their desired operating limits. Energy Limited Resources that are not scheduled in the Day-Ahead Market to operate at a level above their bid-in upper operating limit, may be scheduled in the RTC, or may be called in real-time pursuant to a manual intervention by ISO dispatchers, who will account for the fact that Energy Limited Resource may not be capable of responding.

5.12.11.4 Intermittent Power Resources

Intermittent Power Resources that depend upon wind or solar as their fuel may qualify as Installed Capacity Suppliers, without having to comply with the daily bidding and scheduling requirements set forth in Section 5.12.7 of this Tariff, and may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, claim up to their nameplate Capacity as Installed Capacity. To qualify as Installed Capacity Suppliers, such Intermittent Power Resources shall comply with the requirements of Section 5.12.1 and the outage notification requirements of 5.12.7 of this Tariff.

5.12.12 Sanctions Applicable to Installed Capacity Suppliers and Transmission Owners

Pursuant to this section, the ISO may impose financial sanctions on Installed Capacity Suppliers and Transmission Owners that fail to comply with certain provisions of this Tariff. The ISO shall notify Installed Capacity Suppliers and Transmission Owners prior to imposing any sanction and shall afford them a reasonable opportunity to demonstrate that they should not be sanctioned and/or to offer mitigating reasons why they should be subject to a lesser sanction. The ISO may impose a sanction lower than the maximum amounts allowed by this section at its sole discretion. Installed Capacity Suppliers and Transmission Owners may challenge any sanction imposed by the ISO pursuant to the ISO Dispute Resolution Procedures.

Any sanctions collected by the ISO pursuant to this section will be applied to reduce the Rate Schedule 1 charge under this Tariff.

5.12.12.1 Sanctions for Failing to Provide Required Information

If (i) an Installed Capacity Supplier fails to provide the information required by Sections 5.12.1.1, 5.12.1.2, 5.12.1.3, 5.12.1.4, 5.12.1.7 or 5.12.1.8 of this Tariff in a timely fashion, or (ii) a Supplier of Unforced Capacity from External System Resources located in an External Control Area or from a Control Area System Resource that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to provide the information required for certification as an Installed Capacity Supplier established in the ISO Procedures, the ISO may take the following actions: On the first day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of $500 or $5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing. Starting on the tenth day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of $1000 or $10 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

If an Installed Capacity Supplier fails to provide the information required by Subsection 5.12.1.5 of this Tariff in a timely fashion, the ISO may take the following actions: On the first calendar day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of that first calendar day. Starting on the second calendar day that the required information is late, the ISO may impose a daily financial sanction up to the higher of $500 or $5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

If a TO fails to provide the information required by Subsection 5.11.3 of this Tariff in a timely fashion, the ISO may take the following actions: On the first day that required information is late, the ISO shall notify the TO that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may impose a daily financial sanction up to $5,000 a day. Starting on the tenth day that required information is late, the ISO may impose a daily financial sanction up to $10,000.

5.12.12.2 Sanctions for Failing to Comply with Scheduling, Bidding, and Notification Requirements

On any day in which an Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or in which a Supplier of Installed Capacity from External System Resources or Control Area System Resources located in an External Control Area that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to comply with scheduling, bidding, or notification requirements for certification as an Installed Capacity Supplier established in the ISO Procedures, the ISO may impose a financial sanction up to the product of a deficiency charge (pro-rated on a daily basis) and the maximum number of MWs that the Installed Capacity

Supplier failed to schedule or Bid in any hour in that day provided, however, that no financial sanction shall apply to any Installed Capacity Supplier who demonstrates that the Energy it schedules, bids, or declares to be unavailable on any day is not less than the Installed Capacity that it supplies for that day rounded down to the nearest whole MW. The deficiency charge may be up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction corresponding to where the Installed Capacity Supplier's capacity cleared, and for each month in which the Installed Capacity Supplier is determined not to have complied with the foregoing requirements.

In addition, if an Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or if an Installed Capacity Supplier of Unforced Capacity from External System Resources or from a Control Area System Resource located in an External Control Area that has agreed not to curtail the Energy associated with such Unforced Capacity, or to afford it the same curtailment priority that it affords its own Control Area Load, fails to comply with the scheduling, bidding, or notification requirements for certification as an Installed Capacity Supplier established in the ISO Procedures during an hour in which the ISO curtails Transactions associated with NYCA Installed Capacity Suppliers, the ISO may impose an additional financial sanction equal to the product of the number of MWs the Installed Capacity Supplier failed to schedule during that hour and the corresponding Real-Time LBMP at the applicable Proxy Generator Bus.

If the Installed Capacity Supplier is a Responsible Interface Party that enrolled a SCR with an Incremental ACL in accordance with this Services Tariff, and also reported an increase to the Installed Capacity the SCR has eligible to sell after the first performance test in the

Capability Period, the ISO may impose an additional financial sanction due to the failure of the RIP to report the required performance of the SCR against the Net ACL value in the second performance test in the Capability Period. This sanction shall be the value of the reported increase in the eligible Installed Capacity associated with the SCR that was sold by the RIP in each month of the Capability Period, during which the reported increase was in effect, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

If the Installed Capacity Supplier is a Responsible Interface Party, and the Average Coincident Load of the Special Case Resource has been decreased after the first performance test in the Capability Period, due to a SCR Change of Status in accordance with this Services Tariff and ISO Procedures, the ISO may impose an additional financial sanction resulting from the failure of the RIP to report the required performance of the SCR against the Net ACL value of the SCR when the SCR was required to perform in the second performance test in the Capability Period in accordance with Section 5.12.11.1.3.2 of this Services Tariff. This sanction shall be the value of the Unforced Capacity equivalent of the SCR Change of Status MW reported for the SCR during the months for which the SCR was enrolled with a SCR Change of Status and was required to demonstrate in the second performance test as specified in Section 5.12.11.1.3.2 of this Services Tariff, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

If a RIP fails to provide the information required by Section 5.12.11.1.3 of this Services Tariff in accordance with the ISO Procedures for reporting a Qualified Change of Status Condition, and the ISO determines that a SCR Change of Status occurred within a Capability Period, the ISO may impose a financial sanction equal to the difference, if positive, between the enrolled ACL and the maximum one hour metered Load for the month multiplied by up to one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each month the Installed Capacity Supplier is deemed to have a shortfall in addition to the corresponding shortfall penalty as provided in Section 5.14.2.

For each month in which a RIP fails to report required verification data and the applicable ACL value is set to zero in accordance with Section 5.12.11 of this Services Tariff, the ISO shall have the right to recover any energy payments made to the RIP for performance of the SCR by reducing other payments or other lawful means.

5.13 Installed Capacity Auctions

5.13.1 General Auction Requirements

The ISO will administer Installed Capacity auctions to accommodate LSEs' and Installed Capacity Suppliers' efforts to enter into Unforced Capacity Transactions and to give LSEs an opportunity to acquire sufficient Unforced Capacity to meet their respective LSE Unforced Capacity Obligations. The ISO shall conduct regular auctions, at the request of an LSE, at the times specified in this section and the ISO Procedures, and may conduct additional auction as necessary.

Installed Capacity Suppliers, LSEs and Installed Capacity Marketers that are Customers under this Tariff will be allowed to participate in Installed Capacity auctions, provided that they satisfy the creditworthiness requirements set forth in Attachment K of the ISO OATT. Unforced Capacity purchased in Installed Capacity auctions may not be sold for the purposes of meeting Installed Capacity requirements imposed by operators of External Control Areas. Offers to sell and bids to purchase Unforced Capacity shall be made in $/kW for the time period appropriate to the auction. The ISO shall impose no limits on Bids or offers in any auction, except to the extent required by any applicable capacity market mitigation measures.

Installed Capacity Suppliers that wish to participate in an ISO-administered auction must submit completed certification forms to the ISO in accordance with the ISO Procedures, demonstrating that their Unforced Capacity has not been committed to a Bilateral Transaction.

The ISO Procedures shall specify the dates by which the ISO will post the results of Installed Capacity auctions. The ISO Procedures shall ensure that there are at least four business days between the time that auction results from monthly auctions are posted and the dates that LSEs are required to demonstrate the quantity of Unforced Capacity that has been obtained for the upcoming Obligation Procurement Period, pursuant to Section 5.11.2 of this Tariff. LSEs holding Unforced Capacity which they want credited against their LSE Unforced Capacity Obligations must certify such Unforced Capacity when submitting their Installed Capacity certifications.

5.13.2 Capability Period Auction

A Capability Period Auction will be conducted no later than thirty (30) days prior to the start of each Capability Period in which Unforced Capacity will be purchased and sold for the entire duration of the Capability Period. The exact date of the Capability Period Auction shall be established in the ISO Procedures. The Capability Period Auction is intended to facilitate long-term Unforced Capacity transactions between Market Participants.

The Capability Period Auction will be conducted and solved simultaneously to purchase Unforced Capacity which may be used by an LSE toward all components of its LSE Unforced Capacity Obligation for each Obligation Procurement Period. Participation shall consist of: (i) LSEs seeking to purchase Unforced Capacity; (ii) any other entity seeking to purchase Unforced Capacity; (iii) qualified Installed Capacity Suppliers; and (iv) any other entity that owns excess Unforced Capacity.

Buyers that are awarded Unforced Capacity shall pay the applicable Market-Clearing Price of Unforced Capacity in the Capability Period Auction. Sellers that are selected to provide Unforced Capacity shall receive the applicable Market-Clearing Price of Unforced Capacity in the Capability Period Auction.

The results of the Capability Period Auction will be made available to Market Participants at the time specified in the ISO Procedures, which shall be prior to the start of the Monthly Auction held prior to the beginning of each Capability Period.

5.13.3 Monthly Auctions

Monthly Auctions will be held during which Unforced Capacity may be purchased and sold for the forthcoming Obligation Procurement Period, and any other month or months remaining in the Capability Period, as specified in the ISO Procedures. The exact dates of each Monthly Auction shall be established in the ISO Procedures. Each Monthly Auction is intended to facilitate Unforced Capacity transactions between Market Participants.

Each Monthly Auction will be conducted and solved simultaneously to purchase Unforced Capacity which may be used by an LSE toward all components of its LSE Unforced Capacity Obligation for each Obligation Period. Participation shall consist of: (i) LSEs seeking to purchase Unforced Capacity; (ii) any other entity seeking to purchase Unforced Capacity; (iii) qualified Installed Capacity Suppliers; and (iv) any other entity that owns excess Unforced Capacity.

Buyers that are awarded Unforced Capacity shall pay the applicable Market-Clearing Price of Unforced Capacity in the Monthly Auction. Sellers that are selected to provide Unforced Capacity shall receive the applicable Market-Clearing Price.

The results of each Monthly Auction will be made available to Market Participants in accordance with the ISO Procedures.

5.13.4 Detailed Installed Capacity Auction Description

Additional detail concerning the ISO's Installed Capacity auction procedures are provided in the ISO Procedures.

5.14 Installed Capacity Spot Market Auction and Installed Capacity Supplier Deficiencies

5.14.1 LSE Participation in the ICAP Spot Market Auction

5.14.1.1 ICAP Spot Market Auction

When the ISO conducts each ICAP Spot Market Auction it will account for all Unforced Capacity that each NYCA LSE has certified for use in the NYCA to meet its NYCA Minimum Installed Capacity Requirement or Locational Minimum Installed Capacity Requirement, as applicable, whether purchased through Bilateral Transactions or in prior auctions. The ISO shall receive offers of Unforced Capacity that has not previously been purchased through Bilateral Transactions or in prior auctions from qualified Installed Capacity Suppliers for the ICAP Spot Market Auction. Interim Service Providers must offer at $0.00/kW-month all of their Unforced Capacity into each ICAP Spot Market Auction conducted for each Obligation Procurement Period associate with a month in which it is to receive compensation under Rate Schedule 8 of the Services Tariff. If an Interim Service Provider is expressly precluded from offering all or a portion of its UCAP into an ICAP Spot Market Auction because it is obligated to provide capacity pursuant to a bilateral contract that is effective at the time of the ICAP Spot Market Auction, and was executed and effective before the NYISO received a Generator Deactivation Notice the Interim Service Provider (such contract a “Preexisting Capacity Bilateral”), then the Interim Service Provider shall only be required to offer the amount of its Unforced Capacity into that ICAP Spot Market Auction that it is not expressly required to provide pursuant to the terms of the such Preexisting Capacity Bilateral. The quantity of Unforced Capacity the Interim Service Provider is required to offer in accordance with this paragraph is the “ISP UCAP MW”. The ISO shall also receive offers of Unforced Capacity from any LSE for any amount of Unforced Capacity that the LSE has in excess of its NYCA Minimum Unforced Capacity Requirement or Locational

Minimum Unforced Capacity Requirement, as applicable. Unforced Capacity that will be exported from the New York Control Area during the month for which Unforced Capacity is sold in an ICAP Spot Market Auction shall be certified to the NYISO by the certification deadline for that auction.

The ISO shall conduct an ICAP Spot Market Auction to purchase Unforced Capacity which shall be used by an LSE toward all components of its LSE Unforced Capacity Obligation for each Obligation Procurement Period immediately preceding the start of each Obligation Procurement Period. The exact date of the ICAP Spot Market Auction shall be established in the ISO Procedures. All LSEs shall participate in the ICAP Spot Market Auction. In the ICAP Spot Market Auction, the ISO shall submit monthly bids on behalf of all LSEs at a level per MW determined by the ICAP Demand Curves established in accordance with this Tariff and the ISO Procedures. The ICAP Spot Market Auction will set the LSE Unforced Capacity Obligation for each NYCA LSE in accordance with the ISO Procedures.

The ICAP Spot Market Auction will be conducted and solved simultaneously for Unforced Capacity that may be used by an LSE towards all components of its LSE Unforced Capacity Obligation for that Obligation Procurement Period using the applicable ICAP Demand Curves, as established in accordance with the ISO Procedures. LSEs that are awarded Unforced Capacity in the ICAP Spot Market Auction shall pay to the ISO the Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction using the applicable ICAP Demand Curve. The ISO shall pay each Installed Capacity Supplier that is selected to provide Unforced Capacity the Market-Clearing Price determined in the ICAP Spot Market Auction using the ICAP Demand Curve applicable to its offer.

5.14.1.2 Demand Curve and Adjustments

ICAP Demand Curves will be established to determine (a) the locational component of LSE Unforced Capacity Obligations for each Locality (b) the locational component of LSE Unforced Capacity Obligations for any New Capacity Zone, and (c) the total LSE Unforced Capacity Obligations for all LSEs. The ICAP Demand Curves for the 2016/2017 and 2017/2018 Capability Years shall be established at the following points (in accordance with Section 5.14.1.2.2, the ICAP Demand Curve values for the 2018/2019 through 2020/2021 Capability Years will be determined pursuant to the respective annual updates for each such Capability Year):

Capability Year	5/1/2016 to 4/30/2017	5/1/2017 to 4/30/2018	5/1/2018 to 4/30/2019	5/1/2019 to 4/30/2020	5/1/2020 to 4/30/2021
NYCA	Max @ $14.10 $9.23 @ 100% $0.00 @ 112%	Max @ $15.85 $9.08 @ 100% $0.00 @ 112%	To be posted on the ISO website on or before November 30, 2017	To be posted on the ISO website on or before November 30, 2018	To be posted on the ISO website on or before November 30, 2019
NYC	Max @ $27.31 $19.37 @ 100% $0.00 @ 118%	Max @ $26.14 $18.61 @ 100% $0.00 @ 118%	To be posted on the ISO website on or before November 30, 2017	To be posted on the ISO website on or before November 30, 2018	To be posted on the ISO website on or before November 30, 2019
LI	Max @ $21.81 $8.30 @ 100% $0.00 @ 118%	Max @ $24.37 $12.72 @ 100% $0.00 @ 118%	To be posted on the ISO website on or before November 30, 2017	To be posted on the ISO website on or before November 30, 2018	To be posted on the ISO website on or before November 30, 2019

G-J	Max @ $19.64 $12.68 @ 100% $0.00 @ 115%	Max @ $21.85 $14.84 @ 100% $0.00 @ 115%	To be posted on the ISO website on or before November 30, 2017	To be posted on the ISO website on or before November 30, 2018	To be posted on the ISO website on or before November 30, 2019
NOTE: All dollar figures are in terms of $/kW-month of ICAP and all percentages are in terms of the applicable NYCA Minimum Installed Capacity Requirement and Locational Minimum Installed Capacity Requirement. The defined points describe a line segment with a negative slope that will result in higher values for percentages less than 100% of the NYCA Minimum Installed Capacity Requirement or the Locational Installed Capacity Requirement ("reference point") with the maximum value for each ICAP Demand Curve established at 1.5 times the estimated localized levelized cost per kW-month to develop a new peaking unit in each Locality or in Rest of State, as applicable.					

In subsequent years, the costs assigned by the ICAP Demand Curves to the NYCA Minimum Installed Capacity Requirement, the Locational Minimum Installed Capacity Requirement, and any Indicative NCZ Minimum Installed Capacity Requirement, will be defined by the results of the independent review conducted pursuant to this section. The ICAP Demand Curves will be translated into Unforced Capacity terms in accordance with the ISO Procedures.

5.14.1.2.1 Periodic Reviews of ICAP Demand Curves Applicable Prior to the 2017/2018 Capability Year

For ICAP Demand Curves applicable prior to the 2017/2018 Capability Year, a periodic review of the ICAP Demand Curves shall be performed every three (3) years in accordance with the ISO Procedures to determine the parameters of the ICAP Demand Curves for the next three Capability Years. The periodic review shall assess: (i) the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, to meet minimum capacity requirements, and (ii) the likely projected annual Energy and Ancillary Services revenues of the peaking plant over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services. The cost and revenues of the peaking plant used to set the reference point and maximum value for each ICAP Demand Curve shall be determined under conditions in which the available capacity is equal to the sum of (a) the minimum Installed Capacity requirement and (b) the peaking plant's capacity equal to the number of MW specified in the periodic review and used to determine all costs and revenues. The minimum Installed Capacity requirement for each Locality shall be equal to the Locational Minimum Installed Capacity Requirement in effect for the year in which the independent consultant's final report (referenced below in Section 5.14.1.2.1.6) is issued; for the NYCA, equal to the NYCA Minimum Installed Capacity Requirement based on the Installed Reserve Margin accepted by the Commission and applicable to the Capability Year which begins in the Capability Year in which the independent consultant's final report is issued; and for any New Capacity Zone, equal to the Indicative NCZ Locational Minimum Installed Capacity Requirement determined by the ISO in accordance with Section 5.16.3. The periodic review shall also assess (i) the appropriate shape and slope of the ICAP Demand Curves, and the associated point at which the dollar value of the ICAP Demand Curves should decline to zero; (ii) the appropriate translation of the annual net revenue requirement of the peaking plant determined from the factors specified above, into monthly values that take into account seasonal differences in the amount of capacity available in the ICAP Spot Market Auctions; and (iii) the escalation factor and inflation component of the escalation factor applied to the ICAP Demand Curves. For purposes of this periodic review, a peaking unit is defined as the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable, and a peaking plant is defined as the number of units (whether one or more) that constitute the scale identified in the periodic review.

The periodic review shall be conducted in accordance with the schedule and procedures specified in the ISO Procedures. A proposed schedule will be reviewed with the stakeholders not later than May 30 of the year prior to the year of the filing specified in Section 5.14.1.2.1.11. The schedule and procedures shall provide for:

5.14.1.2.1.1 ISO development, with stakeholder review and comment, of a request for proposals to provide independent consulting services to determine recommended values for the factors specified above, and appropriate methodologies for such determination;

5.14.1.2.1.2 Selection of an independent consultant in accordance with the request for proposals;

5.14.1.2.1.3 Submission to the ISO and the stakeholders of a draft report from the independent consultant on the independent consultant’s determination of recommended values for the factors specified above;

5.14.1.2.1.4 Stakeholder review of and comment on the data, assumptions and conclusions in the independent consultant’s draft report, with participation by the responsible person or persons providing the consulting services;

5.14.1.2.1.5 An opportunity for the Market Monitoring Unit to review and comment on the draft request for proposals, the independent consultant’s report, and-the ISO’s proposed ICAP Demand Curves (the responsibilities of the Market Monitoring Unit that are addressed in this section of the Services Tariff are also addressed in Section 30.4.6.3.1 of Attachment O);

5.14.1.2.1.6 Issuance by the independent consultant of a final report;

5.14.1.2.1.7 Issuance of a draft of the ISO's recommended adjustments to the ICAP Demand Curves for stakeholder review and comment;

5.14.1.2.1.8 Issuance of the ISO's proposed ICAP Demand Curves, taking into account the report of the independent consultant, the recommendations of the Market Monitoring Unit, and the views of the stakeholders together with the rationale for accepting or rejecting any such inputs;

5.14.1.2.1.9 Submission of stakeholder requests for the ISO Board of Directors to review and adjust the ISO's proposed ICAP Demand Curves;

5.14.1.2.1.10 Presentations to the ISO Board of Directors of stakeholder views on the ISO's proposed ICAP Demand Curves; and

5.14.1.2.1.11 Filing with the Commission of ICAP Demand Curves as approved by the ISO Board of Directors incorporating the results of the periodic review, such filing to be made not later than November 30 of the year prior to the year that includes the beginning of the first Capability Year to which such ICAP Demand Curves would be applied. The filing shall specify ICAP Demand Curves for a period of three Capability Years and the inflation rate component of the escalation factor applied to the ICAP Demand Curves.

Upon FERC approval, the ICAP Demand Curves will be translated into Unforced Capacity terms in accordance with the ISO Procedures; provided that nothing in this Tariff shall be construed to limit the ability of the ISO or its Market Participants to propose and adopt alternative provisions to this Tariff through established governance procedures.

5.14.1.2.2 Periodic Reviews of ICAP Demand Curves Applicable Beginning with the 2017/2018 Capability Year

Beginning with the ICAP Demand Curves applicable for the 2017/2018 Capability Year, a periodic review of the ICAP Demand Curves shall be performed every four (4) years in accordance with the ISO Procedures to: (i) identify the methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) establish the ICAP Demand Curves for the first Capability Year covered by the periodic review.

The periodic review shall assess: (i) the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, to meet minimum capacity requirements (for purposes of this Section 5.14.1.2.2 hereinafter referred to as the “peaking plant gross cost”); and (ii) the likely projected annual Energy and Ancillary Services revenues of the peaking plant for the first Capability Year covered by the periodic review, net of the costs of producing such Energy and Ancillary Services (for purposes of this Section 5.14.1.2.2 hereinafter referred to as the “net Energy and Ancillary Services revenue offset”), including the methodology and inputs for determining such projections for the four Capability Years covered by the periodic review. The cost and revenues of the peaking plant used to set the reference point and maximum value for each ICAP Demand Curve shall be determined under conditions in which the available capacity is equal to the sum of (a) the minimum Installed Capacity requirement and (b) the peaking plant’s capacity equal to the number of MW specified in the periodic review and used to determine all costs and revenues (for purposes of this Section 5.14.1.2.2 hereinafter referred to as the “prescribed level of excess”). The minimum Installed Capacity requirement for each Locality shall be equal to the Locational Minimum Installed Capacity Requirement in effect for the year in which the independent consultant's final report (referenced below in Section 5.14.1.2.2.4.6) is issued; for the NYCA, equal to the NYCA Minimum Installed Capacity Requirement based on the Installed Reserve Margin accepted by the Commission and applicable to the Capability Year which begins in the Capability Year in which the independent consultant's final report is issued; and for any New Capacity Zone, equal to the Indicative NCZ Locational Minimum Installed Capacity Requirement determined by the NYISO in accordance with Section 5.16.3. The periodic review shall also assess (i) the appropriate shape and slope of the ICAP Demand Curves, and the associated point at which the dollar value of the ICAP Demand Curves should decline to zero; (ii) the appropriate translation of the annual net revenue requirement of the peaking plant determined from the factors specified above, into monthly values that take into account seasonal differences in the amount of capacity available in the ICAP Spot Market Auctions in accordance with the methodology set forth in Section 5.14.1.2.2.3; and (iii) the escalation factor and inflation component of the escalation factor applied to the peaking plant gross cost, including the methodology and inputs for determining such values. For purposes of this periodic review, a peaking unit is defined as the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable, and a peaking plant is defined as the number of units (whether one or more) that constitute the scale identified in the periodic review.

In the filing referenced in Section 5.14.1.2.2.4.11 below, the ISO will: (i) identify the methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) propose the ICAP Demand Curves for the first Capability Year covered by the periodic review. For the subsequent three Capability Years covered by the periodic review, the ISO will establish the ICAP Demand Curves for each such

Capability Year by updating the following factors in advance of each such subsequent Capability Year: (i) the peaking plant gross cost in accordance with Section 5.14.1.2.2.1; (ii) the net Energy and Ancillary Services revenue offset in accordance with Section 5.14.1.2.2.2; and (iii) the winter-to-summer ratio, as such term is defined in Section 5.14.1.2.2.3, in accordance with Section 5.14.1.2.2.3. The ISO will post the updated ICAP Demand Curves for each subsequent Capability Year covered by the periodic review on or before November 30th of the calendar year immediately preceding the calendar year that includes the start of the Capability Year for which the updated ICAP Demand Curves will apply.

5.14.1.2.2.1 Annual Updates for Peaking Plant Gross Cost

For purposes of the annual updates to the ICAP Demand Curves, the ISO shall determine updated values for the peaking plant gross cost for each peaking plant. Updated values for the peaking plant gross cost shall be determined by application of an escalation factor to the peaking plant gross cost values underlying the then currently effective ICAP Demand Curves. The escalation factor shall consist of the following four components: (i) changes in construction material costs (“materials component”); (ii) changes in turbine generator costs (“turbine component”); (iii) changes in labor costs (“labor component”); and (iv) changes in the general cost of goods and services (“general component”). The escalation factor shall be equal to the sum of the: (i) the twelve month percentage change in the applicable index for the materials component, multiplied by the applicable weighting factor for such component; (ii) the twelve month percentage change in the applicable index for the turbine component, multiplied by the applicable weighting factor for such component; (iii) the twelve month percentage change in the applicable index for the labor component, multiplied by the applicable weighting factor for such component; and (iv) the twelve month percentage change in the applicable index for the general component, multiplied by the applicable weighting factor for such component. For purposes of determining the twelve month percentage change for each component, the values utilized from each applicable index shall be as follows: (i) for indices that publish annual values, the most recently available annual value and the annual value for the calendar year immediately preceding thereto; (ii) for indices that publish monthly values, the average value of the three most recently available monthly values and the average value of values for the same three months from the calendar year immediately preceding thereto; and (iii) for indices that publish quarterly values, the value of the most recently available calendar quarter and the value for the same calendar quarter from the calendar year immediately preceding thereto. The applicable values to be used by the ISO shall be the available finalized values established by the publisher for each index as of October 1st of the same calendar year as the applicable November 30th deadline for posting the updated ICAP Demand Curves. The ISO shall not use any preliminary values published by an index in determining the applicable twelve month percentage change for any component of the escalation factor. The weighting factors applied to each component shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. The specified index for each component shall likewise be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review, unless an index is eliminated, replaced or otherwise terminated by the publisher thereof during the period covered by the periodic review. In such circumstance, the ISO shall utilize the replacement or successor index established by the publisher, if any, or, in the absence of a replacement or successor index, shall select as a replacement a substantially similar index.

5.14.1.2.2.2 Annual Updates for Net Energy and Ancillary Revenue Offset

For purposes of the annual updates to the ICAP Demand Curves, the ISO shall also determine updated values for the net Energy and Ancillary Services revenue offset associated with each peaking plant. Updated values for the net Energy and Ancillary Services revenue offset shall, in part, be determined using a net revenue model that will be developed as part of the periodic review and made available to stakeholders. The model will, at a minimum, determine whether each peaking plant could earn positive net revenue by producing Energy in each hour based on historical prices and the variable costs for each peaking plant over the prior 36 month period ending August 31st of the same calendar year as the applicable November 30th deadline for posting the updated ICAP Demand Curves, as well as the physical operating characteristics of each peaking plant and any operating hours constraints necessary to address any applicable environmental requirements and/or fuel availability. The commitment and dispatch logic and data sources and/or inputs used by the model, as well as the manner in which the model accounts for net Ancillary Services revenues earned by each peaking plant, the physical operating characteristics of each peaking plant and any operating hours constraints applicable to each peaking plant that are necessary to address any applicable environmental requirements and/or fuel availability, will be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review, subject to annual updating of certain data inputs used by the model as described herein.

The model will determine whether each peaking plant could earn positive net revenue by producing Energy in each hour of the period encompassed by the model in a manner consistent with the following equation:

$$\textit{Net Energy revenue}_{z,t} = \max(([\textit{Output}_{z,t} * (\textit{LOE}_{z,t} * \textit{LBMP}_{z,t})] - \textit{MC}_{z,t}),0)$$

where:

$Ouput_{z,t}$ = the quantity of Energy produced by the peaking plant for Load Zone *z* in hour *t*;

$LOE_{z,t}$ = the applicable adjustment factor for Load Zone *z* and hour *t* used to adjust for the prescribed level of excess. The adjustment factors shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review;

$LBMP_{z,t}$ = the Day-Ahead zonal LBMP or time-weighted/integrated zonal RTD LBMP, as applicable, for Load Zone *z* and hour *t*;

$MC_{z,t}$ = variable (or short-run marginal) cost of the peaking plant for Load Zone *z* to produce Energy in hour *t*, calculated as follows:

$$MC_{z,t} = [(HR_{z,t} * Fuel_{z,t}) + VOM_{z,t} + ASC_{z,t} + EC_{z,t} + RS1_{z,t}] * Output_{z,t}$$

where:

$HR_{z,t}$ = the heat rate of the peaking plant for Load Zone *z* and hour *t*. The heat rate for the peaking plant shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review;

$Fuel_{z,t}$ = the applicable fuel cost for the peaking plant for Load Zone *z* and hour *t*, which shall be the lesser of the primary fuel cost and the backup fuel cost, if any, for the peaking plant for Load Zone *z*. The primary fuel and any backup fuel for the peaking plant for Load Zone *z* shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. The applicable fuel cost will be based on the applicable daily spot price for Load Zone *z* published in the specified data source determined as part of the periodic review (unless such data source is revised for the reasons described below), plus an adder to account for any applicable transportation and delivery costs and any applicable fuel taxes, which adder shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. For real-time evaluations only, the otherwise applicable fuel cost shall be increased by the applicable real-time fuel premium adder for Load Zone *z* and hour *t*, which adder shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. The data sources used for determining the applicable daily spot fuel prices shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review, unless the specified data source is eliminated, replaced or otherwise terminated by the publisher thereof during the period covered by the periodic review. In such circumstance, the ISO shall utilize the replacement or successor data source established by the publisher, if any, or, in the absence of a replacement or successor data source, shall select as a replacement a substantially similar data source;

$VOM_{z,t}$ = variable operating and maintenance cost of the peaking plant for Load Zone *z* and hour *t*, which cost shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review;

$ASC_{z,t}$ = amortized start-up cost for the peaking plant for Load Zone *z* and hour *t*. The model will ensure that the total value of this cost is recovered over the number of consecutive hours for which the model determines that the peaking plant should be committed or dispatched to produce Energy following each start of the peaking plant in the same market (Day-Ahead or real-time); provided, however, that in real-time, start-up costs must be recovered over a period of no more than two consecutive hours following the time at which the model determines that the peaking plant should be dispatched to produce Energy;

$EC_{z,t}$ = the sum of CO_2, NO_x and SO_2 emissions allowance costs for the peaking plant for Load Zone *z* and hour *t*, which shall be calculated as follows:

$EC_{z,t} = (CO_2\ emissions\ rate_{z,t} * CO_2\ allowance\ price_{z,t}) + (NO_x\ emissions\ rate_{z,t} * NO_x\ allowance\ price_{z,t}) + (SO_2\ emissions\ rate_{z,t} * SO_2\ allowance\ price_{z,t})$

where:

The applicable emissions rates for the peaking plant for Load Zone *z* and hour *t* shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. The applicable allowance price for each emissions type shall be the price reported by the specified data source for each emissions type determined as part of the periodic review (unless such data source is revised for the reasons described below). The data sources for allowance prices shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review, unless a specified data source is eliminated, replaced or otherwise terminated by the publisher thereof during the period covered by the periodic review. In such circumstance, the ISO shall utilize the replacement or successor data source established by the publisher, if any, or, in the absence of a replacement or successor data source, shall select as a replacement a substantially similar data source; and

$RS1_{z,t}$ = the applicable charges for the ISO annual budget and the annual FERC fee assessed to Injection Billing Units for Load Zone *z* and hour *t* in accordance with Rate Schedule 1 of the ISO OATT.

The results of the model will be used to determine an average annual net revenue value earned by each peaking plant over the period encompassed by the model. Such value will be increased by an adder to account for the estimated annual value of any applicable net Ancillary

Services revenue for each peaking plant that is not determined by the model, which adder shall be determined as part of the periodic review, identified in the filing required by Section 5.14.1.2.2.4.11 and remain fixed for the entire period covered by the periodic review. The resulting value for each peaking plant shall be the updated net Energy and Ancillary Services revenue offset value to be used in establishing the ICAP Demand Curves for the applicable Capability Year.

5.14.1.2.2.3 Annual Updates for ICAP Demand Curve Parameters

The ISO shall use the updated peaking plant gross cost and the updated net Energy and Ancillary Services revenue offset values in determining the parameters of the ICAP Demand Curves for the applicable Capability Year. The maximum value for each ICAP Demand Curve shall be established at 1.5 times the monthly value of the applicable updated peaking plant gross cost. The reference point for each ICAP Demand Curve shall be determined in accordance with ISO Procedures; provided, however, that the ratio of the amount of capacity available in the ICAP Spot Market Auctions in the Winter Capability Period to the amount of capacity available in the ICAP Spot Market Auctions in the Summer Capability Period used in calculating the reference point (the “winter-to-summer ratio”) shall be updated annually based on the average amount of capacity available in the ICAP Spot Market Auctions for the Summer Capability Period months and Winter Capability Period months in each 12-month period (measured from September though the following August) encompassed by the same historical period utilized by the net revenue model. The values used in determining the amount of capacity available in the ICAP Spot Market Auctions shall be the available Unforced Capacity values reported by the ISO and posted on its website for the relevant months, translated to Installed Capacity values based on the applicable translation factors reported by the ISO and posted on its website for each such month. For Resources other than Special Case Resources, the values posted by the ISO shall include the following adjustments to account for ICAP market entry and exit under certain circumstances: (i) if within any of the three 12-month periods (*i.e.*, September through the following August) encompassed by the data used in calculating an updated winter-to-summer ratio value, a Resource (other than a Resource returning to participate in the ICAP market from an Inactive Reserves state) begins to qualify as eligible to participate in the ICAP market in any month encompassed by such 12-month period and remains eligible to participate in the ICAP market for the subsequent months encompassed by that period, the ISO shall adjust the values for all months of that 12-month period to include the Resource's applicable available capacity; and (ii) if within any of the three 12-month periods (*i.e.*, September through the following August) encompassed by the data used in calculating an updated winter-to-summer ratio value, a Resource is Retired or enters a Mothball Outage or ICAP Ineligible Forced Outage state during any month encompassed by such 12-month period and remains ineligible to participate in the ICAP market for the subsequent months encompassed by that period, the ISO shall adjust the values for all months of that 12-month period to exclude the Resource's applicable available capacity. The applicable capacity ratings for each peaking plant utilized in calculating the reference point and the point on each ICAP Demand Curve at which the price of ICAP declines to zero shall be determined as part of the periodic review and shall remain fixed for the entire period covered by the periodic review.

Notwithstanding anything to the contrary herein, for purposes of the annual updates for the 2018/2019, 2019/2020 and 2020/2021 Capability Years, the reference point for each ICAP Demand Curve shall not be permitted to increase by an amount greater than twelve percent (12%) or decrease by an amount greater than eight percent (8%) from one Capability Year to the next, compared to the then currently effective reference point for the relevant ICAP Demand Curve. If the reference point value for an ICAP Demand Curve, as calculated by the ISO pursuant to the annual update procedures, for one of the affected Capability Years exceeds the maximum allowable percentage increase or decrease, the reference point established by the ISO for that ICAP Demand Curve for the relevant Capability Year shall be an amount equal to the price that represents the applicable maximum allowable percentage increase or decrease. If an adjusted reference point value is applied to an ICAP Demand Curve for a Capability Year, the maximum allowable percentage increase or decrease for the next Capability Year shall be determined using the adjusted reference point value. As part of the required posting to establish the updated ICAP Demand Curves for each of the affected Capability Years, the ISO will provide the reference point values calculated by the ISO pursuant to the annual update procedures, as well the adjusted reference point values, if any, that result from the application of the limitation described herein. The limitation described above regarding the allowable annual change to the reference point values calculated by the ISO pursuant to the annual update procedures shall not be applied to the reference point values for any ICAP Demand Curve after the 2020/2021 Capability Year.

The peaking plant gross cost and net Energy and Ancillary Services revenue offset values utilized in determining the parameters of the ICAP Demand Curves for the 2017/2018 Capability Year are as follows:

	Peaking Plant Gross Cost ($ per kW-year)	Net Energy and Ancillary Services Revenue Offset ($ per kW-year)
NYCA	$126.79	$35.70
G-J	$174.79	$40.39
NYC	$209.11	$55.26
LI	$194.96	$104.20

5.14.1.2.2.4 Periodic Review Procedures

The periodic review shall be conducted in accordance with the schedule and procedures specified in the ISO Procedures. A proposed schedule will be reviewed with the stakeholders not later than May 30th of the year prior to the year of the filing specified in Section 5.14.1.2(b).11. The schedule and procedures shall provide for:

5.14.1.2.2.4.1 ISO development, with stakeholder review and comment, of a request for proposals to provide independent consulting services to determine recommended values for the factors specified above, and appropriate methodologies and inputs for such determination;

5.14.1.2.2.4.2 Selection of an independent consultant in accordance with the request for proposals;

5.14.1.2.2.4.3 Submission to the ISO and the stakeholders of a draft report from the independent consultant on the independent consultant's determination of recommended values for the factors specified above, including, as applicable, the methodologies and inputs for determining such values;

5.14.1.2.2.4.4 Stakeholder review of and comment on the data, assumptions and conclusions in the independent consultant's draft report, with participation by the responsible person or persons providing the consulting services;

5.14.1.2.2.4.5 An opportunity for the Market Monitoring Unit to review and comment on the draft request for proposals, the independent consultant's report, and the ISO's proposed: (i) methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Services Tariff are also addressed in Section 30.4.6.3.1 of Attachment O;

5.14.1.2.2.4.6 Issuance by the independent consultant of a final report;

5.14.1.2.2.4.7 Issuance of a draft of the ISO's recommended: (i) methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review, for stakeholder review and comment;

5.14.1.2.2.4.8 Issuance of the ISO's proposed: (i) methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review, taking into account the report of the independent consultant, the recommendations of the Market Monitoring Unit, and the views of the stakeholders together with the rationale for accepting or rejecting any such inputs;

5.14.1.2.2.4.9 Submission of stakeholder requests for the ISO Board of Directors to review and adjust the ISO's proposed: (i) methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review;

5.14.1.2.2.4.10 Presentations to the ISO Board of Directors of stakeholder views on the ISO's proposed: (i) methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) ICAP Demand Curves for the first Capability Year covered by the periodic review; and

5.14.1.2.2.4.11 Filing with the Commission of: (i) a description of the methodologies and inputs used for determining the ICAP Demand Curves for the four Capability Years covered by the periodic review; and (ii) the ICAP Demand Curves for the first Capability Year covered by the periodic review, as approved by the ISO Board of Directors incorporating the results of the periodic review. Such filing will be made not later than November 30th of the year prior to the year that includes the beginning of the first Capability Year covered by the periodic review. The filing will also specify the inflation rate that would have been used to calculate the general component of the escalation factor as if the escalation factor were applicable to the first Capability Year covered by the periodic review. Such inflation rate shall be equal to the twelve month percentage change in the applicable index for the general component, as determined in accordance with Section 5.14.1.2.2.1 utilizing the applicable values of the index as of October 1st in the same calendar year as the November 30th filing deadline specified above. For each of the subsequent three Capability Years encompassed by the periodic review, the value of this inflation rate shall be the twelve month percentage change in the applicable index for the general component of the escalation factor for the applicable Capability Year, as determined pursuant to Section 5.14.1.2.2.1.

The ICAP Demand Curves will be translated into Unforced Capacity terms in accordance with the ISO Procedures; provided that nothing in this Tariff shall be construed to limit the ability of the ISO or its Market Participants to propose and adopt alternative provisions to this Tariff through established governance procedures.

5.14.1.3 Supplemental Supply Fee

Any LSE that has not met its share of the NYCA Minimum Installed Capacity Requirement or its share of the Locational Minimum Installed Capacity Requirement after the completion of an ICAP Spot Market Auction, shall be assessed a supplemental supply fee equal to the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction multiplied by the number of MWs the LSE needs to meet its share of the NYCA Minimum Installed Capacity Requirement or its share of the Locational Minimum Installed Capacity Requirement.

The ISO will attempt to use these supplemental supply fees to procure Unforced Capacity at a price less than or equal to the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction from Installed Capacity Suppliers that are capable of supplying Unforced Capacity including: (1) Installed Capacity Suppliers that were not qualified to supply Capacity prior to the ICAP Spot Market Auction; (2) Installed Capacity Suppliers that offered Unforced Capacity at levels above the ICAP Spot Market Auction Market-Clearing Price; and (3) Installed Capacity suppliers that did not offer Unforced Capacity in the ICAP Spot Market Auction. In the event that different Installed Capacity Suppliers offer the same price, the ISO will give preference to Installed Capacity Suppliers that were not qualified to supply capacity prior to the ICAP Spot Market Auction.

Offers from Installed Capacity Suppliers are subject to review pursuant to the Market Monitoring Plan that is set forth in Attachment O to the Services Tariff, and the Market Mitigation Measures that are set forth in Attachment H to the Services Tariff. Installed Capacity

Suppliers selected by the ISO to provide capacity after the ICAP Spot Market Auction will be paid a negotiated price, subject to the standards, procedures and remedies in the Market Mitigation Measures.

The ISO will not pay an Installed Capacity Supplier more than the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction per MW of Unforced Capacity, or, in the case of In-City generation that is subject to capacity market mitigation measures, the annual mitigated price cap per MW of Unforced Capacity, whichever is less, pro-rated to reflect the portion of the Obligation Procurement Period for which the Installed Capacity Supplier provides Unforced Capacity. Any remaining monies collected by the ISO pursuant to this section will be applied in accordance with Section 5.14.3 of the Services Tariff.

5.14.2 Installed Capacity Supplier Shortfalls and Deficiency Charges

5.14.2.1 General Provisions

In the event that an Installed Capacity Supplier sells in the Capability Period Auctions, in the Monthly Auctions, or through Bilateral Transactions more Unforced Capacity than it is qualified to sell in any specific month due to a de-rating or other cause, the Installed Capacity Supplier shall be deemed to have a shortfall for that month. To cover this shortfall, the Installed Capacity Supplier shall purchase sufficient Unforced Capacity in the relevant Monthly Auction or through Bilateral Transactions, and certify to the ISO consistent with the ISO Procedures that it has covered such shortfall. If the Installed Capacity Supplier does not cover such shortfall or if it does not certify to the ISO in a timely manner, the ISO shall, to the extent the ISO is aware of the shortfall, prospectively purchase Unforced Capacity on behalf of that Installed Capacity Supplier in the appropriate ICAP Spot Market Auction or through post ICAP Spot Market Auction Unforced Capacity purchases to cover the shortfall.

The ISO shall submit a Bid, calculated pursuant to Section 5.14.1 of this Tariff, in the appropriate ICAP Spot Market Auction on behalf of an Installed Capacity Supplier deemed to have a shortfall as if the Installed Capacity Supplier were an LSE. Such Installed Capacity Supplier shall be required to pay to the ISO the applicable Market-Clearing Price of Unforced Capacity established in that ICAP Spot Market Auction. Immediately following the ICAP Spot Market Auction, the ISO may suspend the Installed Capacity Supplier's privileges to sell or purchase Unforced Capacity in ISO-administered Installed Capacity auctions or to submit Bilateral Transactions to the NYISO. Once the Installed Capacity Supplier pays for or secures the payment obligation that it incurred in the ICAP Spot Market Auction, the ISO shall reinstate the Installed Capacity Supplier's privileges to participate in the ICAP markets.

In the event that the ICAP Spot Market Auction clears below the NYCA Minimum Installed Capacity Requirement or the Locational Minimum Installed Capacity Requirement, whichever is applicable to the Installed Capacity Supplier, and the Installed Capacity Supplier is deemed to have a shortfall, the Installed Capacity Supplier shall be assessed the applicable deficiency charge equal to the applicable Market-Clearing Price of Unforced Capacity determined using the applicable ICAP Demand Curve for that ICAP Spot Market Auction, times the amount of its shortfall.

If an Installed Capacity Supplier is found, at any point during a Capability Period, to have had a shortfall for that Capability Period, *e.g.*, when the amount of Unforced Capacity that it supplies is found to be less than the amount it was committed to supply, the Installed Capacity Supplier shall be retrospectively liable to pay the ISO the monthly deficiency charge equal to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined using the applicable ICAP Demand Curve for that ICAP Spot Market Auction times the amount of its shortfall for each month the Installed Capacity Supplier is deemed to have a shortfall. If the Installed Capacity Supplier is a RIP, it may experience a shortfall when, among other reasons, it sells ineligible or unavailable capacity MW associated with a properly or improperly enrolled SCR.

The ISO, when evaluating whether an Installed Capacity Supplier has a shortfall, may use either Unforced Capacity data or Installed Capacity data; provided, however, that the ISO shall convert any shortfall MWs based on Installed Capacity data to its Unforced Capacity equivalent prior to calculating the amount of any deficiency charge. All shortfalls shall be measured in MWs in increments of 0.1 MW.

Any remaining monies collected by the ISO pursuant to Section 5.14.1 and 5.14.2 will be applied as specified in Section 5.14.3.

5.14.2.2 Additional Provisions Applicable to External Installed Capacity Suppliers

In addition to the general provisions set forth in Section 5.14.2.1 above that are applicable to External Installed Capacity Suppliers as Installed Capacity Suppliers, the following provisions shall also apply to External Installed Capacity Suppliers.

In the event that an External Installed Capacity Supplier fails to deliver to the NYCA the Energy associated with the Unforced Capacity it committed to the NYCA due to a failure to obtain appropriate transmission service or rights, the External Installed Capacity Supplier shall be deemed to have a shortfall from the last time the External Installed Capacity Supplier "demonstrated" delivery of its Installed Capacity Equivalent ("ICE"), or any part thereof, until it next delivers its ICE or the end of the term for which it certified the applicable block of Unforced Capacity, whichever occurs first, subject to the limitation that any prior lack of demonstrated delivery will not precede the beginning of the period for which the Unforced Capacity was certified. An External Installed Capacity Supplier deemed to have a shortfall shall be required to pay to the ISO a deficiency charge equal to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for the applicable month, prorated for the number of hours in the month that External Installed Capacity Supplier is deemed to have a shortfall (i.e., (((deficiency charge ÷ 12 months) ÷ total number of hours in month when shortfall occurred) * number of hours the shortfall lasted) * number of MWs of shortfall).

5.14.2.3 Additional Provisions Applicable to RIPs

In addition to the general provisions set forth in Section 5.14.2.1 above that are applicable to RIPs as Installed Capacity Suppliers, this Section 5.14.2.3 establishes the following four specific shortfalls applicable to RIPs: 1. shortfall for Provisional ACL; 2. shortfall for Incremental ACL; 3. shortfall for SCR Change of Status; and 4. shortfall for RIP portfolio performance. The deficiency charge for any such shortfall shall be equal to the Unforced Capacity equivalent of the shortfall multiplied by one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined using the applicable ICAP Demand Curve for the ICAP Spot Market Auction for each month the RIP is deemed to have a shortfall.

There are three distinct measures of shortfall that are applicable to a RIP, described in this Section 15.4.2.3, where individual SCRs that have been enrolled with a Provisional ACL or an Incremental ACL, or that experience a SCR Change of Status may result in a shortfall. When a RIP is subject to multiple deficiency charges for the same SCR for the same Capability Period, the ISO shall assess to the RIP only the greatest deficiency charge related to such SCR. In addition, if the shortfall results in a reduction in the performance of a SCR, the ISO may recover from the RIP any energy payments for which the SCR was ineligible to receive.

5.14.2.3.1 Shortfall for Provisional ACL

Prior to the Summer 2014 Capability Period if the Installed Capacity Supplier is a Responsible Interface Party, after each Special Case Resource with a Provisional Average Coincident Load has its Average Coincident Load determined for the Capability Period in which it had a Provisional Average Coincident Load (such determination in accordance with ISO Procedures and without regard to whether the resource was registered to the same Responsible Interface Party at the time of the ACL determination), the ISO shall determine if there is a shortfall due to the Provisional Average Coincident Load being higher than the Average Coincident Load. This shortfall will be equal to the value, if positive, of (x) the sum of (i) the amount of UCAP a Responsible Interface Party sold in an Monthly or an ICAP Spot Market Auction or certified Bilateral Transactions for a Special Case Resource and (ii) the Special Case Resource's actual metered demand for the month in accordance with ISO Procedures, minus (y) the Special Case Resource's Average Coincident Load. If the ISO does not receive data to determine the Average Coincident Load in accordance with ISO Procedures, for each Capability Period a Special Case Resource had a Provisional Average Coincident Load, for purposes of determining the shortfall, the Average Coincident Load shall equal zero.

Beginning with the Summer of 2014 Capability Period if the Installed Capacity Supplier is a Responsible Interface Party, after each SCR with a Provisional ACL has its Verified ACL determined for the Capability Period in which it had a Provisional ACL (such determination in accordance with Section 5.12.11.1 and ISO Procedures) the ISO shall determine if there is a shortfall due to the Provisional ACL being greater than the Verified ACL. This shortfall shall be equal to the value, if positive, of (x) the Provisional ACL of the SCR, minus (y) the Verified ACL of the SCR. The shortfall calculated for the SCR for a month shall not exceed the amount of Installed Capacity associated with the SCR that was sold for that month. If the ISO does not receive data to determine the SCR's Verified ACL for the Capability Period for which the SCR was enrolled with a Provisional ACL the Verified ACL shall equal zero.

5.14.2.3.2 Shortfall for Incremental ACL

If the Installed Capacity Supplier is a RIP that reported an Incremental ACL, the ISO shall determine there is a shortfall when the Net ACL is greater than the Verified ACL. This shortfall shall be equal to the value, if positive, of (x) the enrolled Net ACL of the SCR, minus (y) the Verified ACL of the SCR for each month in which the RIP sold the SCR's Installed Capacity. The shortfall calculated for the SCR for a month shall not exceed the amount of Installed Capacity associated with the SCR that was sold for that month. If the ISO does not receive data to determine the Verified ACL for each month within the Capability Period that the SCR was enrolled with an Incremental ACL, the Monthly ACL for each unreported month shall equal zero (0) and be used in the calculation of the Verified ACL in accordance with Section 5.12.11.1.5.

5.14.2.3.3 Shortfall for SCR Change of Status

If the Installed Capacity Supplier is a RIP, and a SCR Change of Status occurs, the ISO shall determine if a shortfall exists, based on the RIP's reporting of the SCR Change of Status.

When a SCR Change of Status is reported by the RIP in advance and no Installed Capacity associated with the SCR has been sold, a shortfall has not occurred. If the SCR Change of Status is reported by the RIP, but the Installed Capacity associated with the SCR has already been sold for one or more months a shortfall exists for these months, the shortfall shall be equal to the reduction to the ACL reported in the SCR Change of Status, but shall not exceed the amount of Installed Capacity sold for each month.

When the RIP fails to report the SCR Change of Status during the Capability Period, for each month in which the SCR's Installed Capacity was sold and the SCR Change of Status was in effect, the ISO shall determine the shortfall MW using the maximum one hour metered Load for the month. The shortfall amount for each month in which the SCR Change of Status was in effect shall equal the value of SCR ACL minus the maximum one hour metered Load for the month, but shall not exceed the SCR's Installed Capacity sold for the month.

5.14.2.3.4 Shortfall for RIP Portfolio Performance

In addition to the shortfall evaluations based on individual SCRs, a RIP is subject to a shortfall evaluation, by Load Zone, for its entire SCR portfolio. In this evaluation the shortfall shall be determined for each Load Zone separately. A shortfall will occur if the total of the amount of UCAP sold by the RIP for a month in a Capability Period Auction or a Monthly Auction and certified prior to that month's ICAP Spot Market Auction, the UCAP sold in that month's ICAP Spot Market Auction, and the UCAP sold as a Bilateral Transaction and certified prior to that month's ICAP Spot Market Auction is greater than the greatest quantity MW reduction achieved during a single hour in a test or event called by the ISO in the Capability Period as confirmed by data by the ISO in accordance with ISO Procedures (or the value of zero if data is not received by the ISO in accordance with such procedures).

5.14.3 Application of Installed Capacity Supplier Deficiency Charges

Any remaining monies collected by the ISO through supplemental supply fees or Installed Capacity Supplier deficiency charges pursuant to Section 5.14.1 but not used to procure Unforced Capacity on behalf of LSEs or Installed Capacity suppliers deemed to have a shortfall shall be applied as provided in this Section 5.14.3.

5.14.3.1 General Application of Deficiency Charges

Except as provided in Section 5.14.3.2, remaining monies will be applied to reduce the Rate Schedule 1 charge in the following month.

5.14.3.2 Installed Capacity Rebates

(i) New York City

If an Unforced Capacity shortfall exists during any month, the ISO shall rebate any remaining unspent deficiency charges or supplemental supply fees collected for that month for the New York City Locality allocated among all LSEs in that Locality in proportion to their share of the applicable Locational Minimum Installed Capacity Requirement. Rebates shall include interest accrued between the time payments were collected and the time that rebates are paid.

(ii) Long Island

If an Unforced Capacity shortfall exists during any month, the ISO shall rebate any remaining unspent deficiency charges or supplemental supply fees collected for that month for the Long Island Locality, allocated among all LSEs in that Locality in proportion to their share of the applicable Locational Minimum Installed Capacity Requirement. Rebates shall include interest accrued between the time payments were collected and the time that rebates are paid.

(iii) G-J

If an Unforced Capacity shortfall exists during any month, the ISO shall rebate any remaining unspent deficiency charges or supplemental supply fees collected for that month for the G-J Locality, allocated among all LSEs in that Locality in proportion to their share of the applicable Locational Minimum Installed Capacity Requirement. Rebates shall include interest accrued between the time payments were collected and the time that rebates are paid.

(iv) Rest of State

If an Unforced Capacity shortfall exists during any month, the ISO shall rebate any remaining unspent deficiency charges or supplemental supply fees collected for that month for the Rest of State requirements, allocated among all LSEs in each of the Localities and in Rest of State, in proportion to each LSE's share of the NYCA Minimum Installed Capacity Requirement less that LSE's Locational Minimum Installed Capacity Requirement. Rebates shall include interests accrued between the time payments were collected and the time that rebates are paid.

5.15 Payment and Allocation of Installed Capacity Auction Rebates

The ISO shall rebate to all LSEs with Locational Minimum Installed Capacity Requirements in the New York City Locality, except NYPA, any Excess Amount that remains after the completion of an auction. Such rebates shall be allocated among all New York City LSEs, except NYPA, in proportion to their share of the Locational New York City Installed Capacity Requirement, regardless of whether they actually took part in the Capability Period Auctions or Monthly Auctions. The ISO shall allocate such rebates among In-City LSEs except NYPA on a monthly basis. Rebates shall include interest accrued between the time they were collected and the time that they are paid.

5.16 New Capacity Zone Study and Procedures

Capitalized terms used in this Section 5.16 and not defined in this Services Tariff shall have the meaning set forth in the Open Access Transmission Tariff.

The ISO shall conduct the New Capacity Zone study in accordance with this Section ("NCZ Study") and provide a written report of the results to stakeholders on or before January 15 in each ICAP Demand Curve Reset Filing Year.

5.16.1 NCZ Study Methodology.

5.16.1.1 The NCZ Study, developed in accordance with ISO Procedures, will test, under summer peak system conditions, using the following assumptions and methodology:

5.16.1.1.1 The following assumptions will be applied: (i) transmission facilities (other than existing merchant transmission projects) identified as existing in the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date; (ii) all firm plans for changes to transmission facilities by Transmission Owners in the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date scheduled to be in-service prior to the NCZ Study Capability Period; (iii) planned generation projects or Merchant Transmission Facilities that have accepted either (a) Deliverable MW or (b) a System Deliverability Upgrade cost allocation and provided cash or posted required security pursuant to OATT Attachment S, which for (a) and (b) is from a Class Year Final Decision Round that occurs prior to the NCZ Study Start Date (subject to Section 5.16.1.1.2); (iv) System Upgrade Facilities and System Deliverability Upgrades associated with planned projects identified in (iii) above, except that System Deliverability Upgrades where construction of the System Deliverability Upgrade has been deferred pursuant to OATT Attachment S Sections 25.7.12.2 and 25.7.12.3 will only be included if construction of the System Deliverability Upgrades has been triggered under OATT Attachment S Section 25.7.12.3; (v) all transmission retirements and derates identified in the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date and scheduled to occur prior to the NCZ Study Capability Period; (vi) all existing Generators with CRIS identified in, and all projects with Unforced Capacity Deliverability Rights on the date of, the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date; and all CRIS rights from resources considered "CRIS-inactive" as defined in OATT Attachment S Section 25.9.3.1 unless the ability to transfer those rights has expired without completing a transfer as permitted under OATT Attachment S Section 25.9.4 or 25.9.5 as of the NCZ Study Start Date; and (vii) any transfer of CRIS rights pursuant to OATT Attachment S not identified in the Load and Capacity Data report most recently published prior to the NCZ Study Start Date but is completed and the transferee is operational prior to the NCZ Study Start Date.

5.16.1.1.2 Planned generation and Merchant Transmission Facilities identified pursuant to Section 5.16.1.1.1 will be excluded and not recognized in the NCZ Study if (a) the Commission has accepted the cancellation or termination of a rate schedule consisting of an Interconnection Agreement (absent the filing of another Interconnection Agreement for the project), or (b) for projects that either do not have an executed Interconnection Agreement or have an executed Interconnection Agreement that is (i) not required to be filed with the Commission or (ii) is required to be filed but has not yet been filed, the ISO receives written notice from the project that it is withdrawing from the interconnection queue and/or a Notice of Termination under the interconnection agreement.

5.16.1.1.3 The Load forecast used will be the NCZ Study Capability Period peak demand forecast contained in the ISO's Load and Capacity Data report most recently published prior to the NCZ Study Start Date.

5.16.1.1.4 The base case conditioning steps contained in OATT Attachment S Sections 25.7.8.2.3 (excluding and not recognizing MW of CRIS requested by Developers other than CRIS identified in Section 5.16.1.1.1 (iii)), 25.7.8.2.4, 25. 7.8.2.5, 25.7.8.2.10, and 25.7.8.2.11, will be applied to the above inputs and assumptions.

5.16.1.1.5 The ISO will perform the NCZ Study by applying to the above inputs and assumptions the methodology contained in OATT Attachment S Sections 25.7.8.2.6, 25.7.8.2.7, 25.7.8.2.8, 25.7.8.2.9, 25.7.8.2.12, and 25.7.8.2.13 to Highways. Deliverability will be determined through a shift from generation to generation within each Capacity Region that contains Highways. Each such Capacity Region will be tested on an individual basis.

5.16.1.2 On or before October 1 of the year prior to an ICAP Demand Curve Reset Filing Year, the ISO will review the inputs and assumptions for the NCZ Study with stakeholders and provide an opportunity for stakeholders to comment.

5.16.1.3 The ISO shall provide an opportunity for the Market Monitoring Unit to review and comment on the NCZ Study consistent with Services Tariff Attachment O Section 30.4.6.3.2.

5.16.2 New Capacity Zone Boundary

The ISO shall identify the boundary of a New Capacity Zone if there is a constrained Highway interface into one or more Load Zones. The boundary of the New Capacity Zone may encompass a single constrained Load Zone or group of Load Zones including one or more constrained Load Zones on the constrained side of the Highway. In determining the New Capacity Zone boundary, the ISO shall consider the extent to which incremental Capacity in individual constrained Load Zones could impact the reliability and security of constrained Load Zones, taking into account interface capability between constrained Load Zones.

5.16.3 Indicative NCZ Locational Minimum Installed Capacity Requirement

For each Load Zone or groups of Load Zones identified in the NCZ Study as having a constrained Highway Interface, on or before March 1 of each ICAP Demand Curve Reset Filing Year, the ISO shall determine Indicative NCZ Locational Minimum Installed Capacity Requirement. The ISO shall provide an opportunity to stakeholders to review and comment on the Indicative NCZ Locational Minimum Installed Capacity Requirement. This Indicative NCZ Locational Minimum Installed Capacity Requirement will be used solely for establishing revised ICAP Demand Curves in accordance with 5.14.1.2.

5.16.4 NCZ Report

On or before March 31 of an ICAP Demand Curve Reset Filing Year,

(a) If the NCZ Study identifies a constrained Highway Interface, the ISO shall file for Commission review proposed tariff revisions necessary to establish and recognize the New Capacity Zone or Zones, and shall include in the filing a report of the results of the NCZ Study. If the ISO proposes that a New Capacity Zone that is comprised of a group of Load Zones instead of a single Load Zone, the ISO shall include in the filing the basis for its determination, consistent with Section 5.16.2.

(b) If the NCZ Study does not identify a constrained Highway interface, the ISO shall file with the Commission the ISO's determination that the NCZ Study did not indicate that any New Capacity Zone is required pursuant to this process, along with a report of the results of the NCZ Study.

The ISO shall provide an opportunity for the Market Monitoring Unit to review and comment on the NCZ Study and any proposed tariff revisions, consistent with Services Tariff Attachment O Section 30.4.6.3.2.

5.17 Expedited Dispute Resolution Procedures

5.17.1 Five-Day Consultation Period

Parties to a dispute involving a matter that is subject to the procedures of this section must immediately confer and attempt to resolve the dispute on an informal basis. If the parties are unable to resolve the dispute within five (5) calendar days by mutual agreement, the dispute shall be immediately submitted to the ISO's Dispute Resolution Administrator ("DRA").

5.17.2 Written Submissions

Immediately upon conclusion of the five-day consultation period, the party requesting the dispute resolution shall submit to the DRA and all other parties to the dispute, a concise written statement specifying that expedited dispute resolution under this section is requested and describing the nature of the dispute, the issues to be resolved and the specific award requested. The party opposing the requested relief shall then have five (5) calendar days to submit to the DRA and the party requesting the dispute resolution, a concise written response which shall include a proposed disposition of the dispute.

5.17.3 Appointment of the Arbitrator

The DRA shall keep at all times a list of ten (10) qualified arbitrators for matters which may be subject to the procedures of this section. Within five (5) calendar days of receipt of a request for dispute resolution under this section, the DRA shall appoint one arbitrator from that list to preside over the dispute. The arbitrator shall be selected by the DRA by randomly drawing names from the list until an available arbitrator is found. If none of the arbitrators on the list is available, the DRA shall appoint a qualified arbitrator to preside over the dispute. No person shall be eligible to act as an arbitrator who is a past or present officer, employee of, or consultant to any of the disputing parties, or of an entity related to or affiliated with any of the disputing parties, or is otherwise interested in the matter to be arbitrated except upon the express written consent of the parties. Any individual appointed as an arbitrator shall make known to the disputing parties any such disqualifying relationship or interest and a new arbitrator shall be appointed by the DRA, unless express written consent is provided by each party.

5.17.4 Arbitration Proceeding

There shall be no right to discovery between the parties, including, but not limited to, depositions, interrogatories or other information requests. The arbitrator may request, and the parties shall produce, any information in addition to the written statements that is deemed by the arbitrator to be relevant to the issues presented. The arbitrator shall resolve the arbitration matter solely on the basis of the written statements and evidence submitted by the parties unless, in the sole discretion of the arbitrator, a hearing is deemed necessary. Any such hearing shall be limited to one (1) day and conducted in accordance with the procedures determined by the arbitrator. Absent agreement to the contrary by all parties to the dispute, no person or entity shall be permitted to intervene. Except as otherwise set forth in this section, the arbitrator will follow the Commercial Arbitration Rules of the American Arbitration Association and the expedited procedures contained therein.

5.17.5 Arbitration Award

Within fifteen (15) calendar days of the appointment of the arbitrator, the arbitrator shall select as an arbitration award the award proposed by one of the parties in their written submission (except that, in disputes concerning the development of regional Load growth factors pursuant to Section 5.10 of this Tariff, the arbitration award shall be either the forecast developed by the Transmission Owner or by the ISO) and shall render a concise written decision including findings of fact and the basis for the decision. All costs associated with the time, expenses, and other charges of the arbitrator shall be borne by the unsuccessful party. Each party shall bear its own costs, including attorney and expert fees, if any. No award shall be deemed to be precedential in any other arbitration related to a different dispute.

5.17.6 Limited Appeal

The decision of the arbitrator shall be final and binding upon the parties, except that, within one year of the arbitration decision, a party may request that any federal, state regulatory or judicial authority (in the State of New York) having jurisdiction take such action as may be appropriate with respect to any arbitration decision that is based on fraudulent conduct or demonstrable bias of the arbitrator.

5.18 Generator Outages and Generator Obligations While in These Outages

This Section 5.18 shall apply to a Generator in any outage state that started on or after May 1, 2015.

A Market Participant with a Generator in the NYCA that is in any outage state shall report this status to the ISO pursuant to ISO Procedures.

5.18.1 Forced Outages and Commenced Repair Determinations

5.18.1.1 A Market Participant with a Generator in a Forced Outage shall keep the ISO informed as to progress of its Generator's repairs pursuant to ISO Procedures. A Market Participant may keep its Generator in a Forced Outage beyond the last day of the month which contains the 180th day of its Forced Outage only if it has Commenced Repair of its Generator. A Market Participant that anticipates its Generator will not be able to return to the Energy market before the last day of the month which contains the 180th day of its Forced Outage and which desires to remain eligible to be in the Installed Capacity market beyond the 180th day shall provide a Repair Plan to the ISO by the 120th day of the Forced Outage.

5.18.1.2 A Repair Plan shall include a work plan, with milestones, or set of necessary actions, and shall provide the time it is expected to take to complete each task and describe the repair of the Generator's equipment related to electric production, fuel or station power supply or transmission interconnection, as appropriate, that was either affected by the Forced Outage or otherwise makes the unit available for the Energy market. The Repair Plan's milestones shall include, in appropriate circumstances: damage assessments, engineering assessments, initial cost estimates, purchase orders, inspection reports, initial safety assessments, hazardous material abatement plans, and labor mobilization plans. The Repair Plan shall include the date the Market Participant expects the Generator to be repaired and available for the Energy market (return date) which return date: i) shall be reasonable, ii) may be provided as a good faith estimate, and iii) shall be updated to the extent new information becomes available. The return date or good faith estimate of a return date that a Market Participant provides for its Generator shall be reasonable if it is comparable to the return date that would be included in a Credible Repair Plan pursuant to Section 5.18.1.5 of this Services Tariff.

5.18.1.3 Market Participants requesting that the NYISO determine, pursuant to Services Tariff Section 23.4.5.6.2, that their Generator has experienced a Catastrophic Failure, or that Exceptional Circumstances will delay the submission of data necessary for the ISO to perform an audit and review pursuant to Section 23.4.5.6.2, shall submit their requests, with necessary supporting data, to the NYISO by the 120th day of the Forced Outage if they desire the determination to be issued by the 160th day of the Forced Outage of their Generator.

5.18.1.4 A Market Participant has Commenced Repair of its Generator if it: i) has decided to pursue the repair of its Generator, and based on the ISO's technical/engineering evaluation, ii) has a Repair Plan for the Generator that is consistent with a Credible Repair Plan, and iii) has made appropriate progress in pursuing the repair of its Generator when measured against the milestones of a Credible Repair Plan.

5.18.1.5 For purposes of the determinations required by Section 5.18.1.3(ii) and (iii), and 5.18.1.6 of this Services Tariff, a Credible Repair Plan is the Repair Plan that would be expected from a supplier: i) with a generating facility that is reasonably the same as or similar to the type and vintage of the Generator; ii) intending to return its generating facility to service. A Credible Repair Plan for a Generator that suffered a Forced Outage is a Repair Plan that would also be expected from a supplier with a generating facility that suffered a forced outage that was reasonably the same as or comparable to the Forced Outage suffered by the Generator and which forced outage occurred under the same, or reasonably similar, circumstances as the Generator's. A Credible Repair Plan for a Generator in a Mothball Outage is a Repair Plan that would also be expected from a supplier pursuing a repair to its generating facility which repair is reasonably the same as or comparable to the repair being pursued by the Generator.

5.18.1.6 The determination that a Market Participant has Commenced Repair of its Generator in a Forced Outage shall be made by the ISO by the 160th day of the Forced Outage. If the Market Participant provides updated information after the 120th day of the Forced Outage and before the 180th day of its Generator's Forced Outage, the ISO will, as applicable, take such information into consideration to make its determination or it will update its previously issued determination to the extent practicable.

The determination that a Market Participant has Commenced Repair of its Generator in an ICAP Ineligible Forced Outage, which Market Participant has been determined by the ISO to have one or more Exceptional Circumstances that delay the acquisition of necessary data for an audit and review for economic justification pursuant to Section 23.4.5.6.2 of this Services Tariff, shall be made by the ISO as soon as practicable following receipt of necessary data.

The determination that a Market Participant has Commenced Repair of its Generator in an ICAP Ineligible Forced Outage or Mothball Outage, which Market Participant is seeking to toll expiration of its outage and CRIS rights pursuant to Sections 5.18.2.3.2 or 5.18.3.3.2 of this Services Tariff, will be made by the ISO as soon as practicable following receipt of the necessary data.

5.18.1.7 If a Market Participant has not Commenced Repair of its Generator by the last day of the month which contains the 180th day of the Forced Outage, the Generator's Forced Outage shall expire on the last day of the month which contains the 180th day of the Forced Outage. The Forced Outage of a Generator that Commenced Repair but ceased or unreasonably delayed the Generator's repair shall terminate on the last day of the month containing the date that the Market Participant ceased or unreasonably delayed the repair. The ISO will determine a Market Participant has unreasonably delayed the repair of its Generator if such delay would not have been included in a Credible Repair Plan from a supplier experiencing the situation which caused the Market Participant to delay the repair of its Generator.

5.18.1.8 Upon the expiration or termination of a Generator's Forced Outage, the Generator shall be in an ICAP Ineligible Forced Outage unless the Generator has been Retired by the Market Participant.

5.18.2 ICAP Ineligible Forced Outage

5.18.2.1 A Market Participant may voluntarily reclassify its Generator from a Forced Outage to an ICAP Ineligible Forced Outage only if the Generator has been in a Forced Outage for at least sixty (60) days. A Generator that has been voluntarily reclassified from a Forced Outage to an ICAP Ineligible Forced Outage shall begin its ICAP Ineligible Forced Outage on the first day of the month following the month in which it was voluntarily reclassified to an ICAP Ineligible Forced Outage.

A Generator in an ICAP Ineligible Forced Outage as a result of the expiration or termination of its Forced Outage pursuant to Section 5.18.1.6 of this Services Tariff, shall begin its ICAP Ineligible Forced Outage on the day following the day the Generator's Forced Outage expired or terminated.

A Generator in an ICAP Ineligible Forced Outage as a result of substantial actions that have been taken, such as dismantling or disabling essential equipment, which actions are inconsistent with an intention to operate the Generator in the Energy market shall begin its ICAP Ineligible Forced Outage on the day following the day such actions began.

5.18.2.2 A Generator in an ICAP Ineligible Forced Outage is not eligible to participate in the Installed Capacity market and shall automatically cease to qualify to participate in the Installed Capacity market beginning with the first day of its ICAP Ineligible Forced Outage. The Generator shall no longer be ineligible to participate in the Installed Capacity market**,** by virtue of its ICAP Ineligible Forced Outage, as of the first day the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage. The month for which the Generator will first be eligible to participate in the Installed Capacity market will be based on the date the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage and ISO Procedures.

5.18.2.3 ICAP Ineligible Force Outage Expiration

5.18.2.3.1 Except as provided in Section 5.18.2.3.2, a Generator's ICAP Ineligible Forced Outage shall expire if: i) its CRIS rights have expired; or ii) it did not have CRIS rights and has been in the ICAP Ineligible Forced Outage for 36 consecutive months. A Generator shall be Retired if its ICAP Ineligible Forced Outage expires.

5.18.2.3.2 If a Market Participant with a Generator in an ICAP Ineligible Forced Outage has Commenced Repair prior to when the ICAP Ineligible Forced Outage would expire pursuant to Section 5.18.2.3.1 and has provided a reasonable return date as that term is described in Section 5.18.1.2 of this Services Tariff that occurs after such expiration date, then the outage and the Generator's CRIS rights will be tolled until, and the ICAP Ineligible Forced Outage will expire on, the earlier of: i) 120 days from when the outage would have expired under Section 5.18.2.3.1; or ii) an ISO determination that the Market Participant has ceased or unreasonably delayed the repair of its Generator. The ISO will determine if a Market Participant has unreasonably delayed the repair of its Generator if such delay would not have been included in a Credible Repair Plan from a supplier experiencing the situation which caused the Market Participant to delay the repair of its Generator. The tolling of CRIS rights occurs under this Section 5.18.2.3.2

notwithstanding the three year period in which CRIS-inactive facilities may maintain CRIS rights pursuant to Section 25.9.3.1 of Attachment S to the OATT; provided, however, the expiration period for transfers of CRIS rights provided in Section 25.9.3.1 of Attachment S to the OATT shall not be tolled. A Market Participant seeking to toll its outage and CRIS rights pursuant to this Section 5.18.2.3.2 must submit a Repair Plan no later than 60 days prior to when the ICAP Ineligible Forced Outage would expire under Section 5.18.2.3.1.

5.18.2.4 A Market Participant with a Generator in an ICAP Ineligible Forced Outage that is notified by a Transmission Owner or the ISO that the return to service of its Generator could address a reliability issue shall provide an updated good faith estimate of the Generator's return date. A Market Participant with a Generator in an ICAP Ineligible Forced Outage shall make a timely return to service to resolve a reliability issue, in accordance with Section 5.18.4, as the term "timely return" is described in Section 5.18.4.2 of this Services Tariff. A Market Participant with a Generator in an ICAP Ineligible Forced Outage shall provide temporary use of its Generator's interconnection point in accordance with Section 5.18.5 of this Services Tariff when a transmission solution using the Generator's interconnection point has been selected as the Generator Deactivation Solution, the Gap Solution, or to resolve a reliability issue arising on a non-New York State Bulk Power Transmission Facility during its outage. The Transmission Owner shall provide that power to the station remains available notwithstanding its temporary use of the Generator's interconnection point.

5.18.3 Mothball Outage

5.18.3.1 Prior to entering a Mothball Outage, the Generator must satisfy the prior notice requirement contained in Section 38.3.1 of Attachment FF to the ISO OATT, among other applicable requirements. A Generator in a Mothball Outage is not eligible to participate in the Installed Capacity market and shall automatically cease to qualify to participate in the Installed Capacity market beginning with the date the Generator begins its Mothball Outage. The Generator shall no longer be ineligible to participate in the Installed Capacity market, by virtue of its Mothball Outage, as of the first day the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage. The month for which the Generator will first be eligible to participate in the Installed Capacity market will be based on the date the Generator returns to operation and offers its Energy into the Day-Ahead Market without declaring an outage and ISO Procedures.

5.18.3.2 As part of the Generator Deactivation Notice required prior to entering a Mothball Outage pursuant to Section 38.3.1 of Attachment FF to the ISO OATT, a Market Participant shall notify the ISO whether its Generator will be physically able to return within 180 days to resolve a reliability issue or it has good cause for an alternate period of time, stated in days, to return its Generator to service to resolve a reliability issue. The Market Participant shall establish good cause, to the satisfaction of the ISO, by providing empirical evidence demonstrating the need for the alternate period of time to return its Generator to service to resolve a reliability issue. The number of days within which a Generator in a Mothball Outage can be returned to service to resolve a reliability issue will be shared with the applicable Transmission Owner(s).

5.18.3.3 Mothball Outage Expiration

5.18.3.3.1 Except as provided in Section 5.18.3.3.2, a Generator's Mothball Outage shall expire if: i) its CRIS rights have expired; or ii) it did not have CRIS rights and has been in the Mothball Outage for 36 consecutive months. A Generator shall be Retired if its Mothball Outage expires.

5.18.3.3.2 If a Market Participant with a Generator in a Mothball Outage has Commenced Repair prior to when the Mothball Outage would expire pursuant to Section 5.18.3.3.1 and has provided a reasonable return date as that term is described in Section 5.18.1.2 of this Services Tariff that occurs after such expiration date, then the outage and the Generator's CRIS rights will be tolled until, and the Mothball Outage will expire on, the earlier of: i) 120 days from when the outage would have expired under Section 5.18.3.3.1; or ii) an ISO determination that the Market Participant has ceased or unreasonably delayed the repair of its Generator. The ISO will determine if a Market Participant has unreasonably delayed the repair of its Generator if such delay would not have been included in a Credible Repair Plan from a supplier experiencing the situation which caused the Market Participant to delay the repair of its Generator. The tolling of CRIS rights occurs under this Section 5.18.3.3.2 notwithstanding the three year period in which CRIS-inactive facilities may maintain CRIS rights pursuant to Section 25.9.3.1 of Attachment S to the OATT; provided, however, the expiration period for transfers of CRIS rights provided in Section 25.9.3.1 of Attachment S to the OATT shall not be tolled. A Market Participant seeking to toll its outage and CRIS rights pursuant to this Section 5.18.3.3.2 must submit a Repair Plan no later than 60 days prior to when the Mothball Outage would expire under Section 5.18.3.3.1.

5.18.3.4 A Market Participant with a Generator in a Mothball Outage shall timely return the Generator to service to resolve a reliability issue, in accordance with Section 5.18.4, as the term ‘timely return’ is described in Section 5.18.4.2 of this Services Tariff**.** A Market Participant with a Generator in a Mothball Outage shall provide temporary use of its Generator’s interconnection point, in accordance with Section 5.18.5 of this Services Tariff, when a transmission solution using the Generator’s interconnection point has been selected as the Generator Deactivation Solution, the Gap Solution, or to resolve a reliability issue on a non-New York State Bulk Power Transmission Facility arising during the Generator’s outage. The Transmission Owner shall provide that power to the station remains available notwithstanding its temporary use of the Generator’s interconnection point.

5.18.4 Return to Service of Generators in a Mothball Outage or an ICAP Ineligible Forced Outage to Resolve a Reliability Issue

5.18.4.1 Following: i) notification to a Market Participant that the return to service of its Generator in a Mothball Outage or an ICAP Ineligible Forced Outage for a specified minimum time period has been identified as a Generator Deactivation Solution, a Gap Solution, or to resolve a reliability issue on a non-New York State Bulk Power Transmission Facility arising during the Generator’s outage; and ii) an order establishing compensation for such return from the Federal Energy Regulatory Commission (“Compensation Order”), the Market Participant shall timely return the Generator to service, as the term "timely return" is defined in Section 5.18.4.2 of this Services Tariff.

5.18.4.1.1 Except for Generators selected through the Generator Deactivation Process, within 30 days of a determination by the ISO and the Market Participant that negotiations on compensation for the return to service of the Market Participant's Generator are at an impasse, the Market Participant may submit a filing to the Federal Energy Regulatory Commission under Section 205 of the Federal Power Act for compensation. No later than ten days after such filing is made, the ISO shall file with the Federal Energy Regulatory Commission an unexecuted compensation agreement that includes the non-rate terms and conditions for the return to service of the Market Participant's Generator.

5.18.4.2 A Market Participant's return to service of its Generator in a Mothball Outage to resolve a reliability issue shall be deemed to be a timely return if such return to service was i**)** within 180 days from the date of the Compensation Order, ii) within the alternate period of time following the date of the Compensation Order pursuant to Section 5.18.3.2, or iii) by such other date agreed to by the parties.

A Market Participant's return to service of its Generator in an ICAP Ineligible Forced Outage to resolve a reliability issue shall be deemed to be a timely return if it is returned to service according to the date established by the Compensation Order; *provided, however,* the Market Participant will not be required to return the Generator to service before its estimated return date unless otherwise agreed.

5.18.4.2.1 A Generator's return to service shall not be untimely if the Generator provided the Transmission Owner with access to its interconnection point and is available for a timely return, and the Transmission Owner is unable to reconnect the Generator within the timeframes provided for a timely return to service, pursuant to Section 5.18.4.2 of this Services Tariff**.**

5.18.5 Temporary Use of Interconnection Point to Resolve a Reliability Issue

5.18.5.1 A Market Participant shall provide a Transmission Owner with temporary use of the interconnection point of its Generator in a Mothball Outage or ICAP Ineligible Forced Outage when a transmission solution using the Generator's interconnection point has been selected as the Generator Deactivation Solution, Gap Solution, or to resolve a reliability issue arising on a non-New York State Bulk Power Transmission Facility during its outage.

5.18.5.2 A Market Participant that provided temporary use of the interconnection point of its Generator in a Mothball Outage or ICAP Ineligible Forced Outage pursuant to Section 5.18.5.1 of this Services Tariff shall be permitted to reconnect its Generator to the transmission system by submitting to the ISO a Notice of Intent to Return that provides the date it intends to return to service which submission shall be provided no later than six months before the expiration of its outage, unless otherwise agreed. A Market Participant that submitted a Notice of Intent to Return and that was not requested to return its Generator to service to resolve a reliability issue pursuant to Section 5.18.4.1 of this Services Tariff during its immediately previous Mothball Outage or ICAP Ineligible Forced Outage, shall be permitted to reconnect at no cost.

The Transmission Owner shall reconnect the Generator on or before the indicated return date using efforts that are timely, consistent with Good Utility Practice and that are otherwise substantially equivalent to those the Transmission Owner would use for its own purposes. The Transmission Owner shall report periodically to the ISO and the Generator on the progress of reconnecting such Generator and shall advise the ISO and the Generator promptly if it expects it will not be able to complete the reconnection of the Generator before its indicated return date.

If the Generator returning to service pursuant to this Section 5.18.5.2 of the Services Tariff is available to return but the Transmission Owner is unable to reconnect the Generator before its outage expires, the outage expiration, and expiration of its CRIS rights, where applicable, will be tolled until the date the Transmission Owner reconnects the Generator notwithstanding the three year period in which CRIS-inactive facilities may maintain CRIS rights pursuant to Section 25.9.3.1 of Attachment S to the OATT; provided, however, the expiration period for transfers of CRIS rights provided in Section 25.9.3.1 of Attachment S to the OATT shall not be tolled.

5.18.6 Retired and Termination of Existing Interconnection Agreements

The classification of a Generator with an interconnection agreement other than a Small Generator Interconnection Agreement (SGIA) or Standard Large Generator Interconnection Agreement (LGIA) as Retired may be grounds for the termination of the interconnection agreement depending on the terms and conditions of the applicable agreement. Any termination of such an interconnection agreement will be effective on the filing with the Federal Energy

Regulatory Commission of a notice of termination, which notice and proposed effective date have been accepted by the Federal Energy Regulatory Commission. Either party to the interconnection agreement may file the notice of termination, as appropriate. If and when termination of the interconnection agreement is effective, access to the Point of Interconnection of the Generator will be available on a non-discriminatory basis pursuant to the NYISO's applicable interconnection and transmission expansion processes and procedures. If the existing interconnection agreement is not terminated, the Retired Generator would retain its right to the specific point of interconnection as provided for in the interconnection agreement and access to this point would not be available for new projects.

The impact on a Generator with a LGIA or SGIA that has been classified as Retired is described in OATT Sections 30 and 32 respectively.

6 Confidentiality

6.1 Access to Confidential Information

The ISO may request, and the Customer shall provide, Confidential Information consistent with the disclosure requirements set forth in the ISO Services Tariff (as provided for below). The ISO shall use reasonable procedures to prevent the disclosure of Confidential Information and shall not publish, disclose or otherwise divulge Confidential Information to any person or entity without the prior written consent of the party supplying such Confidential Information, except as provided for under the ISO Market Monitoring Plan and/or ISO Code of Conduct. The provisions of this section shall not apply to any Confidential Information: (i) which was in the public domain at the time of disclosure hereunder; (ii) which thereafter passes into the public domain by acts other than the acts of the ISO; or (iii) that the ISO is required to make publicly available by the Commission, the PSC or other legal process, or for reliability purposes pursuant to Good Utility Practice.

A Customer may request that the ISO keep confidential from another entity Confidential Information that the other entity does not require to perform its obligations and duties hereunder. The Customer must state in writing that the information is to be treated as Confidential Information and the reasons for treating it as Confidential Information, otherwise information will be treated as non-Confidential Information.

6.2 Use of Confidential Information

The ISO shall use Confidential Information for the exclusive purpose of performing its obligations hereunder and under any Service Agreement. The ISO will treat this information in conformity with the standards of conduct contained in Part 37 of the Commission's Regulations and the Code of Conduct set forth in Attachment F to the ISO OATT.

6.3 Disclosure of Bid Information

Pursuant to Commission requirements, the ISO shall make public Bid information from the Energy, Capacity and Ancillary Services markets, including Bids submitted for Virtual Transactions, but not the names of the bidders making any of these Bids, three months after the Bids are submitted. The ISO shall post the data in a way that permits third parties to track each individual bidder's Bids over time. Prior to such disclosure, Bid information submitted to the ISO by Market Participants shall be considered Confidential Information.

6.4 Survival

This Article 6 will survive the termination of the ISO Services Tariff and any associated Service Agreement.

7 Billing and Payment

7.1 ISO as Counterparty; Right to Net or Set Off; ISO Clearing Account

7.1.1 ISO as Counterparty

The ISO shall be for all purposes the contracting counterparty, in its own name and right, to each Customer for any purchase or sale of any product or service, or for any other transaction, that is financially settled by the ISO under the ISO Tariffs.

7.1.2 Right to Net or Set Off Obligations Owed

Unless otherwise specifically set forth in this ISO Services Tariff, if for any settlement period the ISO is required to pay any amount to the Customer and the Customer is required to pay any amount to the ISO under this ISO Services Tariff or the ISO OATT, such amounts shall be netted, and the party owing the greater aggregate amount shall pay to the other party the difference between the amounts owed. Additionally, all outstanding payment obligations under this ISO Services Tariff and the ISO OATT between the ISO and the Customer may be netted, offset, set off, or recouped, and payment shall be owed as set forth above.

7.1.3 ISO Clearing Account

The ISO will establish one or more accounts (the "ISO Clearing Account") at a bank or other financial institution, and Customers shall make payments to the ISO or receive payments from the ISO through the ISO Clearing Account in accordance with their settlement information provided by the ISO as described in Section 7.2 of this ISO Services Tariff.

The funds held by the ISO in the ISO Clearing Account shall not be commingled with funds held by the ISO in any other ISO accounts.

7.1.4 ISO Liability for Payment

The obligation of the ISO to pay Customers for monies owed for a given settlement period shall be limited so that the aggregate liability of the ISO for such payments does not exceed the sum of (i) the aggregate amount paid to or recovered by the ISO from Customers (including by applying a defaulting Customer's financial security) for that settlement period, and (ii) the amount of funds held by the ISO in the Working Capital Fund. The process for declaring and recovering bad debt losses is set forth in Attachment U to the ISO OATT.

7.2 Billing and Payment Procedures

For purposes of this Section 7.2:

(i) the term "Complete Week Settlement Period" shall mean the seven day period between Saturday and Friday for which all of the days are in the same month; and

(ii) the term "Stub Week Settlement Period" shall mean the six or fewer day period between Saturday and Friday for which all of the days are in the same month.

7.2.1 Billing and Settlement Information

The ISO shall provide settlement and billing information to Customers. The ISO shall inform each Customer that provides or is provided services furnished under this ISO Services Tariff or the ISO OATT of the payments due for such service. Such information shall be made electronically available to the Customer.

7.2.2 Invoicing and Payment

7.2.2.1 Weekly Invoice

On or about each Wednesday, as set forth in ISO Procedures, the ISO shall submit an invoice to a Customer that indicates the net amount owed by or owed to the Customer for those services furnished under this ISO Services Tariff or the ISO OATT for the previous Complete Week Settlement Period or Stub Week Settlement Period that are designated as Weekly Invoice Components in ISO Procedures; *provided, however*, that the net amount owed by or owed to the Customer for those services furnished for a Stub Week Settlement Period that concludes a month shall be included in the next monthly invoice issued in accordance with Section 7.2.2.2 of this ISO Services Tariff.

7.2.2.2 Monthly Invoice

Within five (5) business days after the first day of each month, the ISO shall submit an invoice to a Customer that indicates the net amount owed by or owed to the Customer:

(i) for those services furnished under this ISO Services Tariff or the ISO OATT for a Stub Week Settlement Period that concludes the previous month that are designated as Weekly Invoice Components in ISO Procedures;

(ii) for any adjustments to amounts contained in the weekly invoices issued in the previous month pursuant to Section 7.2.2.1 of this ISO Services Tariff;

(iii) for those services furnished under this ISO Services Tariff or the ISO OATT in the previous month that are designated as Monthly Invoice Components in ISO Procedures;

(iv) for any adjustments to amounts contained in a previously issued monthly invoice that was issued on or about one hundred twenty (120) days prior to the issuance of this invoice; and

(v) for any adjustments to amounts contained in a previously issued monthly invoice as part of the Close-Out Settlement of that monthly invoice pursuant to Section 7.4.1.2 of this ISO Services Tariff.

7.2.2.3 Payment by the Customer

A Customer owing payments on net in its weekly invoice or its monthly invoice shall make those payments to the ISO through the ISO Clearing Account by the second business day after the date on which the weekly invoice or monthly invoice is rendered by the ISO unless otherwise specified in ISO Procedures. In accordance with Section 7.1.2 of this ISO Services

Tariff, the ISO may net any overpayment by the Customer for past estimated charges against current amounts due from the Customer or, if the Customer has no outstanding amounts due, the ISO may pay to the Customer an amount equal to the overpayment.

7.2.2.4 Payment by the ISO

Except as provided in Section 7.1.4 of this ISO Services Tariff, the ISO shall pay all net monies owed to a Customer in its weekly invoice or its monthly invoice from the ISO Clearing Account by the second business day after the due date for Customer payments set forth in Section 7.2.2.3 of this ISO Services Tariff unless otherwise specified in ISO Procedures.

7.2.3 Use of Estimated Data and Meter Data

The ISO may use estimates, including estimated meter data, in whole or in part to settle a weekly or monthly invoice in accordance with ISO Procedures. The ISO shall use meter data submitted to the ISO in accordance with Article 13 of this ISO Services Tariff. Any charges based on estimates shall be subject to true-up in invoices subsequently issued by the ISO after the ISO has obtained the requisite actual information, provided that the ISO shall only true-up charges based on meter data prior to the deadline for finalizing meter data established in Section 7.4 of this ISO Services Tariff. A trued-up charge shall include interest amounts calculated at the rate set forth in Section 7.3 of this ISO Services Tariff from the weekly or monthly due date for the charge until the date of payment of the trued-up amount for that charge.

7.2.4 Method of Payment

All payments by the Customer shall be made by either (i) wire transfer in immediately available funds payable to the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures. All payments by the ISO shall be made either (i) by wire transfer in immediately available funds payable to the Customer by the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures.

7.2.5 TCC Auction Settlements

Notwithstanding Sections 7.2.2.1 and 7.2.2.2 of this ISO Services Tariff, the ISO shall make settlements related to the Centralized TCC Auction and the Reconfiguration Auction as set forth in this Section 7.2.5.

7.2.5.1 The ISO shall submit invoices to, and make settlements with, Transmission Owners in connection with the allocation of Net Auction Revenues in accordance with the timeline set forth in ISO Procedures.

7.2.5.2 Customers owing payments to the ISO as a result of their activity in or related to a Centralized TCC Auction or Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, shall make those payments to the ISO through the ISO Clearing Account in accordance with the timeline set forth in ISO Procedures.

7.2.5.3 Except as provided in Section 7.1.4 of this ISO Service Tariff, the ISO shall pay all net monies owed to Customers as a result of their activity in or related to a Centralized TCC Auction or a Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, from the ISO Clearing Account in accordance with ISO Procedures.

7.2.5.4 Sections 7.2.1, 7.2.3, 7.2.4, and 7.2.6 of this ISO Services Tariff and Section 19.9.6 of Attachment M of the ISO OATT shall apply to settlements calculated in accordance with this Section 7.2.5.

7.2.6 Verification of Payments

The ISO shall verify that all payments owed by Customers in accordance with this ISO Services Tariff and the ISO OATT have been paid to the ISO in a timely manner. If a Customer fails to make a payment within the time period established in Sections 7.2.2.1, 7.2.2.2, and 7.2.5 of this ISO Services Tariff or pays less than the amount due, the ISO shall take measures pursuant to Section 7.5 of this ISO Services Tariff. Except as provided in Section 7.1.4 of this ISO Services Tariff, the ISO shall also ensure that monies owed to Customers in accordance with this ISO Services Tariff and the ISO OATT are paid through the ISO Clearing Account in a timely manner.

7.2.7 Payments for TSCs

Bills and payments for TSCs shall be issued in accordance with the ISO OATT. Accordingly, this Section 7 shall not apply to TSCs.

7.3 Interest on Unpaid Balances

Interest on any unpaid amount whether owed to a Customer or to the ISO (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a (a)(2)(iii). Interest on unpaid amounts shall be calculated from the due date of the bill to the date of payment. Invoices shall be considered as having been paid on the date of receipt of payment by the ISO.

If the ISO is unable to provide settlement information on time due to the action or inaction of the Customer, in addition to any other remedies the ISO may have at law or in equity, the Customer shall pay interest on amounts due, as calculated above, from the first day of the Billing Period following the Billing Period in which charges are accrued to the time of payment of those charges.

7.4 Billing Disputes

This Section 7.4 establishes the process and timeframe for review, challenge, and correction of Customer invoices. For purposes of this Section 7.4, any deadline that falls on a Saturday, Sunday, or holiday for which the ISO is closed shall be observed on the ISO's next business day.

For purposes of this Section 7.4, "finalized" data and invoices shall not be subject to further correction, including by the ISO, except as ordered by the Commission or a court of competent jurisdiction; *provided, however*, that nothing herein shall be construed to restrict any stakeholder's right to seek redress from the Commission in accordance with the Federal Power Act.

Challenges to charges and payments in awards rendered by the ISO to Customers buying or selling TCCs in Centralized TCC Auctions and Reconfiguration Auctions shall be governed by Section 19.10 of Attachment M of the ISO OATT and ISO Procedures and shall not be governed by this Section 7.4.

7.4.1 Settlement Cycle for Services Furnished On and After January 1, 2009

7.4.1.1 ISO Corrections or Adjustments and Customer Challenges to the Accuracy of Settlement Information

Settlement information for services furnished beginning January 1, 2009, and thereafter shall be subject to review, comment, and challenge by a Customer and correction or adjustment by the ISO for errors at any time for up to five (5) months from the date of the initial invoice for the month in which service is rendered as set forth in Section 7.2.2.2 of this ISO Services Tariff and as further provided in Section 7.4.1.2, subject to the following requirements and limitations:

7.4.1.1.1 A Supplier or meter authority may review, comment on, and challenge Generator, tie-line, and sub-zone Load metering data for fifty-five (55) days from the date of the initial invoice for the month in which service is rendered. Following this review period, the ISO shall then have five (5) days to process and correct Generator, tie-line, and sub-zone Load metering data, after which time it shall be finalized.

7.4.1.1.2 The meter authority shall provide to the ISO all LSE bus metering data then available within seventy (70) days from the date of the initial invoice and shall provide any necessary updates to the LSE bus metering data as soon as possible thereafter. The ISO shall post all available LSE bus metering data within approximately seventy-five (75) days from the date of the initial invoice and shall continue to post incoming LSE bus metering data as soon as practicable after it is received.

7.4.1.1.3 The ISO shall post advisory settlement information, including available LSE bus metering data, within ninety (90) days from the date of the initial invoice. Customers may review, comment on, and challenge this settlement information, except for Generator, tie-line, and sub-zone Load metering data, after which the ISO shall process and correct the data and issue a corrected invoice with the regular monthly invoice issued on or about one hundred twenty (120) days from the date of the initial invoice. Following the ISO's issuance of a corrected invoice, Customers may continue to review, comment on, and challenge their settlement information, excepting Generator, tie-line, and sub-zone Load metering data, until the end of the five-month review period.

7.4.1.1.4 The meter authority shall provide to the ISO any final updates or corrections to LSE bus metering data within one hundred thirty (130) days from the date of the initial invoice. The ISO shall then post any updated and corrected LSE bus metering data within one hundred thirty-five (135) days from the date of the initial invoice. Customers may then review, comment on, and challenge the LSE bus metering data for an additional ten (10) days. Following this review period, the ISO shall have five (5) days to process and correct the LSE bus metering data, after which it shall be finalized.

The ISO shall use reasonable means to post metering revisions for review by Customers and to notify Customers of the approaching expiration of review periods. To challenge settlement information contained in an invoice, a Customer shall first make payment in full, including any amounts in dispute. Customer challenges to settlement information shall: (i) be submitted to the ISO in writing, (ii) be clearly identified as a settlement challenge, (iii) state the basis for the Customer's challenge, and (iv) include supporting documentation, if applicable. The ISO shall notify all Customers of errors identified and the details of corrections or adjustments made pursuant to this Section 7.4.1.1.

7.4.1.2 Review and Correction of Challenged Invoices

The ISO shall evaluate a settlement challenge as soon as possible within two (2) months following the conclusion of the challenge period specified in Section 7.4.1.1; *provided, however*, the ISO may, upon notice to Customers within this time of extraordinary circumstances requiring a longer evaluation period, take up to six (6) months to evaluate a settlement challenge. The ISO shall not be limited to the scope of Customer challenges in its review of a challenged invoice and may, at its discretion, review and correct any other elements and intervals of a challenged invoice, except Load and meter data as specified in Section 7.4.1.1. Corrections to a challenged invoice shall be applied to all Customers that were or should have been affected by the original settlement and shall not be limited to the Customer challenging the invoice; *provided, however*, that the ISO may recover *de minimis* amounts or amounts that the ISO is unable to collect from individual Customers through Rate Schedule 1 of this ISO Services Tariff.

Upon completing its evaluation, the ISO shall provide written notice to the challenging Customer of the ISO's final determination regarding the Customer's settlement challenge. If the ISO determines that corrections or adjustments to a challenged invoice are necessary and can quantify them with reasonable certainty, the ISO shall provide all Customers with the details of the corrections or adjustments within the timeframe established in this Section 7.4.1.2. The ISO shall then provide a period of twenty-five (25) days for Customers to review the corrected settlement information and provide comments to the ISO regarding the implementation of those corrections or adjustments; *provided, however*, that in the event of a dispute resolution proceeding conducted in accordance with Section 7.4.2 of this ISO Services Tariff, this twenty-five (25) day period shall not start or, if it has already started, shall be suspended until the conclusion of the dispute resolution proceeding. Following the conclusion of the dispute resolution proceeding, the ISO shall make any corrections to Customers' settlement invoices that it determines to be necessary and shall then start or re-start the twenty-five (25) day Customer comment period.

If no errors in the implementation of corrections or adjustments are identified during the twenty-five (25) day Customer comment period, the ISO shall issue a finalized close-out settlement ("Close-Out Settlement"), clearly identified as such, in the next regular monthly billing invoice. If an error in the implementation of a correction or adjustment is identified during the twenty-five (25) day Customer comment period, the ISO shall have one (1) month to make such further corrections as are necessary to address the error and provide Customers with one additional period of twenty-five (25) days to review and comment on the implementation of those further corrections. If an error in the implementation of those further corrections is identified, the ISO shall then have one (1) month to make any final corrections that are necessary and shall issue a finalized Close-Out Settlement in the next regular monthly billing invoice.

7.4.2 Expedited Dispute Resolution Procedures for Unresolved Settlement Challenges

7.4.2.1 Applicability of Expedited Dispute Resolution Procedures

This Section 7.4.2 establishes expedited dispute resolution procedures applicable to address any dispute between a Customer and the ISO regarding a Customer settlement that was not resolved in the ordinary settlement review, challenge, and correction process; *provided, however*, that nothing herein shall restrict a Customer or the ISO from seeking redress from the Commission in accordance with the Federal Power Act.

A Customer may request expedited dispute resolution if it has previously presented a settlement challenge consistent with the requirements of Section 7.4.1.1 of this ISO Services Tariff and has received from the ISO a final, written determination regarding the settlement challenge pursuant to Section 7.4.1.2 of this ISO Services Tariff. The scope of an expedited dispute resolution proceeding shall be limited to the subject matter of the Customer's prior settlement challenge. Customer challenges regarding Generator, tie-line, sub-zone Load, and LSE bus metering data shall not be eligible for formal dispute resolution proceedings under this ISO Services Tariff. To ensure consistent treatment of disputes, separate requests for expedited dispute resolution regarding the same issue and the same service month or months may be resolved on a consolidated basis, consistent with applicable confidentiality requirements.

7.4.2.2 Initiation of Expedited Dispute Resolution Proceeding

To initiate an expedited dispute resolution proceeding, a Customer shall submit a written request to the ISO Chief Financial Officer within eleven (11) business days from the date that the ISO issues a final, written determination regarding a Customer settlement challenge pursuant to Section 7.4.1.2 of this ISO Services Tariff. A Customer's written request for expedited dispute resolution shall contain: (i) the name of the Customer making the request, (ii) an indication of other potentially affected parties, to the extent known, (iii) an estimate of the amount in controversy, (iv) a description of the Customer's claim with sufficient detail to enable the ISO to determine whether the claim is within the subject matter of a settlement challenge previously submitted by the Customer, (v) copies of the settlement challenge materials previously submitted by the Customer to the ISO, and (vi) citations to the ISO Tariffs and other relevant materials upon which the Customer's settlement challenge relies.

The ISO Chief Financial Officer shall acknowledge in writing receipt of the Customer's request to initiate an expedited dispute resolution proceeding. If the ISO determines that the proceeding would be likely to aid in the resolution of the dispute, the ISO shall accept the Customer's request and provide written notice of the proceeding to all Customers through the ordinary means of communication for settlement issues. The ISO shall provide written notice to the Customer in the event that the ISO declines its request for expedited dispute resolution.

7.4.2.3 Participation by Other Interested Customers

Any Customer with rights or interests that would be materially affected by the outcome of an expedited dispute resolution proceeding may participate; *provided, however*, that a Customer seeking or supporting a change to the NYISO's determination regarding a Customer settlement challenge must have previously raised the issue in a settlement challenge consistent with the requirements of Section 7.4.1.1 of this ISO Services Tariff. To participate, such Customer shall submit to the ISO Chief Financial Officer a written request to participate that meets the requirements for an initiating request for expedited dispute resolution within eleven (11) business days from the date that the ISO issues notice of the expedited dispute resolution proceeding. If the ISO determines that the Customer has met the requirements of this Section 7.4.2.3, the ISO will accept the Customer's request to participate in the dispute resolution proceeding.

7.4.2.4 Selection of a Neutral

As soon as reasonably possible following the ISO's acceptance of a Customer's request for expedited dispute resolution under Section 7.4.2.2, the ISO shall appoint a neutral to preside over the proceeding by randomly selecting from a list (i) provided to the ISO by the American Arbitration Association or (ii) developed by the ISO with input from the appropriate stakeholder committee, until an available neutral is found. To the extent possible, the neutral shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues and the financial settlement of electric markets.

No person shall be eligible to act as a neutral who is a past or present officer, employee, or consultant to any of the disputing parties, or of an entity related to or affiliated with any of the disputing parties, or is otherwise interested in the matter in dispute except upon the express written consent of the parties. Any individual appointed as a neutral shall make known to the disputing parties any such disqualifying relationship or interest and a new neutral shall be appointed, unless express written consent is provided by each party.

7.4.2.5 Conduct of the Expedited Dispute Resolution Proceeding

The neutral shall schedule the initial meeting of the disputing parties within five (5) business days of appointment. Except as otherwise provided in this Section 7.4.2, the neutral shall have discretion over the conduct of the dispute resolution process including, but not limited to: (i) requiring the disputing parties to meet for discussion, (ii) allowing or requiring written submissions, (iii) establishing guidelines for such written submissions, and (iv) allowing the participation of Customers that have requested an opportunity to be heard.

Within sixty (60) days of the appointment of the neutral, if the dispute has not been resolved, the neutral shall provide the disputing parties with a written, confidential, and non-binding recommendation for resolving the dispute. The disputing parties shall then meet in an attempt to resolve the dispute in light of the neutral's recommendation. If the disputing parties have not resolved the dispute within ten (10) days of receipt of the neutral's recommendation, the dispute resolution process will be concluded.

Neither the recommendation of the neutral, nor statements made by the neutral or any party, including the ISO, or their representatives, nor written submissions prepared for the dispute resolution process, shall be admissible for any purpose in any proceeding.

7.4.2.6 Allocation of Costs

Each party to a dispute resolution proceeding shall be responsible for its own costs incurred during the process and for a pro rata share of the costs of a neutral.

7.5 Customer Default

7.5.1 Events of Default

An event of default ("Default") shall occur in the event a Customer (the "Defaulting Party") shall:

(i) fail to comply with the ISO's creditworthiness requirements and receive notice of such failure;

(ii) fail to comply with Section 8.4 of this Tariff;

(iii) make an assignment or any general arrangement for the benefit of creditors;

(iv) fail to timely make a payment due to the ISO, regardless of whether such payment is in dispute, and receive notice from the ISO of such failure;

(v) fail to cure its default in another independent system operator/regional transmission organization market;

(vi) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a case, petition, proceeding, or cause of action under any bankruptcy or insolvency law or similar law for the protection of debtors or creditors, or have such a petition, case, proceeding or cause of action filed or commenced against it and such case, petition, proceeding or cause of action is not withdrawn or dismissed within thirty (30) days after such filing or commencement;

(vii) otherwise become bankrupt or insolvent (however evidenced);

(viii) be unable or unwilling to pay its debts to third parties as they fall due;

(ix) otherwise become adjudicated a debtor in bankruptcy or insolvent (however evidenced);

(x) be unable (or admits in writing its inability) generally to pay its debts as they become due;

(xi) be dissolved (other than pursuant to a consolidation, acquisition, amalgamation or merger);

(xii) have a resolution passed for its winding-up official management or liquidation (other than pursuant to a consolidation, acquisition, amalgamation or merger);

(xiii) seek or become subject to the appointment of an administrator, provisional liquidator, conservator, assignee, receiver, trustee, custodian or other similar entity or official for all or substantially all of its assets;

(xiv) have a secured party take possession of all or substantially all of its assets or has a distress, levy, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all of its assets and such secured party maintains possession, or any such process is not dismissed, discharged, stayed or restrained, in each case within thirty (30) days thereafter;

(xv) cause or subject to any event with respect to which, under the applicable laws of any jurisdiction, said event has an analogous effect to any of the events specified in clauses (iv) to (xii) (inclusive);

(xvi) take any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts; or

(xvii) fail to perform any material covenant set forth in the Tariff or a Service Agreement (other than the events that are otherwise specifically covered in this Section as a separate Event of Default), and such failure is not excused by Force

Majeure or cured within five (5) business days after written notice thereof to the Defaulting Party;

7.5.2 Cure

Unless otherwise provided in Attachment K to this Services Tariff:

(i) A Defaulting Party shall have one (1) business day to cure a Default resulting from its failure to timely make a payment due to the ISO.

(ii) A Defaulting Party shall have two (2) business days to cure a Default resulting from its failure to comply with the ISO's creditworthiness requirements; *provided*, *however*, that a Customer shall have one (1) business day to cure a default resulting from its failure to comply with the ISO's creditworthiness requirements following termination of a Prepayment Agreement.

7.5.3 ISO Remedies

In addition to any and all other remedies available under the ISO Tariffs or pursuant to law or equity, the ISO shall have the following remedies:

(i) **Default.** Upon an event of Default and expiration of any cure period, the ISO shall have the right to suspend and/or terminate service to the Defaulting Party and the Service Agreement between the ISO and the Defaulting Party immediately upon notice to the Commission. In addition, in the event of a payment default, the ISO shall have the sole and exclusive right to initiate debt collection procedures against a Customer on account of any such default. The process for declaring and recovering bad debt losses is set forth in Attachment U to the ISO OATT.

(ii) **Financial Distress.** In the event of a reduction in the amount of a Customer's Unsecured Credit (a) by fifty percent (50%) or more as determined in accordance with Section 26.5 of Attachment K to the ISO Services Tariff, or (b) as a result of a material adverse change as determined in accordance with Section 26.14 of Attachment K to the ISO Services Tariff, then the ISO shall have the right to: (1) immediately issue an invoice to such Customer requiring payment within two (2) business days from the invoice date for initial settlements representing the sum of that Billing Period's daily billing data available as of the invoice date, and/or (2) require such Customer to prepay estimated charges weekly for up to twelve months in accordance with ISO Procedures.

(iii) **Default in Another ISO/RTO.** In the event a Customer fails to cure its default in another independent system operator/regional transmission organization market, then the ISO shall have the right to: (1) demand immediate payment by the Customer to the ISO for any amounts owed as of the date of the demand, and/or (2) require the Customer to prepay estimated charges weekly for a minimum of twelve months in accordance with ISO Procedures, and/or (3) reduce or eliminate the amount of the Customer's Unsecured Credit.

(iv) **Two Late Payments**. In the event a Customer fails to pay its invoice when due on two occasions within a rolling twelve (12) month period, then the ISO shall have the right to: (1) require the Customer to prepay estimated charges weekly, based on the charges incurred by the Customer in the previous week, for up to twelve months, and/or (2) reduce or eliminate the amount of the Customer's Unsecured Credit for up to twelve (12) months.

7.5.4 Forward Contracts

By entering into Transactions under this Tariff, the Customer agrees that its Service Agreement and Transactions under this Tariff shall constitute a "forward contract" within the meaning of the United States Bankruptcy Code.

7.5.5 Notice to Customers

The ISO shall notify all Customers in the event that a Customer is in default and shall also notify all Customers in the event that the Customer subsequently cures the default or the ISO terminates the Customer due to the default. In the event of a payment default or creditworthiness default, the ISO will disclose in its notice to Customers the approximate amount of the default as follows:

Default Amount	Type of Default	
Range	Payment	Creditworthiness
$0 to $100,000		
$100,001 to $500,000		
$500,001 to $1,000,000		
$1,000,001 to $5,000,000		
$5,000,001 to $10,000,000		
> $10,000,000		

In addition, in the event of a payment default, unless otherwise precluded, the ISO will also disclose the amount and type of collateral, if any, held by the ISO to secure the defaulting Customer's obligations to the ISO.

7.6 Survival

This Article 7 will survive the termination of the ISO Services Tariff and any associated Service Agreement.

8 Eligibility For ISO Services

In order to participate in any ISO-Administered Market or to be a Primary Holder of a TCC, a Customer must satisfy the applicable requirements of this Article 8 and Attachment K to this Services Tariff, including the minimum participation criteria set forth in Section 26.1 of Attachment K.

8.1 Requirements Common to all Customers

8.1.1 Creditworthiness

All Customers and applicants seeking to become a Customer shall be subject to the creditworthiness requirements contained in Attachment K to this Services Tariff, including the minimum participation criteria set forth in Section 26.1 of Attachment K.

8.1.2 Completed Application and Minimum Technical Requirements

A Customer shall submit a Completed Application in accordance with Article 9 and shall receive ISO approval prior to obtaining any services under the ISO Services Tariff. A Customer also shall demonstrate to the ISO's reasonable satisfaction that it is capable of performing all functions required by the ISO Services Tariff including operational communications, financial and Settlement requirements.

8.1.3 Additional Eligibility Requirements for all Customers

All Customers and applicants seeking to become a Customer shall at all times be:

(a) an "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act; or

(b) an "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR 1.3(m); or

(c) a "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in paragraph 5(g) of the Final Order of the Commodity Futures Trading Commission at 78 FR 19879.

Each Customer must demonstrate compliance with the requirements of this Section 8.1.3 by submitting to the ISO on or before September 15, 2013 an officer's certificate, in a form acceptable to the ISO, that (i) certifies under penalty of perjury that the Customer is now and will remain in compliance with this requirement, (ii) further certifies that if it no longer satisfies this requirement it shall immediately notify the ISO and immediately cease all participation in the ISO-Administered Markets; (iii) is signed by an authorized officer of Customer, and (iv) is notarized.

Each applicant seeking to become a Customer must demonstrate compliance with the requirements of this Section 8.1.3 by submitting to the ISO with its Completed Application an officer's certificate, in a form acceptable to the ISO, that (i) certifies under penalty of perjury that the applicant is now and will remain in compliance with this requirement, (ii) further certifies that if it no longer satisfies this requirement it shall immediately notify the ISO and cease all participation in the ISO-Administered Markets (iii) is signed by an authorized officer of applicant, and (iv) is notarized.

In the event a Customer or applicant seeking to become a Customer experiences a change that results in the Customer or applicant no longer satisfying the requirements of this Section 8.1.3, the Customer or applicant shall immediately notify the ISO of this change, and the Customer shall immediately cease all participation in the ISO-Administered Markets.

8.2 Additional Requirements Applicable to Suppliers

In addition to the requirements set forth in Section 8.1 above, Suppliers shall satisfy the communication requirements of Article 4 and the metering requirements of Article 13 prior to entering into a Transaction with the ISO.

8.3 Additional Requirements Applicable to LSEs

In addition to the requirements set forth in Section 8.1 above, each LSE shall satisfy the following requirements prior to taking services under the Tariff:

8.3.1 All requirements and conditions contained within an approved retail access plan in the service territory of the Transmission Owner in which the LSE's Load is located, which retail access plan has been approved by the PSC or other appropriate authority or, in the case of the LIPA, has been approved by the Trustees of the Long Island Power Authority.

8.3.2 All New York State application and license requirements, and any other authorization required by New York State to serve retail Load; and

8.3.3 The LSE must be: (a) aggregating or serving Load that is of an amount greater than or equal to one (1) MW in each hour as measured between a single Point of Injection and a single Point of Withdrawal; or (b) making purchases from the ISO Administered Markets at a single bus of an amount greater than or equal to one (1) MW in each hour.

8.4 Eligibility to Obtain Services Under This Tariff In Response To Sales Tax Issues

8.4.1 In addition to any other requirements set forth in this Tariff, every Customer and every agent of a Customer ("Agent") seeking to purchase any services under this Tariff shall supply to the ISO and have on file with the ISO at the time the

Customer or Agent commences such purchases the following:

8.4.1.1 If the Customer is registered or required to be registered with the New York State Department of Taxation and Finance under Articles 28 and 29 of the New York State Tax Law, or, if the Customer is a non-New York State purchaser, a valid, properly completed New York State exemption document, for example, without limitation, a Resale Certificate, an exempt organization certificate, an exempt purchase certificate or a direct pay permit, issued in accordance with New York State Tax Law; or in the case of a Customer that is a non-New York State purchaser, a written statement of such Customer, sworn to or affirmed under penalties of perjury by the principal executive officer of such Customer, stating its name and address and certifying that the Customer is a non-New York State purchaser, that is not registered or required to be registered with the New York State Department of Taxation and Finance under Articles 28 and 29 of the New York State Tax Law and is not qualified for any New York State Exemption Document, that it makes no purchase of electricity or other tangible personal property or services in markets administered by the ISO for resale or for its own use in New York State and that it makes no retail sales of electricity or other tangible personal property or services in New York State; or

8.4.1.2 If the Customer is not required to register, and is not registered, for sales and compensating use tax purposes under Articles 28 and 29 of the New York State Tax Law, and is not a Customer described in paragraph (A)(3) of this Section 8.4, a valid, properly completed exempt organization certificate issued in accordance with New York State Tax Law; or

8.4.1.3 If the Customer is an entity described in paragraphs one, two or three of subdivision (a) of Section 1116 of the New York State Tax Law, evidence satisfactory under such law that it is such an entity and it is not subject to New York State and local sales and compensating use taxes on its purchases of services under this Tariff; or

8.4.1.4 If the person or entity seeking to make a purchase under this Tariff is an Agent, (a) the appropriate documents described above that its principal would be required to supply and have on file with the ISO if it were making the purchase directly and (b) evidence satisfactory under the New York State Tax Law to establish that person's or entity's status as Agent.

8.4.2 Customer's change in status.

8.4.2.1 If a Customer's certificate of authority issued under Articles 28 and 29 of the New York State Tax Law is revoked, suspended, cancelled, surrendered or otherwise terminated or expires or,

8.4.2.2 If a Customer's status as an exempt organization under New York State Tax Law is revoked, suspended, cancelled, surrendered or otherwise terminated or expires, or,

8.4.2.3 If a Customer is no longer eligible to rely on the exemption document, exempt organization certificate or other satisfactory evidence it furnished to the ISO, that Customer shall immediately notify the ISO of its change in status and shall furnish to the ISO all other information the ISO may require to enable it to comply with its obligations under this Tariff and New York State Tax Law.

8.4.3 Agent's change in status.

8.4.3.1 If an Agent's certificate of authority issued under Articles 28 and 29 of the New York State Tax Law is revoked, suspended, cancelled, surrendered or otherwise terminated or expires or,

8.4.3.2 If an Agent's relationship with a Customer is revoked, suspended, cancelled, surrendered or otherwise terminated or expires, that Agent or former Agent shall immediately notify the ISO of its change in status and shall furnish to the ISO all other information the ISO may require to enable that Agent to comply with its obligations under this Tariff and New York State Tax Law.

8.4.4 Regardless of whether a Customer or its Agent or former Agent notifies the ISO of any change in status, as described in Sections 8.4.2 and 8.4.3 of this Tariff, of either the Customer or of the Agent or former Agent, a change in status, as described in Sections 8.4.2 and 8.4.3 of this Tariff, shall, from the time of its occurrence, be a Default under Section 7.5 of this Tariff and the Customer or Agent, as the case may be, as a Defaulting Party, shall, from the time of that change in status, be required to pay any State and local sales taxes lawfully imposed on its purchases. A Defaulting Party shall have ten days from its change in status to cure the Default and to notify the ISO that it has so cured the Default. Regardless of whether the ISO has notice of any change in status from the affected Customer, Agent or from a third party, such as the New York State Commissioner of Taxation and Finance, as of the date of Default, the Customer or its Agent on the Customer's behalf shall continue to be allowed to purchase services under this Tariff for ten days from the time that the ISO has actual notice of a change in status.

8.4.5 Immediately upon the ISO receiving notice from a Customer or its Agent described in Sections 8.4.2 and 8.4.3 of this Tariff, or immediately upon learning that a Customer's or its Agent's status has changed as described in Sections 8.4.2 and 8.4.3 of this Tariff, the ISO shall notify the New York State Commissioner of Taxation and Finance of the name, address and federal identifying number of the Customer, and of any Agent of such a Customer, and of the change of status; and the ISO shall keep records of the type, quantity, price, etc. of services any such Customer purchases, or has purchased on its behalf by any Agent, after a change in status; and the ISO shall furnish such information to the Commissioner of Taxation and Finance in such form as the Commissioner requests.

8.4.6 If a Defaulting Party has not cured its Default prior to the expiration of the ten day period described in Section 8.4.4 of this Tariff, in addition to any and all other remedies available under this Tariff or pursuant to law or in equity, the ISO shall have the right to suspend and/or terminate the Defaulting Party's Service Agreement immediately upon notice to the Commission.

9 Application And Registration Procedure

9.1 Application

Each Customer requesting to schedule, take or provide any services under the ISO Services Tariff must apply to the ISO in writing at least sixty (60) days in advance of the month in which service is to commence. The ISO will consider requests for such services on shorter notice when feasible. Service commencement will depend on the ISO's ability to accommodate the request. To apply, the Customer shall complete and deliver a Service Agreement (in the form of Attachment A) and an Application to the ISO.

9.2 Completed Application

A Completed Application shall provide all of the information reasonably required by the ISO to permit the ISO to perform its responsibilities under the ISO Services Tariff. A Customer taking or providing service under the Tariff shall provide the ISO, upon application for service, with a list identifying its parent company as well as any Affiliate. The Customer shall notify the ISO within 30 days of the effective date of any change to the original list. Any Customer shall notify the ISO within 30 days of the effective date of any change to the original list. Any Customer shall respond within 10 days to a request by the ISO to update the list of Affiliates and/or parent company. In addition, a Customer and an applicant seeking to become a Customer shall inform the ISO of any Affiliates that are currently taking service or applying to take service under the Tariffs. The ISO shall treat the information provided in the Application as Confidential Information except to the extent that disclosure of the information is required by the ISO Services Tariff, by regulatory or judicial order or for reliability purposes pursuant to Good Utility Practice. The ISO also shall treat the information in conformity with the standards of conduct contained in Part 37 of the Commission's Regulations and the Code of Conduct set forth in Attachment F to the ISO OATT.

9.3 Approval of Application and/or Notice of Deficient Application

The ISO will promptly review the Application and may request additional information to determine whether the applicant meets the ISO's minimum financial and technical requirements. The ISO will notify the applicant within thirty (30) days of receipt of a Completed Application. If the ISO rejects an Application, the ISO shall provide a written explanation within fourteen (14) days of the rejection. The ISO will attempt to remedy minor deficiencies in the Application through informal communications with the applicant. If such efforts are unsuccessful, the ISO shall return the Application.

9.4 Filing of Service Agreement

The ISO will file Service Agreements with the Commission in compliance with applicable Commission regulations and the ISO Services Tariff.

10 Recordkeeping and Audit

The ISO and each Customer shall keep complete and accurate records of service taken or provided under the ISO Services Tariff including, but not limited to, meter readings (if any), dispatch logs, Bid data and other memoranda of Applications and service. Upon thirty (30) days prior written notice, and subject to the provisions in Article 6, the Customer, the ISO, the applicable Transmission Owner, the NYSRC, the Commission or the PSC shall have the right to inspect all records, meter readings and memoranda for the purpose of ascertaining the accuracy of all settlement information prepared pursuant to Article 7 and in compliance with the provisions of the ISO Services Tariff and the Reliability Rules. These inspections shall be performed in a reasonable manner and so as to avoid disrupting the business of the party whose records are being inspected. The costs of all these inspections, including the costs of the party whose records are being inspected, shall be borne by the inspecting party, except that there shall be no charge to the PSC or the Commission for such inspections or for the costs associated with such inspections. Historical records shall be kept as follows: (i) settlement information rendered under the ISO Services Tariff shall be maintained for at least twenty-four (24) months from the date that settlement information is rendered; (ii) Applications under the ISO Services Tariff shall be maintained for twelve (12) months after the date of termination of the service or twelve (12) months after the Application was rejected; and (iii) any other records associated with service under the ISO Services Tariff that are not listed above shall be maintained for twelve (12) months after the date of termination of the service.

11 Dispute Resolution Procedure

11.1 Purpose and Applicability of Dispute Resolution Procedure

11.1.1 Purpose and General Provisions

A party, or parties, and the ISO, having a dispute involving service under the ISO Market Administration and Control Area Services Tariff ("Services Tariff") or the Open Access Transmission Tariff ("OATT"), ISO Procedures, or any Agreement entered into under either Tariff**,** may utilize the provisions of this Section 11 for resolution. The purpose of the dispute resolution processes provided herein is to avoid litigation when possible, and to pursue resolution of the dispute in the most cost-effective and prompt method possible.

Nothing herein restricts the rights of any party or the ISO to file a complaint or seek any other remedy from the Commission under the relevant provisions of the Federal Power Act.

11.1.2 Exceptions

This Article 11 shall not apply to the following disputes, which shall be resolved in accordance with the provisions of the ISO Tariffs, or otherwise, as indicated below:

(i) disputes regarding the Standard Large Facility Interconnection Procedures or Standard Large Generator Interconnection Agreement, which disputes shall be governed by Attachment X to the ISO OATT, or disputes regarding the Small Generator Interconnection Procedures or Standard Small Generator Interconnection Agreement, which disputes shall be governed by Attachment Z to the ISO OATT;

(ii) disputes regarding the Local Transmission Planning Procedures, which disputes shall be governed by Section 31.2.1.3 of Attachment Y to the ISO OATT;

(iii) disputes over cost estimates provided in interconnection agreements as provided in Attachment S, which disputes shall be resolved under the interconnection agreement;

(iv) disputes regarding a Customer's settlements that were not resolved in the ordinary settlement review, challenge, and correction process, which disputes shall be governed by Section 7.4 of this ISO Services Tariff or Sections 2.7.4.2 or 2.7.4.3 of the ISO OATT;

(v) disputes regarding certain ICAP-related issues that Section 5 of the ISO Services Tariff expressly indicates shall be governed by other provisions of the ISO Services Tariff;

(vi) disputes regarding Centralized TCC Auction or Reconfiguration Auction awards, which disputes shall be governed by Attachment M, Section 19 of the ISO OATT;

(vii) disputes involving applications for changes in rates, changes in terms or conditions of service, or other changes to the ISO Tariffs, ISO Procedures, or agreements to which the ISO is a party and disputes that may result in an obligation to transmit electricity under circumstances where the Commission is precluded from ordering transmission service pursuant to FPA Section 212(h). Parties with these disputes have exclusively those rights provided for under the FPA or otherwise provided by law and have no right to invoke dispute resolution processes under this Section 11.

11.2 Initiation of Dispute Resolution Proceedings

11.2.1 Notice of Dispute

In the event of a dispute that the party or parties have been unable to resolve, any party or parties may initiate a dispute resolution proceeding pursuant to this Article 11 ("Dispute Resolution Proceeding") by submitting a written notice to the ISO. The written notice shall describe the dispute in detail and set forth the factual and legal assertions underlying the dispute (including specific reference to applicable provisions of the ISO Tariffs, or ISO Procedures, or relevant Service Agreements), and shall designate one or more authorized representatives of each of the party or parties initiating the dispute to participate in the Dispute Resolution Proceeding on their behalf.

11.2.2 Parties to Dispute Resolution Proceeding

The party or parties initiating the dispute pursuant to the provisions of Section 11.2.1 and the ISO shall be parties to the Dispute Resolution Proceeding ("Parties").

11.3 Informal Discussions

Within thirty (30) days of written notice of the dispute pursuant to Section 11.2.1, senior representative(s) of each Party shall attempt in good faith to fully and finally resolve the dispute through informal discussions.

11.4 Available Formal Proceedings

In the event the Parties are unable, through informal discussions in accordance with Section 11.3 to resolve the dispute within thirty (30) days after the NYISO receives written notice of the dispute, then:

11.4.1

Upon their express written agreement, the Parties may submit all or some portion of the dispute to non-binding mediation as specified in Section 11.5; or

11.4.2

The Parties, upon their express written agreement, may submit all or some portion of the dispute to arbitration as specified in Section 11.6, provided however, if the mediation procedures are used, the Parties may submit all or some portion of the dispute to arbitration only after the conclusion of mediation that does not resolve the dispute; or

11.4.3

The Parties may commence legal proceedings before the Commission, or a court of competent jurisdiction as to any matter not within the primary or exclusive jurisdiction of the Commission, for purposes of adjudicating all or some portion of the dispute; provided, however, that if the Parties agreed in writing to submit the dispute to non-binding mediation, termination of the mediation, as certified in writing by the mediator selected by the parties, is a condition precedent to the commencement of any legal proceeding, except to the extent necessary to preserve a claim subject to expiration under an applicable statute of limitations.

11.5 Non-Binding Mediation

If the Parties agree to submit all or some portion of the dispute to non-binding mediation, as specified in Section 11.4.1, they shall do so either (i) pursuant to a written agreement setting forth or adopting all necessary terms, conditions and rules of procedure governing the mediation as agreed by the Parties, or (ii) pursuant to a written agreement adopting the procedures of 11.5.1 through 11.5.3:

11.5.1 Selection of a Mediator

Within ten (10) days of the Parties' written agreement to mediate, the Parties shall exchange lists of proposed mediators, and the Parties shall seek to agree on a mediator.

Any individual designated as the mediator shall make known to the Parties whether he or she is a past or present officer, employee or consultant to any of the Parties, or of any entity related to or Affiliated with any of the Parties or is otherwise interested in the matter to be mediated. Any person with such a relationship shall not be eligible to serve as the mediator, absent the express written consent of all Parties.

If the Parties are unable to agree on a mediator, they shall invoke the assistance of the Commission's Dispute Resolution Service to select a mediator.

11.5.2 Scope of Mediator's Duties

The disputing parties shall attempt in good faith to resolve their dispute in accordance with the schedule established by the mediator but in no event, may the schedule extend beyond ninety (90) days from the date of appointment of the mediator.

The mediator may require the disputing parties to:

1. submit additional written statements of issue(s) and position(s), along with supporting documents or affidavits;
2. meet for discussions; and/or
3. comply with additional mediation procedures designated by the mediator.

If the Parties have not resolved the dispute within ninety (90) days after the date the mediator was appointed, then the mediator shall promptly provide the Parties with a written, confidential, non-binding recommendation to resolve the dispute. The recommendation shall include an assessment by the mediator of the merits of the principal positions being advanced by each of the Parties . The Parties shall then meet in a good faith attempt to resolve the dispute in light of the mediator's recommendation. This recommendation shall be limited to resolving the specific issues presented for mediation.

The recommendation of the mediator, and any other statements made by any Party during the mediation process, shall not be admissible for any purpose, in any subsequent proceeding.

11.5.3 Costs

Each Party will bear an equal share of the costs associated with the time, expenses and other charges of the mediator. Each Party shall bear its own costs, including attorney and expert fees.

11.6 Arbitration

If the Parties agree in writing to submit all or some portion of the dispute to arbitration as specified in Section 11.4.2, they shall do so either (i) pursuant to a written agreement invoking the assistance of the Commission Dispute Resolution Service in reaching an agreement on the selection of a neutral arbitrator or arbitrators, and the adoption of all necessary terms, conditions and rules of procedure to govern an arbitration or other resolution of the dispute, or (ii) pursuant to a written agreement adopting the procedures of 11.6.1. Only if all Parties include in their agreement, submitting all or a portion of their dispute to arbitration, that the decision of the arbitrator shall be final and binding on the Parties, shall such decision be final and binding on the Parties whether they choose to pursue the arbitration pursuant to 11.6(i) or 11.6(ii).

11.6.1 Procedural Provisions

11.6.1.1 Selection of an Arbitrator

Within ten (10) days of the date the Parties submit a written agreement to invoke the arbitration provisions of this Section 11.6, and unless such written agreement has invoked the Commission's Dispute Resolution Service pursuant to Section 11.6, the Parties shall exchange lists of qualified arbitrators. No person shall be eligible for selection as an arbitrator who is a past or present officer, employee of or consultant to any of the Parties, or of an entity related to or affiliated with any of the Parties, or is otherwise interested in the matter to be arbitrated, except upon the express written consent of the Parties. Any individual designated as an arbitrator shall make known to the Parties any such disqualifying relationship or interest and a new arbitrator shall be designated, unless express written consent is provided by each Party.

If the Parties cannot agree upon an arbitrator, the Parties shall invoke the services of the Commission's Dispute Resolution Service in the selection of an arbitrator.

11.6.1.2 Scope of Arbitrator's Duties

The arbitrator shall have no power to modify or change any agreement, tariff or rule or otherwise create any additional rights or obligations for any Party. The scope of the arbitrator's decision shall be limited to the issues presented for arbitration. The arbitrator shall determine discovery procedures, intervention rights, how evidence shall be taken, what written submittals may be made, and other such procedural matters, taking into account the complexity of the issues involved, the extent to which factual matters are disputed, and the extent to which the credibility of witnesses is relevant to a resolution. Each Party shall produce all evidence determined by the arbitrator to be relevant to the issues presented. To the extent such evidence involves proprietary or Confidential Information, the arbitrator may issue an appropriate protective order which shall be complied with by all Parties. The arbitrator may elect to resolve the arbitration matter solely on the basis of written evidence and arguments.

The arbitrator shall consider all issues underlying the dispute, and the arbitrator shall take evidence submitted by the Parties in accordance with procedures established by the arbitrator and may request additional information including the opinion of recognized technical bodies or experts. The Parties shall be afforded a reasonable opportunity to rebut any such additional information.

Absent agreement to the contrary by all Parties, no person or entity that is not among the Party or Parties initiating the dispute pursuant to Section 11.2.1 of this Tariff shall be permitted to intervene, but see Section 11.7 concerning consolidation of separate disputes.

11.6.2 The Arbitration Decision

Within ninety (90) days of the appointment of the arbitrator, and after providing the parties with an opportunity to be heard, the arbitrator shall render a written decision, including findings of fact and the legal basis for the decision. The arbitrator will follow the Commercial Arbitration Rules of the American Arbitration Association.

If the arbitrator concludes that no proposed award is consistent with the ISO Services Tariff, the ISO OATT, the FPA and Commission's then-applicable standards and policies, or would address all issues in dispute, the arbitrator may determine no award is available or the arbitrator may develop a compromise solution consistent with the terms of the ISO Services Tariff, the ISO OATT or the FPA. In all cases, the arbitrator shall provide to the Parties a written decision including findings of fact and explaining the basis for the award, the basis for the compromise award or, if no award is available, the basis for the decision that no award is available. No award shall be deemed to be precedential in any other arbitration related to a different dispute.

11.6.3 Costs

All costs associated with the time, expenses and other charges of the arbitrators shall be borne by the unsuccessful Party. Each Party shall bear its own costs, including attorney and expert fees.

11.6.4 Filing and Finality.

All arbitration decisions that affect matters subject to the jurisdiction of the Commission shall be filed with the Commission. Any arbitration decision that affects matters subject to the jurisdiction of the PSC under the PSL may be filed with the PSC. The judgment of the arbitrator, agreed to be final and binding by written agreement of the Parties, pursuant to Section 11.6, may be entered on the award by any court in New York having jurisdiction.

Within one (1) year of the arbitration decision, a Party may request that the Commission or any other federal, state, regulatory or judicial authority (in the State of New York) having jurisdiction over such matter vacate, modify or take such other action as may be appropriate with respect to any arbitration decision that is:

1. based upon an error of law;
2. contrary to the statutes, rules or regulations administered by such authority;
3. violative of the Federal Arbitration Act or Administrative Dispute Resolution Act; or
4. based on conduct by an arbitrator that is violative of the Federal Arbitration Act or Administrative Dispute Resolution Act.

11.7 Consolidation of Related Arbitration Proceedings

Upon the written consent of all Parties who have agreed to arbitration of a dispute pursuant to Sections 11.4.2 and 11.6, and with the consent of all Parties to pending arbitration proceedings commenced pursuant to the same provision, such arbitration proceedings may be consolidated if the disputes in each proceeding (i) arise out of or relate to essentially the same set of facts or fact pattern, series or type of transactions or legal issues, and (ii) are governed by the same provisions of the ISO Tariffs and applicable law, provided however, arbitration proceedings which the Parties have agreed, pursuant to Section 11.6, shall result in a final and binding decision shall be consolidated, to the extent otherwise permitted by this section, only with other arbitration proceedings which the Parties have agreed, pursuant to Section 11.6, shall result in a final and binding decision. Any Party to an arbitration proceeding who agrees to consolidation as provided herein may not, and forever waives any right to, challenge a final award, in whole or in part, whether on appeal or otherwise, on the ground that it was prejudiced or deprived of any right by virtue of the consolidation.

11.8 Ongoing Duty to Perform

The pendency of a Dispute Resolution Proceeding under this Article 11 shall not relieve the Parties of any duty to perform their respective obligations under the ISO Tariffs, ISO Procedures, or relevant agreement.

11.9 Rights Under the Federal Power Act

Nothing in Section 11 of this Tariff shall restrict the rights of any Party to file a complaint, rate or tariff or other contract change with the Commission under the relevant provisions of the Federal Power Act. No arbitrator shall select an award which requires the transmission of electricity under circumstances where the Commission is precluded from ordering Transmission Services pursuant to FPA Section 212(h).

12 Liability and Indemnification

12.1 Force Majeure

The ISO, the NYSRC, the Transmission Owners and any Customer or Market Participant shall not be considered to be in default or breach under the ISO Services Tariff or a Service Agreement, and shall be excused from performance, or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of the ISO Services Tariff or a Service Agreement, except the obligation to pay any amount when due, arising out of or from any act, omission or circumstance occasioned by or in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials, act of the public enemy, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment, or by any other cause or causes beyond such party's reasonable control, including any Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or by the making of repairs necessitated by an Emergency circumstance not limited to those listed above upon the property or equipment of the ISO or any party to the ISO Agreement. Nothing contained in this section shall relieve any entity of the obligation to make payments when due hereunder or pursuant to a Service Agreement. Any party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except the settlement of all labor disturbances shall be in the sole judgment of the affected party.

Nothing contained in this section shall relieve a party to a Service Agreement of its obligations to pay all charges due under the Tariff, even if such charges would not have been due had the party claiming force majeure not experienced the force majeure.

12.2 Claims by Employees and Insurance

Each Transmission Owner, Customer, Market Participant and the ISO shall be solely responsible for and shall bear all of the costs of claims by its own employees, contractors, or agents arising under, and covered by, any workers' compensation law. Each of the parties shall furnish, at its sole expense, such insurance coverage and such evidence thereof, or evidence of self-insurance, as is reasonably necessary to meet its obligations under this section.

12.3 Limitation on Liability

The ISO, Transmission Owners and NYSRC shall not be liable (whether based on contract, indemnification, warranty, tort, strict liability or otherwise, to any Customer, Market Participant, or any third party or other party for any damages whatsoever including, without limitation, direct, incidental, consequential, punitive, special, exemplary or indirect damages resulting from any act or omission in any way associated with a Service Agreement or the ISO Services Tariff, except to the extent that the ISO, Transmission Owner or NYSRC is found liable for gross negligence or intentional misconduct, in which case the ISO, Transmission Owner or NYSRC will not be liable for any incidental, consequential, punitive, special, exemplary or indirect damages. This section, however, does not limit in any way the ISO's obligation to indemnify the Transmission Owners pursuant to the ISO/TO Agreement or any other agreement.

Nothing in the ISO Services Tariff, or any Service Agreement pursuant to the ISO Services Tariff, express or implied, is intended to confer on any person, other than the parties to a Service Agreement, any rights or remedies under or by reason of the ISO Services Tariff.

The protections provided to the ISO, Transmission Owners and NYSRC in this Section 12.3 regarding limitation of liability and damages shall be applicable to Generators acting in good faith to implement or comply with the directives of the ISO, Transmission Owner or

NYSRC.

12.4 Indemnification

For the purpose of this section, the terms Market Participant(s) and Customer(s) shall not include a Transmission Owner with respect to acts or omissions related in any way to the Transmission Owner's ownership or operation of its transmission facilities when such acts or omissions are either (1) pursuant to or consistent with ISO Procedures or direction or (2) in any way related to the Transmission Owner's or the ISO's performance under this Tariff.

Subject to the ISO's obligations to the Transmission Owners under the ISO/TO Agreement and the ISO Agreement, each Customer and Market Participant shall indemnify, save harmless and defend the ISO, the Transmission Owners and the NYSRC including their directors, members, managers, officers, employees, trustees, committee members and agents, or each of them (individually the "Indemnitee" or collectively the "Indemnitees") from and against all claims, demands, losses, liabilities, judgments, damages, and related costs and expenses (including, without limitation, reasonable attorney and expert fees, and disbursements incurred by the Indemnitees in any actions or proceedings between the Indemnitees and a third party, the Customer or Market Participant or any other party) arising out of or related to the Indemnitee's or the Customer's acts or omissions related in any way to performance under the ISO Services Tariff, a Service Agreement, an ISO Related Agreement, or ISO Procedures except to the extent that the Indemnitees are found liable for gross negligence or intentional misconduct.

The ISO will procure insurance or other alternative risk financing arrangements sufficient to cover the risks associated with the carrying out of its responsibilities under this Tariff. The proceeds from such insurance shall be used prior to the invocation by the ISO of its right to indemnification under this section through the Rate Schedule 1 charge. Except to the extent that indemnification of the ISO is required from a particular Market Participant or Customer because of the acts or omissions of that Market Participant or Customer, indemnification of or by the ISO shall be effected through the Rate Schedule 1 charge of the ISO OATT.

Nothing in this section shall preclude the ISO from seeking indemnification of penalty costs against Customers and Market Participants, including Transmission Owners, as provided in Schedule 11 of the ISO OATT, except that the ISO shall not be indemnified in instances of its gross negligence or intentional misconduct.

12.5 Other Remedies

Nothing in the ISO Services Tariff shall be construed as in any way to limit the Transmission Owner's rights and remedies, at law or in equity, with respect to a party in the event of an act or omission related to the ISO Services Tariff by such party.

12.6 Survival

The provisions of this Article 12, "Liability and Indemnification," shall survive termination or expiration of the ISO Services Tariff or any associated Service Agreement.

13 Metering

13.1 General Requirements

Existing metering in the NYCA provides revenue-quality metering information among the currently designated electrical zones separated by the designated transmission Interfaces. In addition, sufficient metering information will be made available by the ISO to calculate Load for the individual Transmission Owners within each Load Zone. The ISO will require adequate metering for all Generators and Loads within the NYCA to ensure the reliable operation of the NYS Power System.

13.2 Requirements Pertaining to Customers

Customers shall provide to the ISO such information and data as the ISO reasonably deems necessary in order to perform its functions and fulfill its responsibilities under the ISO Services Tariff and in accordance with the ISO Market Power Monitoring Program. Such information will be provided on a timely basis and in the formats prescribed in the ISO Procedures. The ISO shall establish metering specifications and standards for all metering that is used as a data source by the ISO. Customers shall install and maintain such metering at their own expense and deliver data to the ISO without charge.

A Customer taking service under the ISO Services Tariff will make available to the ISO metered data that meets ISO requirements by one of the following means: (i) direct transmission to the ISO; (ii) direct transmission to the ISO through Transmission Owner communications equipment, or (iii) indirectly through metering provided by the Transmission Owner in whose Load Zone it is located.

The Customer also shall provide its metered data to the Transmission Owner in whose Load Zone it is located, to the extent that the Transmission Owner determines that the metered data provided to the ISO is required for its system operation and planning functions, for the billing of services it provides to the Customer, or to perform calculations required as part of the ISO Settlement procedures.

13.2.1 Load Serving Entities

Any Load that is not directly metered, as described above, will have its Load determined by the Transmission Owner in whose Load Zone it is located in accordance with the Transmission Owner’s retail access plan on file with the PSC or otherwise authorized.

13.2.2 Ancillary Service Suppliers

Suppliers shall ensure that adequate metering data is made available to the ISO as described above. Additionally, for operational purposes, metered data provided to the ISO must also simultaneously be provided to the Transmission Owner, which will handle such information in conformity with the OASIS standards of conduct as specified in Order No. 889.

13.2.3 Third Party Metering Services

Customers whose metering services are provided by third parties qualified under rules, regulations and procedures of applicable state regulatory authorities shall be responsible to ensure that all data described in this section are satisfactorily made available to the ISO and applicable Transmission Owner(s) by those third parties.

13.2.4 Estimation of Metering

In the event of a meter malfunction or inadequate metering data, the ISO may use estimates to determine Customer’s rights and responsibilities under the ISO Services Tariff.

14 Miscellaneous

14.1 Notices

Except as specified in the ISO Procedures, all written notices under the ISO Services Tariff shall be deemed as having been given: (i) when delivered in person; (ii) when sent by United States registered or certified mall (return receipt requested), postage prepaid, or (iii) when sent by a reputable overnight courier to the other party at the address stated in the Service Agreement between the ISO and each Customer or at the last changed address given by the other party as hereinafter specified. Either party may, at any time, change its address for notification purposes by sending the other party written notice stating the change and setting forth the new address. The ISO shall adopt procedures for the provision of all notices and protocols required to implement the ISO Services Tariff.

14.2 Tax Exempt Financing Pursuant to Section 142 (f) of the Internal Revenue Code

This provision is applicable only to Transmission Owners that have financed facilities for the local furnishing of Energy with Local Furnishing Bonds as described in Section 142(f) of the Internal Revenue Code ("Local Furnishing Bonds"). Notwithstanding any other provision of the ISO Services Tariff, neither the ISO nor the Transmission Owner shall be required to take any action or provide any service if the taking of such action or provision of such service would result in loss of the tax-exempt status of any Local Furnishing Bonds. In the event a Transmission Owner is ordered to take an action on behalf of a Customer that results in the loss of tax-exempt status of any Local Furnishing Bonds, such Customer shall be obligated to pay to the Transmission Owner all costs associated with the loss of tax-exempt status of the Local Furnishing Bonds.

14.3 LIPA and NYPA Tax Exempt Obligations

This provision is applicable to LIPA and NYPA, which have financed transmission facilities with the proceeds of tax-exempt bonds issued pursuant to the Internal Revenue Code. Notwithstanding any other provision of the ISO OATT or the ISO Services Tariff, neither the ISO nor the Transmission Owner shall be required to provide Transmission Service to any Customer pursuant to an ISO Tariff if the provision of such Transmission Service would result in loss of tax-exempt status of the NYPA Tax Exempt Bonds or LIPA Tax Exempt Bonds or impair LIPA's or NYPA's ability to issue future tax-exempt obligations. If, by virtue of an order issued by the Commission pursuant to Section 211 of the FPA, the ISO or a Transmission Owner is required to provide Transmission Service that would adversely affect the tax-exempt status of the LIPA Tax Exempt Bonds or NYPA's Tax Exempt Bonds or any other tax-exempt debt obligations, then the Customer receiving such Transmission Service will compensate LIPA or NYPA for all costs, if any, associated with the loss of tax-exempt status plus the normal costs of Transmission Service.

14.4 Amendments

Nothing contained in the ISO Services Tariff or any Service Agreement shall be construed as affecting in any way the right of the ISO or a Transmission Owner under the ISO/TO Agreement to make application to the Commission for a change in: rates, terms, conditions, charges, or classifications of service; the provision of Ancillary Services; a Service Agreement; or a rule or regulation, under the FPA and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the ISO Services Tariff of any Service Agreement shall be construed as affecting in any way the ability of any Transmission Customer or Transmission

Owner to exercise its rights under the FPA including, but not limited to, the right to file a complaint under Section 206 of the FPA or any successor statute and pursuant to the Commission's rules and regulations promulgated thereunder.

Notwithstanding any other provision of the ISO Services Tariff, the ISO Services Tariff may be amended only in accordance with the ISO Agreement, the ISO/TO Agreement, and consistent with the requirements of the FPA and the Commission's rules and regulations promulgated thereunder.

14.5 Applicable Law and Forum

The ISO Services Tariff and any Service Agreement shall be governed by and construed in accordance with the law of the State of New York, except its conflict of law provisions. Customers irrevocably consent that any legal action or proceeding arising under or relating to the ISO Services Tariff or any Service Agreement shall be brought in any court of the State of New York or any federal court of the United States of America located in the State of New York.

Customers irrevocably waive any objection that they may now or in the future have to the designated courts in the State of New York as the proper and exclusive forum for any legal action or proceeding arising under or relating to the ISO Services Tariff or any Service Agreement.

14.6 Counterparts

Any Service Agreement entered into pursuant to the ISO Services Tariff may be executed in several counterparts, each of which shall be an original and all of which shall constitute one and the same instrument.

14.7 Waiver

No delay or omission in the exercise of any right under a Service Agreement or the ISO Services Tariff shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time-to-time and as often as may be deemed expedient. If any obligation or covenant under a Service Agreement or the ISO Services Tariff shall be breached and thereafter waived, such waiver shall be limited to the particular breach so waived and shall not be deemed to waive any other breach hereunder or under a Service Agreement.

14.8 Assignment

Obligations under the ISO Services Tariff and any Service Agreement shall be binding on the successors and assigns of the Service Agreement. No assignment shall relieve the original Customer from its obligations under the ISO Services Tariff or any Service Agreement.

14.9 Representations, Warranties & Covenants

A Service Agreement entered into under the ISO Services Tariff shall contain representations, warranties and covenants, as the parties deem appropriate and in accordance with the pro forma Service Agreement, regarding the Customer's ability to perform, and the enforceability of, the Service Agreement.

15 ISO Market Administration and Control Area Service Tariff Rate Schedules

15.1 Rate Schedule 1 - ISO Annual Budget Charge and Other Non-Budget Charges and Payments

The terms of Schedule 1 of the ISO OATT are hereby incorporated by reference into this Tariff. In applying the terms of Schedule 1 of the ISO OATT in connection with this Tariff, all terms in Schedule 1 of the ISO OATT that are applicable to "Transmission Customers" shall be similarly applicable to "Customers" under this Rate Schedule 1, and the ISO shall interpret all other defined terms and cross references in Schedule 1 that are specific to the ISO OATT consistent with the similar terms and provisions of this Tariff, unless otherwise specified.

15.2 Rate Schedule 2 - Payments for Supplying Voltage Support Service

This Rate Schedule applies to payments to Suppliers who provide Voltage Support Service to the ISO. Transmission Customers and Customers will purchase Voltage Support Service from the ISO under the ISO OATT.

Suppliers provide Voltage Support Service from eligible providers which are Generators with an Automatic Voltage Regulator ("Generators," for the purpose of this Rate Schedule 2), synchronous condensers, and Qualified Non-Generator Voltage Support Resources. An RMR Generator operating under an RMR Agreement that provided Voltage Support Service at any time during the most recent twelve (12) months that it participated in the ISO Administered Markets must provide Voltage Support Service during the term of its RMR Agreement, unless it demonstrates to the ISO's satisfaction that it is no longer capable of providing the service. An Interim Service Provider that provided Voltage Support Service during the most recent twelve (12) months that it participated in the ISO Administered Markets must continue to provide Voltage Support Service, unless it demonstrates to the ISO's satisfaction that it is no longer capable of providing the service. The rate provided in this Rate Schedule shall be used to calculate payments to eligible Suppliers providing Voltage Support Service as applied on a technology-specific basis. The ISO shall calculate payments on an annual basis, and make payments monthly.

15.2.1 Responsibilities

The ISO shall coordinate the Voltage Support Service provided by Suppliers that qualify to provide such services as described in Section 15.2.1.1 of this Rate Schedule 2. The ISO shall also establish methods and procedures for Reactive Power (MVAr) capability testing.

15.2.1.1 Suppliers

To qualify for payments, Suppliers of Voltage Support Service shall provide a Generator that has an AVR, or a Qualified Non-Generator Voltage Support Resource with, other than the Cross Sound Scheduled Line, an AVR, or a synchronous condenser, each of which must be electrically located within the NYCA. All Suppliers of Voltage Support Service must successfully perform Reactive Power (MVAr) capability testing in accordance with the ISO Procedures and prevailing industry standards. The ISO may direct Suppliers to operate their Generators, Qualified Non-Generator Voltage Support Resources, or synchronous condensers within these demonstrated reactive capability limits. Suppliers of Voltage Support Service will test their Generators, Qualified Non-Generator Voltage Support Resources, and synchronous condensers and provide these services in accordance with ISO Procedures.

Voltage Support Service includes the ability to produce or absorb Reactive Power within the Generators, Qualified Non-Generator Voltage Support Resource's or synchronous condensers tested reactive capability, and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the Generators, Qualified Non-Generator Voltage Support Resource's or synchronous condensers stated reactive capability. The requirement for a Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource to absorb Reactive Power may be set aside by the ISO with input from the Transmission Owner in whose Transmission District the Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource is located, which input may include, at the Transmission Owner's option, an executive level review. To grant an exemption from the requirement that the Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource be able to absorb Reactive Power, the ISO shall have determined that: 1) the Generator, synchronous condenser, or Qualified Non-Generator Voltage

Support Resource is unable, due to transmission system configuration, to absorb Reactive Power; 2) the ability of the Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource to produce Reactive Power is needed for system reliability; and 3) for purposes of system reliability the Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource does not need to have the ability to absorb Reactive Power.

An RMR Generator that is required to provide Voltage Support Service must timely perform the annual testing applicable to all Suppliers of Voltage Support Service described in this Section 15.2.1 and in ISO Procedures so that it remains continuously eligible to provide Voltage Support Service during the term of its RMR Agreement. If such an RMR Generator did not timely perform all of the annual testing required for it to provide Voltage Support Service prior to the start of the term of its RMR Agreement, then the ISO shall permit the RMR Generator to perform Reactive Power (MVAr) capability testing in accordance with the ISO Procedures upon entering the RMR Agreement and shall permit the RMR Generator to be a Qualified Supplier of Voltage Support Service. An Interim Service Provider must timely perform the annual testing applicable to all Suppliers of Voltage Support Service described in this Section 15.2.1 and in ISO Procedures so that it remains continuously eligible to provide Voltage Support Service. If such an Interim Service Provider did not timely perform all of the annual testing required for it to provide Voltage Support Service, then the ISO shall permit the Interim Service Provider to perform Reactive Power (MVAr) capability testing in accordance with the ISO Procedures promptly upon becoming an Interim Service Provider and shall permit the Interim Service Provider to be a Qualified Supplier of Voltage Support Service.

15.2.2 Payments

Each month, Suppliers whose Generator(s) meet the requirements to supply Installed Capacity, as described in Article 5 of the ISO Services Tariff, and are under contract to supply Installed Capacity, shall receive one-twelfth (1/12th) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule for Voltage Support Service.

Each month, Suppliers whose Generators are not under contract to supply Installed Capacity, Suppliers with synchronous condensers, and, except as noted in the following paragraph, Qualified Non-Generator Voltage Support Resources shall receive one-twelfth (1/12th) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule , pro-rated by the number of hours that the Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource operated in that month, as recorded by the ISO.

Each month, the Cross-Sound Scheduled Line shall receive one-twelfth (1/12th) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule, pro-rated by the number of hours that it is energized in that month, as recorded by the ISO.

15.2.2.1 Annual Payment for Voltage Support Service

For purposes of the calculation set forth in Section 15.2.2 of this Rate Schedule, the annual payment to Suppliers qualified and eligible to provide Voltage Support Service shall equal: (i) in the case of Generators and synchronous condensers the product of $3919/MVAr and the tested MVAr capacity of the Generator or synchronous condenser; (ii) in the case of Qualified Non-Generator Voltage Support Suppliers, other than the Cross-Sound Scheduled Line, the product of $3919/MVAr and its tested MVAr capacity as determined pursuant to the ISO Procedures; and (iii) in the case of the Cross-Sound Scheduled Line, the product of

$3919/MVAr and its tested Reactive Power (MVAr) capacity measured at maximum real power flow.

15.2.2.2 Lost Opportunity Costs

A Supplier of Voltage Support Service from a Generator that is being dispatched by the ISO shall also receive a payment for Lost Opportunity Costs ("LOC") when the ISO directs the Generator to reduce its real power (MW) output below its Economic Operating Point in order to allow the Generator to produce or absorb more Reactive Power (MVAr), unless the Supplier is already receiving a Day-Ahead Margin Assurance Payment for that reduction under Attachment J to this ISO Services Tariff. The Lost Opportunity Cost payment shall be calculated as the maximum of zero or the difference between: (i) the product of: (a) the appropriate MW of output reduction and (b) the Real-Time LBMP at the Generator bus; and (ii) the Generator's Energy Bid for the reduced output of the Generator multiplied by the time duration of reduction in hours or fractions thereof.

The formula below describes the calculation of LOC as applied to each Generator supplying Voltage Support Service.

$$LOC_i = max\left(\left(LBMP_{RT,i} * \left(EOP_i - \ max(AEI_i, RTS_i, DAS_i)\right) - \int_{max(AEI_i,RTS_i,DAS_i)}^{EOP_i} Bid\right), 0\right) * \frac{S_i}{3600}$$

Where:

LOC_i = Lost Opportunity Cost for interval *i*

$LBMP_{RT,i}$ = Real-time LBMP for interval *i*

EOP_i = The Generator's Economic Operating Point for interval *i*

AEI_i = The Generator's Actual Energy Injection for the interval *i*

RTS_i = The Generator's Real-Time Energy Schedule for interval *i*

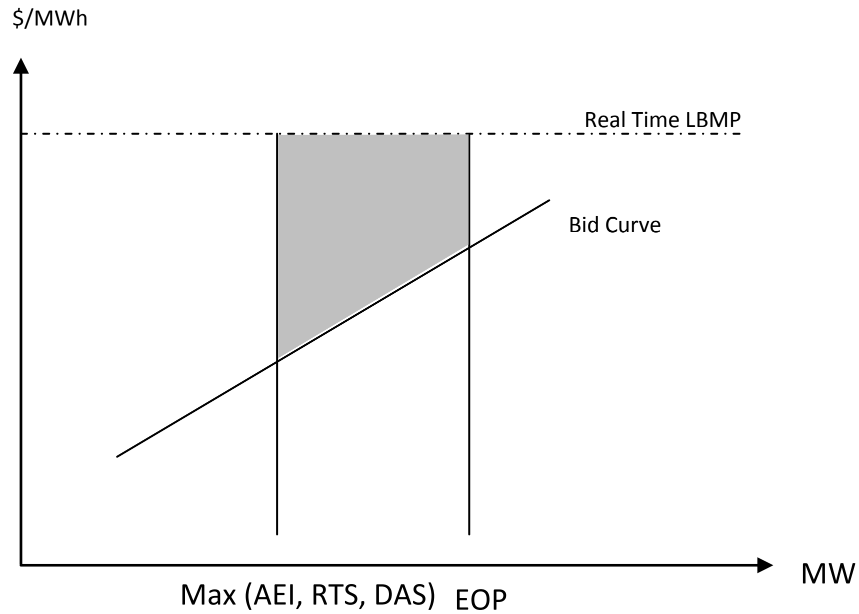
DAS_i = The Generator's Day-Ahead Schedule for the hour containing *i*

Bid_i = Generator's Bid curve in effect for interval *i*

$S_i/3600$ = The length of interval *i*, containing $S_i^{seconds}$ in units of hours

Figure 2.0(b) below graphically portrays the calculation of the LOC for a Generator which reduced its MW output to allow it to produce or absorb more Reactive Power (MVAr).

Figure 2.0(b) - Incremental Bid Curve Used to Calculate LOC



15.2.2.3 Other Payments to Synchronous Condensers and Qualified Non-Generator Voltage Support Resources

If a synchronous condenser or Qualified Non-Generator Voltage Support Resource energizes in order to provide Voltage Support Service in response to a request from the ISO, the ISO shall compensate the facility for the cost of Energy it consumes to energize converters and other equipment necessary to provide that Voltage Support Service.

15.2.3 Failure to Perform by Suppliers

A Generator, synchronous condenser, or a Qualified Non-Generator Voltage Support Resource will have failed to provide voltage support if it:

15.2.3.1 when operating at real-power levels consistent with test conditions, fails within ten minutes to be within 5% (+/-) of the requested Reactive Power (MVAr) level of production or absorption as requested by the ISO or applicable Transmission Owner unless it was prevented from doing so by transmission system conditions and except when the Generator, synchronous condenser, or a Qualified Non-Generator Voltage Support Resource is requested not to produce or absorb Reactive Power in which case that Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource fails to provide Voltage Support if the absolute value of its level of Reactive Power production or absorption within ten minutes is greater than 5% multiplied by the sum of the absolute values of (a) that Generator's, synchronous condenser's, or Qualified Non-Generator Voltage Support Resource's maximum reactive power production level under test conditions and (b) that Generator, synchronous condenser, or a Qualified Non-Generator Voltage Support Resource's maximum reactive power absorption level under test conditions;

15.2.3.2 when operating at real-power levels consistent with test conditions, fails within ten minutes to be at 95% or greater of the Generator's, synchronous condenser's, or Qualified Non-Generator Voltage Support Resource's demonstrated Reactive Power capability (tested pursuant to ISO Procedures) in the appropriate lead or lag direction when requested to go to maximum lead or lag reactive capability by the ISO or applicable Transmission Owner unless it was prevented from doing so by transmission system conditions;

15.2.3.3 fails to provide Voltage Support Service in a Contingency, as defined by ISO Procedures;

15.2.3.4 fails to maintain its automatic voltage regulator (as appropriate) in service and in automatic voltage control mode, or fails to commence timely repairs to the automatic voltage regulator.

Suppliers of Voltage Support Service that fail to comply with the ISO Procedures will be assessed charges by the ISO in the manner described in Sections 15.2.4, 15.2.5, and 15.2.6 below.

15.2.4 Failure to Respond to ISO's Request for Steady-State Voltage Control

Failure: If a Supplier's Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource fails to comply with the ISO's request for steady-state voltage control, the ISO shall withhold Voltage Support Service payments from the non-complying Supplier equivalent to the VSS Failure to Perform Penalty for that specific Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource for that month. The Supplier shall also be liable for any additional cost in procuring replacement Voltage Support Service including LOC incurred by the ISO as a direct result of the Supplier's non-performance.

The formula below describes the monthly VSS Failure to Perform Penalty (VFP)

$$VFP = (VSS\ payment\ for\ the\ month) * (F/R)$$

Where:

F = number of failures in the month

R = number of times the Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource was called upon for Voltage Support in the month

Repeated Failures: In addition to the charges for failure, the non-complying Supplier will also be subject to the charges described in this paragraph. If a Supplier's Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource fails to comply with fifty percent (50%) or more of the ISO's requests for two consecutive months, then the non-complying Supplier will no longer be eligible for Voltage Support Service payments for service provided by that Generator, synchronous condenser, or Qualified Non-Generator Voltage

Support Resource. The ISO may reinstate payments once the Supplier complies with the following conditions to the ISO's satisfaction:

15.2.4.1 the Supplier's Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource must successfully perform a Reactive Power (MVAr) capability test, and

15.2.4.2 the Supplier’s Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource must provide Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service or LOC will be made to the Supplier on account of Voltage Support Service from such Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource during this period.

15.2.5 Failure to Provide Voltage Support Service When a Contingency Occurs on the NYS Power System

If a Supplier's Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource fails to respond to a contingency, based on ISO review and analysis, the ISO shall withhold Voltage Support Service payments from the non-complying Supplier as follows:

Initial Failure: The ISO will withhold from the Supplier one-twelfth (1/12th) of the annual payment for the specific Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource (or an amount equal to the last month's voltage support payment made to it, if it is not an Installed Capacity provider).

Second Failure within the same thirty (30) day period: The ISO shall withhold from the Supplier one-fourth (1/4th) of the annual payment for the specific Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource (or an amount equal to the last three (3) months' voltage support payments made to it, if it is not an Installed Capacity provider).

In addition, the Supplier that is in violation shall be prohibited from receiving Voltage Support Service payments for the non-complying Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource until the Supplier complies with the following conditions to the ISO's satisfaction:

15.2.5.1 the Supplier's Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource shall successfully perform a Reactive Power (MVAr) capability test, and

15.2.5.2 the Supplier's Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource shall provide Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service, or LOC shall be made to the Supplier on account of Voltage Support Service from such Generator, synchronous condenser, or Qualified Non-Generator Voltage Support Resource during this period.

15.2.6 Failure to Maintain an Automatic Voltage Regulator or Commence Timely Repairs

If a Supplier's Generator or Qualified Non-Generator Voltage Support Resource, other than the Cross Sound Scheduled Line, fails to maintain its automatic voltage regulator in operation and fails to commence timely repairs following a failure of the automatic voltage regulator within a 30-day period, the Generator or Qualified Non-Generator Voltage Support Resource will be disqualified as a supplier of Voltage Support Service.

The Supplier will not receive Voltage Support Service payments for the disqualified Generator or Qualified Non-Generator Voltage Support Resource until the Supplier complies with the following conditions:

(1) the Supplier provides documentation to the NYISO of the completion of the repairs;

(2) the Supplier's Generator or Qualified Non-Generator Voltage Support Resource successfully performs a Reactive Power (MVAr) capability test, and;

(3) the Supplier's Generator or Qualified Non-Generator Voltage Support Resource provides Voltage Support Service for thirty (30) consecutive days without any compliance failures. No payments for Voltage Support Service or LOC on account of Voltage Support Service from such Generator or Qualified Non-Generator Voltage Support Resource shall be made to the Supplier during this period.

15.2.7 Consistence with Cross-Sound Scheduled Line Protocols

Nothing in this Rate Schedule shall be construed to change existing protocols between the ISO and ISO New England, Inc. regarding the operation of the Cross-Sound Scheduled Line.

15.3 Rate Schedule 3 - Payments for Regulation Service

This Rate Schedule applies to Suppliers that provide Regulation Service to the ISO. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit that is dispatched as a single aggregate unit is not qualified to provide Regulation Service to the ISO. Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

15.3.1 Obligations of the ISO and Suppliers

15.3.1.1 The ISO shall:

(a) Establish Regulation Service criteria and requirements in the ISO Procedures to ensure that Suppliers follow changes in Load consistent with the Reliability Rules;

(b) Provide RTD Base Point Signals and AGC Base Point Signals to Suppliers providing Regulation Service to direct their output;

(c) Establish criteria in the ISO Procedures that Suppliers must meet to qualify, or re-qualify, to supply Regulation Service;

(d) Establish minimum metering requirements and telecommunication capability required for a Supplier to be able to respond to AGC Base Point Signals and RTD Base Point Signals sent by the ISO;

(e) Select Suppliers to provide Regulation Service in the Day-Ahead Market and Real-Time Market and establish Regulation Service schedules, in MWs of Regulation Capacity, for each scheduled Regulation Supplier in the Day-Ahead and Real-Time Markets, as described in Section 15.3.2 of this Rate Schedule;

(f) Pay Suppliers for providing Regulation Service as described in this Rate Schedule;

(g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 15.3.3 of this Rate Schedule; and

(h) Take into account the speed and accuracy of regulation resources in determining reserve requirements for Regulation Service.

15.3.1.2 Each Supplier shall:

(a) Register with the ISO the Regulation Capacity its resources are qualified to bid in the Regulation Services market;

(b) Provide the ISO with the Resource's Regulation Capacity Response Rate and the Resource's Regulation Movement Response Rate;

(c) Offer only Resources that are; (i) ISO-Committed Flexible or Self-Committed Flexible, provided however that Demand Side Resources shall be offered as ISO-Committed Flexible; within the dispatchable portion of their operating range, and; (ii) able to respond to AGC Base Point Signals sent by the ISO pursuant to the ISO Procedures, to provide Regulation Service;

(d) Not use, contract to provide, or otherwise commit Regulation Capacity that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to any party other than the ISO;

(e) Pay any charges imposed under this Rate Schedule;

(f) Ensure that all of its Resources that are selected to provide Regulation Service comply with Base Point Signals issued by the ISO at all times pursuant to the ISO Procedures; and ensure that all of its Resources that are selected to provide

Regulation Service comply with all criteria and ISO Procedures that apply to providing Regulation Service.

15.3.2 Selection of Suppliers in the Day-Ahead Market and the Real-Time Market

(a) The ISO shall select Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day and in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day, from those that have Bid to provide Regulation Service from Resources and that meet the qualification standards and criteria established in Section 15.3.1 of this Rate Schedule and in the ISO Procedures.

(b) In order to schedule Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day, the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Day-Ahead Regulation Capacity Bid Price and b) the product of the Supplier's Day-Ahead Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.

(c) In order to schedule Suppliers in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Real-Time Regulation Capacity Bid Price and b) the product of the Supplier's Real-Time Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.

(d) The ISO shall establish separate Regulation Capacity Market Prices in the Day-Ahead Market and the Real-Time Market under Sections 15.3.4, 15.3.5 and 15.3.7

of this Rate Schedule and shall establish a Real-Time Regulation Movement Market Price under Section 15.3.5.1 of this Rate Schedule. The ISO shall also compute Regulation Revenue Adjustment Payments and Regulation Revenue Adjustment Charges under Section 15.3.6 of this Rate Schedule.

15.3.2.1 Bidding Process

(a) A Supplier may submit a Bid in the Day- Ahead Market or the Real-Time Market to provide Regulation Service from eligible Resources, provided, however, that Bids submitted by Suppliers that are attempting to re-qualify to provide Regulation Service, after being disqualified pursuant to Section 15.3.3 of this Rate Schedule 3, may be limited by the ISO pursuant to ISO Procedures.

(b) Bids rejected by the ISO may be modified and resubmitted by the Supplier to the ISO in accordance with the terms of the ISO Tariff.

(c) Each Bid shall contain the following information: (i) the maximum amount of capability (in MW) that the Resource is willing to provide as Regulation Capacity; (ii) the Supplier's Bid Price (in $/MW) for Regulation Capacity; (iii) the Suppliers Bid Price (in $/MW) for Regulation Movement; and (iv) the physical location and name or designation of the Resource.

(d) Regulation Service Offers from Limited Energy Storage Resources: The ISO may reduce the real-time Regulation Service offer (in MWs) from a Limited Energy Storage Resource to account for the Energy storage capacity of such Resource.

15.3.3 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

(a) The ISO shall establish (i) Resource performance measurement criteria; (ii) procedures to disqualify Suppliers whose Resources consistently fail to meet those criteria; and (iii) procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.

(b) The ISO shall establish and implement a Performance Tracking System to monitor the performance of Suppliers that provide Regulation Service. The ISO shall develop performance indices, which may vary with Control Performance, as part of the ISO Procedures. The ISO shall use the values provided by the Performance Tracking System to adjust settlements for real-time Regulation Movement pursuant to Section 15.3.5.4.1 and to compute a performance charge to apply to real-time Regulation Service providers pursuant to Section 15.3.5.4.2 of this Rate Schedule.

(c) Resources that consistently fail to perform adequately may be disqualified by the ISO, pursuant to ISO Procedures.

15.3.4 Regulation Service Settlements - Day-Ahead Market

15.3.4.1 Calculation of Day-Ahead Market Prices

The ISO shall calculate a Day-Ahead Regulation Capacity Market Price for each hour of the following day. The Day-Ahead Regulation Capacity Market Price for each hour shall equal the Day-Ahead Shadow Price of the ISO's Regulation Service constraint for that hour, which shall be established under the ISO Procedures, minus the product of i) the Day-Ahead Regulation Movement Bid Price of the marginal Resource selected to provide Regulation Service; and ii) the applicable Regulation Movement Multiplier. Day-Ahead Shadow Prices will be calculated by the ISO's SCUC. Each hourly Day-Ahead Shadow Price shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that hour, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price shall include the Day-Ahead Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale of Energy or Operating Reserves in the Day-Ahead Market that the Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Regulation Service Demand Curve.

Each Supplier that is scheduled Day-Ahead to provide Regulation Service shall be paid the Day-Ahead Regulation Capacity Market Price in each hour, multiplied by the amount of Regulation Capacity that it is scheduled Day-Ahead to provide in that hour.

15.3.4.2 Other Day-Ahead Payments

A Supplier that bids on behalf of a Generator that provides Regulation Service may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the ISO in the Day-Ahead Market, except to the extent that a Supplier is directed to provide the excess amount by the ISO.

15.3.5 Regulation Service Settlements - Real-Time Market

15.3.5.1 Calculation of Real-Time Market Prices

The ISO shall calculate a Real-Time Regulation Capacity Market Price and a Real-Time Regulation Movement Market Price for every RTD interval, except as noted in Section 15.3.8 of this Rate Schedule. The Real-Time Regulation Capacity Market Price for each interval shall equal the real-time Shadow Price for the ISO's Regulation Service constraint for that RTD interval, which shall be established under the ISO Procedures, minus the product of: i) the real-time Regulation Movement Bid of the marginal Resource selected to provide Real-Time Regulation Service; and ii) the applicable Regulation Movement Multiplier. Real-time Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that interval, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that interval. As a result, the Shadow Price shall include the Real-Time Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale of Energy or Operating Reserves in the Real-Time Market that Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled at a cost greater than the Demand Curve indicates.

During any period when the ISO sets Resources' Regulation Service Schedules to zero, pursuant to Section 15.3.8 of this Rate Schedule, the Real-Time Regulation Capacity Market

Price and the Real-Time Regulation Movement Market Price shall automatically be set to zero, which shall be the price used for real-time balancing and settlement purposes.

The ISO shall calculate a Real-Time Regulation Movement Market Price for every RTD interval. The Real-Time Regulation Movement Market Price shall be the Regulation Movement Bid of the marginal Resource selected to provide Regulation Service in that interval.

15.3.5.2 Real-Time Regulation Capacity Balancing Payments, Regulation Movement Payments and Performance Charges

Any deviation from a Supplier's Day-Ahead schedule to provide Regulation Service shall be settled pursuant to the following rules. In addition, Suppliers scheduled to provide Regulation Service in real-time shall be settled pursuant to the following rules.

(a) When the Supplier's real-time Regulation Capacity schedule is less than its Day-Ahead Regulation Capacity schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Regulation Capacity Market Price ; and (ii) the difference between the Supplier's Day-Ahead Regulation Capacity schedule and its real-time Regulation Capacity schedule.

(b) When the Supplier's real-time Regulation Capacity schedule is greater than its Day-Ahead Regulation Capacity schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Regulation Capacity Market Price; and (ii) the difference between the Supplier's real-time Regulation Capacity schedule and its Day-Ahead Regulation Capacity schedule.

(c) The ISO shall pay Suppliers with real-time Regulation Capacity schedules a real-time payment for Regulation Movement provided in each interval. The payment amount shall equal the product of: (a) the Real-Time Regulation Movement

Market Price in that interval; (b) the Regulation Movement instructed during the interval, and (c) the performance factor calculated for that Regulation Service provider in that interval pursuant to Section 15.3.5.4.1.

(d) The ISO shall assess a performance charge, pursuant to Section 15.3.5.4.2 to all Suppliers of Regulation Service with real-time Regulation Service schedules.

(e) No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the ISO in the Real Time Market, except to the extent that a Supplier is directed to provide the excess amount by the ISO.

15.3.5.3 Other Real-Time Regulation Service Payments

A Supplier that bids on behalf of a Regulation Service provider may be eligible for a real-time Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

A Supplier that bids on behalf of a Regulation Service provider may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.6.5 and Attachment J of this ISO Services Tariff.

15.3.5.4 Performance-Based Adjustment to Payments for Regulation Service Providers and Performance Based Charges

15.3.5.4.1 Performance-Based Adjustment to Payments for Regulation Service Suppliers

The amount paid to each Supplier for providing Regulation Movement in each RTD interval, pursuant to Section 15.3.5.2 shall be reduced to reflect the Supplier's performance using a performance factor developed pursuant to the following equation:

$$K_{PIi} = (PI_i - PSF)/(1 - PSF)$$

Where:

K_{PIi} = the performance factor derived from the Regulation Service Performance index for the Resource for interval *i*;

PI_i = the performance index of the Resource for interval *i*, with a value between 0.0 and 1.0 inclusive, derived from each Supplier's Regulation Service performance, as measured by the performance indices set forth in the ISO Procedures; and

PSF = the payment scaling factor, established pursuant to ISO Procedures. The PSF shall be set between 0 and the minimum performance index required for payment for Regulation Service.

The PSF is established to reflect the extent of ISO compliance with the standards established by NERC, NPCC or Good Utility Practice for Control Performance and System Security. The PSF is set initially at zero. Should the ISO's compliance with these measures deteriorate, in a manner that can be improved if regulation performance improves, the PSF will be increased. Resources providing Regulation Service will be required to increase their performance index to obtain the same total Regulation Service payment as they received during periods of good ISO performance, as measured by these standards.

15.3.5.4.2 Performance-Based Charge to Suppliers of Regulation Service

In addition, each Supplier that is scheduled in real-time to provide Regulation Service shall be assessed a performance charge for interval *i* in accordance with the following formula.

$$Performance\ Charge_i = \Big(\big((1 - K_{PIi}) * RTRinccap_i * \text{-}1.1 * RTMPreg_i\big) + \Big(\big((1 - K_{PIi}) * (RTRcap_i - RTRinccap_i) * \text{-}1.1\big) * Max\big(DAMPreg_,, RTMPreg_i\big)\Big)\Big) * (S_i/3600)$$

$DAMPreg_i$ = is the applicable Regulation Capacity Market Price (in $/MW), in the Day-Ahead Market, as established by the ISO pursuant to Section 15.3.4.1 of this Rate Schedule for the hour that includes RTD interval *i*;

$RTMPreg_i$ = is the applicable Regulation Capacity Market Price (in $/MW), in the Real-Time Market as established by the ISO under Section 15.3.5.1 of this Rate Schedule in RTD interval *i*;

$RTRcap_i$ = is the Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in RTD interval *i*;

$RTRinccap_i$ = is the incremental Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in the RTD interval i which is in excess of Regulation Capacity offered and selected by the ISO in the Day-Ahead Market for the hour that includes interval *i*;

S_i = is the number of seconds in interval *i*; and

K_{PIi} = is the performance factor for the Resource for interval *i* as defined in Section 15.3.5.4.1.

15.3.6 Energy Settlement Rules for Generators Providing Regulation Service

15.3.6.1 Energy Settlements

A. For any interval in which a Generator that is not a Limited Energy Storage Resource is providing Regulation Service, it shall receive a settlement payment for Energy consistent with a real-time Energy injection equal to the lower of its actual generation or its AGC Base Point Signal. Demand Side Resources providing Regulation Service shall not receive a settlement payment for Energy.

B. For any hour in which a Limited Energy Storage Resource has injected or withdrawn Energy, pursuant to an ISO schedule to do so, it shall receive a settlement payment (if the amount calculated below is positive) or charge (if the amount calculated below is negative) for Energy pursuant to the following formula:

$$Energy\ Settlements_h = Net\ MWHR_h * LBMP_h$$

Where:

$Net\ MWHR_h$ = the amount of Energy injected by the Limited Energy Storage Resource in hour *h* minus the amount of Energy withdrawn by that Limited Energy Storage Resource in hour *h*

$LBMP_h$ = the time-weighted average LBMP in hour *h* calculated for the location of that Limited Energy Storage Resource

15.3.6.2 Additional Payments/Charges

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that differs from its RTD Base Point Signal, it shall receive or pay a Regulation Revenue Adjustment Payment ("RRAP") or Regulation Revenue Adjustment Charge ("RRAC") calculated under the terms of this subsection, provided however no RRAP shall be payable and no RRAC shall be charged to a Limited Energy Storage Resource.

15.3.6.2.1 Additional Payments/Charges When AGC Base Point Signals Exceed RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall receive a RRAP. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at is location at that interval, the Generator shall be assessed a RRAC. RRAPs and RRACs shall be calculated using the following formula:

$$Payment/Charge = \int_{RTD\ Base\ Point\ Signal}^{max(RTD\ BasePoint\ Signal, min(AGC\ BasePoint\ Signal, Actual\ Output))} [Bid - LBMP] * S/3600$$

Where:

S = the number of seconds in the RTD interval;

If the result of the calculation is positive then the Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of applying this formula, whenever the Generator's actual Bid exceeds the applicable LBMP the "Bid" term shall be set at a level equal to the lesser of the Generator's actual Bid or its reference Bid plus $100/MWh. Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.

15.3.6.2.2 Additional Charges/Payments When AGC Base Point Signals Are Lower than RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is lower than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall be assessed a RRAC. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at its location in that interval, the Generator shall receive a RRAP. RRAPs and RRACs shall be calculated using the following formula:

$$Payment/Charge = \int_{min(RTD\ BasePoint\ Signal, max(AGC\ BasePoint\ Signal, Actual\ Output))}^{RTD\ BasePoint\ Signal} -[Bid - LBMP] * S/3600$$

Where:

S = the number of seconds in the RTD interval;

If the result of the calculation is positive then the Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of this formula, whenever the Generator's actual Bid is lower than the applicable LBMP the "Bid" term shall be set at a level equal to the higher of the Generator's actual Bid or its reference Bid minus $100/MWh.

Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.

15.3.7 Regulation Service Demand Curve

The ISO shall establish a Regulation Service Demand Curve that will apply to both the Day-Ahead and real-time Regulation Capacity Market Price and settlements. The Regulation Capacity Market Prices calculated pursuant to Sections 15.3.4.1 and 15.3.5.1 of this Rate Schedule shall take account of the demand curve established in this Section so that Regulation Capacity is not scheduled by SCUC, RTC, or RTD at a cost higher than the demand curve indicates should be paid in the relevant market.

The ISO shall establish and post a target level of Regulation Service for each hour, which will be the number of MW of Regulation Capacity that the ISO would seek to maintain as its Regulation Service requirement in that hour. The ISO will then define a Regulation Service demand curve for that hour as follows:

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service minus 80 MW, the price on the Regulation Service demand curve shall be $775/MW.

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service minus 25 MW but that exceed the target level of Regulation Service minus 80 MW, the price on the Regulation Service demand curve shall be $525/MW.

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service but that exceed the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be $25/MW.

For all other quantities, the price on the Regulation Service demand curve shall be $0/MW. However, the ISO shall not schedule more Regulation Service than the target level for the requirement for that hour.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure Regulation Capacity at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Regulation Service Demand Curve the ISO, in consultation with its Advisor, shall conduct an initial review in accordance with the ISO Procedures. The scope of the review shall be upward or downward in order to optimize the economic efficiency of any, or all, the ISO-Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.3.7 is in effect. After the first year, the

ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Regulation Service Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 3 to the Services Tariff are also addressed in Section 30.4.6.4.1 of Attachment O.

15.3.8 Temporary Suspension of Regulation Service Markets During Reserve Pickups and Maximum Generation

During any period in which the ISO has activated its RTD-CAM software and called for a "large event" or "small event" reserve or maximum generation pickup, as described in Article 4.4.4.1 of this ISO Services Tariff, the ISO will set all Regulation Service schedules to zero , The ISO will establish real-time Regulation Market Prices for Regulation Capacity and Regulation Movement of zero for settlement and balancing purposes. The ISO will restore real-time Regulation Service schedules as soon as possible after the end of the reserve or maximum generation pickup.

15.3A Rate Schedule "3-A" -Charges Applicable to Suppliers That Are Not Providing Regulation Service

15.3A.1 Persistent Undergeneration Charges

A Supplier, other than a Supplier included in Section 15.3A.2.3 of this Rate Schedule, that is not providing Regulation Service and that persistently operates at a level below its Energy schedule shall pay a persistent undergeneration charge to the ISO, unless its operation is within a tolerance described below, provided, however, no persistent undergeneration charges shall apply to a Fixed Block Unit that has reached a percentage of its Normal Upper Operating Limit, which percentage shall be set pursuant to ISO Procedures and shall be initially set at seventy percent (70%). Persistent undergeneration charges per interval shall be calculated as follows:

$$\text{Persistent undergeneration charge} = \text{Energy Difference} \times \text{Max}(MPRC_{DAM}, MPRC_{RT}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the actual Energy provided by the Supplier from its RTD Base Point Signal for the dispatch interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall initially be 3% of the Supplier's Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes;

$MPRC_{DAM}$ is the Regulation Capacity Market Price in the Day-Ahead Market; and

$MPRC_{RT}$ is the Regulation Capacity Market Price in the Real-Time Market.

15.3A.1.1 Overgeneration Charges

An Intermittent Power Resource that depends on wind as its fuel, for which the ISO has imposed a Wind Output Limit after October 31, 2009, or after February 1, 2010 for an Intermittent Power Resource that depends on wind as its fuel in commercial operation before 2006 with nameplate capacity of 30 MWs or less, that operates at a level above its schedule shall pay an overgeneration charge to the ISO, unless its operation is within a tolerance described below.

Overgeneration charges per interval shall be calculated as follows:

$$\text{Overgeneration charge} = \text{Energy Difference} \times \text{Max}(MPRC_{DAM}, MPRC_{RT}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the RTD Base Point Signal for the dispatch interval from the actual Energy provided by the Intermittent Power Resource for the same interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, which shall initially be set at 3% of the Supplier's Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable;

$MPRC_{DAM}$ is the Regulation Capacity Market Price in the Day-Ahead Market; and

$MPRC_{RT}$ is the Regulation Capacity Market Price in the Real-Time Market

15.3A.2 Exemptions

The following types of Generator shall not be subject to persistent undergeneration charges:

15.3A.2.1 Generators, except for the Generator of a Behind-the-Meter Net Generation Resource, providing Energy under contracts (including PURPA contracts), executed and effective on or before November 18, 1999, in which the power purchaser does not control the operation of the supply source but would be responsible for payment of the persistent undergeneration or performance charge;

15.3A.2.2 Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 523 MW of such units;

15.3A.2.3 Intermittent Power Resources that depend on wind as their fuel and Limited Control Run of River Hydro Resources within the NYCA in operation on or before November 18, 1999, plus up to an additional 3300 MW of such Generators;

15.3A.2.4 Intermittent Power Resources that depend on landfill gas or solar energy as their fuel;

15.3A.2.5 Capacity Limited Resources and Energy Limited Resources to the extent that their real-time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their Real-Time Scheduled Energy Injections;

15.3A.2.6 Generators operating in their Start-Up Period or their Shutdown Period and, for Generators comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, each of the grouped generating units when one of the grouped generating units is operating in its Start-Up or Shutdown Period; and

15.3A.2.7 Generators operating during a Testing Period.

For Generators and Resources described in Sections 15.3A.2.1, 15.3A.2.2, 15.3A.2.3, and 15.3A.2.4 above, this exemption shall not apply in an hour if the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible.

15.4 Rate Schedule 4 - Payments for Supplying Operating Reserves

This Rate Schedule applies to payments to Suppliers that provide Operating Reserves to the ISO. Transmission Customers will purchase Operating Reserves from the ISO under Rate Schedule 5 of the ISO OATT.

15.4.1 General Responsibilities and Requirements

15.4.1.1 ISO Responsibilities

The ISO shall procure on behalf of its Customers a sufficient quantity of Operating Reserve products to comply with the Reliability Rules and with other applicable reliability standards, as well as Scarcity Reserve Requirements. These quantities shall be established under Section 15.4.7 of this Rate Schedule for locational Operating Reserve requirements and Section 15.4.6.2 of this Rate Schedule for Scarcity Reserve Requirements. To the extent that the ISO enters into Operating Reserve sharing agreements with neighboring Control Areas its Operating Reserves requirements shall be adjusted as, and where, appropriate.

The ISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible, under Section 15.4.1.2 of this Rate Schedule, to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The ISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central-East, in Southeastern New York and on Long Island. In addition to being subject to the preceding limitations on Suppliers that can meet each of these requirements, the requirements for Operating Reserve located East of Central-East may only be met by eligible Suppliers that are located East of Central-East, requirements for Operating

Reserve located in Southeastern New York may only be met by eligible Suppliers that are located in Southeastern New York, and requirements for Operating Reserve located on Long Island may only be met by eligible Suppliers located on Long Island. Each of these Operating Reserve requirements shall be defined consistent with the Reliability Rules and other applicable reliability standards. The ISO shall also establish Scarcity Reserve Requirements in the Real-Time Market pursuant to Section 15.4.6.2 of this Rate Schedule, which may be met by Suppliers eligible to provide 30-Minute Reserve. Scarcity Reserve Requirements may only be met by eligible Suppliers that are located in the Scarcity Reserve Region associated with a given Scarcity Reserve Requirement. The ISO shall select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements and Scarcity Reserve Requirements, as part of its overall co-optimization process.

The ISO shall select Operating Reserves Suppliers that are properly located electrically so that all locational Operating Reserves requirements determined consistently with the requirements of Section 15.4.7 of this Rate Schedule and Scarcity Reserve Requirements determined consistently with the requirements of Section 15.4.6.2 of this Rate Schedule are satisfied, and so that transmission Constraints resulting from either the commitment or dispatch of Generators do not limit the ISO’s ability to deliver Energy to Loads in the case of a Contingency. The ISO will ensure that Suppliers that are compensated for using Capacity to provide one Operating Reserve product are not simultaneously compensated for providing another Operating Reserve product, or Regulation Service, using the same Capacity (consistent with the additive market clearing price calculation formulae in Sections 15.4.5.1 and 15.4.6.1 of this Rate Schedule).

15.4.1.2 Supplier Eligibility Criteria

The ISO shall enforce the following criteria, which define which types of Suppliers are eligible to supply particular Operating Reserve products.

15.4.1.2.1 Spinning Reserve:

Suppliers that are ISO Committed Flexible or Self-Committed Flexible, are operating within the dispatchable portion of their operating range, are capable of responding to ISO instructions to change their output level within ten minutes, and that meet the criteria set forth in the ISO Procedures shall be eligible to supply Spinning Reserve (except for Demand Side Resources that are Local Generators and Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit).

15.4.1.2.2 10-Minute Non-Synchronized Reserve:

(i) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes, (ii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within ten (10) minutes, and (iii) Demand Side Resources that are capable of reducing their Energy usage within ten (10) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply 10-Minute Non-Synchronized Reserve.

15.4.1.2.3 30-Minute Reserve:

Generators, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range and Demand Side Resources, that are not Local Generators, that are capable of reducing their Energy usage within thirty (30) minutes shall be eligible to supply synchronized 30-Minute Reserves. (i) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes, (ii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within thirty (30) minutes, and (iii) Demand Side Resources that are capable of reducing their Energy usage within thirty (30) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply non-synchronized 30-Minute Reserves.

15.4.1.2.4 Self-Committed Fixed and ISO-Committed Fixed Generators:

Shall not be eligible to provide any kind of Operating Reserve.

15.4.1.3 Other Supplier Requirements

All Suppliers of Operating Reserve must be located within the NYCA and must be under ISO Operational Control. Each Supplier bidding to supply Operating Reserve or reduce demand must be able to provide Energy or reduce demand consistent with the Reliability Rules and the ISO Procedures when called upon by the ISO.

All Suppliers that are selected to provide Operating Reserves shall ensure that their Resources maintain and deliver the appropriate quantity of Energy, or reduce the appropriate quantity of demand, when called upon by the ISO during any interval in which they have been selected.

Generators or Demand Side Resources that are selected to provide Operating Reserve in the Day-Ahead Market or any supplemental commitment may increase their Incremental Energy Bids or Demand Reduction Bids for portions of their Resources that have been scheduled through those processes; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. They may not, however, reduce their Day-Ahead Market or supplemental commitments in real-time except to the extent that they are directed to do so by the ISO. Generators and Demand Side Resources may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Operating Reserve.

15.4.2 General Day-Ahead Market Rules

15.4.2.1 Bidding and Bid Selection

Resources capable of providing Spinning Reserve, 10-Minute Non-Synchronized Reserve and/or 30-Minute Reserve in the Day-Ahead commitment may submit Availability Bids for each hour of the upcoming day. If a Supplier offers Resources that are capable, based on their indicated commitment status, of providing Operating Reserves but does not submit an Availability Bid, its Day-Ahead Bid will be rejected in its entirety. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new bid is timely.

The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the Resource's emergency response rate multiplied by ten; (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid; and (iii) for synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by twenty.

However, the sum of the amount of Energy or Demand Reduction each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E, whichever is applicable.

The ISO shall select Operating Reserve Suppliers for each hour of the upcoming day through a co-optimized Day-Ahead commitment process that minimizes the total bid cost of Energy, Operating Reserves and Regulation Service, using Bids submitted pursuant to Article 4.2 of, and Attachment D to, this ISO Services Tariff. As part of the co-optimization process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements specified above.

15.4.2.2 ISO Notice Requirement

The ISO shall notify each Operating Reserve Supplier that has been selected in the Day-Ahead Market of the amount of each Operating Reserve product that it has been scheduled to provide.

15.4.2.3 Real-Time Market Responsibilities of Suppliers Scheduled to Provide Operating Reserves in the Day-Ahead Market

Suppliers that are scheduled Day-Ahead to provide Operating Reserves shall either provide Operating Reserve, Energy or Demand Reductions in real-time when scheduled by the ISO in all hours for which they have been selected to provide Operating Reserve and are physically capable of doing so. However, Suppliers that are scheduled Day-Ahead to provide Operating Reserves and have startup periods of two hours or less may advise the ISO no later than three hours prior to the first hour of their Day-Ahead schedule that they will not be available to provide Operating Reserves or Energy in real-time under normal conditions. Such Suppliers will be required to settle their Day-Ahead schedule at real-time prices pursuant to Section 15.4.6.3 of this Rate Schedule. The only restriction on Suppliers' ability to exercise this option is that all Suppliers with Day-Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the ISO for dispatch in the RTD if the ISO initiates a Supplemental Resource Evaluation.

15.4.3 General Real-Time Market Rules

15.4.3.1 Bid Selection

The ISO will automatically select Operating Reserves Suppliers in real-time from eligible Resources, that submit Real-Time Bids pursuant to Section 4.4 of, and Attachment D to, this ISO Services Tariff. Each Supplier will automatically be assigned a real-time Operating Reserves Availability bid of $0/MW for the quantity of Capacity that it makes available to the ISO in its Real-Time Bid. The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the Resource's emergency response rate multiplied by ten; (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid); and (iii) for synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by twenty. However, the sum of the amount of Energy or Demand Reduction, that each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E, whichever is applicable.

Suppliers will thus be selected on the basis of their response rates, their applicable upper operating limits, and their Energy Bids (which will reflect their opportunity costs) through a co-optimized real-time commitment process that minimizes the total bid cost of Energy, or Demand

Reduction, Regulation Service, and Operating Reserves. As part of the process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements and Scarcity Reserve Requirements specified above.

15.4.3.2 ISO Notice Requirement

The ISO shall notify each Supplier of Operating Reserve that has been scheduled by RTD of the amount of Operating Reserve that it must provide.

15.4.3.3 Obligation to Make Resources Available to Provide Operating Reserves

Any Resource that is eligible to supply Operating Reserves and that is made available to ISO for dispatch in Real-Time must also make itself available to provide Operating Reserves.

15.4.3.4 Activation of Operating Reserves

All Resources that are selected by the ISO to provide Operating Reserves shall respond to the ISO's directions to activate in real-time.

15.4.3.5 Performance Tracking and Supplier Disqualifications

When a Supplier committed to supply Operating Reserves is activated, the ISO shall measure and track its actual Energy production or its Demand Reduction against its expected performance in real-time. The ISO may disqualify Suppliers that consistently fail to provide Energy or Demand Reduction when called upon to do so in real-time from providing Operating Reserves in the future. If a Resource has been disqualified, the ISO shall require it to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from it. Disqualification and re-qualification criteria shall be set forth in the ISO Procedures.

15.4.4 Operating Reserves Settlements - General Rules

15.4.4.1 Establishing Locational Reserve and Scarcity Reserve Requirement Prices

Except as noted below, the ISO shall calculate separate Day-Ahead Market and Real-Time Market prices for each of the products in four locations: (i) West of Central-East ("West" or "Western"); (ii) East of Central-East excluding Southeastern New York ("Eastern"); (iii) Southeastern New York excluding Long Island ("Southeastern"); and (iv) Long Island ("L.I."). The ISO will thus calculate twelve different locational Operating Reserve prices in both the Day-Ahead Market and the Real-Time Market. The ISO will also calculate prices in the Real-Time Market for each of the products in a Scarcity Reserve Region, if applicable. Day-Ahead locational reserve prices shall be calculated pursuant to Section 15.4.5 of this Rate Schedule. Real-Time locational Operating Reserves prices and Scarcity Reserve Requirement prices shall be calculated pursuant to Section 15.4.6 of this Rate Schedule

15.4.4.2 Settlements Involving Suppliers of Operating Reserves Located on Long Island

Suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York, except in the case of a Scarcity Reserve Requirement for a Scarcity Reserve Region that includes Long Island in addition to one or more other Load Zones. In this instance, suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York and in the applicable Scarcity Reserve Region. The ISO will calculate separate locational Long Island Operating Reserves prices and Long Island Scarcity Reserve Requirement prices for Scarcity Reserve Regions that include Long Island but will not post them or use them for settlement purposes.

15.4.4.3 "Cascading" of Operating Reserves

The ISO will deem Spinning Reserve to be the "highest quality" Operating Reserve, followed by 10-Minute Non-Synchronized Reserve and by 30-Minute Reserve. The ISO shall substitute higher quality Operating Reserves in place of lower quality Operating Reserves, when doing so lowers the total as-bid cost, *i.e.*, when the marginal cost for the higher quality Operating Reserve product is lower than the marginal cost for the lower quality Operating Reserve product, and the substitution of a higher quality for the lower quality product does not cause locational Operating Reserve requirements or Scarcity Reserve Requirements to be violated. To the extent, however, that reliability standards require the use of higher quality Operating Reserves, substitution cannot be made in the opposite direction.

The market clearing price of higher quality Operating Reserves will not be set at a price below the market clearing price of lower quality Operating Reserves in the same location or Scarcity Reserve Region. Thus, the market clearing price of Spinning Reserves will not be below the price for 10-Minute Non-Synchronized Reserves or 30-Minute Reserves and the market clearing price for 10-Minute Non-Synchronized Reserves will not be below the market clearing price for 30-Minute Reserves.

15.4.5 Operating Reserve Settlements – Day-Ahead Market

15.4.5.1 Calculation of Day-Ahead Market Clearing Prices

The ISO shall calculate hourly Day-Ahead Market clearing prices for each Operating Reserve product at each location. Each Day-Ahead Market clearing price shall equal the sum of the relevant Day-Ahead locational Shadow Prices for that product in that hour, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

The Day-Ahead Market clearing price for a particular Operating Reserve product in a particular location shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements, that a particular Operating Reserves product from a particular location may be used to satisfy in a given hour. The ISO shall calculate Day-Ahead Market clearing prices using the following formulae:

Market clearing price for Western 30-Minute Reserves = SP1

Market clearing price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2

Market clearing price for Western Spinning Reserves = SP1 + SP2 + SP3

Market clearing price for Eastern 30-Minute Reserves = SP1 + SP4

Market clearing price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5

Market clearing price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6

Market clearing price for Southeastern 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for Southeastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Market clearing price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 + SP12

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint for the hour

SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the hour

SP3 = Shadow Price for total Spinning Reserve requirement constraint for the hour

SP4 = Shadow Price for Eastern, Southeastern, or L.I. 30-Minute Reserve requirement constraint for the hour

SP5 = Shadow Price for Eastern, Southeastern, or L.I. 10-Minute Reserve requirement constraint for the hour

SP6 = Shadow Price for Eastern, Southeastern, or L.I. Spinning Reserve requirement constraint for the hour

SP7 = Shadow Price for Southeastern, or L.I. 30-Minute Reserve requirement constraint for the hour

SP8 = Shadow Price for Southeastern, or L.I. 10-Minute Reserve requirement constraint for the hour

SP9 =Shadow Price for Southeastern, or L.I. Spinning Reserve requirement constraint for the hour

SP10 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour

SP11 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour

SP12 = Shadow Price for Long Island Spinning Reserve requirement constraint for the hour

Day-Ahead locational Shadow Prices will be calculated by SCUC. Each hourly Day-Ahead Shadow Price for each Operating Reserves requirement shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that hour, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement shall include the Day-Ahead Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Day-Ahead Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by SCUC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If more Operating Reserve of a particular quality than is needed is scheduled to meet a particular locational Operating Reserve requirement, the Shadow Price for that Operating Reserve requirement constraint shall be set at zero.

Each Supplier that is scheduled Day-Ahead to provide Operating Reserve shall be paid the applicable Day-Ahead Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each hour.

15.4.5.2 Other Day-Ahead Payments

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

15.4.6 Operating Reserve Settlements – Real-Time Market

15.4.6.1 Calculation of Real-Time Market Clearing Prices

The ISO shall calculate Real-Time Market clearing prices for each Operating Reserve product for each location in every interval and Scarcity Reserve Region in each interval for which a Scarcity Reserve Requirement is established by the ISO. Each real-time market-clearing price shall equal the sum of the relevant real-time locational Shadow Prices and Scarcity Reserve Requirement Shadow Prices for a given product, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

The Real-Time Market clearing price for a particular Operating Reserve product for a particular location or Scarcity Reserve Region shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements and Scarcity Reserve Requirements, that a particular Operating Reserves product from that location or Scarcity Reserve Region may be used to satisfy in a given interval. The ISO shall calculate the Real-Time Market clearing prices using the following formulae:

Market clearing price for Western 30-Minute Reserves = SP1

Market clearing price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2

Market clearing price for Western Spinning Reserves = SP1 + SP2 + SP3

Market clearing price for Eastern 30-Minute Reserves = SP1 + SP4

Market clearing price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5

Market clearing price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6

Market clearing price for Southeastern 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for Southeastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Market clearing price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 +SP12

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the interval

SP3 = Shadow Price for total Spinning Reserve requirement constraint for the interval

SP4 = Shadow Price for Eastern, Southeastern, or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP5 = Shadow Price for Eastern, Southeastern, or L.I. 10-Minute Reserve requirement constraint for the interval

SP6 = Shadow Price for Eastern, Southeastern, or L.I. Spinning Reserve requirement constraint for the interval

SP7 = Shadow Price for Southeastern, or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP8 = Shadow Price for Southeastern, or L.I. 10-Minute Reserve requirement constraint for the interval

SP9 = Shadow Price for Southeastern, or L.I. Spinning Reserve requirement constraint for the interval

SP10 = Shadow Price for Long Island 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP11 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP12 = Shadow Price for Long Island Spinning Reserve requirement constraint for the interval

Real-time locational and Scarcity Reserve Requirement Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that interval, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that interval, as calculated during the second RTD pass described in Section 17.1.2.1.2.2 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, shall include the Real-Time Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve or Scarcity Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Real-Time Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by RTC at a cost greater than the relevant Operating Reserve Demand Curve or Scarcity Reserve Demand Curve indicates should be paid. If there is more Operating Reserve of the required quality than is needed to meet a particular locational Operating Reserve requirement or Scarcity Reserve Requirement then the Shadow Price for that Operating Reserve requirement or Scarcity Reserve Requirement constraint shall be zero.

Each Supplier that is scheduled in real-time to provide Operating Reserve shall be paid the applicable Real-Time Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each interval that was not scheduled Day-Ahead.

15.4.6.1.1 The Real-Time Market clearing price shall also reflect the Shadow Price for any Scarcity Reserve Requirement constraint as part of the applicable 30-Minute Reserve requirement constraint Shadow Price for the Load Zones included in the Scarcity Reserve Region. The inclusion of Scarcity Reserve Requirement constraint Shadow Prices in the calculation of Real-Time Market clearing prices is as set forth below:

(a) When the Load Zones included in a Scarcity Reserve Region are identical to the Load Zones of an existing locational reserve region, the Scarcity Reserve Requirement will be added to the existing 30-Minute Reserve requirement for the locational reserve region and the Shadow Price for the Scarcity Reserve Requirement will be the Shadow Price for the revised 30-Minute Reserve requirement. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones A, B, C, D, E, F, G, H, I, J and K (*i.e.*, all Load Zones), then the Shadow Price for the Scarcity Reserve Requirement shall be SP1. SP1 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones F, G, H, I, J and K (*i.e.*, all East of Central-East Load Zones), but does not include Load Zones A, B, C, D or E, then the Shadow Price for the Scarcity Reserve Requirement shall be SP4. SP4 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones G, H, I, J and K (*i.e.*, all Southeastern New York Load Zones), but does not include Load Zones A, B, C, D, E or F, then the Shadow Price for the Scarcity Reserve Requirement shall be SP7. SP7 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices; or

iv. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zone K (*i.e.*, Long Island only), but does not include Load Zones A, B, C, D, E, F, G, H, I or J, then the Shadow Price for the Scarcity Reserve Requirement shall be SP10. SP10 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices.

(b) When the Load Zones included in the Scarcity Reserve Region are not identical to the Load Zones of an existing locational reserve region, the Shadow Price attributable to the Scarcity Reserve Requirement will be added to the applicable Shadow Price for the 30-Minute Reserve requirement for the existing locational reserve region to which all of the Load Zones included in the Scarcity Reserve Region belong. The inclusion of the Scarcity Reserve Requirement Shadow Prices shall apply only to the Load Zones included as part of a Scarcity Reserve Region. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones A, B, C, D or E and Section 15.4.6.1.1(a)(i) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP1 for each of the Load Zones included in the Scarcity Reserve Region. This SP1 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region;

ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least Load Zone F, but does not include Load Zones A, B, C, D or E and Section 15.4.6.1.1(a)(ii) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP4 for each of the Load Zones included in the Scarcity Reserve Region. This SP4 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region; or

iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones G, H, I or J, but does not include Load Zones A, B, C, D, E or F and Section 15.4.6.1.1(a)(iii) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP7 for each of the Load Zones included in the Scarcity Reserve Region. This SP7 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region.

15.4.6.2 Establishment of Scarcity Reserve Requirements in the Real-Time Market During EDRP/SCR Activations

The ISO will establish a Scarcity Reserve Requirement for each Scarcity Reserve Region when it has called upon the EDRP and/or SCRs in identified Load Zones to reduce Load to address a reliability need. The Scarcity Reserve Requirement will be applicable for all real-time intervals during which the ISO has activated EDRP and/or SCRs within the applicable Scarcity Reserve Region to provide Load reduction. The Scarcity Reserve Requirement for each affected real-time interval shall be an amount equal to the sum of the applicable values for the Expected EDRP/SCR MW for all of the Load Zones included in a Scarcity Reserve Region, less the Available Operating Capacity in the Scarcity Reserve Region; provided, however, that a Scarcity Reserve Requirement shall not have a value less than zero.

The applicable value of the Expected EDRP/SCR MW for each Load Zone included in a Scarcity Reserve Region to be used in calculating the Scarcity Reserve Requirement is dependent upon whether the Load reduction for a given interval is deemed voluntary or mandatory for purposes of calculating the Scarcity Reserve Requirement, as further described below. If the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of this ISO Services Tariff for the SCRs within any Load Zone for any hour encompassed by the EDRP/SCR activation(s) for the day at issue, the Load reduction for all intervals encompassed by such activation(s) are deemed to be mandatory for the purposes of calculating any Scarcity Reserve Requirement only and the corresponding value for a mandatory Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. In all other circumstances not encompassed by the preceding sentence, the Load reduction for all intervals encompassed by such EDRP/SCR activation(s) are deemed to be voluntary for the day at issue and the corresponding value for a voluntary Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. For EDRP, Load reduction is deemed to be voluntary in all intervals and the value for EDRP included in the Expected EDRP/SCR MW value for each Load Zone reflects the voluntary nature of the Load reduction.

15.4.6.3 Operating Reserve Balancing Payments

Any deviation in performance from a Supplier's Day-Ahead schedule to provide Operating Reserves, including deviations that result from schedule modifications made by the ISO, shall be settled pursuant to the following rules.

(a) When the Supplier's real-time Operating Reserves schedule is less than its Day-Ahead Operating Reserves schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserves Product in the relevant location or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

(b) When the Supplier's real-time Operating Reserves schedule is greater than its Day-Ahead Operating Reserves schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserve product in the relevant location or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

15.4.6.4 Other Real-Time Payments

The ISO shall pay Generators that are selected to provide Operating Reserves Day-Ahead, but are directed to convert to Energy production in real-time, the applicable Real-Time LBMP for all Energy they are directed to produce in excess of their Day-Ahead Energy schedule.

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

A Supplier that provides Operating Reserves may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.6.5 and Attachment J of this ISO Services Tariff.

15.4.7 Operating Reserve Demand Curves and Scarcity Reserve Demand Curve

The ISO shall establish twelve Operating Reserve Demand Curves, one for each locational Operating Reserves requirement. Specifically, there shall be a demand curve for: (i) Total Spinning Reserves; (ii) Eastern, Southeastern or Long Island Spinning Reserves; (iii) Southeastern or Long Island Spinning Reserves (iv) Long Island Spinning Reserves; (v) Total 10-Minute Reserves; (vi) Eastern, Southeastern or Long Island 10-Minute Reserves; (vii) Southeastern or Long Island 10-Minute Reserves; (viii) Long Island 10-Minute Reserves; (ix) Total 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement); (x) Eastern, Southeastern or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); (xi) Southeastern or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); and (xii) Long

Island 30-Minute Reserves (including a separate demand curve applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply). Each Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location, except for those demand curves that apply to certain Scarcity Reserve Requirements which will be applicable only during the real-time intervals that a Scarcity Reserve Requirement has been established by the ISO. The ISO shall also establish a Scarcity Reserve Demand Curve for each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. A Scarcity Reserve Demand Curve will be applicable only during the real-time intervals that such a Scarcity Reserve Requirement has been established by the ISO.

The market clearing pricing for Operating Reserves shall be calculated pursuant to Sections 15.4.5.1 and 15.4.6.1 of this Rate Schedule and in a manner consistent with the demand curves established in this Section so that Operating Reserves are not purchased by SCUC, RTC or RTD at a cost higher than the relevant demand curve indicates should be paid.

The ISO Procedures shall establish and post a target level for each locational Operating Reserves requirement for each hour, which will be the number of MW of Operating Reserves meeting that requirement that the ISO would seek to maintain in that hour. To the extent not otherwise already adjusted pursuant to Section 15.4.6.1.1(a) of this Rate Schedule, during each real-time interval in which the ISO has established a Scarcity Reserve Requirement, the ISO will adjust the target level for the locational 30-Minute Reserves requirement to account for the Scarcity Reserve Requirement within the existing locational reserve region(s) to which all the Load Zones included in the Scarcity Reserve Region belong. The ISO will then define an

Operating Reserves demand curve for that hour corresponding to each Operating Reserves requirement as follows:

(a) Total Spinning Reserves: For quantities of Operating Reserves meeting the total Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total Spinning Reserves demand curve shall be $775/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be $0/MW.

(b) Eastern, Southeastern or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island Spinning Reserves demand curve shall be $0/MW.

(c) Southeastern or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern or Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern or Long Island Spinning Reserves demand curve shall be $0/MW.

(d) Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island Spinning

Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island Spinning Reserves demand curve shall be $0/MW.

(e) Total 10-Minute Reserves: For quantities of Operating Reserves meeting the total 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total 10-minute reserves demand curve shall be $750/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be $0/MW.

(f) Eastern, Southeastern or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island 10-minute reserves demand curve shall be $775/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 10-minute reserves demand curve shall be $0/MW.

(g) Southeastern or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island 10-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern or Long Island 10-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern or Long Island 10-Minute Reserves demand curve shall be $0/MW.

(h) Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 10-

minute reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 10-minute reserves demand curve shall be $0/MW.

(i) Total 30-Minute Reserves: For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 655 MW but that exceed the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $200/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 300 MW but that exceed the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be $100/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement but that exceed the target level for that locational requirement minus 300 MW, the price on the total 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the requirement for that hour. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in

Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("NYCA scarcity target level") that are less than or equal to the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the NYCA scarcity target level that are less than or equal to the NYCA scarcity target level but that exceed the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the Scarcity Reserve Requirement for that interval.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted NYCA target level") that are less than or equal to the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the adjusted NYCA target level that are less than or equal to the adjusted NYCA target level but that exceed the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the applicable Scarcity Reserve Requirement(s) for that interval.

(j) Eastern, Southeastern or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Eastern scarcity target level") that are less than or equal to the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Eastern scarcity target level that are less than or equal to the Eastern scarcity target level but exceed the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target level, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the East of Central-East reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted Eastern target level") that are less than or equal to the adjusted Eastern target level, the price on the Eastern, Southeastern or Long

Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

(k) Southeastern or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Southeastern scarcity target level") that are less than or equal to the Southeastern scarcity target level, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the Southeastern

New York reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted Southeastern target level") that are less than or equal to the adjusted Southeastern target level, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

(l) Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Long Island scarcity target level") that are less than or equal to the

Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target, the price on the Long Island 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Long Island scarcity target level that are less than or equal to the Long Island scarcity target level but exceed the Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target level, the price on the Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be $0/MW.

The ISO will procure additional Operating Reserves to meet each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. The Scarcity Reserve Demand Curve for each real-time interval in which the ISO has established such a Scarcity Reserve Requirement shall be defined as follows: For quantities of Operating Reserves meeting the Scarcity Reserve Requirement that are less than or equal to the Scarcity Reserve Requirement, the price on the Scarcity Reserve Demand Curve shall be $500/MW. For all other quantities, the price on the Scarcity Reserve Demand Curve shall be $0/MW.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure any Operating Reserve product at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Operating Reserves Demand Curves the ISO, in consultation with its Market Advisor, shall conduct an initial review of them in accordance with the ISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether any Operating Reserve Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the ISO Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.4.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 4 to the Services Tariff are also addressed in Section 30.4.6.4.2 of Attachment O.

15.4.8 Self-Supply

Transactions may be entered into to provide for Self-Supply of Operating Reserves. Except as noted in the next paragraph, Customers seeking to Self-Supply Operating Reserves must place the Generator(s) supplying any one of the Operating Reserves under ISO control. The Generator(s) must meet ISO rules for acceptability. The amount that any such Customer will be charged for Operating Reserves will be reduced by the market value of the services provided by the specified Generator(s) as determined in the ISO Services Tariff.

Alternatively, Customers, including LSEs, may enter into Day-Ahead Bilateral financial Transactions, *e.g.*, contracts-for-differences, in order to hedge against price volatility in the Operating Reserves markets.

15.5 Rate Schedule 5 - Payments and Charges for Black Start and System Restoration Services

Black start and system restoration services ("Restoration Services") are provided under the ISO's black start and system restoration plan ("ISO Plan") or an individual Transmission Owner's black start and system restoration plan by generating units that are capable of starting without an outside electrical supply or are otherwise integral to the restoration of the NYS Transmission System after an outage. This Rate Schedule establishes the terms under which a Generator shall provide, and be paid by the ISO for providing, Restoration Services under the ISO Plan or an individual Transmission Owner's plan. This Rate Schedule also establishes the terms under which the ISO shall recover the costs of Restoration Services payments from Customers. Provisions specific to the Consolidated Edison Company of New York, Inc. ("Consolidated Edison") black start and system restoration plan ("Consolidated Edison Plan") are set forth in Section 15.5.4.

15.5.1 Requirements

The ISO shall develop and periodically review the ISO Plan. The ISO may amend the ISO Plan and may solicit offers for additional resources if it determines that additional Restoration Services are needed. The ISO shall establish procedures for acquiring Restoration Services and requiring that the selected Generators test their units providing Restoration Services ("Black Start Capability Test"). The ISO shall make Restoration Services payments only to those selected Generators that have appropriate equipment installed and available for service at the request of the ISO.

A Transmission Owner shall develop and periodically review its black start and system restoration plan. A Transmission Owner shall designate generating units with the capability to provide Restoration Services to be included in its plan if it determines that the Restoration

Services are needed. The ISO will make payments for such local Restoration Services to the Generators that provide them under the terms of this Rate Schedule. Generators that are obligated to provide Restoration Services as a result of divestiture contract agreements will not receive Restoration Services payments from the ISO for those services if they are already compensated as part of those divestiture contracts. Customers in the local Transmission Owner service territories will be charged for those services by the ISO under the terms of this Rate Schedule. Customers may not Self-Supply Restoration Services.

15.5.2 Payments to Generators for Provision of Restoration Services Under the ISO Plan and Transmission Owners' Plans, Excluding the Consolidated Edison Plan

By May 1st of each year, Generators selected to provide Restoration Services under the ISO Plan and under the plans developed by individual Transmission Owners, except for under the Consolidated Edison Plan, must provide the following cost information to the ISO based upon FERC Form No. 1 or equivalent data:

- Capital and fixed operation and maintenance costs associated with only that equipment which provides Restoration Services capability;
- Annual costs associated with training operators in Restoration Services; and
- Annual costs associated with Black Start Capability Tests in accordance with the ISO Plan or the plan of an individual Transmission Owner.

Each Billing Period, the ISO shall pay each Generator on the basis of its costs filed with the ISO. The daily rate for Restoration Services payments will be determined by dividing the Generator's annual cost by the number of days in the year from May 1st through April 30th of the following year.

Generators that provide Restoration Services shall conduct Black Start Capability Tests that are deemed necessary and appropriate for providers of these services under the ISO Procedures or local Transmission Owner procedures, as applicable. Any Generator that is awarded Restoration Services payments and fails a Black Start Capability Test shall forfeit all payments for such services since its last successful test. Payments to that Generator shall resume upon its successful completion of the test.

15.5.3 Charges to Support Payments to Generators Under the ISO Plan and Individual Transmission Owners' Plans, Excluding the Consolidated Edison Plan.

Each Billing Period, the ISO shall charge, and each Customer shall pay based on its supply of Load that is *not* used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the costs of the ISO's payments to Generators providing Restoration Services under the ISO Plan. The charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the NYCA that is *not* used to supply Station Power as a third-party provider for each hour in the Billing Period, and (ii) the ISO's total payments to Generators providing Restoration Services under the ISO Plan under Section 15.5.2 to this Rate Schedule for the Billing Period, divided by the total number of hours in the Billing Period, (B) summed for all hours in the Billing Period.

Each Billing Period, the ISO shall charge, and each Customer shall pay based on its supply of Load that is used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the costs of the ISO's payments to Generators providing Restoration Services under the ISO Plan. The charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the NYCA that is used to supply Station Power as a third-party provider for each day in the Billing Period, and (ii) the ISO's total payments to Generators providing Restoration Services under the ISO Plan under Section 15.5.2 to this Rate Schedule for the Billing Period, divided by the total number of days in the Billing Period, (B) summed for all days in the Billing Period. The ISO shall credit these daily charge amounts to Customers based on their share of the Load in the NYCA that is not used to supply Station Power as a third-party provider for that day. The ISO shall sum these daily credits for all days in the Billing Period.

A Customer will be responsible for the following additional charge if the Transmission Owner in whose Transmission District the Customer is located maintains a Restoration Services plan, except with respect to the Consolidated Edison Plan, the cost recovery requirements of which are set forth in Section 15.5.4.2 to this Rate Schedule. Each Billing Period, the ISO shall charge, and each Customer in the local Transmission Owner's Transmission District shall pay, a charge for the recovery of the costs of the ISO's payments to Generators providing Restoration Services under the Transmission Owner's local Restoration Services plan. This charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the Transmission Owner's Transmission District for each hour in the Billing Period, and (ii) the ISO's total payments to Generators providing Restoration Services under the Transmission Owner's Restoration Services plan under Section 15.5.2 to this Rate Schedule for the Billing Period, divided by the total number of hours in the Billing Period, (B) summed for all hours in the Billing Period.

15.5.4 Payments to Generators Providing Restoration Services Under the Consolidated Edison Plan and Recovery of Associated Costs

A Generator that provides Restoration Services under the Consolidated Edison Plan shall provide, and be paid for providing, Restoration Services under the terms set forth in Section 15.5.4.1 and Appendix I to this Rate Schedule. If Consolidated Edison determines that additional Restoration Services are needed, it may from time to time designate for inclusion in the Consolidated Edison Plan: (i) an existing generating unit that is capable of providing Restoration Services but that is not currently doing so, or (ii) a generating unit for which the Generator has provided notice to withdraw from the Consolidated Edison Plan pursuant to Section 15.5.4.1.1. A generating unit designated by Consolidated Edison may elect to participate in the Consolidated Edison Plan; otherwise it shall be required to participate in the Consolidated Edison Plan unless the ISO determines that: (i) the generating unit would not provide a material benefit to system restoration in Zone J, or (ii) the Generator shows good cause that it would be unduly burdensome or unreasonable to require it to provide Restoration Services from the designated generating unit.

The provision of Restoration Services will be deemed to provide a material benefit to system restoration in Zone J if, among other things, it would materially improve the speed, adequacy, or flexibility of the Consolidated Edison Plan for restoring electric service in Zone J in a safe, orderly, and prompt manner following a major system disturbance.

To facilitate the ISO's determination regarding material benefit, Consolidated Edison shall provide a study and/or other documentation, performed at its own expense, supporting the conclusion that the designated generating unit would provide a material benefit for system restoration in Zone J. Consolidated Edison's documentation must: (i) include its assessment of the adequacy of resources already committed to provide Restoration Services under the Consolidated Edison Plan and the need for additional resources, (ii) describe the manner in which the designated generating unit would provide a material benefit for system restoration in Zone J, and (iii) summarize alternative solutions evaluated, if applicable, and indicate whether other generating units would provide the particular material benefit identified. Consolidated Edison shall provide its documentation to the ISO and the relevant Generator, subject to appropriate confidentiality protections. Upon request, Consolidated Edison shall provide the documentation to other parties that have a direct interest in this matter, subject to appropriate confidentiality protections.

If the Generator asserts that good cause exists for not requiring its generating unit to participate in the Consolidated Edison Plan, it must seek an exemption from the ISO. The Generator shall provide a study or other documentation demonstrating the engineering, technical, financial, environmental, and/or other reasons that provision or continued provision of Restoration Services by the designated generating unit would be unduly burdensome or unreasonable. The Generator shall provide its documentation to the ISO and Consolidated Edison, subject to appropriate confidentiality protections. The Generator may provide the documentation to other parties that have a direct interest in this matter as well, subject to appropriate confidentiality protections. In making its determination, the ISO may rely on the supporting documentation provided by the Generator and Consolidated Edison, along with any information developed by the ISO.

If the ISO determines that good cause exists to grant a requested exemption, the designated generating unit will not be required to participate in the Consolidated Edison Plan. Otherwise, the designated generating unit will be required to participate in the Consolidated Edison Plan and will be assigned by the ISO to a Commitment Group under Section 15.5.4.1.1. The ISO shall inform NYSRC of a designated generating unit's request for an exemption and the ISO's determination under this Section 15.5.4.

A Generator's unit that is designated by Consolidated Edison to participate in the Consolidated Edison Plan, and is not granted an exemption under this Section 15.5.4 shall provide, and be paid for providing, Restoration Services under the terms set forth in Section 15.5.4.1 and AppendixI to this Rate Schedule.

The ISO shall recover the costs of the payments established in Section 15.5.4.1 from Customers in the Consolidated Edison Transmission District under the terms set forth in Section 15.5.4.2.

Within thirty (30) days of receipt of an updated Consolidated Edison Plan, including changes to unit designations as described in this section, the ISO will file a copy with FERC on an informational basis with a non-public Critical Energy Infrastructure Information designation.

15.5.4.1 Payments to Generators that Provide Restoration Services Under the Consolidated Edison Plan

15.5.4.1.1 Commitment Requirements for Restoration Services

Each generating unit committed to provide Restoration Services under the Consolidated Edison Plan before November 1, 2012, was included in one of three groups ("Commitment Groups") with the following initial commitment periods:

Commitment Group 1: November 1, 2012, through April 30, 2015.

Commitment Group 2: November 1, 2012, through April 30, 2016.

Commitment Group 3: November 1, 2012, through April 30, 2017.

The ISO shall assign a generating unit subsequently designated to provide Restoration Services under the Consolidated Edison Plan to one of these Commitment Groups.

At the conclusion of each commitment period, a generating unit shall begin a new three (3) year commitment period to provide Restoration Services under the Consolidated Edison Plan; provided, however, that the unit shall not begin a new commitment period if the Generator or Consolidated Edison provides the ISO with notice at least two years prior to the conclusion of the previous commitment period that the unit will no longer be part of the Consolidated Edison Plan following the conclusion of that commitment period.

Notwithstanding the foregoing, a unit previously designated under Section 15.5.4 shall be required to begin a new commitment period if: (i) Consolidated Edison provides the ISO and the Generator with notice at least one year prior to the conclusion of the previous commitment period that the unit continues to be required to provide a material benefit to system restoration in

Zone J, (ii) and the ISO determines that the unit should continue to provide service in accordance with the designation requirements in Section 15.5.4, including the opportunity for the Generator to request an exemption.

Consolidated Edison shall not remove from the Consolidated Edison Plan a new or repowered unit that was required to provide Restoration Services in the Consolidated Edison Plan pursuant to Section 30.2.5 of Attachment X to the ISO OATT before the Generator recovers the incremental capital costs it incurred in installing the Restoration Services capability for its unit. The Generator shall be deemed to have recovered these costs: (a) twenty-five years from the start of the unit's provision of Restoration Services if the Generator is taking payment pursuant to Section 15.5.4.1.3.1 to this Rate Schedule, or (b) over the period set forth in the Generator's unit-specific rate approved by FERC pursuant to Section 15.5.4.1.3.2 to this Rate Schedule. If a Generator withdraws its unit from the Consolidated Edison Plan before the completion of this time period, it will forfeit its entitlement to recover its incremental capital costs.

If a Generator withdraws a unit from the ISO's energy and capacity markets, the unit may cease its provision of Restoration Services at the same time without completing its commitment period. If the Generator returns the unit to the ISO's energy and capacity markets within three years of its withdrawal, the unit shall be required to provide Restoration Services for that portion of its commitment period that it had not completed.

15.5.4.1.2 Generator Testing and Training Requirements

A Generator shall conduct an annual Black Start Capability Test of each unit committed to provide Restoration Services under the Consolidated Edison Plan in accordance with the test protocols required by the Reliability Rules and applicable reliability standards and set forth in ISO Procedures. A Generator shall also identify its unit's critical Restoration Services equipment, maintain this equipment and perform tests to verify the condition of this critical equipment in accordance with good utility practice. Upon the performance of a Black Start Capability Test for its unit, the Generator shall submit a certification to the ISO each year – in the form provided in Appendix II to this Rate Schedule – indicating whether its unit has successfully completed its annual Black Start Capability Test and certifying that it maintains and tests the unit's critical Restoration Services equipment in accordance with good utility practice. The Generator shall also ensure that all appropriate personnel are trained in Restoration Services operations.

15.5.4.1.3 Payments to Generators for Providing Restoration Services Under the Consolidated Edison Plan

15.5.4.1.3.1 Standard Compensation

Except as set forth in Section 15.5.4.1.3.2 to this Rate Schedule, the ISO shall pay a Generator each Billing Period the pro rata share of the sum of the annual payment amounts for the provision of Restoration Services under the Consolidated Edison Plan at each of the Generator's facilities, as determined for each facility as follows.

The ISO shall calculate the annual Restoration Services payment amount for each Generator's facility for the compensation period of May 1 of each year through the following April 30; *provided, however*, the ISO shall recalculate the annual Restoration Services payment amount if, during the May 1 through April 30 compensation period, one of the Generator's units withdraws from the Consolidated Edison Plan pursuant to Section 15.5.4.1.1 to this Rate Schedule or fails a Black Start Capability Test pursuant to Section 15.5.4.1.3.4 to this Rate Schedule.

The annual Restoration Services payment amount for each Generator's facility shall be equal to the sum of the annual payment amounts, calculated according to the following formula, for: (i) each unit at a Generator's facility providing Restoration Services under the Consolidated Edison Plan that is the sole user of equipment necessary to black start the unit and is not designated with other units as a group by the ISO ("Sole Black Start Unit"), and (ii) each group of units at the Generator's facility providing Restoration Services under the Consolidated Edison Plan that share the equipment necessary to black start the units or are otherwise designated as a group by the ISO ("Black Start Unit Group"). The ISO shall designate a Generator's unit as a Sole Black Start Unit or as part of a Black Start Unit Group at the start of the unit's commitment period, and this designation shall not be subject to change for the duration of the unit's commitment period.

$RSPayment_{AnnBSU}$ =

$$ActRSUnits_{BSU} \times \left(\frac{RSSlCap_{Ann} + RSSlO\&M_{Ann} + RSAddCap_{Ann} + RSAddO\&M_{Ann}}{DesRSUnits_{BSU}} \right)$$

Where:

BSU = The Sole Black Start Unit or the Black Start Unit Group.

$RSPayment_{AnnBSU}$ = The annual amount, in $, that the ISO shall pay a Generator for the Sole Black Start Unit or the Black Start Unit Group providing Restoration Services under the Consolidated Edison Plan.

$DesRSUnits_{BSU}$ = The number of units in the Sole Black Start Unit or the Black Start Unit Group designated by Consolidated Edison as participants in the Consolidated Edison Plan.

$ActRSUnits_{BSU}$ = The number of units in the Sole Black Start Units or the Black Start Unit Group actually participating in the Consolidated Edison Plan, which shall not include any unit designated by Consolidated Edison as a participant in the Consolidated Edison Plan that has withdrawn from the plan pursuant to Section 15.5.4.1.1 to this Rate Schedule or has failed a Black Start Capability Test pursuant to Section 15.5.4.1.3.4 to this Rate Schedule.

$RSSlCap_{Ann}$ = The station-level capital payment amount, in $, for the Sole Black Start Unit or for one unit of the Black Start Unit Group, as specified in the "Station-level" column of Table A, below, on the basis of that unit's size.

$RSSlO\&M_{Ann}$ = The station-level operating and maintenance amount, in $, for the Sole Black Start Unit or for one unit of the Black Start Unit Group, as specified in the "Station-level" column of Table B, below, on the basis of the unit's size.

$RSAddCap_{Ann}$ = The sum of the incremental capital payment amounts, in $, for the remaining units in the Black Start Unit Group, as specified in the "Additional Resource" column of Table A, below, on the basis of the remaining units' sizes.

$RSAddO\&M_{Ann}$ = The sum of the incremental operating and maintenance payment amounts, in $, for the remaining units in the Black Start Unit Group, as specified in the "Additional Resource" column in Table B, below, on the basis of the remaining units' sizes.

Table A - Restoration Services Capital Payments

Resource Type	Station-level Capital Payment	Additional Resource Capital Payment
MVA ≤ 10	$21,770	$10,880
10 < MVA ≤ 60	$214,570	$10,880
60 < MVA ≤ 90	$248,460	$10,880
90 < MVA ≤ 300, Small Starting Requirement	$414,980	$10,880
90 < MVA ≤ 300, Medium Starting Requirement	$957,920	$10,880
90 < MVA ≤ 300, Large Starting Requirement	$1,785,080	$10,880
300 < MVA, Large Starting Requirement	$1,833,750	$32,650

Table B - Restoration Services O&M Payments

Resource Type	Station-level O&M Payment	Additional Resource O&M Payment
MVA ≤ 10	$22,335	$6,040
10 < MVA ≤ 60	$42,295	$8,200
60 < MVA ≤ 90	$49,850	$10,140
90 < MVA ≤ 300, Small Starting Requirement	$118,255	$33,665
90 < MVA ≤ 300, Medium Starting Requirement	$252,265	$65,600
90 < MVA ≤ 300, Large Starting Requirement	$388,865	$65,820
300 < MVA, Large Starting Requirement	$414,540	$77,685

The figures in Tables A and B are determined as of 2011. The ISO shall adjust these figures annually using the “Gas Turbogenerators” subcategory of the “Other Production Plant” category of the Handy Whitman Index for the North Atlantic Region.

15.5.4.1.3.2 Unit-Specific Compensation

A Generator shall be entitled to recover through this ISO Services Tariff the actual, incremental cost of its unit’s or units’ provision of Restoration Services under the Consolidated Edison Plan. If the Generator determines that its actual, incremental cost of providing Restoration Services to the ISO from its unit(s) exceeds the payment amount determined under Section 15.5.4.1.3.1 to this Rate Schedule, the Generator shall submit to the ISO actual incremental cost documentation showing: (1) that the actual, incremental costs are reasonably and prudently incurred, (2) that the actual incremental costs are incurred solely for the purpose of providing Restoration Services, and (3) that the actual incremental costs exceed the payment amount determined under Section 15.5.4.1.3.1 to this Rate Schedule. Within thirty (30) days of receipt of all necessary documentation, or longer if the parties agree, the ISO will file at FERC, jointly with the Generator, the information provided by the Generator along with the proposed tariff appendix. The Generator will retain the burden to show that its unit(s)-specific rate request meets the cost showing requirements outlined in this section. NYISO may subsequently comment on the substance of the proposed filing during the FERC noticed comment period. Upon approval by FERC, the Generator’s unit(s)-specific rate shall be included as an appendix to this Rate Schedule. In such case, the ISO shall pay a Generator each Billing Period the pro rata share of the FERC-approved annual rate for its unit(s), except as set forth in Section 15.5.4.1.3.4 to this Rate Schedule. The ISO shall recover the costs of these payments from Customers in the Consolidated Edison Transmission District under Section 15.5.4.2 to this Rate Schedule.

15.5.4.1.3.3 Eligibility for Additional Cost Recovery

The ISO shall reimburse Generators for equipment damage if the ISO reasonably finds: (1) the damage resulted from operating such equipment in response to operational orders from the ISO, or Consolidated Edison, pursuant to the ISO Tariffs, (2) that reasonably available and customary insurance was not available for the damages incurred, and (3) the damage would not have occurred but for the Generator's provision of Restoration Services. The burden of making such showings shall be upon the Generator.

The payments for each Billing Period shall also include compensation for legitimate, verifiable, and adequately documented costs incurred solely as a result of a Generator's compliance with NERC critical infrastructure protection ("CIP") reliability standards applicable to the provision of Restoration Services, *i.e.*, a CIP cost that would not have been incurred if it were not providing Restoration Services. The Generator shall provide such invoices to the ISO, which will review and determine if compensation is appropriate.

15.5.4.1.3.4 Forfeiture of Payments As a Result of Failed Black Start Capability Tests

If a Generator's unit fails a Black Start Capability Test, the Generator shall forfeit all Restoration Service payments for that unit under Sections 15.5.4.1.3.1 and 15.5.4.1.3.2 from the date of the failed test; provided, however, that if the Generator's unit successfully completes the Black Start Capability Test within thirty days of the failed test, the Generator shall not forfeit its payments. This thirty-day period may be extended if agreed upon by the ISO, the Generator, and Consolidated Edison. If the Generator does not successfully complete its Black Start Capability Test within this thirty day, or extended, period and successfully completes the test at a later date, it shall receive its Restoration Services payments only from the date of the later, successful test going forward.

15.5.4.2 Charges to Support Payments to Generators Under the Consolidated Edison Plan

Each Billing Period, the ISO shall charge, and each Customer in the Consolidated Edison Transmission District shall pay based on its supply of Load in that Transmission District that is *not* used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the ISO's payments to Generators providing Restoration Services under the Consolidated Edison Plan under Section 15.5.4.1 to this Rate Schedule. This charge shall be equal to: (A) the product of : (i) the Customer's share of Load in the Consolidated Edison Transmission District that is not used to supply Station Power as a third-party provided for each hour in the Billing Period, and (ii) the ISO's total payments to Generators for Restoration Services under the Consolidated Edison Restoration Plan under Sections 15.5.4.1 for the Billing Period, divided by the total number of hours in the Billing Period, (B) summed for all hours in the Billing Period.

Each Billing Period, the ISO shall charge, and each Customer in the Consolidated Edison Transmission District shall pay based on its supply of Load in that Transmission District that is used to supply Station Power as a third-party provider under Part 5 of the ISO OATT, a charge for the recovery of the ISO's payments to Generators providing Restoration Services under the Consolidated Edison Plan under Section 15.5.4.1 to this Rate Schedule. This charge shall be equal to: (A) the product of: (i) the Customer's share of Load in the Consolidated Edison Transmission District that is used to supply Station Power as a third-party provided for each day in the Billing Period, and (ii) the ISO's total payments to Generators for Restoration Services under the Consolidated Edison Restoration Plan under Section 15.5.4.1 for the Billing Period, divided by the total number of days in the Billing Period, (B) summed for all days in the Billing Period. The ISO shall credit these daily charge amounts to Customers based on their share of

Load in the NYCA that is not used to supply Station Power as a third-party provider for that day.

The ISO shall sum these daily credits for all days in the Billing Period.

Rate Schedule 5. Appendix I
Restoration Services Certification Form

[Name of Generator] hereby certifies that the **[name/location of unit]** performed a Black Start Capability Test on **[date]** and **[successfully completed/did not complete]** this test in accordance with the applicable ISO Procedures.

[Name of Generator] further certifies that it has identified a list of critical components in its units providing Restoration Services (e.g., batteries, diesel back-up generators, inverters etc.), maintains such critical components, and has performed tests to verify the condition of these critical components in accordance with good utility practice.

____

Signature of Officer

15.6 Rate Schedule 6 - Quick Start Reserves

This Rate Schedule applies to the scheduling and payment mechanisms for Quick Start Reserves.

15.6.1 Qualification to Provide Quick Start Reserves

15.6.1.1 A Supplier may offer Quick Start Reserves from one or more blocks of generator units to the Transmission Owner to which the block of generator units is interconnected if the block of generator units is (i) qualified to provide 30-Minute Reserves, and (ii) capable of being set to Quick Start Mode.

15.6.1.2 A Supplier intending to offer Quick Start Reserves shall undertake a test scheduled pursuant to the ISO Procedures for Installed Capacity Suppliers qualifying to sell Installed Capacity in the NYCA to determine the DMNC of the Supplier's block of generator units. The Supplier shall, while undertaking the DMNC test in Quick Start Mode, make record of and notify, for information purposes, the Transmission Owner in the Supplier's Transmission District and the ISO of (i) the output level in MWs that the block of generator units produced at ten (10) minutes following start-up; and (ii) the output level in MWs that the block of generator units produced at fifteen (15) minutes following start-up. Delivery of this information to the Transmission Owner in the Supplier's Transmission District and the ISO shall constitute and be deemed to be a standing offer to provide Quick Start Reserves pursuant to Section 15.6.2 of this Rate Schedule until (i) the Supplier performs another DMNC test and provides the information required pursuant to this Section 15.6.1.2 to the ISO and the Transmission Owner, (ii) thirty (30) days after providing a notice to the ISO and the Transmission Owner that it no longer offers Quick Start Reserves from any one or more blocks of generator units, provided that the supplier is not otherwise required to provide Quick Start Reserves, or (iii) the Supplier is not paid for Quick Start Reserves as provided herein.

15.6.1.3 A Supplier shall maintain each block of generator units for which Quick Start Reserves are offered in good working order to provide Energy in an amount at its temperature-adjusted DMNC within fifteen (15) minutes of remote start-up.

15.6.1.4 A Transmission Owner receiving the information specified in Section 15.6.1.2 of this Rate Schedule shall confirm to the ISO and the Supplier whether the Transmission Owner has the ability to remotely start up a block of generator units that the Supplier has offered for Quick Start Reserves. This confirmation informs the Supplier that the Transmission Owner or the ISO may elect to purchase Quick Start Reserves from each block of generator units that the Supplier has offered for Quick Start Reserves.

15.6.2 Purchase and Selection of Quick Start Reserves and Associated Duties

15.6.2.1 When a Transmission Owner has issued confirmation pursuant to Section 15.6.1.4 of this Rate Schedule and requires Quick Start Reserves, the Transmission Owner may purchase Quick Start Reserves from the Supplier by telephonic request; provided, however, that the Transmission Owner shall not purchase Quick Start Reserves unless the Transmission Owner has received the ISO's concurrence with the proposed purchase of Quick Start Reserves. The telephonic request shall specify the starting time and either the number of MWs of Quick Start Reserves required or the block of generator units from which the

Supplier is to sell Quick Start Reserves. In addition, the telephonic request shall, if available and for information purposes only, specify the estimated number of hours for which the Transmission Owner intends to purchase Quick Start Reserves. The Transmission Owner shall give written notice by electronic mail (or fax if electronic mail is not available) to each of the Supplier and the ISO of the telephonic request within ten (10) minutes of making the telephonic request, and the written notice by electronic mail or fax shall provide the same information specified in the Transmission Owner's telephonic request and shall also provide the time of the telephonic request. If the Supplier has not received such written notice or disagrees with its contents, the Supplier shall give notice by electronic mail (or fax if electronic mail is not available) to each of the ISO and the Transmission Owner confirming the telephonic request, and the notice by electronic mail or fax shall provide the same information specified in the Transmission Owner's telephonic request and shall also provide the time of the telephonic request.

15.6.2.2 A Transmission Owner shall stop purchasing some or all the Quick Start Reserves from a Supplier upon giving telephonic notice to the Supplier that the Transmission Owner no longer requires some or all the Quick Start Reserves; provided, however, that the Transmission Owner shall not stop the purchase of Quick Start Reserves without the ISO's concurrence. The Transmission Owner shall give written notice by electronic mail (or fax if electronic mail is not available) to each of the Supplier and the ISO of the telephonic notice within ten (10) minutes of providing the telephonic notice, and the written notice by electronic mail or fax shall provide the time of the telephonic notice. If the Supplier has not received such written notice or disagrees with its contents, the Supplier shall give notice by electronic mail (or fax if electronic mail is not available) to each of the ISO and the Transmission Owner of the telephonic notice, and the notice by electronic mail or fax shall provide the same information specified in the Transmission Owner's telephonic notice and shall also provide the time of the telephonic notice.

15.6.2.3 The ISO shall maintain complete and accurate records of all notices received by electronic mail or fax pursuant to Sections 15.6.2.1 and 15.6.2.2 of this Rate Schedule.

15.6.2.4 A Supplier offering Quick Start Reserves that receives a telephonic request to purchase or to select Quick Start Reserves shall set one or more blocks of generator units to Quick Start Mode as requested within ten (10) minutes of the telephonic request; provided, however, that the Supplier shall have no obligation to set a block of generator units to or to maintain a block of generator units in Quick Start Mode during (i) periods of forced outage, (ii) maintenance outages that are approved in advance pursuant to the ISO Services Tariff, or (iii) any period when the requested block of generator units is producing Energy.

15.6.2.5 During any period when the Transmission Owner has not purchased Quick Start Reserves from an offered block of generator units, the Supplier shall not be required to set the block of generator units to or to maintain the block of generator units in Quick Start Mode, subject to the requirement that the Supplier set the block of generator units to Quick Start Mode within ten (10) minutes of a request pursuant to Section 15.6.2.1 of this Rate Schedule.

15.6.2.6 A Supplier offering Quick Start Reserves shall maintain Hour-Ahead Bids for Energy at all times for each of the Supplier's block of generator units comprising the offered, purchased, or selected Quick Start Reserves, and shall maintain these Bids in the Real-Time Market.

15.6.3 Duty to Produce Energy

15.6.3.1 A Transmission Owner may remotely start up any block of generator units that is providing Quick Start Reserves. Upon remote start-up, the Transmission Owner shall give notice to the ISO that the block of generator units have been started up out of merit for local reliability. A Transmission Owner may dispatch off a block of generator units started up out of merit when Energy from the block of generator units is no longer required for local reliability, subject to any minimum run time of the block of generator units; provided, however, that the Transmission Owner shall not dispatch off the block of generator units without the ISO's concurrence.

15.6.3.2 During each period when a Transmission Owner has purchased Quick Start Reserves, the Supplier shall respond to each remote start-up order from the Transmission Owner, and shall cause the Supplier's remotely started up block of generator units to be synchronized and at full output within fifteen (15) minutes.

15.6.4 Failure to Achieve Timely Synchronization

If a Supplier that has sold Quick Start Reserves fails to have the block of generator units synchronized in the amount of the Energy Bid pursuant to Section 15.6.2.6 of this Rate Schedule within fifteen (15) minutes of a remote start-up, the Supplier shall be subject to the provisions applicable to Suppliers of 10-Minute Non-Spinning Reserves and 30-Minute Reserves that fail to provide Energy within the time allotted; provided, however, that charges against Quick Start Reserves payments shall be based upon the blended rate of 85% of $P_{10MNSR,h}$ plus 15% of $P_{30MR,h}$, as applied in Section 15.6.5.1 of this Rate Schedule.

15.6.5 Payments to Suppliers; Payments by Load Serving Entities

15.6.5.1 A Supplier that provides Quick Start Reserves shall receive each Billing Period a payment for each block of generator units that provided Quick Start Reserves in any hour of the previous Billing Period, unless the block of generator units also produced Energy during the hour. The amount of this payment shall equal:

$$\sum_h \left(C_h * \left(0.85 * P_{10MNSR,h} + 0.15 * P_{30MR,h}\right) - Q_h * P_{30MR,h}\right)$$

where:

h = An hour in which the block of generator units provided Quick Start Reserves, unless the block of generator units produced Energy during the hour

C = Capacity in MWs of Hour-Ahead Bids for Energy for the block of generator units

P_{10MNSR} = Price of 10-Minute NSR (SENY) in the Day-Ahead Market

P_{30MR} = Price of 30-Minute Reserves (SENY) in the Day-Ahead Market

Q = Quantity of MWs from the block of generator units accepted into the 30-Minute Reserves market.

15.6.5.2 Any block of generator units requested for Quick Start Reserves for any portion of an hour shall be deemed to have provided Quick Start Reserves for the entire hour unless the block of generator units also produced Energy during the hour.

15.6.5.3**.** In addition to payments due to a Supplier of Quick Start Reserves pursuant to Section 15.6.5.1 of this Rate Schedule, the Supplier shall be eligible to receive payments for Energy, Installed Capacity, Operating Reserves, and other Ancillary Services pursuant to the other provisions of this Services Tariff.

15.6.5.4 Amounts due to a Supplier pursuant to this Rate Schedule that are attributable to local reliability shall be recovered from LSEs in the Transmission District of the Supplier selling the Quick Start Reserves on the basis of each LSE's contribution to Load share in the Billing Period in which the payment obligation is incurred. Amounts attributable to local reliability are those amounts incurred pursuant to Sections 15.6.2.1 and 15.6.3.1 of this Rate Schedule.

15.6.6 Dispute Resolution

15.6.6.1 In the event of a dispute between a Transmission Owner and a Supplier of Quick Start Reserves regarding the hours or MWs of Quick Start Reserves purchased by a Transmission Owner or the Energy output achieved within fifteen (15) minutes of a remote start-up, the Transmission Owner and Supplier shall attempt to resolve the dispute promptly, and either party may request the ISO to refer to the ISO logs to help resolve the dispute. If a Transmission Owner and a Supplier selling Quick Start Reserves cannot resolve any dispute regarding the hours or MWs of Quick Start Reserves purchased by a Transmission Owner or the Energy output achieved within fifteen (15) minutes of a remote start-up within fifteen (15) days, then the Transmission Owner and Supplier may resolve the dispute through the ISO's Expedited Dispute Resolution Procedures.

15.6.6.2 Disputes other than those addressed pursuant to Section 15.6.6.1 of this Rate Schedule may be resolved through the ISO's Dispute Resolution Process.

15.7 Rate Schedule 7 - Charges for Wind Forecasting Service

The ISO shall charge each Intermittent Power Resource that depends on wind as its fuel that is interconnected in the New York Control Area in order to provide Energy to the LBMP Market or bilaterally to a Load internal or external to the NYCA, pursuant to this ISO Services Tariff or the NYISO OATT, and that has entered commercial operation ("Wind Generators"), for Wind Forecasting Service pursuant to this Rate Schedule, provided however no charge shall be assessed against any Intermittent Power Resource in commercial operation as of January 1, 2002 with nameplate capacity of 12 MWs or fewer.

The ISO shall calculate and assess such charges each Billing Period.

15.7.1 Responsibilities

The ISO shall cal**c**ulate a wind forecasting charge which shall include a fixed component and a component that varies by the nameplate capacity of the Wind Generator. Such charge shall be based upon the costs the NYISO incurs in producing a forecast of the expected generation output of each Wind Generator subject to this charge.

15.7.1.1 Wind Generators

Wind Generators shall pay the charge for Wind Forecasting Service each Billing Period.

15.7.2 Charges

Each Billing Period, the ISO shall assess to each Wind Generator the portion of the following monthly wind forecasting charges allocated to that Billing Period:

- $500.00 as a fixed fee and
- $7.50 / MW of name plate capacity

15.8 Rate Schedule 8 – Payments to RMR Generators

15.8.1 Payment to an RMR Generator Providing Service Pursuant to an RMR Agreement with an Availability and Performance Rate

The ISO shall make a payment each Billing Period to each RMR Generator providing service pursuant to an RMR Agreement with an Availability and Performance Rate that has been accepted for filing by the Commission, or the ISO may pay subject to refund pending Commission action. The payment shall equal:

$$\sum_{d \in P} \left(RMRAvoidCost_{g,d} + VarCost_{g,d} \right)$$

Where:

d = the relevant market day;

P = the relevant Billing Period;

g = the relevant RMR Generator that is providing service under an Availability and Performance Rate established pursuant to the ISO Tariffs and an RMR Agreement between the ISO and the RMR Generator;

$RMRAvoidCost_{g,d}$ = RMR Avoidable Cost amount for RMR Generator g for day *d* that has been accepted for filing by the Commission, or as calculated by the ISO in accordance with Sections 38.8 and 38.17 of the OATT pending Commission action, shaped on a Capability Period basis, and Additional Costs in accordance with Section 38.16 of the OATT;

$$VarCost_{g,d} = Energy_{g,d} + AncServices_{g,d} + VSS_{g,d} + RS_{g,d}$$

Where:

$Energy_{g,d}$ = the energy cost of RMR Generator g for day *d*. The cost of all energy MWhs that are scheduled and produced in real-time by RMR Generator g that do not exceed RMR Generator g's Day-Ahead schedule shall be equal to the lesser of RMR Generator g's Day-Ahead reference levels and RMR Generator g's Day-Ahead Bids. The cost of all energy MWhs that are scheduled and produced in real-time (including Compensable Overgeneration, if any) that exceed RMR Generator g's Day-Ahead schedule (if any) shall be equal to the lesser of RMR Generator g's real-time reference levels and RMR Generator g's real-time Bids;

$AncServices_{g,d}$ = the cost of Operating Reserves and Regulation Service for RMR Generator g for day *d*. The cost of all MWhs of Operating Reserves that are scheduled and of Regulation Service that are scheduled and provided in real-time by RMR

Generator *g* that do not exceed RMR Generator *g*'s Day-Ahead schedule shall be equal to the lesser of RMR Generator *g*'s Day-Ahead reference levels and RMR Generator *g*'s Day-Ahead Bids. The cost of all MWhs of Operating Reserves and Regulation Service that are scheduled and provided in real-time by RMR Generator *g* that exceed RMR Generator *g*'s Day-Ahead schedule (if any) shall be equal to the lesser of RMR Generator *g*'s real-time reference levels and RMR Generator *g*'s real-time Bids;

$VSS_{g,d}$ = the Voltage Support Service payment for RMR Generator *g* for day *d* pursuant to Rate Schedule 2 of the ISO Services Tariff;

$RS_{g,d}$ = the Restoration Services payment for RMR Generator *g* for day *d* pursuant to Rate Schedule 5 of the ISO Services Tariff.

15.8.2 Performance Incentive Payment

The ISO will pay on a monthly basis an RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate any Performance Incentive payment owed to that RMR Generator for its performance in that month in accordance with the following formulae.

PI_m = the amount of the Performance Incentive payment, calculated for each month *m*, and is a dollar value calculated as:

$$PI_m = \frac{1}{12} PI_{max} * \begin{cases} 50\%, & \text{for } LB_{PI} \leq PF_m < UB_{PI} \\ 80\%, & \text{for } UB_{PI} \leq PF_m < TL_{PI} \\ 100\%, & \text{for } TL_{PI} \leq PF_m \end{cases}$$

Where:

PI_{max} = the maximum annual Performance Incentive payment, calculated as 5% of the RMR Generator's *Non-CapEx Avoidable Costs;*

$Non\text{-}CapEx\ Avoidable\ Costs$ = the RMR Avoidable Costs the RMR Generator is authorized to recover annually, pursuant to an Availability and Performance Rate that has been accepted for filing by the Commission, or that the RMR Generator is recovering subject to refund pending Commission action, less the Capital Expenditures included in such RMR Avoidable Costs;

LB_{PI} = the Bandwidth Lower Bound, a percentage defined as:

$$LB_{PI} = \begin{cases} 0.9 * BL_{PI}, & if\ BL_{PI} < 50\% \\ BL_{PI} - 5\%, & if\ BL_{PI} \geq 50\% \end{cases}$$

UB_{PI} = the Bandwidth Upper Bound, a percentage defined as:

$$UB_{PI} = BL_{PI} + min\left\{\frac{1}{3}(100\% - BL_{PI}),\ \max\left\{5\%, \frac{1}{10}(100\% - BL_{PI})\right\}\right\}$$

TL_{PI} = the Target Limit, a percentage defined as:

$$TL_{PI} = BL_{PI} + min\left\{\frac{2}{3}(100\% - BL_{PI}), max\left\{10\%, \frac{1}{5}(100\% - BL_{PI})\right\}\right\}$$

Where:

BL_{PI} = the Baseline percentage determined for the RMR Generator's performance, as set forth in the RMR Generator's RMR Agreement.

PF_m = the RMR Performance Factor for month m, a percentage defined as:

$$PF_m = \quad 100\% - \frac{\sum_{t=t_0}^{T}(max\{PLU_t - Pr_t, 0\})}{\sum_{t=t_0}^{T} PLU_t}$$

Where:

t_0 = the first RTD interval of month *m*;

T = the last RTD interval of month *m*;

Pr_t = the Real-Time output of the RMR Generator over RTD interval *t*, in MW; and

PLU_t = the Penalty Limit for Under-Generation of the RMR Generator over RTD interval *t*, expressed in MW, calculated in accordance with the ISO's Billing and Accounting Manual.

15.8.3 Availability Incentive Payment

The ISO will pay on a Capability Period basis an RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate for any Availability Incentive payment owed to that RMR Generator. The ISO will make the Availability Incentive payment in the Billing Period following the first month of the Capability Period for a payment earned for the previous Capability Period in accordance with the following formulae.

AI_{cp} = the amount of the Availability Incentive, calculated for each Capability Period *cp*, and is a dollar value calculated as:

$$AI_{cp} = \frac{1}{2} AI_{max} * \begin{cases} 50\%, & \text{for } LB_{AI,cp} \leq EAF_{cp} < UB_{AI,cp} \\ 80\%, & \text{for } UB_{AI,cp} \leq EAF_{cp} < TL_{AI,cp} \\ 100\%, & \text{for } TL_{AI,cp} \leq EAF_{cp} \end{cases}$$

Where:

AI_{max} = the maximum Availability Incentive payment, calculated as 20% of the RMR Generators *Non-CapEx Avoidable Costs;*

$Non\text{-}CapEx\ Avoidable\ Costs$ = the RMR Avoidable Costs the RMR Generator is authorized to recover annually, pursuant to an Availability and Performance Rate that has been accepted for filing by the Commission, or that the RMR Generator is recovering subject to refund pending Commission action, less the Capital Expenditures included in such RMR Avoidable Costs;

$LB_{AI,cp}$ = the Bandwidth Lower Bound, a percentage defined as:

$$LB_{AI,cp} = \begin{cases} 0.9 * BL_{AI,cp}, & if\ BL_{AI,cp} < 50\% \\ BL_{AI,cp} - 5\%, & if\ BL_{AI,cp} \geq 50\% \end{cases}$$

$UB_{AI,cp}$ = the Bandwidth Upper Bound, a percentage defined as:

$$UB_{AI,cp} = BL_{AI,cp} + min\left\{\tfrac{1}{3}\left(100\% - BL_{AI,cp}\right),\ \max\left\{5\%, \tfrac{1}{10}\left(100\% - BL_{AI,cp}\right)\right\}\right\}$$

$TL_{AI,cp}$ = the Target Limit, a percentage defined as:

$$TL_{AI,cp} = BL_{AI,cp} + min\left\{\tfrac{2}{3}\left(100\% - BL_{AI,cp}\right), max\left\{10\%, \tfrac{1}{5}\left(100\% - BL_{AI,cp}\right)\right\}\right\}$$

Where:

$BL_{AI,cp}$ = the Baseline percentage for Capability Period *cp* determined for the RMR Generator's availability, as set forth in the RMR Generator's RMR Agreement;

EAF_{cp} = the RMR Generator's equivalent availability factor for Capability Period *cp*, a percentage defined as:

$$EAF_{cp} = 100\% * \left(\frac{\left(AH - \left(DH_{EU} + DH_{EP} + DH_{ESE}\right)\right)}{PH}\right)$$

Where:

AH = the RMR generator's available hours, calculated for Capability Period *cp* in accordance with ISO procedures;

PH = the RMR Generator's period hours, calculated for Capability Period *cp* in accordance with ISO procedures, as the number of hours that the RMR Generator was in an active state;

DH_{EU} = the RMR Generator's unplanned derated hours, calculated for Capability Period *cp* in accordance with ISO procedures, as the product of unplanned derated hours and size of reduction, divided by net maximum capacity;

DH_{EP} = the RMR Generator's planned derated hours, calculated for Capability Period *cp* in accordance with ISO procedures, as the product of planned derated hours and size of reduction, divided by net maximum capacity; and

DH_{ESE} = the RMR Generator's net maximum capacity, determined in accordance with ISO procedures, less net dependable capacity, determined in accordance with ISO procedures, multiplied by available hours in accordance with ISO procedures, and divided by net maximum capacity.

GADS Data used to calculate Availability Incentive payments, as it may be modified by the ISO, shall be subject to review, challenge, and correction in accordance with Section 7.4 of the ISO Services Tariff.

15.8.4 Limitation on Total Penalties, Sanctions and Deficiency Charges Assessed to RMR Generators Providing Service Pursuant to an RMR Agreement with an Availability and Performance Rate

An RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate is subject to all of the penalties, sanctions, deficiency charges and any similar charges, except for under-generation penalties (collectively, for purposes of this paragraph, "penalties"), that may apply to Generators under the ISO Tariffs. *Provided, however,* that the total amount of penalties that can be assessed to an RMR Generator that is providing service pursuant to an RMR Agreement with an Availability and Performance Rate shall be capped at the total, cumulative amount of Performance Incentive payments and Availability Incentive payments computed by the ISO to be due to that RMR Generator through the end of the month in which the penalty or penalties are charged. The ISO shall charge any penalties to the RMR Generator and remit the revenues from each penalty, or any reduced amount, in accordance with the applicable provisions of the ISO Services Tariff.

15.8.5 Payment to an RMR Generator Providing Service Pursuant to an RMR Agreement with a Rate Other Than an Availability and Performance Rate

The ISO shall make a payment each Billing Period to each RMR Generator providing service pursuant to an RMR Agreement with a rate other than an Availability and Performance Rate that has been accepted for filing by the Commission, or the ISO may pay subject to refund pending Commission action. The payment shall equal:

$$\sum_{d \in P} \left(RMRCost_{g,d} + VarCost_{g,d} \right)$$

Where:

g = the relevant RMR Generator that is providing service under a rate other than an Availability and Performance Rate;

$RMRCost_{g,d}$ = the costs RMR Generator g is authorized to recover for day d pursuant to a rate for RMR Generator g that has been accepted for filing by the Commission, or that RMR Generator g is recovering subject to refund pending Commission action, shaped on a Capability Period basis, and Additional Costs in accordance with Section 38.16 of the OATT.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Section 15.8.1 above.

15.8.6 Payment to a Generator that is Required to Continue Operating Beyond the Later of the 180th Day of the 365 Day Notice Period or its Requested Deactivation Date

Consistent with the rules set forth in Section 38.13 of the OATT and Sections 23.6 and 5.14.1.1 of the Services Tariff, commencing on the later of (a) the 181st day of the relevant 365 day notice period set forth in Attachment FF of the OATT (for purposes of this Rate Schedule 8, the "365 Day Notice Period"), or (b) the Generator's requested deactivation date, the ISO shall make a payment each Billing Period to each Generator that remains in service as an Interim Service Provider. Generators that are in an ICAP Ineligible Forced Outage shall not be compensated as Interim Service Providers.

The payment to an Interim Service Provider shall equal:

$$\sum_{d \in P} \left(RMRAvoidCost_{g,d} + VarCost_{g,d} \right)$$

Where:

d = the relevant market day;

P = the relevant Billing Period;

g = the relevant Generator that satisfies the conditions set forth in Section 38.13 of the OATT, and Sections 23.6, 5.14.1.1 and 15.8.6 of the Services Tariff;

$RMRAvoidCost_{g,d}$ = the Avoidable Cost amount for Generator g for day d calculated by the ISO in accordance with Sections 38.8, 38.16 and 38.17 of the OATT, shaped on a Capability Period basis. The NYISO will incorporate Preexisting Capacity Bilaterals into its calculation of $RMRAvoidCost_{g,d}$ for Interim Service Providers consistent with the rules set forth below;

$$VarCost_{g,d} = Energy_{g,d} + AncServices_{g,d} + VSS_{g,d} + RS_{g,d}$$

Where:

$Energy_{g,d}$ = the energy cost of Generator g for day d. The cost of all energy MWhs that are scheduled and produced in real-time by Generator g that do not exceed Generator g's Day-Ahead schedule shall be equal to the lesser of Generator g's Day-Ahead reference levels and Generator g's Day-Ahead Bids. The cost of all energy MWhs that are scheduled and produced in real-time (including Compensable Overgeneration, if any) that exceed Generator g's Day-Ahead schedule (if any) shall be equal to the lesser of Generator g's real-time reference levels and Generator g's real-time Bids;

$AncServices_{g,d}$ = the cost of Operating Reserves and Regulation Service for Generator g for day d. The cost of all MWhs of Operating Reserves that are scheduled and of Regulation Service that are scheduled and provided in real-time by Generator g that do not exceed Generator g's Day-Ahead schedule shall be equal to the lesser of Generator g's Day-Ahead reference levels and Generator g's Day-Ahead Bids. The cost of all MWhs of Operating Reserves and Regulation Service that are scheduled and provided in real-time by Generator g that exceed Generator g's Day-Ahead schedule (if any) shall be equal to the lesser of Generator g's real-time reference levels and Generator g's real-time Bids;

$VSS_{g,d}$ = the Voltage Support Service payment for Generator g for day d pursuant to Rate Schedule 2 of the ISO Services Tariff;

$RS_{g,d}$ = the Restoration Services payment for Generator g for day d pursuant to Rate Schedule 5 of the ISO Services Tariff.

If an Interim Service Provider has a Preexisting Capacity Bilateral, as such term is defined in Section 5.14.1.1 of the Services Tariff, then the ISO will reduce the *RMRAvoidCost* it calculates for the Interim Service Provider to reflect up to the revenues the ISO determines the Interim Service Provider is expected to receive under the Preexisting Capacity Bilateral.

If the Interim Service Provider's Preexisting Capacity Bilateral is with an Affiliate, or was entered into less than one year before the ISO received the Interim Service Providers Generator Deactivation Notice, then the *RMRAvoidCost* the ISO calculates for the Interim Service Provider shall be reduced by up to the revenues that the ISO determines the Interim Service Provider would reasonably be expected to receive if offered its Unforced Capacity at \$0.00/kW-month into the ICAP Spot Market Auction conducted for the relevant Obligation Procurement Period based on the ISO's forecast of the Market-Clearing Price for the applicable ICAP Spot Market Auction.

Payments pursuant to this Section 15.8.6 shall cease at the conclusion of the 365 Day Notice Period.

15.8.7 Recovery of Capital Expenditures or Above Market Rates from Former RMR Generators and Former Interim Service Providers

If, pursuant to the terms of an RMR Agreement, the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was necessary to permit a Generator to provide service during the term of an RMR Agreement or as an Interim Service Provider; or if the NYISO compensated an RMR Generator pursuant to this Rate Schedule 8 amounts that exceeded the Generator's going-forward costs whilst providing RMR service; then in order for such a former

RMR Generator or former Interim Service Provider to be permitted to return to participating in the ISO Administered Markets while it is eligible to receive market-based rates, the Generator will be required to repay to the ISO the higher of the repayment obligation determined in accordance with Section 15.8.7.1 below, or the repayment obligation determined in accordance with Section 15.8.7.2 below. The higher of the two repayment obligations, divided by the applicable number of repayment periods, is the "Monthly Repayment Obligation."

A Generator is "participating in the ISO Administered Markets while it is eligible to receive market-based rates" if the Generator (a) is not in a Mothball Outage or an ICAP Ineligible Forced Outage, and is not Retired, and (b) is not an RMR Generator or an Interim Service Provider.

The ISO shall apply the Monthly Repayment Obligation to the physical Generator that is a former RMR Generator or a former Interim Service Provider, without regard to any changes in ownership or control of that Generator. The Monthly Repayment Obligation shall be applied whenever the former RMR Generator or former Interim Service Provider is participating in the ISO Administered Markets while it is eligible to receive market-based rates, until the applicable repayment obligation has been fully repaid. The Monthly Repayment Obligation shall not be imposed while a former RMR Generator or former Interim Service Provider is in a Mothball Outage or IIFO, or is Retired. If a former RMR Generator or former Interim Service Provider returns from being Retired, or from being in a Mothball Outage or IIFO, to participate in the ISO Administered Markets while it is eligible to receive market-based rates, then the ISO shall recalculate and reinstate an updated Monthly Repayment Obligation.

15.8.7.1 Recovery of Capital Expenditures from Former RMR Generators and Former Interim Service Providers

If, pursuant to the terms of an RMR Agreement, the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was incurred to permit an RMR Generator to provide service during the term of the RMR Agreement, or if the ISO reimbursed all or a portion of the cost of a Capital Expenditure that was incurred to permit a Generator to provide service as an Interim Service Provider, and the Generator is no longer an Interim Service Provider or the subject of any RMR Agreement, then in order for the ISO to permit the Generator to be offered into or be scheduled in any ISO Administered Markets while it is eligible to receive market-based rates, the cost of Capital Expenditures (if any) that the ISO paid to enable the former RMR Generator to provide service under an RMR Agreement or to enable a former Interim Service Provider to provide service, less depreciation, plus interest, must be repaid to the ISO on a monthly basis over the period specified in the definition of "*mCapEx*" below. Depreciation will be calculated for each Capital Expenditure at the time the former RMR Generator or former Interim Service Provider proposes to re-enter the ISO Administered Markets.

A Generator that was an RMR Generator or an Interim Service Provider that deactivated and that wants to return to participating in any of the ISO Administered Markets while it is eligible to receive market-based rates must give the ISO at least 60 days advance notice of its desire to return to the ISO Administered Markets in order to permit the ISO to determine its Monthly Repayment Obligation (if any) and any associated credit requirement.

The following formula shall be used to determine the repayment obligation:

$$RMRCapExRecovery\ repayment\ obligation = \sum_{i \in I} \left(\sum_{j \epsilon M} A_{ij} - \sum_{k \in Y} P_{ik} \right)$$

Where:

i = a Capital Expenditure in *I*, the set of all Capital Expenditures for the former RMR Generator or former Interim Service Provider;

j = a month in *M*, the set of all months that the former RMR Generator or former Interim Service Provider received payment for Capital Expenditure *i*;

k = a year in *Y*, the set of all years beginning with the year Capital Expenditure *i* entered service or was otherwise integrated into the RMR Generator or Interim Service Provider, or the year the NYISO terminated the RMR Agreement if Capital Expenditure *i* was not completed or did not enter service while the Generator was operating under an RMR Agreement, and continuing to the present year;

A_{ij} = the payment made to the former RMR Generator or former Interim Service Provider in month *j*, for Capital Expenditure *i*;

P_{ik} = the annual depreciation expense, determined by the ISO, for Capital Expenditure *i* in year *k*; and

For the component of a former RMR Generator's or former Interim Service Provider's Above Market Revenues that is Capital Expenditures, the value derived in the calculation above shall be divided by "*mCapEx*" months;

mCapEx = For a former RMR Generator, the shorter of 36 months or twice the duration of the applicable RMR Agreement in months. For a former Interim Service Provider, twelve months. Alternatively, if the former RMR Generator or former Interim Service Provider elects to repay its entire obligation before it begins participating in the ISO Administered Markets at market-based rates, then *mCapEx* shall be one month.

Accumulated interest will be computed on a quarterly basis and assessed based on the dates the ISO paid the former RMR Generator or former Interim Service Provider for each Capital Expenditure. Following the date a former RMR Generator or former Interim Service Provider returns to participating in the ISO Administered Markets while it is eligible to receive market-based rates, a fixed interest rate will be used to determine the Monthly Repayment Obligation.

The repayment obligation specified in this Section 15.8.7.1 shall remain in effect until all Capital Expenditures that are due (as determined in accordance with the formula set forth above) have been repaid. As explained in Section 15.8.7 of this Rate Schedule 8, the repayment obligation shall take effect, be reinstated, or remain in effect (as appropriate) (i) if a former RMR Generator does not deactivate at the conclusion of its RMR Agreement, or (ii) if a former Interim

Service Provider does not deactivate at the conclusion of the 365 Day Notice Period, or (iii) if a former RMR Generator that entered a Mothball Outage, an ICAP Ineligible Forced Outage or Inactive Reserves returns to service from such state, or (iv) if a former Interim Service Provider that entered a Mothball Outage or an ICAP Ineligible Forced Outage returns to service from such state, or (v) if a former RMR Generator or former Interim Service Provider becomes Retired and subsequently returns to service as a new Generator, and/or (vi) if a former RMR Generator or former Interim Service Provider is sold, leased or otherwise transferred to a new owner or owners and remains in service or returns to service.

15.8.7.2 Recovery of Above Market Revenues from Former RMR Generators

If the ISO made payments to a Generator under Section 15.8.5 of this Rate Schedule 8 to permit the Generator to provide service during the applicable term of an RMR Agreement, and the former RMR Generator is no longer the subject of any RMR Agreement, and the former RMR Generator continues participating in, or returns to, the ISO Administered Markets while it is eligible to receive market-based rates; then the cost of the Above Market Revenues (including but not limited to the ISO's reimbursement of the cost of Capital Expenditures), that the ISO paid to compensate the Generator for providing RMR service, less depreciation where applicable, plus interest, must be repaid to the ISO on a monthly basis. The period over which Above Market Revenues must be repaid is specified in the definition of "*mAMR*" below.

The following formula shall be used to determine the Above Market Revenue repayment obligation:

$$Above\ RMRAvoidCost\ Revenue_g = max\{0,\ \sum_{d \in ToS}(RMRCost_{g,d} - RMRAvoidCost_{g,d})\}$$

Where:

Above RMRAvoidCost Revenue $_g$ = the difference between (x) the total revenues Generator g would have been eligible to receive in reimbursement of its RMR Avoidable Costs during the term of the RMR Agreement if it had been compensated at a rate developed in accordance with Section 15.8.1 of this Rate Schedule 8 (excluding any payments that Generator *g* would have been eligible to receive as Performance Incentives or Availability Incentives), and (y) the total revenues Generator g received in accordance with its accepted RMR Agreement to reimburse RMR Costs during the term of that RMR Agreement, paid in accordance with Section 15.8.5 of this Rate Schedule 8;

ToS = the duration of the applicable RMR Agreement;

$RMRAvoidCost_{g,d}$ = The revenue Generator *g* would have received for day *d* if it had been compensated for its RMR Avoidable Costs at a rate developed by the ISO in accordance with Section 15.8.1 of this Rate Schedule 8 (without Performance Incentives or Availability Incentives), using the market participation, commitment, scheduling and dispatch that occurred on day *d*; and

$RMRCost_{g,d}$ = the payment RMR Generator *g* received for day *d* in accordance with Section 15.8.5 of this Rate Schedule 8, excluding payment for Variable Costs.

The *Above RMRAvoidCost Revenue* shall be divided by "*mAMR*" to determine the Monthly Repayment Obligation.

mAMR = the shorter of 36 months or twice the duration of the applicable RMR Agreement in months. Alternatively, if the former RMR Generator elects to repay its entire obligation before it begins participating in the ISO Administered Markets at market-based rates, then *mAMR* shall be one month.

Accumulated interest will be computed and assessed quarterly, on a *pro rata* basis, based on the date of payment to the Generator for each relevant Billing Period *P* (as defined in Section 15.8.1 of this Rate Schedule 8). Following the date a former RMR Generator returns to participating in the ISO Administered Markets while it is eligible to receive market-based rates, a fixed interest rate will be used to determine the Monthly Repayment Obligation.

The definitions of the remaining variables in this equation are identical to the definitions for such variables set forth in Sections 15.8.1 and 15.8.7.1 above.

The reimbursement obligation specified in this Section 15.8.7.2 shall remain in effect until the entire amount, including interest has been reimbursed. As explained in Section 15.8.7 of this Rate Schedule 8, the reimbursement obligation shall take effect, be reinstated, or remain in effect (as appropriate) whenever a former RMR Generator continues participating in, or returns to, the ISO Administered Markets while it is eligible to receive market-based rates. The reimbursement obligation shall continue to apply or shall be reinstated, as appropriate, when (i) a former RMR Generator that entered a Mothball Outage, an ICAP Ineligible Forced Outage or Inactive Reserves returns to service from such state, or (ii) a former RMR Generator becomes Retired and subsequently returns to service as a new Generator, and/or (iii) a former RMR Generator is sold, leased or otherwise transferred to a new owner or owners and remains in service or returns to service.

16 Attachment A - Form Of Service Agreement For New York ISO Market Administration and Control Area Services Tariff

1.0 This Service Agreement dated as of **_______________** is entered into by and between the New York Independent System Operator ("ISO") and **_______________________** ("the Customer").

2.0 The Customer represents and warrants that it has met all applicable requirements set forth in the ISO Market Administration and Control Area Services Tariff (the "ISO Services Tariff") and has complied with all applicable ISO Procedures. The Customer has submitted a Completed Application pursuant to Article 9 of the ISO Services Tariff.

The ISO agrees to provide and the Customer agrees to pay for Market Services and Control Area Services in accordance with the provisions of the Tariff and to satisfy all obligations under the terms and conditions of the ISO Services Tariff, as may be amended from time-to-time, filed with the Federal Energy Regulatory Commission (the "Commission"). The ISO and the Customer also agree that this Service Agreement shall be subject to, and shall incorporate by reference, all of the terms and conditions of the ISO Services Tariff and ISO Procedures.

It is understood that, in accordance with the ISO Services Tariff, the ISO may amend the terms and conditions of this Service Agreement by notifying the Customer in writing and making the appropriate filing with the Commission.

3.0 The Customer represents and warrants that:

(a) The Customer is an entity duly organized, validly existing and/or otherwise qualified to do business under the laws of the State of New York, and is in good standing under its [insert organizational document] and the laws of the State of [insert state of organization];

(b) This Service Agreement, or any Transaction entered into pursuant to the Service

Agreement, as applicable, has been duly authorized;

(c) The execution, delivery and performance of this Service Agreement will not materially conflict with, constitute a material breach of, or a material default under, any of the terms, conditions, or provisions of any law or order of any agency of government, the [insert organizational document] of the Customer, any contractual limitation, organizational limitation or outstanding trust indenture, deed of trust, mortgage, loan agreement, other evidence of indebtedness, or any other agreement or instrument to which the Customer is a party or by which it or any of its property is bound, or result in a material breach of, or a material default under, any of the foregoing; and

(d) This Service Agreement is the legal, valid, and binding obligation of the Customer enforceable in accordance with its terms, except as it may be rendered unenforceable by reason of bankruptcy or other similar laws affecting creditors' rights, or general principles of equity.

The Customer warrants and covenants that, during the term of the Service Agreement the Customer shall be in compliance with all federal, state and local laws, rules and regulations related to the Customer's performance under the agreement.

4.0 Service under this Service Agreement shall commence on the later of: ___________________, or such other date as it is permitted to become effective by the Commission. Service under this Service Agreement shall terminate on

______________________.

5.0 The ISO agrees to provide and the Customer agrees to take and pay for, or to supply to the ISO, Energy, Capacity and Ancillary Services in accordance with the provisions of the ISO Services Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below:

ISO:
____
____
____

Customer:
____
____
____

7.0 Cancellation Rights:

If the Commission or any regulatory agency having authority over this Service Agreement determines that any part of this Service Agreement must be changed, the ISO shall offer to the Customer an amended Service Agreement reflecting such changes. In the event that the Customer does not execute such an amendment within thirty (30) days, or longer if the Parties mutually agree to an extension, after the Commission's action, this Service Agreement and the amended Service Agreement shall be void.

8.0 Early Termination by the Customer:

The Customer may terminate service under this Service Agreement no earlier than ninety (90) days after providing the ISO with written notice of the Customer's intention to terminate; except that a Load Serving Entity must continue to take service under this Tariff as long as it continues to serve Load within the NYCA. In the event that tax-exempt financing of a Customer is jeopardized by its participation under this Service Agreement, the Customer may terminate this Service Agreement upon thirty (30) days prior written notice to the ISO. The Customer's provision of notice to terminate service under this Service Agreement shall not relieve the Customer of its obligation to pay any rates, charges, or fees due under this Service Agreement, and which are owed as of the date of termination.

9.0 The Customer hereby appoints the ISO as its agent for the limited purpose of effectively transacting on the Customer's behalf in accordance with the Customer's written instructions, listed herein and the terms of the ISO Services Tariff and ISO Procedures. The Customer agrees to pay all amounts due and chargeable to the Customer in accordance with the terms of the ISO Services Tariff and ISO Procedures.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

ISO:______________________________

By: _______________________________

Dated:_____________________________

Title: _____________________________

Customer:________________________

By:______________________________

Dated:___________________________

Title:____________________________

17 Attachment B

17.1 LBMP Calculation

The Locational Based Marginal Prices ("LBMPs" or "prices") for Suppliers and Loads in the Real-Time Market will be based on the system marginal costs produced by the Real-Time Dispatch ("RTD") program and during intervals when certain conditions exist at Proxy Generator Buses, the Real-Time Commitment ("RTC") program. LBMPs for Suppliers and Loads in the Day-Ahead Market will be based on the system marginal costs produced by the Security Constrained Unit Commitment ("SCUC"). LBMPs calculated by SCUC and RTD will incorporate the incremental dispatch costs of Resources that would be scheduled to meet an increment of Load and, to the extent that tradeoffs exist between scheduling providers to produce Energy or reduce demand, and scheduling them to provide Regulation Service or Operating Reserves, LBMPs shall reflect the effect of meeting an increment of Load, given those tradeoffs, at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Bids for Regulation Service or Operating Reserves; or (ii) shortage costs associated with the inability to meet a Regulation Service or Operating Reserves requirement under the Regulation Service Demand Curve set forth in Rate Schedule 3 of this ISO Services Tariff and Operating Reserve Demand Curves and Scarcity Reserve Demand Curve set forth in Rate Schedule 4 of this ISO Services Tariff.

Additionally, for the purpose of calculating Real-Time LBMPs when RTD is committing and dispatching Resources meeting Minimum Generation Levels and capable of starting in ten minutes pursuant to Section 4.4.2.4 of this ISO Services Tariff, RTD shall include in the incremental dispatch cost of each such Resource a start-up cost based on the Start-Up Bid of each such Resource and shall assume for each such Resource a zero downward response rate.

17.1.1 LBMP Bus Calculation Method

System marginal costs will be utilized in an *ex ante* computation to produce Day-Ahead and Real-Time LBMP bus prices using the following equations.

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma_i^L + \gamma_i^C$$

Where:

γ_i	=	LBMP at bus *i* in $/MWh
λ^R	=	the system marginal price at the Reference Bus
γ_i^L	=	Marginal Losses Component of the LBMP at bus *i* which is the marginal cost of losses at bus *i* relative to the Reference Bus
γ_i^C	=	Congestion Component of the LBMP at bus *i* which is the marginal cost of Congestion at bus *i* relative to the Reference Bus

The Marginal Losses Component of the LBMP at any bus i is calculated using the equation:

$$\gamma_i^L = (DF_i - 1)\lambda^R$$

Where:

DF_i = delivery factor for bus *i* to the system Reference Bus and:

$$DF_i = \left(1 - \frac{\partial L}{\partial P_i}\right)$$

Where:

L	=	NYCA losses; and
P_i	=	injection at bus *i*

The Congestion Component of the LBMP at bus i is calculated using the equation:

$$\gamma_i^c = -\left(\sum_{k \in K}^{n} GF_{ik}\mu_k\right)$$

Where:

K	=	the set of Constraints;
GF_{ik}	=	Shift Factor for bus *i* on Constraint *k* in the pre- or post-Contingency case which limits flows across that Constraint (the Shift Factor measures the incremental change in flow on Constraint *k*, expressed in per unit, for an increment of injection at bus *i* and a corresponding withdrawal at the Reference Bus); and
μ_k	=	the Shadow Price of Constraint *k* expressed in \$/MWh, provided however, this Shadow Price shall not exceed the Transmission Shortage Cost.

Substituting the equations for γ_i^L and γ_i^C into the first equation yields:

$$\gamma_i = \lambda^R + (DF_i - 1)\lambda^R - \sum_{k \epsilon K} GF_{ik}\mu_k$$

LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the Day-Ahead Market, the three components of the LBMP at each location will be calculated from the SCUC results and posted for each of the twenty four (24) hours of the next day. The Real-Time LBMPs will be calculated and posted for each execution of RTD.

17.1.1.1 Determining Shift Factors and Incremental System Losses

For the purposes of pricing and scheduling, Shift Factors, GF_{ik}, and loss delivery factors, DF_i, will reflect expected power flows, including expected unscheduled power flows. When determining prices and schedules, SCUC, RTC and RTD shall include both the expected power flows resulting from NYISO interchange schedules (*see* Section 17.1.1.1.2), and expected unscheduled power flows (*see* Section 17.1.1.1.1). All NYCA Resource, NYCA Load and Proxy Generator Bus Shift Factors and loss delivery factors will incorporate internal and coordinated external transmission facility outages, power flows due to schedules, and expected unscheduled power flows.

17.1.1.1.1 Determining Expected Unscheduled Power Flows

In the Day-Ahead Market, expected unscheduled power flows will ordinarily be determined based on historical, rolling 30-day on-peak and off-peak averages. To ensure expected unscheduled power flows accurately reflect anticipated conditions, the frequency and/or period used to determine the historical average may be modified by the NYISO to address market rule, system topology, operational, or other changes that would be expected to significantly impact unscheduled power flows. The NYISO will publicly post the Day-Ahead on-peak and off-peak unscheduled power flows on its web site.

In the Real-Time Market, expected unscheduled power flows will ordinarily be determined based on current power flows, modified to reflect expected changes over the real-time scheduling horizon.

17.1.1.1.2 Determining Expected Power Flows Resulting from NYISO Interchange Schedules

In the Day-Ahead Market, for purposes of scheduling and pricing, SCUC will establish expected power flows for the ABC interface, JK interface and Branchburg-Ramapo interconnection based on the following:

a. Consolidated Edison Company of New York's Day-Ahead Market hourly election under OATT Attachment CC, Schedule C;

b. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the Branchburg-Ramapo interconnection. The expected flow may also be adjusted by a MW offset to reflect expected operational conditions;

c. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the ABC interface; and

d. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the JK interface.

The terms “ABC interface” and “JK interface” have the meaning ascribed to them in Schedule C to Attachment CC to the OATT.

The NYISO shall post the percentage values it is currently using to establish Day-Ahead and real-time expected Branchburg-Ramapo interconnection, ABC interface and JK interface flows for purposes of scheduling and pricing on its web site. If the NYISO determines it is necessary to change the posted Branchburg-Ramapo, ABC or JK percentage values, it will provide notice to its Market Participants as far in advance of the change as is practicable under the circumstances.

In the Day-Ahead Market, scheduled interchange that is not expected to flow over the ABC interface, JK interface or Branchburg-Ramapo interconnection (or on Scheduled Lines) will be expected to flow over the NYISO’s other interconnections. Expected flows over the NYISO’s other interconnections will be determined consistent with the expected impacts of scheduled interchange and consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

For pricing purposes, flows in the Real-Time Market will be established for the ABC interface, JK interface, and Branchburg-Ramapo interconnection based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon in a manner that is consistent with the method used to establish Day-Ahead power flows over these facilities. Expected flows over the NYISO’s other interconnections will be determined based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon, and shall be consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

17.1.1.1.3 Scheduled Lines and Chateauguay Interconnection with Hydro Quebec

For purposes of scheduling and pricing, the NYISO expects that power flows will ordinarily match the interchange schedule at Scheduled Lines, and at the NYCA's Chateauguay interconnection with Hydro Quebec, in both the Day-Ahead and Real-Time Markets.

17.1.2 Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Sections 17.1.2.1-17.1.2.1.4 to calculate Real-Time LBMPs at each Load Zone and Generator bus. The LBMP bus and zonal calculation procedures are described in Sections 17.1.1 and 17.1.5 of this Attachment B, respectively. Procedures governing the calculation of LBMPs at Proxy Generator Buses are set forth below in Section 17.1.6 of this Attachment B.

17.1.2.1 General Procedures

17.1.2.1.1 Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes of each RTD run, except as noted below in Section 17.1.2.1.3. A new RTD run will initialize every five minutes and each run will produce prices and schedules for five points in time (the optimization period). Only the prices and schedules determined for the first time point of the optimization period will be binding. Prices and schedules for the other four time points of the optimization period are advisory.

Each RTD run shall, depending on when it occurs during the hour, have a bid optimization horizon of fifty, fifty-five, or sixty minutes beyond the first, or binding, point in time that it addresses. The posting time and the first time point in each RTD run, which establishes binding prices and schedules, will be five minutes apart. The remaining points in time in each optimization period can be either five, ten, or fifteen minutes apart depending on when the run begins within the hour. The points in time in each RTD optimization period are arranged so that they parallel as closely as possible RTC's fifteen minute evaluations.

For example, the RTD run that posts its results at the beginning of an hour ("RTD_0") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD_0 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at the beginning of the hour) and ending at the first time point in its optimization period (i.e., five minutes after the hour). It will produce advisory prices and schedules for its second time point, which is ten minutes after the first time point in its optimization period, and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at five minutes after the beginning of the hour ("RTD_5") will initialize at the beginning of the hour and produce prices over a fifty minute optimization period. RTD_5 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at five minutes after the hour) and ending at the first time point in its optimization period (i.e., ten minutes after the hour.) It will produce advisory prices and schedules for its second time point (which is five minutes after the first time point), and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at ten minutes after the beginning of the hour ("RTD_{10}") will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD_{10} will produce binding prices and schedules for the interval beginning when it posts its results (i.e., at ten minutes after the hour) and ending at the first time point in its optimization period (i.e., fifteen minutes after the hour.) It will produce advisory prices and schedules for its second, third, fourth and fifth time points, each of which would be fifteen minutes after the preceding time point.

17.1.2.1.2 Description of the Real-Time Dispatch Process

17.1.2.1.2.1 The First Pass

The first RTD pass consists of a least bid cost, multi-period co-optimized dispatch for Energy, Regulation Service and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO as if they were blocked on at their UOL_N or UOL_E, whichever is applicable. Resources meeting Minimum Generation Levels and capable of being started in ten minutes that have not been committed by RTC are treated as flexible (i.e. able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable). The first pass establishes "physical base points" (i.e., real-time Energy schedules) and real-time schedules for Regulation Service and Operating Reserves for the first time point of the optimization period. Physical base points and schedules established for the first time point shall be binding and shall remain in effect until the results of the next run are posted. Physical base points and schedules established for all subsequent time points shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point Signals that the ISO sends to Suppliers.

When establishing physical base points, the ISO shall assume that each Generator will move toward the physical base point established during the first pass of the prior RTD run at its specified response rate.

17.1.2.1.2.1.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind as Their Fuel

When setting physical base points for a Dispatchable Resource at the first time point, the ISO shall ensure that they do not fall outside of the bounds established by the Dispatchable Resource's lower and upper dispatch limits. A Dispatchable Resource's dispatch limits shall be determined based on whether it was feasible for it to reach the physical base point calculated by the last RTD run given its: (A) metered output level at the time that the RTD run was initialized; (B) response rate; (C) minimum generation level; and (D) UOL_N or UOL_E, whichever is applicable. If it was feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E, as applicable, and starting from its previous base point. If it was not feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E, as applicable, but instead starting from the feasible output level closest to its previous base point.

When setting physical base points for a Dispatchable Resource at later time points, the ISO shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper dispatch limits for that time point. A Resource's dispatch limits at later time points shall be based on its: (A) dispatch limits from the first time point; (B) response rate; (C) minimum generation; and (D) UOL_N or UOL_E, whichever is applicable.

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by increasing the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by decreasing the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level or to a Demand Side Resource's Demand Reduction level.

The RTD Base Point Signals sent to Dispatchable Resources shall be the same as the physical base points determined above.

17.1.2.1.2.1.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind as Their Fuel

For all time points of the optimization period, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind Energy Forecast.

17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators

When setting physical base points for Self-Committed Fixed Generators in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels that it specified in its self-commitment request for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

When setting physical base points for ISO-Committed Fixed Generators in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels scheduled for it by RTC for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

The RTD Base Point Signals sent to Self-Committed Fixed Generators shall follow the quarter hour operating schedules that those Generators submitted in their real-time self-commitment requests

The RTD Base Point Signals sent to ISO-Committed Fixed Generators shall follow the quarter hour operating schedules established for those Generators by RTC, regardless of their actual performance. To the extent possible, the ISO shall honor the response rates specified by such Generators when establishing RTD Base Point Signals. If a Self-Committed Fixed Generator's operating schedule is not feasible based on its real-time self-commitment requests then its RTD Base Point Signals shall be determined using a response rate consistent with the operating schedule changes.

17.1.2.1.2.2 The Second Pass

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats all Fixed Block Units that are committed by RTC, all Resources meeting Minimum Generation Levels and capable of starting in ten minutes that have not been committed by RTC and all units otherwise instructed to be online or remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable), regardless of their minimum run-time status. The second pass calculates real-time Energy prices and real-time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Article 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this ISO Services Tariff respectively. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Resources shall be the same as the physical base points calculated in the first pass.

17.1.2.1.2.2.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind as Their Fuel

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the higher of: (A) its upper dispatch limit from the first pass; or (B) its "pricing base point" from the first time point of the prior RTD interval adjusted up within its Dispatchable range for any possible ramping since that pricing base point was issued less the higher of: (i) the physical base point established during the first pass of the RTD immediately prior to the previous RTD minus the Resource's metered output level at the time that the current RTD run was initialized, or (ii) zero.

The lower dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the lower of: (A) its lower dispatch limit from the first pass; or (B) its "pricing base point" from the first time point of the prior RTD interval adjusted down within its Dispatchable range to account for any possible ramping since that pricing base point was issued plus the higher of: (i) the Resource's metered output level at the time that the current RTD run was initialized minus the physical base point established during the first pass of the RTD immediately prior to the previous RTD; or (ii) zero.

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource shall be determined by increasing its upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable. The lower dispatch limit for the later time points of the second pass for such a Resource shall be determined by decreasing its lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level.

17.1.2.1.2.2.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind as Their Fuel

For the first time point and later time points for Intermittent Power Resources that depend on wind as their fuel, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind Energy Forecast.

17.1.2.1.2.3 The Third Pass

The third RTD pass is reserved for future use.

17.1.2.1.3 Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 17.1.2.1.1 and 17.1.2.1.2 shall apply.

First, if the ISO enters reserve pickup mode: (i) the ISO will produce prices and schedules for a single ten minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments before executing the three RTD passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator to be set to the higher of the Generator's physical base point or its actual generation level.

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator within the affected area towards its UOL_E at its emergency response rate or set it at a level equal to its physical base point.

Third, if the ISO enters basepoints ASAP – no commitments mode it will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period).

Fourth, if the ISO enters basepoints ASAP – commit as needed mode: (i) the ISO will produce price and schedules for a single five minute interval (not for a multi-point co-optimization period); and (ii) the ISO may make additional commitments of Generators that are capable of starting within ten minutes before executing the three RTD passes.

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization period consisting of two five-minute time points.

17.1.2.1.4 The Real-Time Commitment ("RTC") Process and Automated Mitigation

Attachment H of this Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are implemented they shall be incorporated into the RTC software through the establishment of a second, parallel, commitment evaluation that will assess the impact of the mitigation measures. The first evaluation, referred to as the "RTC evaluation," will determine the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the “RT-AMP” evaluation, will determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow the rules governing RTC’s operation that are set forth in Article 4 and this Attachment B to this ISO Services Tariff.

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, RTC_{15} and RT-AMP_{15} will perform Resource commitment evaluations simultaneously. RT-AMP_{15} will then apply the mitigation “impact” test, account for reference bid levels as appropriate and determine which Resources are actually to be mitigated. This information will then be conveyed to RTC_{30} which will make Resource commitments consistent with the application of the mitigation measures (and will thus indirectly be incorporated into future RTD runs).

17.1.3 Day-Ahead LBMP Calculation Procedures

LBMPs in the Day-Ahead Market are calculated using five passes. The first two passes are commitment and dispatch passes; the last three are dispatch only passes.

Pass 1 consists of a least cost commitment and dispatch to meet Bid Load and reliable operation of the NYS Power System that includes Day-Ahead Reliability Units.

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment (“SCUC”) to meet Bid Load. At the end of this step, committed Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed

Block Units are dispatched to meet Bid Load with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure (“AMP”) activation.

If AMP is activated, Step 1B tests to determine if the AMP will be triggered by mitigating offer prices subject to mitigation that exceed the conduct threshold to their respective reference prices. These mitigated offer prices together with all originally submitted offer prices not subject to automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This step is another iteration of the SCUC process. At the end of Step 1B, committed Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources, and non-Fixed Block Units are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are again calculated from this dispatch. The LBMPs determined at the end of Step 1B are compared to the LBMPs determined at the end of Step 1A to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the SCUC process. At the end of Step 1C, committed Fixed Block Units, Imports, Exports, virtual supply, virtual load, Demand Side Resources, and non-Fixed Block Units are again dispatched to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are again calculated from this dispatch.

All Demand Side Resources and non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of and the AMP) are blocked on at least to minimum load in Passes 4 through 6. The resources required to meet local system reliability are determined in Pass 1.

Pass 2 consists of a least cost commitment and dispatch of Fixed Block Units, Imports, Exports, Demand Side Resources and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load, considering the Wind Energy Forecast, that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fixed Block Units are dispatchable on a flexible basis. Incremental Import Capacity needed to meet forecast Load requirements is determined in Pass 2. Fixed Block Units committed in this pass are not included in the least cost dispatches of Passes 5 or 6. Demand Side Resources and non-Fixed Block Units committed in this step are blocked on at least to minimum Load in Passes 4 through 6. Intermittent Power Resources that depend on wind as their fuel committed in this pass as a result of the consideration of the Wind Energy Forecast are not blocked in Passes 5 or 6.

Pass 3 is reserved for future use.

Pass 4 consists of a least cost dispatch to forecast Load. It is not used to set schedules or prices. It is used for operational purposes and provides a dispatch of Fixed Block Units, Imports, Exports, Demand Side Resources and non-Fixed Block Units committed in Passes 1 or 2. Incremental Import Capacity committed in Pass 2 is re-evaluated and may be reduced if no longer required.

Pass 5 consists of a least cost dispatch of Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units committed to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fixed Block Units are treated as dispatchable on a flexible basis. LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

Pass 6 consists of a least cost dispatch of all Day-Ahead committed Resources, Imports, Exports, Virtual Supply, Virtual Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units committed in the final step of Pass 1 blocked on at maximum Capacity. Final schedules for Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

17.1.4 Determination of Transmission Shortage Cost

The applicable Transmission Shortage Cost depends on whether a particular transmission Constraint is associated with a transmission facility or Interface that includes a non-zero constraint reliability margin value. The ISO shall establish constraint reliability margin values for transmission facilities and Interfaces. Non-zero constraint reliability margin values established by the ISO shall be equal to or greater than 20 MW.

For transmission facilities and Interfaces with a non-zero constraint reliability margin value, SCUC, RTC and RTD shall include consideration of a two step demand curve consisting of up to an additional 5 MW of available resource capacity at a cost of $350/MWh and up to an additional 15 MW of available resource capacity at a cost of $1,175/MWh when evaluating transmission Constraints associated with such facilities and Interfaces. In no event, however, shall the Shadow Price for such transmission Constraints exceed $4,000/MWh.

For transmission facilities and Interfaces with a constraint reliability margin value of zero, the Shadow Price for transmission Constraints associated with such facilities and Interfaces shall not exceed $4,000/MWh. SCUC, RTC and RTD shall not include consideration of the available resource capacity provided by the two step demand curve described above for such transmission Constraints.

In evaluating all transmission Constraints, the ISO will determine whether sufficient available resource capacity exists to solve each transmission Constraint at its applicable limit. If sufficient available resource capacity does not exist to solve the transmission Constraint at its otherwise applicable limit, the ISO shall increase the applicable limit for such transmission Constraint to an amount achievable by the available resource capacity plus 0.2 MW. For transmission facilities and Interfaces with a non-zero constraint reliability margin value, the ISO shall account for the 20 MW of available resource capacity from the two step demand curve described above in determining: (i) whether sufficient available resource capacity exists to solve transmission Constraints associated with such facilities and Interfaces at their otherwise applicable limit; and (ii) the extent of any limit adjustment required to solve such transmission Constraints.

The ISO may periodically evaluate the Transmission Shortage Cost to determine whether it is necessary to modify the Transmission Shortage Cost to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this evaluation. If the ISO determines that it is necessary to modify the Transmission Shortage Costs in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to ninety days, provided however the NYISO shall file such change with the Commission pursuant to Section 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will: (i) consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change; and (ii) notify Market Participants of any temporary modification.

The responsibilities of the ISO and the Market Monitoring Unit in evaluating and modifying the Transmission Shortage Cost, as necessary are addressed in Attachment O, Section 30.4.6.8.1 of this Market Services Tariff ("Market Monitoring Plan").

17.1.5 Zonal LBMP Calculation Method

The computation described in Section 17.1.1 of this Attachment B is at the bus level. An eleven (11) zone model will be used for the LBMP billing related to Loads. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the Load Zone. The Load weights which will sum to unity will be calculated from the load bus MW distribution. Each component of the LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone *j* can be written as:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

where:

$\gamma_j^Z =$ LBMP for zone j,

$\gamma_j^{L,Z} = \sum_{i=1}^{n} W_i \gamma_i^L$ is the Marginal Losses Component of the LBMP for zone j;

$\gamma_j^{C,Z} = \sum W_i \gamma_i^L$ is the Congestion Component of the LBMP for zone j;

$n =$ number of Load buses in zone j for which LBMPs are calculated; and

$W_i =$ Load weighting factor for bus i.

The NYISO also calculates and posts zonal LBMP for four (4) external zones for informational purposes only. Settlements for External Transactions are determined using the Proxy Generator Bus LBMP. Each external zonal LBMP is equal to the LBMP of the Proxy Generator Bus associated with that external zone. The table below identifies which Proxy Generator Bus LBMP is used to determine each of the posted external zonal LBMPs.

External Zone	External Zone PTID	Proxy Generator Bus	Proxy Generator Bus PTID
HQ	61844	HQ_GEN_WHEEL	23651
NPX	61845	N.E._GEN_SANDY_POND	24062
OH	61846	O.H._GEN_BRUCE	24063
PJM	61847	PJM_GEN_KEYSTONE	24065

Consistent with the ISO Services Tariff**,** LBMPs at Proxy Generator Buses are determined using calculated bus prices as described in this Section 17.1.

17.1.6 Real Time LBMP Calculation Methods for Proxy Generator Buses, Non-Competitive Proxy Generator Buses and Proxy Generator Buses Associated with Designated Scheduled Lines

17.1.6.1 Definitions

Interface ATC Constraint: An Interface ATC Constraint exists when proposed economic transactions over an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed the transfer capability for the Interface or for an associated Proxy Generator Bus.

Interface Ramp Constraint: An Interface Ramp Constraint exists when proposed interchange schedule changes pertaining to an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed any Ramp Capacity limit imposed by the ISO for the Interface or for an associated Proxy Generator Bus.

NYCA Ramp Constraint: A NYCA Ramp Constraint exists when proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole.

Proxy Generator Bus Constraint: Any of an Interface ATC Constraint, an Interface Ramp Constraint, or a NYCA Ramp Constraint (individually and collectively).

External Interface Congestion: The product of: (i) the portion of the Congestion Component of the LBMP at a Proxy Generator Bus that is associated with a Proxy Generator Bus Constraint and (ii) a factor, between zero and 1, calculated pursuant to ISO Procedures.

Proxy Generator Bus Border LBMP: The LBMP at a Proxy Generator Bus minus External Interface Congestion at that Proxy Generator Bus.

Unconstrained RTD LBMP: The LBMP as calculated by RTD less any congestion associated with a Proxy Generator Bus Constraint.

17.1.6.2 General Rules

Transmission Customers and Customers with External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. Those with External Generators may arrange LBMP Market sales and/or Bilateral Transactions with Internal or External Loads and External Loads may arrange LBMP Market purchases and/or Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of Proxy Generator Buses. LBMPs will be calculated for each Proxy

Generator Bus within this limited set. When an Interface with multiple Proxy Generator Buses is constrained, the ISO will apply the constraint to all of the Proxy Generator Buses located at that Interface. Except as set forth in Sections 17.1.6.3 and 17.1.6.4, the NYISO will calculate the three components of LBMP for Transactions at a Proxy Generator Bus as provided in the tables below.

When determining the External Interface Congestion, if any, to apply to determine the LBMP for RTD intervals that bridge two RTC intervals, the NYISO shall use the External Interface Congestion associated with the second (later) RTC interval.

17.1.6.2.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses

The pricing rules for Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.2.2 Pricing rules for Variably Scheduled Proxy Generator Buses

The pricing rules for Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
2	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$

17.1.6.2.3 Pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled

The pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
3	RTC_{15} is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$

17.1.6.3 Rules for Non-Competitive Proxy Generator Buses and Associated Interfaces

Real-Time LBMPs for an Interface that is associated with one or more Non-Competitive Proxy Generator Buses or for a Non-Competitive Proxy Generator Bus shall be determined as provided in the tables below. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

17.1.6.3.1 Pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.3.2 Pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$

4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface RampConstraint	Into NYCA (Import)	If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.3.3 Pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
6	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
7	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.4 Special Pricing Rules for Proxy Generator Buses Associated with Designated Scheduled Lines

Real-Time LBMPs for the Proxy Generator Buses associated with designated Scheduled Lines shall be determined as provided in the tables below. The Proxy Generator Buses that are associated with designated Scheduled Lines are identified in Section 4.4.4 of the Services Tariff.

17.1.6.4.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are to be determined.

17.1.6.4.2 Pricing rules for Variably Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Variably Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Into NYCA (Import)	If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Out of NYCA (Export)	If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$)

17.1.6.4.3 Pricing rules for Proxy Generator Buses that are associated with Designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Proxy Generator Buses that are associated with designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses, are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
6	RTC_{15} is subject to an Interface ATC Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
7	RTC_{15} is subject to an Interface ATC Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.5 Method of Calculating Marginal Loss and Congestion Components of Real-Time LBMP at Non-Competitive Proxy Generator Buses and Proxy Generator Buses that are Subject to the Special Pricing Rule for Designated Scheduled Lines

Under the conditions specified below, the Marginal Losses Component and the Congestion Component of the Real-Time LBMP, calculated pursuant to the preceding paragraphs in Sections 17.1.6.3 and 17.1.6.4, shall be constructed as follows:

When the Real-Time LBMP is set to zero and that zero price was not the result of using the RTD, RTC or SCUC-determined LBMP;

$$Marginal\ Losses\ Component\ of\ the\ Real\text{-}Time\ LBMP = Losses_{RTD\ PROXY\ GENERATOR\ BUS}$$

and

$$Congestion\ Component\ of\ the\ Real\text{-}Time\ LBMP = -(Energy_{RTD\ REF\ BUS} + Losses_{RTD\ PROXY\ GENERATOR\ BUS})$$

where:

$Energy_{RTD\ REF\ BUS}$ = The marginal Bid cost of providing Energy at the reference Bus, as calculated by RTD for that 5-minute interval; and

$Losses_{RTD\ PROXY\ GENERATOR\ BUS}$ = The Marginal Losses Component of the LBMP as calculated by RTD for that 5-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line.

17.2 Accounting For Transmission Losses

17.2.1 Charges

Subject to Attachment K to the ISO OATT, the ISO shall charge all Transmission Customers for transmission system losses based on the marginal cost of losses on either a bus or zonal basis, described below.

17.2.1.1 Loss Model

The ISO's RTD software will use a power flow model and penalty factors to estimate losses incurred in performing generation dispatch and billing functions for losses.

17.2.1.2 Residual Loss Payment

The ISO will determine the difference between the payments by Transmission Customers for losses and the payments to Suppliers for losses associated with all Transactions (LBMP Market or Transmission Service under Parts 3, 4 and 5 of the ISO OATT) for both the Day-Ahead and Real-Time Markets. The accounting for losses at the margin may result in the collection of more revenue than is required to compensate the Generators for the Energy they produced to supply the actual losses in the system. This over collection is termed residual loss payments. The ISO shall calculate residual loss payments revenue on an hourly basis and will credit them against the ISO's Residual Adjustment (See Rate Schedule 1 of the ISO OATT).

17.2.2 Computation of Residual Loss Payments

17.2.2.1 Marginal Losses Component LBMP

The ISO shall utilize the Marginal Losses Component of the LBMP on an Internal bus, an External bus, or a zone basis for computing the marginal contribution of each Transaction to the system losses. The computation of these quantities is described in this Attachment.

17.2.2.1.1 Marginal Losses Component Day-Ahead

The ISO shall utilize the Marginal Losses Component computed by SCUC for computing the marginal contributions of each Transaction in the Day-Ahead Market.

17.2.2.1.2 Marginal Losses Component Real -Time

The ISO shall utilize the Marginal Losses Component calculated by the (i) RTD programs in most cases; or, (ii) during intervals when the conditions specified in Part 17.1 of this Attachment B exist at Proxy Generator Buses, the RTC program, for computing the Marginal Losses Component associated with each Transaction scheduled in the Real-Time Market (or deviations from Transactions scheduled in the Day-Ahead Market). The computations will be performed on an RTD-interval basis and aggregated to an hourly total.

17.2.2.2 Payments and Charges

Payments and charges to reflect the impact of Energy supplied by each Generator, consumed by each Load, or transmitted by each Transmission Customer on the Marginal Losses Component shall be determined as follows. Each of these payments or charges may be negative.

17.2.2.3 Day-Ahead Payments and Charges

As part of the LBMP paid to all Suppliers scheduled Day-Ahead to provide Energy to the LBMP Market, the ISO shall pay each such Supplier the product of: (a) the injection scheduled Day-Ahead from each of that Supplier's Generators in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at each of those Generators' buses, in $/MWh.

As part of the LBMP charged to all LSEs scheduled Day-Ahead to purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of: (a) the withdrawal scheduled Day-Ahead in each Load Zone by that LSE in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP in that Load Zone, in $/MWh.

As part of the TUC charged to all Transmission Customers whose Transmission Service has been scheduled Day-Ahead, the ISO shall charge each such Transmission Customer the product of: (a) the amount of Energy scheduled Day-Ahead to be injected and withdrawn by that Transmission Customer in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of Delivery (*i.e.*, Load Zone in which Energy is scheduled to be withdrawn or the bus where Energy is scheduled to be withdrawn if the Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Day-Ahead LBMP at the Point of Receipt, in $/MWh.

17.2.2.4 Real-Time Payments and Charges

As part of the LBMP paid to all Suppliers providing Energy to the Real-Time LBMP Market, the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators in each hour (to the extent that actual injections do not exceed the AGC or RTD Base Points Signals sent to that Supplier for those Generators plus any Compensable Overgeneration payable pursuant to ISO Procedures), minus the amount of Energy each of those Generators was scheduled Day-Ahead to inject in that hour, in MWh; and (b) the loss component of the Real-Time LBMP at each of those Generator's buses, in $/MWh.

As part of the LBMP charged to all LSEs that purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of (a) the Actual Energy Withdrawals by that LSE in each Load Zone in each hour, minus the Energy withdrawal scheduled Day-Ahead in that Load Zone by that LSE for that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $MWh.

As part of the TUC charged to all Transmission Customers whose Transmission Service was scheduled after the determination of the Day-Ahead schedule, or who schedule additional Transmission Service after the determination of the Day-Ahead schedule, the ISO shall charge each such Transmission Customer the product of: (a) actual Energy Withdrawals scheduled RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (i.e., the Load Zone in which Energy is scheduled to be withdrawn or the External bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Real-Time LBMP at the Point of Receipt, in $MWh.

As part of the LBMP paid to all Suppliers generating an amount of Energy that differs from the amount of Energy those Suppliers were scheduled by RTD to generate in an hour in association with Bilateral Transactions, the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators in each hour (to the extent that actual injections do not exceed the AGC or RTD Base Points Signals sent to that Supplier for those Generators plus any Compensable Overgeneration payable pursuant to ISO Procedures) minus the amount of Energy each of those Generators was scheduled by RTD to inject in that hour in association with Bilateral Transactions, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at each of those Generators' buses, in $/MWh.

As part of the LBMP charged to all LSEs consuming an amount of Energy that deviates from the amount of Energy those LSEs were scheduled by RTD to consume in an hour in association with Bilateral Transactions, the ISO shall charge each such LSE the product of: (a) the Actual Energy Withdrawals by that LSE in each Load Zone in each hour, minus the Energy withdrawal scheduled by RTD in that Load Zone by that LSE for that hour in association with Bilateral Transactions, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $/MWh.

17.3 Bilateral Transaction Bidding, Transmission Service, Schedules and Curtailment

All Transmission Customers and interested entities should refer to Attachment J, Section 16.3 of the ISO OATT for all information related to Transmission Service, Schedules and Curtailment.

17.4 Sale and Award Of Transmission Congestion Contracts ("TCCs")

All Transmission Customers and all applicants seeking to become Transmission Customers should refer to Attachment M of the ISO OATT for all information related to the sale and award of TCCs.

17.5 Congestion Settlements Related To the Day-Ahead Market and TCC Auction Settlements

See Attachment N of the ISO OATT for provisions regarding the Congestion settlements related to the Day-Ahead Market and the settlements related to Centralized TCC Auctions and Reconfiguration Auctions.

18 Attachment C -Formulas For Determining Bid Production Cost Guarantee Payments

18.1 Introduction

Ten Bid Production Cost Guarantee (BPCG) payments for eligible Suppliers are described in this attachment: (i) a Day-Ahead BPCG for Generators; (ii) a Day-Ahead BPCG for Imports; (iii) a real-time BPCG for Generators in RTD intervals other than Supplemental Event Intervals ; (iv) a BPCG for Generators for Supplemental Event Intervals; (v) a real-time BPCG for Imports; (vi) a BPCG for long start-up time Generators (i.e., Generators that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) whose start is aborted by the ISO prior to their dispatch; (vii) a BPCG for Demand Reduction in the Day-Ahead Market; (viii) a Special Case Resources BPCG; (ix) a BPCG for Demand Side Resources providing synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market; and (x) a BPCG for Demand Side Resources providing synchronized Operating Reserves and / or Regulation Service in the Real-Time Market. Suppliers shall be eligible for these payments in accordance with the eligibility requirements and formulas established in this Attachment C.

The Bid Production Cost guarantee payments described in this Attachment C are each calculated and paid independently from each other. A Customer's eligibility to receive one type of Bid Production Cost guarantee payment shall have no impact on the Customer's eligibility to be considered to receive another type of Bid Production Cost guarantee payment, in accordance with the rule set forth in this Attachment C.

18.2 Day-Ahead BPCG For Generators

18.2.1 Eligibility to Receive a Day-Ahead BPCG for Generators

18.2.1.1 Eligibility.

A Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO Committed Flexible Generator that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment.

18.2.1.2 Non-Eligibility (includes both partial and complete exclusions).

Notwithstanding Section 18.2.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator that is committed by the ISO in the Day-Ahead Market shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment if that Generator has been committed in the Day-Ahead Market for any other hour of the day as a result of a Self-Committed Fixed or Self-Committed Flexible bid.

18.2.2 Formulas for Determining Day-Ahead BPCG for Generators

18.2.2.1 Applicable Formula. A Supplier's BPCG for a Generator "g" shall be as follows:

Day-Ahead Bid Production Cost Guarantee for Generator g =

$$Max\left[\sum_{h=1}^{N}\left(\int_{MGH_{gh}^{DA}}^{EH_{gh}^{DA}} C_{gh}^{DA} + MGC_{gh}^{DA}MGH_{gh}^{DA} + SUC_{gh}^{DA}NSUH_{gh}^{DA} - LBMP_{gh}^{DA}EH_{gh}^{DA} - NASR_{gh}^{DA}\right), 0\right]$$

18.2.2.2 Variable Definitions. The terms used in this Section 18.2.2 shall be defined as follows:

N = number of hours in the Day-Ahead Market day;

EH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by Generator *g* in hour *h* expressed in terms of MWh;

MGH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by the minimum generation segment of Generator *g* in hour *h* expressed in terms of MWh;

C_{gh}^{DA} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost curve for Generator *g*, in the Day-Ahead Market for hour *h* expressed in terms of $/MWh;

MGC_{gh}^{DA} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator *g*, for hour *h* in the Day-Ahead Market, expressed in terms of $/MWh.

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day and Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), then Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Day-Ahead Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gh}^{DA} = Start-Up Bid by Generator *g* in hour *h*, or when applicable the mitigated Start-Up Bid for Generator *g*, in hour *h* in the Day-Ahead Market expressed in terms of $/start; *provided, however*, that the Start-Up Bid for Generator *g* in hour *h* or, when applicable, the mitigated Start-Up Bid, for Generator *g* in hour *h*, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled, and to operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator *g*'s Day-Ahead or SRE schedule.

If Generator *g* was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* Generator *g* shall have its Start-Up Bid set to zero for purposes of calculating a Day-Ahead Bid Production Cost guarantee.

For a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the ISO and runs in real-time, the Start-Up Bid for Generator g in hour h shall be the Generator's Start-Up Bid, or when applicable the mitigated Start-Up Bid for Generator g, for the hour (as determined at the point in time in which the ISO provided notice of the request for start-up):

$NSUH_{gh}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in hour h;

$LBMP_{gh}^{DA}$ = Day-Ahead LBMP at Generator g's bus in hour h expressed in $/MWh;

$NASR_{gh}^{DA}$ = Net Ancillary Services revenue, expressed in terms of $, paid to Generator g as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that hour, if it is not a Supplier of Installed Capacity and has been scheduled to operate in that hour; (2) Regulation Service payments made to that Generator for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less that Generator's Day-Ahead Regulation Capacity Bid to provide that amount of Regulation Service in that hour; and (3) payments made to that Generator for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less that Generator's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.3 Day-Ahead BPCG For Imports

18.3.1 Eligibility to Receive a Day-Ahead BPCG for Imports

A Supplier that bids an Import that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment.

18.3.2 BPCG Calculated by Transaction ID

For purposes of calculating a Day-Ahead Bid Production Cost guarantee payment for an Import under this Section 18.3, the ISO shall treat the Import as being from a single Resource for all hours of the Day-Ahead Market day in which the same Transaction ID is used, and the ISO shall treat the Import as being from a different Resource for all hours of the Day-Ahead Market day in which a different Transaction ID is used.

18.3.3 Formula for Determining Day-Ahead BPCG for Imports

Day-Ahead Bid Production Cost guarantee for Import t by Supplier =

$$max\left[\sum_{h=1}^{N}(DecBid_{th}^{DA} - LBMP_{th}^{DA}) * SchImport_{th}^{DA}, 0\right]$$

Where;

N = number of hours in the Day-Ahead Market day;

$DecBid_{th}^{DA}$ = Decremental Bid, in $/MWh, supplied for Import t for hour h;

$LBMP_{th}^{DA}$ = Day-Ahead LBMP, in $/MWh, for hour h at the Proxy Generator Bus that is the source of the Import t and

$SchImport_{th}^{DA}$ = total Day-Ahead schedule, in MWh, for Import t in hour h.

18.4 Real-Time BPCG For Generators In RTD Intervals Other Than Supplemental Event Intervals

18.4.1 Eligibility for Receiving Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event Intervals

18.4.1.1 Eligibility.

A Supplier shall be eligible to receive a real-time Bid Production Cost guarantee payment for intervals (excluding Supplemental Event Intervals) if it bids on behalf of:

18.4.1.1.1 an ISO-Committed Flexible Generator or an ISO-Committed Fixed Generator that is committed by the ISO in the Real-Time Market; or

18.4.1.1.2 a Self-Committed Flexible Generator if the Generator's minimum operating level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; or

18.4.1.1.3 a Generator committed via SRE, or committed or dispatched by the ISO as Out-of-Merit generation to ensure NYCA or local system reliability for the hours of the day that it is committed via SRE or is committed or dispatched by the ISO as Out-of-Merit generation to meet NYCA or local system reliability without regard to the Bid mode(s) employed during the Dispatch Day, except as provided in Sections 18.4.2 and 18.12, below.

18.4.1.2 Non-Eligibility (includes both partial and complete exclusions).

Notwithstanding Section 18.4.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator that is committed by the ISO in the real-time market shall not be eligible to receive a real-time Bid Production Cost guarantee payment if that Generator has been committed in real-time, in any other hour of the day, as the result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule, *provided however*, a Generator that has been committed in real time as a result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule will not be precluded from receiving a real-time Bid Production Cost guarantee payment for other hours of the Dispatch Day, in which it is otherwise eligible, due to these Self-Committed mode Bids if such bid mode was used for: (i) an ISO authorized Start-Up, Shutdown or Testing Period, or (ii) for hours in which such Generator was committed via SRE or committed or dispatched by the ISO as Out-of-Merit to meet NYCA or local system reliability.

18.4.2 Formula for Determining Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee for Generator g =

$$Max\left[\left(\sum_{i\in M}\left(\left(\int_{max(EI_{gi}^{DA},MGI_{gi}^{RT})}^{max(EI_{gi}^{RT},MGI_{gi}^{RT})} C_{gi}^{RT} + MGC_{gi}^{RT} * \left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right) - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - EI_{gi}^{DA}\right)\right) * \frac{S_i}{3600}\right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi} + \sum_{j\in L} SUC_{gj}^{RT} * \left(NSUI_{gj}^{RT} - NSUI_{gj}^{DA}\right)\right), 0\right]$$

where:

S_i = number of seconds in RTD interval i;

C_{gi}^{RT} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost for Generator g, in the RTD for the hour that includes RTD interval i expressed in terms of $/MWh, except in intervals in which the dispatch of the Generator is constrained by its downward ramp rate for that interval, unless that Generator was scheduled to provide Regulation Service in that interval and its RTD basepoint was less than its AGC basepoint, and except in hours in which the NYISO has increased Generator g's minimum operating level, either (i) at the Generator's request including through an adjustment to the Resource's self-commitment schedule, or (ii) in order to reconcile the ISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

MGI_{gi}^{RT} = metered Energy produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;

MGI_{gi}^{DA} = Energy scheduled Day-Ahead to be produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;

MGC_{gi}^{RT} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, in the Real-Time Market for the hour that includes RTD interval i, expressed in terms of $/MWh, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), *then* Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Real-Time Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gj}^{RT} = Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, for hour j into RTD expressed in terms of $/start, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

provided, however,

(i) the Start-Up Bid shall be deemed to be zero for (1) Self-Committed Fixed and Self-Committed Flexible Generators, (2) Generators that are economically committed by RTC or RTD that have 10-minute start-up times that are not synchronized and producing Energy within 20 minutes after their scheduled start time, and (3) Generators that are economically committed by RTC that have greater than 10-minute start-up times that are not synchronized and producing Energy within 45 minutes after their scheduled start time;

(ii) if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time commitment that did not result from a Day-Ahead commitment, the Generator's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be the Start-Up Bid submitted in response to the SRE request (subject to mitigation, where appropriate);

(iii) if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time schedule that resulted from a Day-Ahead commitment, then the Generator's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be set to zero;
(iv) the real-time Start-Up Bid for Generator g for hour j or, when applicable, the mitigated real-time Start-Up Bid, for Generator g for hour j, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled and operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator g's Day-Ahead or SRE schedule; and

(v) if Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* Generator g shall have its Start-Up Bid set to zero for purposes of calculating a Real-Time Bid Production Cost guarantee.

$NSUI_{gj}^{RT}$ = number of times Generator g started up in hour j;

$NSUI_{gj}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in hour j;

$LBMP_{gi}^{RT}$ = Real-Time LBMP at Generator g's bus in RTD interval i expressed in terms of $/MWh;

M = the set of eligible RTD intervals in the Dispatch Day consisting of all of the RTD intervals in the Dispatch Day except:

(i) Supplemental Event Intervals (which are addressed separately in Section 18.5 below);

(ii) intervals during authorized Start-Up Periods, Shutdown Periods, or Testing Periods for Generator g;

L = the set of all hours in the Dispatch Day

EI_{gi}^{RT} = either, as the case may be:

(i) if $EOP_{ig} > AEI_{ig}$ then $\min(\max(AEI_{ig}, RTSen_{ig}), EOP_{ig})$; or

(ii) if otherwise, then max(min(AEI_{ig},$RTSen_{ig}$),EOP_{ig}).

EI_{gi}^{DA} = Energy scheduled in the Day-Ahead Market to be produced by Generator g in the hour that includes RTD interval i expressed in terms of MW;

$RTSen_{ig}$ = Real-time Energy scheduled for Generator g in interval i, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Generator g during the course of interval i expressed in terms of MW;

AEI_{ig} = average Actual Energy Injection by Generator g in interval i but not more than $RTSen_{ig}$ plus any Compensable Overgeneration expressed in terms of MW;

EOP_{ig} = the Economic Operating Point of Generator g in interval i expressed in terms of MW;

$NASR_{gi}^{TOT}$ = Net Ancillary Services revenue, expressed in terms of $, paid to Generator g as a result of either having been committed Day-Ahead to operate in the hour that includes RTD interval i or having operated in interval i which is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that RTD interval, if it is not a Supplier of Installed Capacity; (2) Regulation Service payments that would be made to that Generator for that hour based on a Performance Index of 1, less the Regulation Capacity and Regulation Movement Bids placed by that Generator to provide Regulation Service in that hour at the time it was committed to produce Energy for the LBMP Market and/or Ancillary Services to do so; (3) payments made to that Generator for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by that Generator to provide such reserves in that hour at the time it was scheduled to do so; and (4) Lost Opportunity Cost payments made to that Generator in that hour as a result of reducing that Generator's output in order for it to provide Voltage Support Service.

$NASR_{gi}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, expressed in terms of $, that is applicable to interval i calculated by multiplying the $NASR_{gh}^{DA}$ for the hour that includes interval i by $_{Si}$/3600.

$RRAP_{gi}$ = Regulation Revenue Adjustment Payment for Generator g in RTD interval i expressed in terms of $.

$RRAC_{gi}$ = Regulation Revenue Adjustment Charge for Generator g in RTD interval i expressed in terms of $.

18.4.3 Bids Used For Intervals at the End of the Hour

For RTD intervals in an hour that start 55 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour in accordance with ISO Procedures. For RTD-CAM intervals in an hour that start 50 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour, in accordance with ISO Procedures.

18.5 BPCG For Generators In Supplemental Event Intervals

18.5.1 Eligibility for BPCG for Generators in Supplemental Event Intervals

18.5.1.1 Eligibility

For intervals in which the ISO has called a large event reserve pick-up, as described in Section 4.4.4.1.1 of this ISO Services Tariff, or an emergency under Section 4.4.4.1.2 of this ISO Services Tariff, any Supplier who meets the eligibility requirements for a real-time Bid Production Cost guarantee payment described in subsection 18.4.1.1 of this Attachment C, shall be eligible to receive a BPCG under this Section 18.5.

18.5.1.2 Non-Eligibility

Notwithstanding subsection 18.5.1.1, a Supplier shall not be eligible to receive a Bid Production Cost guarantee payment for Supplemental Event Intervals if the Supplier is not eligible for a real-time Bid Production Cost guarantee payment for the reasons described in Section 18.4.1.2 of this Attachment C.

18.5.1.3 Additional Eligibility

Notwithstanding Section 18.5.1.2, a Supplier shall be eligible to receive a Bid Production Cost guarantee payment for a Generator producing energy during Supplemental Event Intervals occurring as a result of an ISO emergency under Section 4.4.4.1.2 of this ISO Services Tariff regardless of bid mode used for the day.

18.5.2 Formula for Determining BPCG for Generators in Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee Payment for Generator g =

$$\sum_{i \in P} \left(\max \left(\begin{array}{l} \left(\int_{\max\left(EI_{gi}^{DA}, MGI_{gi}^{RT}\right)}^{\max\left(EI_{gi}^{RT}, MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT} * \left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right) \right) * \frac{S_i}{3600} \\ - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - EI_{gi}^{DA}\right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi} \end{array} \right), 0 \right)$$

where:

P = the set of Supplemental Event Intervals in the Dispatch Day but excluding any intervals in which there are maximum generation pickups or large event reserve pickups where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA}; and

EI_{gi}^{RT} = (i) for any intervals in which there are maximum generation pickups, and the three intervals following, for Generators in the location for which the maximum generation pickup has been called -- the average Actual Energy Injections, expressed in MWh, for Generator g in interval i, and for all other Generators EI_{gi}^{RT} is as defined in Section 18.4.2 above.

(ii) for any intervals in which there are large event reserve pickups and the three intervals following, EI_{gi}^{RT} is as defined in Section 18.4.2 above.

C_{gi}^{RT} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost for Generator g, in the RTD for the hour that includes RTD interval i expressed in terms of $/MWh, except in hours in which the NYISO has increased Generator g’s minimum operating level, either (i) at the Generator’s request, or (ii) in order to reconcile the ISO’s dispatch with the Generator’s actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

The definition of all other variables is identical to those defined in Section 18.4 above.

In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 15.3.8 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

18.6 Real-Time BPCG For External Transactions

External Transactions are not eligible to receive Bid Production Cost guarantee payments in the Real-Time Market.

18.7. BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their dispatch

18.7.1 Eligibility for BPCG for Long Start-Up Time Generators Whose Starts Are Aborted by the ISO Prior to their Dispatch

A Supplier that bids on behalf of a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the ISO for reliability purposes as a result of a Supplemental Resource Evaluation and whose start is aborted by the ISO prior to its dispatch, as described in Section 4.2.5 of the ISO Services Tariff, shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.7.

18.7.2 Methodology for Determining BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their Dispatch

A Supplier whose long start-up time Generator's start-up is aborted shall receive a prorated portion of its Start-Up Bid submitted for the hour in which the ISO requested that the Generator begin its start-up sequence, based on the portion of the start-up sequence that it has completed prior to the signal to abort the start-up (*e.g.,* if a long start-up time Generator with a seventy-two (72) hour start-up time has its start-up sequence aborted after forty-eight (48) hours, it would receive two-thirds (2/3) of its Start-Up Bid).

18.8 BPCG For Demand Reduction In The Day-Ahead Market

18.8.1 Eligibility for BPCG for Demand Reduction in the Day-Ahead Market

A Demand Reduction Provider that bids a Demand Side Resource that is committed by the ISO in the Day-Ahead Market to provide Demand Reduction shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.8.

18.8.2 Formula for Determining BPCG for Demand Reduction in the Day-Ahead Market

$Day\text{-}Ahead\ BPCG\ for\ Demand\ Reduction\ Provider\ d =$

$$Max\left(\sum_{h=1}^{N}\left(MinCurCost_d^h + IncrCurCost_d^h - CurRev_d^h\right) + CurInitCost_d, 0\right)$$

where:

$$CurInitCost_d = \left(\sum_{h=1}^{N}\left(Min\left(ActCur_d^h, SchdCur_d^h\right)\right) / \left(\sum_{h=1}^{N} SchdCur_d^h\right)\right) * CurCost_d$$

$$MinCurCost_d^h = Min\left(\left(max(ActCur_d^h, 0), MinCur_d^h\right)\right) * MinCurBid_d^h$$

$$IncrCurCost_d^h = \left(\int_{MinCur_d^h}^{max\left(MinCur_d^h, min\left(SchdCur_d^h, ActCur_d^h\right)\right)} IncrCurBid_d^h\right)$$

$$CurRev_d^h = LBMP_{dh}^{DA} * min(max(ActCur_d^h, 0), SchdCur_d^h)$$

N	=	number of hours in the Day-Ahead Market day.
$CurInitCost_d$	=	daily Curtailment Initiation Cost credit for Day-Ahead Demand Reduction Provider *d*;

$MinCurCost_d^h$ = minimum Curtailment cost credit for Day-Ahead Demand Reduction Provider d in hour h;

$IncrCurCost_d^h$ = incremental Curtailment cost credit for Day-Ahead Demand Reduction Provider d for hour h;

$CurCost_d$ = total bid Curtailment Initiation Costs for Day-Ahead Demand Reduction Provider d for the day;

$CurRev_d^h$ = actual revenue for Day-Ahead Demand Reduction Provider d in hour h;

$ActCur_d^h$ = actual Energy curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$SchdCur_d^h$ = Energy scheduled Day-Ahead to be curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$MinCurBid_d^h$ = minimum Curtailment initiation Bid submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of $/MWh;

$IncrCurBid_d^h$ = Bid cost submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of $/MWh;

$MinCur_d^h$ = Energy scheduled Day-Ahead to be produced by the minimum Curtailment segment of Day-Ahead Demand Reduction Provider d for hour h expressed in terms of MWh; and

$LBMP_{dh}^{DA}$ = Day-Ahead LBMP for Day-Ahead Demand Reduction Provider d for hour h expressed in $/MWh.

18.9 BPCG For Special Case Resources

18.9.1 Eligibility for Special Case Resources BPCG

Any Supplier that bids a Special Case Resource that is committed by the ISO for an event in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.9. Suppliers shall not be eligible for a Special Case Resource Bid Production Cost guarantee payment for the period over which a Special Case Resource is performing a test.

18.9.2 Methodology for Determining Special Case Resources BPCG

A Special Case Resource Bid Production Cost guarantee payment shall be made when the Minimum Payment Nomination for any Special Case Resource committed by the ISO over the period of requested performance or four (4) hours, whichever is greater, exceeds the LBMP revenue received for performance by that Special Case Resource; provided, however, that the ISO shall set to zero the Minimum Payment Nomination for Special Case Resource Capacity in each interval in which such capacity was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy.

18.10 BPCG For Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service In The Day-Ahead Market

18.10.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service in the Day-Ahead Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.10.

18.10.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market

A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves and/or Regulation Service schedule in the Day-Ahead Market shall be calculated as follows:

BPCG for Demand Side Resource d Providing synchronized Operating Reserves and/or Regulation Service Day-Ahead =

$$max\left(\left(-\sum_{h=1}^{N} NASR_{dh}^{DA}\right), 0\right)$$

where:

N = number of hours in the Day-Ahead Market day.

$NASR_{dh}^{DA}$ = Net Ancillary Services revenue, in $, paid to Demand Side Resource d as a result of having been committed to provide Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Regulation Service payments made to that Demand Side Resource for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less Demand Side Resource d’s Day-Ahead Regulation Capacity Bid to provide that amount of Regulation Service in that hour; and (2) payments made to Demand Side Resource d for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less Demand Side Resource d’s Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.11 BPCG For Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service In The Real-Time Market

18.11.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Real-Time Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.11.

18.11.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Real-Time Market

A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves and/or Regulation Service schedule in the real-time Market shall be calculated as follows:

BPCG for Demand Side Resource d Providing synchronized Operating Reserves and/or Regulation Service in Real-Time =

$$max\left(-\sum_{i \in L}\left(NASR_{di}^{TOT} - NASR_{di}^{DA}\right), 0\right)$$

where:

L	=	set of RTD intervals in the Dispatch Day;
$NASR_{di}^{TOT}$	=	Net Ancillary Services revenue, in $, paid to Demand Side Resource d as a result of either having been scheduled Day-Ahead in the hour that includes RTD interval i or having been scheduled in real-time interval i which is computed by summing the following: (1) Regulation Service payments that would be made to Demand Side Resource d for that hour based on a Performance Index of 1, less the Regulation Capacity and Regulation Movement Bids placed by Demand Side Resource d to provide Regulation Service in that hour at the time it was committed to provide Ancillary Services; and (2) payments made to Demand Side Resource d for providing Spinning Reserve or synchronized 30-Minute Reserve in that

hour, less the Bid placed by Demand Side Resource d to provide such reserves in that hour at the time it was scheduled to do so; and

$NASR_{di}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, in $, that is applicable to interval i calculated by multiplying the $NASR_{dh}^{DA}$ for the hour that includes interval i by the quotient of the number of seconds in RTD interval i divided by 3600.

18.12 Proration Of Start-Up Bid For Generators That Are Committed In The Day-Ahead Market, Or Via Supplemental Resource Evaluation

18.12.1 Eligibility to Recover Operating Costs and Resulting Obligations

Generators committed in the Day-Ahead Market or via SRE that are not able to complete their minimum run time within the Dispatch Day in which they are committed are eligible to include in their Start-Up Bid expected net costs of operating on the day following the dispatch day at the minimum operating level specified for the hour in which the Generator is committed, for the hours necessary to complete the Generator's minimum run time.

Generators that receive Day-Ahead or SRE schedules that are not scheduled to operate in real-time, or that do not operate in real-time, at the MW level included in the Minimum Generation Bid for the first hour of the Generator's Day-Ahead or SRE schedule, for the longer of (a) the duration of the Generator's Day-Ahead or SRE schedule, or (b) the minimum run time specified in the Bid that was accepted for the first hour of the Generator's Day-Ahead or SRE schedule, will have the start-up cost component of the Bid Production Cost guarantee calculation prorated in accordance with the formula specified in Section 18.12.2, below. The rules for prorating the start-up cost component of the Bid Production Cost guarantee calculation apply both to operation within the Dispatch Day and to operation on the day following the Dispatch Day to satisfy the minimum run time specified for the hour in which the Generator was scheduled to start-up on the Dispatch Day.

Rules for calculating the reference level that the NYISO uses to test Start-Up Bids for possible mitigation are included in the Market Power Mitigation Measures that are set forth in Attachment H to the ISO Services Tariff. Proration of the start-up cost component of a Generator's Bid Production Cost guarantee based on the Generator's operation in real-time is different/distinct from the mitigation of a Start-Up Bid.

18.12.2 Proration of Eligible Start-Up Cost when a Generator Is Not Scheduled, or Does Not Operate to Meet the Schedule Specified in the Accepted Day-Ahead or SRE Start-Up Bid.

The start-up costs included in the Bid Production Cost guarantee calculation may be reduced *pro rata* based on a comparison of the actual MWs delivered in real-time to an hourly minimum MW requirement. The hourly MWh requirement is determined based on the MW component of the Minimum Generation Bid submitted for the Generator's accepted start hour (as mitigated, where appropriate).

18.12.2.1 Total Energy Required to be Provided in Order to Avoid Proration of a Generator's Start-Up Costs

$$TotMWReq_{g,s} = MinOpMW_{g,s} * n_{g,s}$$

Where:

$TotMWReq_{g,s}$ = Total amount of Energy that Generator g, when started in hour s, must provide for its start-up costs not to be prorated

$MinOpMW_{g,s}$ = Minimum operating level (in MW) specified by Generator g in its hour s Bid

$n_{g,s}$ = The last hour that Generator g must operate when started in hour s to complete both its minimum run time and its Day-Ahead schedule. The variable $n_{g,s}$ is calculated as follows:

$$n_{g,s} = max\left(LastHrDASched_{g,s}, LastMinRunHr_{g,s}\right)$$

Where:

$LastHrDASched_{g,s}$ = The last date/hour in a contiguous set of hours in the Dispatch Day, beginning with hour s, in which Generator g is scheduled to operate in the Day-Ahead Market

$LastMinRunHr_{g,s}$ = The last date/hour in a contiguous set of hours in which Generator g would need to operate to complete its minimum run time if it starts in hour s

18.12.2.2 Calculation of Prorated Start-Up Cost

$$ProratedSUC_{g,s} = SubmittedSUC_{g,s} * \frac{\sum_{h=s}^{n_{g,s}} MinOpEnergy_{g,h,s}}{TotalMWReq_{g,s}}$$

Where:

$ProratedSUC_{g,s}$ = the prorated start-up cost used to calculate the Bid Production Cost guarantee for Generator g that is scheduled to start in hour s

$SubmittedSUC_{g,s}$= the Start-Up Bid submitted (as mitigated, where appropriate) for Generator g that is scheduled to start in hour s

$MinOpEnergy_{g,h,s}$ = the amount of Energy produced during hour h by Generator g during the time required to complete both its minimum run time and its Day-Ahead schedule, if that generator is started in hour s. $MinOpEnergy_{g,h,s}$ is calculated as follows:

$$MinOpEnergy_{g,h,s} = min\left(MetActEnergy_{g,h}, MinOpMW_{g,s}\right)$$

Where:

$MetActEnergy_{g,h}$ = the metered amount of Energy produced by Generator g during hour h

18.12.2.3 Additional Rules/Clarifications that Apply to the Calculation of Prorated Start-Up Cost

a. For any hour that a Generator is derated below the minimum operating level specified in its accepted Start-Up Bid for reliability, either by the ISO or at the request of a Transmission Owner, the Generator will receive credit for that hour as if the Generator had produced metered actual MWh equal to its $MinOpMW_{g,s}$.

b. A Generator must be scheduled and operate in real-time to produce Energy consistent with the $MinOpMW_{g,s}$ specified in the accepted Start-Up Bid for each hour that it is expected to run. *See* Section 18.12.2.1, above. These rules do not specify or require any particular bidding construct that must be used to achieve the desired commitment.

However, submitting a self-committed Bid may preclude a Generator from receiving a BPCG. *See, e.g.*, Sections 18.2.1.2.2 and 18.4.1.2.3 of this Attachment C.

19 Attachment D – This Section is reserved for future use

20 Attachment E - Procedures for Reserving and Correcting Erroneous Energy and Ancillary Services Prices

These provisions shall control the reservation and correction of Energy and Ancillary Services prices that are posted on OASIS and used in ISO settlements. The ISO shall review market clearing prices calculated for Energy and Ancillary Services and shall correct any price it determines not to have been calculated in accordance with the ISO tariffs as established in this Attachment E. .

20.1 Market Clearing Price Errors Requiring Correction

To be deemed a price that does not require correction, an Energy and Ancillary Service clearing price must be: (i) calculated correctly according to the relevant provision(s) of the ISO tariffs; (ii) based on the appropriate price-setting resource (*i.e.*, the marginal resource, except as otherwise provided by the ISO tariffs); and (iii) posted to the OASIS before the reservation deadline.

20.1.1 Calculation Errors

A calculation error occurs when, notwithstanding the selection of the correct price-setting unit, an Energy or Ancillary Service market clearing price is computed in a manner that is inconsistent with the ISO tariffs. In addition, a calculation error occurs when no price is calculated or a correctly calculated price is not timely posted to OASIS. Subject to the deadlines established in Section 20.3 of this Attachment E, the ISO shall correct a price that it determines to have resulted from a calculation error.

20.1.2 Errors in Selecting the Price-Setting Resource

The ISO shall schedule, commit, and dispatch supply resources on a least total bid production cost basis. An Energy or Ancillary Services market clearing price must be based on the appropriate price-setting resource (*i.e.*, the marginal resource, unless otherwise provided by the tariffs). Subject to the deadlines established in Section 20.3 of this Attachment E, the ISO shall correct a price that it determines to have resulted from an error in selecting the appropriate price-setting resource.

20.2 Methodology for Correcting Prices

The ISO shall recalculate an erroneous price in accordance with the relevant provision(s) of the ISO tariffs. In the event that the ISO cannot practicably recalculate an erroneous price, due to the unavailability of necessary data or otherwise, the ISO shall determine a price as close as reasonably possible to the price that should have resulted from the operation of the relevant tariff provisions consistent with system conditions by drawing as appropriate from: (i) prices calculated for electrically similar points, (ii) prices in surrounding intervals, (iii) Real-Time Commitment prices, (iv) Day-Ahead Market prices, or (v) Real-Time Dispatch prices for the affected interval(s).

In the event of a catastrophic failure of the ISO's price calculation software, the ISO shall provide notice of the problem to the Commission and Customers as soon as possible, but in no event later than the next business day. Within two additional business days, the ISO shall inform the Commission and Customers regarding the nature of the problem and the schedule for determining the procedures to be used by the ISO to construct prices. Following consultation with Transmission Customers regarding the procedures to be used, the ISO shall construct prices as close as possible to the prices that should have resulted from the application of the market rules established in the tariffs to prevailing system conditions.

20.3 Deadlines for Price Corrections

The ISO shall provide notice reserving a potentially erroneous real-time price not later than 17:00 of the calendar day following the operating day for which the price was calculated. The ISO shall provide notice reserving a potentially erroneous Day-Ahead price prior to the start of the operating day for which the price was calculated.

The ISO shall correct a price it has timely reserved and determines to be erroneous and shall provide notice of the correction as soon as possible, but not later than three days after the price reservation deadline. Whenever possible, the ISO will make price corrections prior to the reservation deadline and will provide notice of those corrections along with the reservation notices.

Erroneous prices not reserved and corrected within these timeframes shall not be corrected by the ISO except as directed by the Commission or a court of competent jurisdiction. Nothing herein shall be construed to restrict any stakeholder's right to seek redress from the Commission in accordance with the Federal Power Act.

20.4 Reporting Requirements

In the event that the ISO corrects a price, it shall provide Customers with supporting tariff references and information regarding:

(i) the affected price intervals;

(ii) the affected LBMP zone(s) or the affected Ancillary Service(s);

(iii) the type of pricing error (either a calculation error or an error in selecting the price-setting resource);

(iv) a description of the nature of the pricing error;

(v) a description of the underlying cause of the pricing error; and

(vi) the price correction method used.

The ISO shall provide this information to Transmission Customers as soon as possible but within ten days following the price correction unless extraordinary circumstances necessitate additional time to provide this information, in which case the ISO shall provide this information as soon as possible, but no later than 30 days following the price correction.

The ISO shall provide quarterly reports to Customers regarding the cause of each error requiring correction and steps taken or planned by the ISO to eliminate or diminish the incidence of the error in the future. In its quarterly reports, the ISO shall also detail any price errors of which it becomes aware after the deadlines for reservation or correction of the price error.

20.5 Liability

The ISO shall not be liable for errors of commission or omission relating to price errors that are left uncorrected by operation of these rules except in cases of gross negligence or intentional misconduct.

21 Attachment F - Bid Restrictions

21.1 Definitions

Except as noted below, all capitalized terms used in Attachment F shall have the meanings specified in Article 2 of the ISO Services Tariff, or in Section 1 of the ISO OATT. In addition, the following terms, which are not defined in the ISO Tariffs, shall have the meanings specified below.

"Bid Restriction" shall mean the maximum or minimum Bid Price that may be submitted in connection with certain Bids, as specified in Section 21.5 of this Attachment F.

"Emergency External Purchases" shall mean the purchase, by the ISO, of Capability or Energy from External Suppliers for the purpose of eliminating an Operating Reserve deficiency, as described in the ISO Procedures.

"Price Cap Load Bid" a Bid identifying the maximum price above which an Internal Load is not willing to be scheduled in the Day-Ahead Market.

21.2 Supremacy of Attachment F

During the period that this Attachment F is in effect, the provisions set forth herein shall be deemed incorporated by reference into every provision of the ISO Services Tariff affected by this Attachment F, including each of the ISO Services Tariff's Rate Schedules and Attachments. In the event of a conflict between the terms of this Attachment F and the terms of any other provision of the ISO Services Tariff, the terms of Attachment F shall prevail.

21.3 Effective Date

Attachment F shall become effective on July 25, 2000 for Suppliers submitting Day-Ahead Bids to sell Energy in the July 26, 2000 Day-Ahead Market, and on July 26, 2000 for all other Suppliers and for any Demand Reduction Providers that submit Bids which are subject to Section 21.5 below.

21.4 Establishment of Bid Restrictions

During the period that Attachment F is in effect, the Bid Restriction for all Bids referenced in Section 21.5.1 below shall be ± $1,000/MWh. If a Bid exceeds an applicable maximum Bid Restriction or is less than an applicable minimum Bid Restriction, the Bid shall be automatically rejected by the ISO.

21.5 Applicability of Bid Restrictions

21.5.1 The Bid Restriction established in Section 21.4 shall apply to Day-Ahead and real-time Energy Bids, Minimum Generation Bids, Decremental Bids, Price Cap Load Bids, Sink Price Cap Bids and real-time CTS Interface Bids , as applicable. All Suppliers and Demand Side Resources, whether External or Internal to the NYCA, shall be subject to a Bid Restriction for all Bids specified herein.

21.5.2. The Bid Restriction established in Section 21.4 shall not apply to Ancillary Services Bids, Start-Up Bids or to any other Bid that is not specified in Section 21.5.1, provided however a Bid floor of $0.00 shall apply to Regulation Capacity Bids and Regulation Movement Bids. This Attachment F does not supercede the reference level calculation rule or special mitigation procedures applicable to 10-Minute Non-Synchronized Reserve Bids under Sections 23.3.1.4.4 and 23.5.3 of Attachment H to this ISO Services Tariff.

21.5.3 Bid Restrictions shall not apply to Emergency External Purchases. Bids or Offers made in connection with External Emergency Purchases shall not establish market-clearing prices.

22 Attachment G - Emergency Demand Response Program

22.1 Effective Date

The Emergency Demand Response Program became effective on May 1, 2001. The ISO will review the Emergency Demand Response Program's performance semi-annually and will propose appropriate changes as necessary.

22.2 Qualification Requirements For Curtailment Services Providers

Curtailment Services Providers must be Customers or, in the case of entities that would be Customers solely for the purpose of participating in the Emergency Demand Response Program, must be Limited Customers. The requirements for Limited Customers are set forth in ISO Procedures.

Curtailment Service Providers must: (i) comply with the registration requirements set forth in the ISO Procedures; (ii) designate one or more contact persons to receive ISO communications; (iii) comply with the metering requirements set forth below in Section 22.8 of this Attachment, and as provided in ISO Procedures; and (iv) in accordance with ISO Procedures, be capable of reducing at least 100 kW of NYCA Load in a single Load Zone within two hours of receiving notice of the ISO's deployment of the Emergency Demand Response Program. The required Load reduction may be accomplished by Curtailing Load and/or by serving Load with a Local Generator pursuant to ISO Procedures.

22.3 Relationship Of The Emergency Demand Response Program To Other Demand Side Response Measures

The Emergency Demand Response Program is intended to complement other demand-side response programs developed by the ISO, the PSC and LSEs. Except as noted in Section 22.4 below, Curtailment Service Providers are free to participate in other demand response programs, to the extent that those programs allow: provided, however, that the ISO will pay under only one program for each MWh of delivered Load reduction. This restriction is not intended to limit payment for installed capacity otherwise available to Curtailment Service Providers.

22.4 Prohibition On The Double Subscription Of Load

Curtailment Service Providers may not offer to reduce NYCA Load in the Emergency Demand Response Program that has already been subscribed to the Program by another Curtailment Service Provider.

22.5 ISO Deployment Of The Emergency Demand Response Program

The ISO may deploy the Emergency Demand Response Program in response to: (i) a Real-Time Locational, Zonal or NYCA-wide Operating Reserve shortage or an ISO peak forecast of a locational, zonal or NYCA-wide Operating Reserve shortage; (ii) an ISO-declared Major Emergency State; (iii) a request for assistance from a Transmission Owner for Load reduction purposes or as a result of a Local Reliability Rule; or (iv) in the event that the ISO instructs Special Case Resources to reduce their consumption of Energy.

In accordance with ISO Procedures, the ISO may elect to call on a subset of participants subscribed in the Emergency Demand Response Program within Load Zone J when responding to the request for assistance from the Transmission Owner for Load reductions within the Load Zone.

22.6 Notification To Curtailment Service Providers

The ISO will, whenever possible, provide Curtailment Service Providers with day-ahead notice that it may deploy the Emergency Demand Response Program. Providing day-ahead notice of possible deployment does not commit the ISO to deploy the Emergency Demand Response Program or to make payments. The notice shall specify the time at which the ISO requests that Load reductions begin and shall, whenever possible, specify when the need for Load reductions will end. The ISO will also provide notice to Curtailment Service Providers of the deployment of the Emergency Demand Response Program at least two hours in advance of the start time specified to begin Load reductions, except that, when necessary, the ISO may immediately deploy the Emergency Demand Response Program without advance notice and call upon Curtailment Service Providers to provide Load reductions as soon as possible.

22.7 Voluntariness Of Emergency Demand Response Program

Participation in the Emergency Demand Response Program shall be voluntary. The ISO shall not penalize Curtailment Service Providers that decline to take steps to reduce Load when the Emergency Demand Response Program is deployed. Special Case Resources that have not sold their capacity shall be temporarily transferred to the Emergency Demand Response Program for each month in which their capacity remains unsold.

22.8 Metering

Curtailment Service Providers shall provide sufficient hourly interval metering data, pursuant to ISO procedures, to allow verification of their Load reduction performance.

22.9 Verification

Curtailment Service Providers shall report their Load reduction performance data to the ISO in accordance with ISO Procedures on or before the 75th day after each deployment of the Emergency Demand Response Program. If the ISO does not receive timely performance data, the ISO shall refuse to pay for that Curtailment Service Provider’s claimed Load reductions. All Load reduction data are subject to audit by the ISO. If the ISO determines that it has made an erroneous payment to a Curtailment Service Provider it shall have the right to recover it either by reducing other payments to that Curtailment Service Provider or by any other lawful means.

22.10 Payment

The ISO shall pay Curtailment Service Providers that have caused a verified reduction in Load in response to the deployment of the Emergency Demand Response Program. Payment shall be made in the manner set forth in this section and in accordance with ISO Procedures.

22.10.1 Curtailment Service Provider Eligibility Requirements for Payment

When the ISO deploys an Emergency Demand Response Program event (for the purposes of this subsection, "a deployment event"), each Curtailment Service Provider shall be eligible to be paid for verified Load reductions made during each hour of the payment eligibility period. The first hour of the payment eligibility period shall begin at the top of the hour within which the deployment event is to start as identified by the ISO. For immediate deployment events, the ISO-identified start is the time of the deployment message. The payment eligibility period shall end at the later of the third consecutive hour following the first hour of the payment eligibility period or the deployment event end time identified in the deployment message; provided, however, that the end time may be adjusted by the ISO in messages subsequent to the deployment message.

To be eligible for payment provided under this section the Curtailment Service Provider shall submit to the ISO as provided by Sections 22.8 and 22.9 above and in accordance with ISO Procedures, timely and sufficient Load reduction performance data including, but not limited to, interval metering data for each hour of the payment eligibility period.

22.10.2 Payment for Program Deployment

22.10.2.1 Program deployment lasting two hours or fewer

For deployment events of two hours or less, each Curtailment Service Provider shall be paid the higher of $500/MWh, or the zonal Real-Time LBMP for its verified Load reduction during the first two hours of the payment eligibility period, provided however if the deployment event starts after the top of the hour, the Curtailment Service Provider that reduces Load shall be paid the higher of $500/ MWh or the zonal Real-Time LBMP for its verified Load reduction during the third hour of the payment eligibility period. Each Curtailment Service Provider shall be paid the zonal Real-Time LBMP for each MWh of its verified Load reduction for the remaining hour(s) of the payment eligibility period.

22.10.2.2. Program deployment lasting between two and three hours

If the ISO deploys the Emergency Demand Response Program for more than two hours but not exceeding three hours, each Curtailment Service Provider that reduces Load shall be paid the higher of $500/MWh or the zonal Real-Time LBMP for its verified Load reduction during the first three hours of the payment eligibility period or for each hour of the payment eligibility period in which the program is deployed as established by the start and end times specified by the ISO in the deployment message(s). Each Curtailment Service Provider shall be paid the zonal Real-Time LBMP for each MWh of its verified Load reduction for the remaining hour of the payment eligibility period, if applicable.

22.10.2.3 Program deployment exceeding three hours

If the ISO deploys an Emergency Demand Response Program event that exceeds three hours, each Curtailment Service Provider that reduces Load shall be paid the higher of $500/MWh or the zonal Real-Time LBMP for its verified Load reduction during each hour of the payment eligibility period.

22.11 Cost Allocation

Payments made to Curtailment Service Providers for Load reductions provided under the Emergency Demand Response Program shall be recovered from all Transmission Customers pursuant to Rate Schedule 1 of the ISO OATT.

23 Attachment H - ISO Market Power Mitigation Measures

23.1. Purpose and Objectives

23.1.1 These ISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the ISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO Administered Markets, while avoiding unnecessary interference with competitive price signals. Consistent with the provisions of the ISO's Market Monitoring Plan that is set forth in Attachment O to the ISO Services Tariff, these Mitigation Measures are intended to minimize interference with open and competitive markets, and thus to permit, to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the Mitigation Measures authorize the mitigation only of specific conduct that exceeds well-defined thresholds specified below.

23.1.2 In addition, the ISO and its Market Monitoring Unit shall monitor the markets the ISO administers for conduct that the ISO or the Market Monitoring Unit determine~~s~~ constitutes an abuse of market power but that does not trigger the thresholds specified below for the imposition of mitigation measures by the ISO. If the ISO identifies or is made aware of any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified in Section 23.3.2.3 below, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d (1999) ("§ 205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, shall incorporate or address the recommendation of its Market Monitoring Unit, and shall set forth the ISO's justification for imposing that mitigation measure. The Market Monitoring Unit's reporting obligations are specified in Sections 30.4.5.3 and 30.4.5.4 of Attachment O. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.1 of Attachment O.

23.2 Conduct Warranting Mitigation

23.2.1 Definitions

The following definitions are applicable to this Attachment H:

For purposes of Section 23.4.5 of this Attachment H, "**Additional CRIS MW**" shall mean the MW of Capacity for which CRIS was requested for an Examined Facility pursuant to the provisions in ISO OATT Sections 25, 30, or 32 (OATT Attachments S, X, or Z), including either: (i) all, or a portion, of the MW of Capacity of that Examined Facility for which CRIS had not been obtained in prior Class Years through a prior Class Year process or through a transfer completed in accordance with OATT Section 25 (OATT Attachment S); and/or (ii) all, or a portion, of an increase in the Capacity of that Examined Facility. Additional CRIS MW does not include any MW quantity of CRIS that is exempt from an Offer Floor pursuant to Section 23.4.5.7.7(a) or (b), Section 23.4.5.7.8, or an increase of 2 MW or less in an Examined Facility's MW quantity of CRIS obtained pursuant to Section 30.3.2.6 of Attachment X to the OATT.

For purposes of Section 23.4.5 of this Attachment H, **"Affiliated Entity"** shall mean, with respect to a person or Entity:

i) all persons or Entities that directly or indirectly control such person or Entity;

ii) all persons or Entities that are directly or indirectly controlled by or under common control with such person or Entity, and (1) are authorized under ISO Procedures to participate in a market for Capacity administered by the ISO, or (2) possess, directly or indirectly, an ownership, voting or equivalent interest of ten percent or more in a Mitigated Capacity Zone Installed Capacity Supplier;

iii) all persons or Entities that provide services to such person or Entity, or for which such person or Entity provides services, if such services relate to the determination or submission of offers for Unforced Capacity in a market administered by the ISO or offers of capacity from a Generator electrically located in a MCZ Import Constrained Locality; or

iv) all persons or Entities, except if for ISP UCAP MW or an RMR Generator, with which such person or Entity has any form of agreement under which such person or Entity has retained or has conferred rights of (i) Control of Unforced Capacity or (ii) the ability to determine the quantity or price of offers to supply capacity from a Generator that has Capacity Resource Interconnection Service, pursuant to the applicable provisions of Attachment X, Attachment S and Attachment Z and is electrically located in an MCZ Import Constrained Locality, even if such capacity does not meet the requirements to be Unforced Capacity.

In the foregoing definition, **"control"** means the possession, directly or indirectly, of the power to direct the management or policies of a person or Entity, and shall be rebuttably presumed from an ownership, voting or equivalent interest of ten percent or more.

Catastrophic Failure: shall mean a Forced Outage initially suffered by a Generator which would have reasonably required a repair time of at least 270 days, from the date of the event resulting in the Forced Outage, had it, or a comparable Forced Outage been suffered at a generating facility that is reasonably the same as or similar to the Generator's, the owner of which is intending to return it to service. Repair time includes the reasonable number of days for initial clean up, safety inspections, engineering assessment; damage assessment, cost estimates; site prep and clean up, equipment orders, and actual repair, provided the foregoing are necessitated by the Catastrophic Failure. The determination that a Generator has suffered a Catastrophic Failure shall be based on a technical/engineering evaluation, shall be made by the ISO, and may be made at any time following the event that caused the Forced Outage provided that adequate information is provided to the ISO to support such determination.

"Class Year Study" means a Class Year Interconnection Facilities Study as that term is defined in OATT Section 25 (OATT Attachment S).

"Cleared UCAP" means the amount of MW (rounded down to the nearest tenth of a MW) that had been subject to an Offer Floor but has cleared in accordance with Section 23.4.5.7.

"Commenced Construction" shall mean (a) all of the following site preparation work is completed: ingress and egress routes exist; the site on which the project will be located is cleared and graded; there is power service to the site; footings are prepared; and foundations have been poured consistent with purchased equipment specifications and project design; or (b) the following financial commitments have been made: (i) (A) an engineering, procurement, and construction contract ("EPC") has been executed by all parties and is effective; or (B) contracts (collectively, "EPC Equivalents") for all of the following have been executed by all parties and is effective: (1) project engineering, (2) procurement of all major equipment, and (3) construction of the project, and (ii) the cumulative payments made by the developer under the EPC or EPC Equivalents to the counterparties to those respective agreements is equal to at least thirty (30) percent of the total costs of the EPC or EPC Equivalents.

"Constrained Area" shall mean: (a) the In-City area, including any areas subject to transmission constraints within the In-City area that give rise to significant locational market power; and (b) any other area in the New York Control Area that has been identified by the ISO as subject to transmission constraints that give rise to significant locational market power, and that has been approved by the Commission for designation as a Constrained Area.

For purposes of Section 23.4.5 of this Attachment H, **"Control"** with respect to Unforced Capacity shall mean the ability to determine the quantity or price of offers to supply Unforced Capacity from a Mitigated Capacity Zone Installed Capacity Supplier submitted into an ICAP Spot Market Auction; but excluding ISP UCAP MW or UCAP from an RMR Generator.

For purposes of Section 23.4.5.7 "**CRIS MW**" shall mean the MW of Capacity for which CRIS was assigned to a Generator or UDR project pursuant to ISO OATT Sections 25, 30, or 32 (OATT Attachments S, X, or Z).

"Developer" shall have the meaning specified in the ISO's Open Access Transmission Tariff.

"Electric Facility" shall mean a Generator or an electric transmission facility.

For purposes of Section 23.4.5 of this Attachment H, **"Entity"** shall mean a corporation, partnership, limited liability corporation or partnership, firm, joint venture, association, joint-stock company, trust, unincorporated organization or other form of legal or juridical organization or entity.

Exceptional Circumstances: shall mean one or more unavoidable circumstances, as determined by the ISO, that individually or collectively render as unavailable the data necessary for the ISO to perform an audit and review of a Market Party, pursuant to Section 23.4.5.6.2 of this Services Tariff. Exceptional Circumstances may include, but are not limited to: the inaccessibility of the physical facility; the inaccessibility of necessary documentation or other data; and the unavailability of information regarding the regulatory obligations with which the Market Party will be required to comply in order to return its Generator to service which regulatory obligations are not yet known but which will be made known by the applicable regulatory authority under existing laws and regulations provided that none of the above described circumstances are the result of delay or inaction by the Market Party. The magnitude of the repair cost, alone, shall not be an Exceptional Circumstance.

"Exempt Renewable Technology" shall mean, in all Mitigated Capacity Zones, an Intermittent Power Resource solely powered by wind or solar energy.

For purposes of Section 23.4.5 of this Attachment H, **"Going-Forward Costs"** shall mean: either (a) the costs, including but not limited to mandatory capital expenditures necessary to comply with federal or state environmental, safety or reliability requirements that must be met in order to supply Installed Capacity, net of anticipated energy and ancillary services revenues, as determined by the ISO as specified in Section 23.4.5.3, for each of the following instances, as applicable, of supplying Installed Capacity that could be avoided if an Installed Capacity Supplier otherwise capable of supplying Installed Capacity were either (1) to cease supplying Installed Capacity and Energy for a period of one year or more while retaining the ability to re-enter such markets, or (2) to retire permanently from supplying Installed Capacity and Energy; or (b) the opportunity costs of foregone sales outside of a Mitigated Capacity Zone, net of costs that would have been incurred as a result of the foregone sale if it had taken place.

For purposes of Section 23.4.5 of this Attachment H, "**Indicative Mitigation Net CONE**" shall mean the capacity price calculated by the NYISO for informational purposes only if there is not an effective ICAP Demand Curve and the Commission (i) has accepted an ICAP Demand Curve for the Mitigated Capacity Zone that will become effective when the Mitigated Capacity Zone is first effective, in which case, the Indicative Mitigation Net CONE shall be the capacity price on such ICAP Demand Curve for the Mitigated Capacity Zone corresponding to the average amount of excess capacity above the Indicative NCZ Locational Minimum Installed Capacity Requirement, as applicable, expressed as a percentage of that requirement that formed the basis for the ICAP Demand Curve accepted by the Commission; or, (ii) has not accepted an ICAP Demand Curve for the Mitigated Capacity Zone, but the ISO has filed an ICAP Demand Curve for the Mitigated Capacity Zone pursuant to Services Tariff Section 5.14.1.2.2.4.11, in which case the Indicative Mitigation Net CONE shall be the capacity price on such ICAP Demand Curve corresponding to the average amount of excess capacity above the Indicative NCZ Locational Minimum Installed Capacity Requirement, expressed as a percentage of that requirement, that formed the basis for such ICAP Demand Curve.

"Initial Decision Period" shall have the meaning specified in Section 25 (Attachment S) of the ISO's Open Access Transmission Tariff.

"Interconnection Customer" shall have the meaning specified in Section 32 (Attachment Z) of the ISO's Open Access Transmission Tariff.

“Interconnection Facilities Study Agreement” shall have the meaning specified in Section 30 (Attachment X) of the ISO’s Open Access Transmission Tariff.

“Market Monitoring Unit” shall have the same meaning in these Mitigation Measures as it has in Attachment O.

“Market Party” shall mean any person or entity that is, or for purposes of the determinations to be made pursuant to Section 23.4.5.7 of this Attachment H proposes or plans a project that would be, a buyer or a seller in; or that makes bids or offers to buy or sell in; or that schedules or seeks to schedule Transactions with the ISO in or affecting any of the ISO Administered Markets including through the submission of bids or offers into any External Control Area, or any combination of the foregoing.

For purposes of Section 23.4.5 of this Attachment H, **“Mitigated UCAP”** shall mean one or more megawatts of Unforced Capacity that are subject to Control by a Market Party that has been identified by the ISO as a Pivotal Supplier.

For purposes of Section 23.4.5 of this Attachment H, “**Mitigation Net CONE**” shall mean the capacity price on the currently effective ICAP Demand Curve for the Mitigated Capacity Zone corresponding to the average amount of excess capacity above the Mitigated Capacity Zone Installed Capacity requirement, expressed as a percentage of that requirement, that formed the basis for the ICAP Demand Curve approved by the Commission.

“NCZ Examined Project” shall mean any Generator or UDR project that is not exempt pursuant to 23.4.5.7.8 and either (i) is in a Class Year on the date the Commission accepts the first ICAP Demand Curve to apply to a Mitigated Capacity Zone or (ii) meets the criteria specified in 23.4.5.7.3(II). An NCZ Examined Project may be at any phase of development or in operation or an Installed Capacity Supplier.

For purposes of Section 23.4.5 of this Attachment H, **“Net CONE”** shall mean the localized levelized embedded costs of a peaking unit in a Mitigated Capacity Zone, net of the likely projected annual Energy and Ancillary Services revenues of such unit, as determined in connection with establishing the Demand Curve for a Mitigated Capacity Zone pursuant to Section 5.14.1.2 of the Services Tariff, or as escalated as specified in Section 23.4.5.7 of Attachment H.

“New Capacity” shall mean a new Generator, a substantial addition to the capacity of an existing Generator, or the reactivation of all or a portion of a Generator that has been out of service for five years or more that commences commercial service after the effective date of this definition.

For purposes of Section 23.4.5 of this Attachment H, **“Offer Floor”** for a Mitigated Capacity Zone Installed Capacity Supplier that is not a Special Case Resource shall mean the lesser of (i) a numerical value equal to 75% of the Mitigation Net CONE translated into a seasonally adjusted monthly UCAP value (“Mitigation Net CONE Offer Floor”), or (ii) the numerical value that is the first year value of the Unit Net CONE determined as specified in Section 23.4.5.7, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate, (“Unit Net CONE Offer Floor”). The Offer Floor for a Mitigated Capacity Zone Installed Capacity Supplier that is a Special Case Resource shall mean a numerical value determined as specified in Section 23.4.5.7.5. The Offer Floor for Additional CRIS MW shall mean a numerical value determined as specified in Section 23.4.5.7.6.

"Owner" shall have the meaning specified in Section 31.1.1 of the ISO's Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, **"Pivotal Supplier"** shall mean (i) for the New York City Locality, a Market Party that, together with any of its Affiliated Entities, (a) Controls 500 MW or more of Unforced Capacity, and (b) Controls Unforced Capacity some portion of which is necessary to meet the New York City Locality Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction; (ii) for the G-J Locality, a Market Party that, together with any of its Affiliated Entities, (a) Controls 650 MW or more of Unforced Capacity; and (b) Controls Unforced Capacity some portion of which is necessary to meet the G-J Locality Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction; and (iii) for each Mitigated Capacity Zone except the New York City Locality and the G-J Locality, if any, a Market Party that Controls at least the quantity of MW of Unforced Capacity specified for the Mitigated Capacity Zone and accepted by the Commission. Unforced Capacity that are MW of an External Sale of Capacity shall not be included in the foregoing calculations

"Project Cost Allocation" shall have the meaning specified in Section 25 (Attachment S) of the ISO's Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, **"Responsible Market Party"** shall mean the Market Party that is authorized, in accordance with ISO Procedures, to submit offers in an ICAP Spot Market Auction to sell Unforced Capacity from a specified Installed Capacity Supplier.

"Revised Project Cost Allocation" shall have the meaning specified in Section 25 (Attachment S) of the ISO's Open Access Transmission Tariff.

"Self Supply LSE" shall mean a Load Serving Entity in one or more Mitigated Capacity Zones that operates under a long-standing business model to meet more than fifty percent of its Load obligations through its own generation and that is a Public Power Entity, "Single Customer Entity," or "Vertically Integrated Utility." For purposes of this definition only: (i) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in a non-bypassable charge in its regulated rates, earns a regulated return on its investment in such generation, and that as of the date of its request for a Self Supply Exemption, has not divested more than seventy-five percent of its generation assets owned on May 20, 1996; and (ii) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

"Subsequent Decision Period" shall have the meaning specified in Section 25 (Attachment S) of the ISO's Open Access Transmission Tariff.

For purposes of Section 23.4.5 of this Attachment H, **"Surplus Capacity"** shall mean the amount of Installed Capacity, in MW, available in a Mitigated Capacity Zone in excess of the Locational Minimum Installed Capacity Requirement for such Mitigated Capacity Zone.

"Total Evaluated CRIS MW" shall mean the Additional CRIS MW requested plus either (i) if the Installed Capacity Supplier previously received an exemption under Sections 23.4.5.7.2(b), 23.4.5.7.6(b), 23.4.5.7.7 or 23.4.5.7.8, all prior Additional CRIS MW since the facility was last exempted under Sections 23.4.5.7.2(b), 23.4.5.7.6(b), or 23.4.5.7.8, or (ii) for all other Installed

Capacity Suppliers, all MW of Capacity for which an Examined Facility obtained CRIS pursuant to the provisions in ISO OATT Sections 25, 30, or 32 (OATT Attachments S, X, or Z).

For purposes of Section 23.4.5 of this Attachment H, **"UCAP Offer Reference Level"** shall mean a dollar value equal to the projected clearing price for each ICAP Spot Market Auction determined by the ISO on the basis of the applicable ICAP Demand Curve and the total quantity of Unforced Capacity from all Installed Capacity Suppliers in a Mitigated Capacity Zone for the period covered by the applicable ICAP Spot Market Auction.

For purposes of Section 23.4.5 of this Attachment H, **"Unit Net CONE"** shall mean localized levelized embedded costs of a specified Installed Capacity Supplier, including interconnection costs, and for an Installed Capacity Supplier located outside a Mitigated Capacity Zone including embedded costs of transmission service, in either case net of likely projected annual Energy and Ancillary Services revenues, and revenues associated with other energy products (such as energy services and renewable energy credits, as determined by the ISO, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate. The Unit Net CONE of an Installed Capacity Supplier that has functions beyond the generation or transmission of power shall include only the embedded costs allocated to the production and transmission of power, and shall not net the revenues from functions other than the generation or transmission of power.

23.2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling or operation of an "Electric Facility"; or (ii) as specified in Section 23.2.4.2.

23.2.3 Conditions for the Imposition of Mitigation Measures

23.2.3.1 To achieve the foregoing purpose and objectives, Mitigation Measures should only be imposed to remedy conduct that would substantially distort or impair the competitiveness of any of the ISO Administered Markets. Accordingly, the ISO shall seek to impose Mitigation Measures only to remedy conduct that:

23.2.3.1.1 is significantly inconsistent with competitive conduct; and

23.2.3.1.2 would result in a material change in one or more prices in an ISO Administered Market or production cost guarantee payments ("guarantee payments") to a Market Party.

23.2.3.2 In general, the ISO shall consider a Market Party's or its Affiliates' conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Party or its Affiliates in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the three categories of conduct specified in Section 23.2.4 below.

23.2.4 Categories of Conduct that May Warrant Mitigation

23.2.4.1 The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or guarantee payments in an ISO Administered Market if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO Administered Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

23.2.4.1.1 Physical withholding of an Electric Facility, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Administered Market. Such withholding may include, but not be limited to, (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable, (ii) refusing to offer Bids or schedules for an Electric Facility when such conduct would not be in the economic interest of the Market Party or its Affiliates in the absence of market power; (iii); making an unjustifiable change to one or more operating parameters of a Generator that reduces its ability to provide Energy or Ancillary Services or (iv) operating a

Generator in real-time at a lower output level than the Generator would have been expected to produce had the Generator followed the ISO's dispatch instructions, in a manner that is not attributable to the Generator's verifiable physical operating capabilities and that would not be in the economic interest of the Market Party or its Affiliates in the absence of market power.

For purposes of this Section and Section 23.4.3.2, the term "unjustifiable change" shall mean a change in an Electric Facility's operating parameters that is: (a) not attributable to the Electric Facility's verifiable physical operating capabilities, and (b) is not a rational competitive response to economic factors other than market power.

23.2.4.1.2 Economic withholding of an Electric Facility, that is, submitting Bids for an Electric Facility that are unjustifiably high so that (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the Bids will set a market clearing price.

23.2.4.1.3 Uneconomic production from an Electric Facility, that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint.

23.2.4.2 Mitigation Measures may also be imposed, subject to FERC's approval, to mitigate the market effects of a rule, standard, procedure or design feature of an ISO Administered Market that allows a Market Party or its Affiliate to manipulate market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure or design feature to preclude such manipulation of prices or impairment of efficiency.

23.2.4.3 Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than an ISO Administered Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

23.2.4.4 The ISO and the Market Monitoring Unit shall monitor the ISO Administered Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices or guarantee payments in an ISO Administered Market. The ISO shall: (i) seek to amend the foregoing list as may be appropriate, in accordance with the procedures and requirements for amending the Plan, to include any such conduct that would substantially distort or impair the competitiveness of any of the ISO Administered Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.2 of Attachment O.

23.3 Criteria for Imposing Mitigation Measures

23.3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 23.2.4 above, which shall be detected through the use of indices and screens developed, adopted and made available as specified in Attachment O. The thresholds listed in Sections 23.3.1.1 to 23.3.1.3 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

23.3.1.1 Thresholds for Identifying Physical Withholding

23.3.1.1.1 The following initial thresholds will be employed by the ISO to identify physical withholding of a Generator or generation by a Market Party and its Affiliates:

23.3.1.1.1.1 Except for conduct addressed in Section 23.3.1.1.1.2: Withholding that exceeds (i) 10 percent of a Generator's capability, or (ii) 100 MW of a Generator's capability, or (iii) 5 percent of the total capability of a Market Party and its Affiliates, or (iv) 200 MW of the total capability of a Market Party and its Affiliates.

For a Generator or a Market Party in a Constrained Area for intervals in which an interface or facility into the area in which the Generator or generation is located has a Shadow Price greater than $0.04/MWh, indicating an active constraint, withholding that exceeds (i) 10 percent of a Generator's capability, or (ii) 50 MW of a Generator's capability, or (iii) 5 percent of the total capability of a Market Party and its Affiliates, or (iv) 100 MW of the total capability of a Market Party and its Affiliates.

23.3.1.1.1.2 Operating a Generator or generation in real-time at a lower output level than would have been expected had the Market Party's and its Affiliate's Generator or generation followed the ISO's dispatch instructions, resulting in a difference in output that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator, or (iii) 200 MW of the total capability of a Market Party and its Affiliates. For a Generator or a Market Party in a Constrained Area for intervals in which an interface or facility into the area in which the generation is located has a Shadow Price greater than $0.04/MWh, indicating an active constraint, operating a Generator or generation in real-time at a lower output level than would have been expected had the Market Party's and its Affiliate's Generator or generation followed the ISO's dispatch instructions, resulting in a difference in output that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 50 MW of a Generator's capability, or (iii) 100 MW of the total capability of a Market Party and its Affiliates.

23.3.1.1.2 The amounts of generating capacity considered withheld for purposes of applying the thresholds in this Section 23.3.1.1 shall include unjustified deratings, and the portions of a Generator's output that is not Bid or subject to economic withholding. The amounts deemed withheld shall not include (i) generating output that is subject to a forced outage, subject to verification by the ISO as may be appropriate that an outage was forced, (ii) capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, or (iii) generating capacity that is not Bid in the Real-Time Market, because and to the extent it would have to use unauthorized natural gas to operate, subject to verification by the ISO as may be appropriate that operation would require the use of unauthorized natural gas. See Section 23.3.1.4.6.2.1.1 below.

23.3.1.1.3 A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes or contributes to transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule.

23.3.1.2 Thresholds for Identifying Economic Withholding

23.3.1.2.1 The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of a Generator in an area that is not a Constrained Area, or in a Constrained Area during periods not subject to transmission constraints affecting the Constrained Area, and shall be determined with respect to a reference level determined as specified in Section 23.3.1.4:

23.3.1.2.1.1 Incremental Energy and Minimum Generation Bids: An increase exceeding 300 percent or $100 per MWh, whichever is lower; provided, however, that Incremental Energy or Minimum Generation Bids below $25 per MWh shall be deemed not to constitute economic withholding.

23.3.1.2.1.2 Operating Reserves and Regulation Service Bids:

23.3.1.2.1.2.1 Operating Reserves and Regulation Capacity Bids: A 300 percent increase or an increase of $50 per MW, whichever is lower; provided, however, that such Bids below $5 per MW shall be deemed not to constitute economic withholding.

23.3.1.2.1.2.2 Regulation Movement Bids: A 300 percent increase.

23.3.1.2.1.3 Start-Up Bids: A 200 percent increase.

23.3.1.2.1.4 Time-based Bid parameters: An increase of 3 hours, or an increase of 6 hours in total for multiple time-based Bid parameters. Time-based Bid parameters include, but are not limited to, start-up times, minimum run times and minimum down times.

23.3.1.2.1.5 Bid parameters expressed in units other than time or dollars, including the MW component of a Minimum Generation Bid (also referred to as the "minimum operating level"): A 100 percent increase for parameters that are minimum values, or a 50 percent decrease for parameters that are maximum values (including but not limited to ramp rates and maximum stops).

23.3.1.2.2 The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of a Generator in an area that is a Constrained Area, and shall be determined with respect to a reference level determined as specified in Section 23.3.1.4:

23.3.1.2.2.1 For Energy and Minimum Generation Bids for the Real-Time Market: for intervals in which an interface or facility into the area in which a Generator is located has a Shadow Price greater than $0.04/MWh, indicating an active constraint, the lower of the thresholds specified for areas that are not Constrained Areas or a threshold determined in accordance with the following formula:

$$Threshold = \frac{2\% * Average\ Price * 8760}{Constrained\ Hours}$$

where:

Average Price = the average price in the Real-Time Market in the Constrained Area over the past 12 months, adjusted for fuel price changes, and adjusted for Out-of-Merit Generation dispatch as feasible and appropriate; and

Constrained Hours = the total number of minutes over the prior 12 months, converted to hours (retaining fractions of hours), in which the real-time Shadow Price has been greater than $0.04/MWh, indicating an active constraint, on any interface or facility leading into the Constrained Area in which the Generator is located. For the In-City area, “Constrained Hours” shall also include the number of minutes that a Storm Watch is in effect. Determination of the number of Constrained Hours shall be subject to adjustment by the ISO to account for significant changes in system conditions.

23.3.1.2.2.2 For so long as the In-City area is a Constrained Area, the thresholds specified in subsection 23.3.1.2.2.1 shall also apply: (a) in intervals in which the transmission capacity serving the In-City area is subject to Storm Watch limitations; (b) to an In-City Generator that is operating as Out-of-Merit Generation; and (c) to a Generator dispatched as a result of a Supplemental Resource Evaluation.

23.3.1.2.2.3 For Energy and Minimum Generation Bids for the Day-Ahead Market: for all Constrained Hours for the Generator being Bid, a threshold determined in accordance with the formula specified in subsection 23.3.1.2.2.1 above, but where Average Price shall mean the average price in the Day-Ahead Market in the Constrained Area over the past twelve months, adjusted for fuel price changes, and where Constrained Hours shall mean the total number of hours over the prior 12 months in which the Shadow Price in the Day-Ahead Market has been greater than $0.04/MWh, indicating an active constraint, on any interface or facility leading into the Constrained Area in which the Generator is located. Determination of the number of Constrained Hours shall be subject to adjustment by the ISO to account for significant changes in system conditions.

23.3.1.2.2.4 For Start-Up Bids; a 50% increase.

23.3.1.2.2.5 The thresholds listed in Sections 23.3.1.2.1.2 and 23.3.1.2.1.4 through 23.3.1.2.1.5.

23.3.1.2.3 The following thresholds shall be employed by the ISO to identify economic withholding that requires the mitigation of a Generator that is committed outside the ISO's economic evaluation process to protect NYCA or local area reliability in an area that is not a designated Constrained Area. Whether the thresholds specified in Sections 23.3.1.2.3.3(i) through 23.3.1.2.3.3(v) below have been exceeded shall be determined with respect to a reference level determined as specified in Section 23.3.1.4 of these Mitigation Measures.

If provisions 23.3.1.2.3.1 and 23.3.1.2.3.2 below are met for a Generator in the New York Control Area that is not located in a designated Constrained Area, the ISO shall substitute a reference level for each Bid, or component of a Bid, for which the applicable threshold specified in provisions 23.3.1.2.3.3(i) through 23.3.1.2.3.3(vi) below is exceeded. Where mitigation is determined to be appropriate, the mitigated results will be used in all aspects of the NYISO's settlement process.

23.3.1.2.3.1 The Generator was committed outside the ISO's economic merit order selection process to protect or maintain New York Control Area or local system reliability as a Day-Ahead Reliability Unit ("DARU") or via a Supplemental Resource Evaluation ("SRE"), or was committed as a DARU or via SRE and was also dispatched Out-of-Merit above its minimum generation level to protect or maintain New York Control Area or local system reliability; and

23.3.1.2.3.2 One of the following three (i) – (iii) conditions in this Section 23.3.1.2.3.2 must be satisfied in order for mitigation to be applied:

i the Market Party (including its Affiliates) that owns or offers the Generator is the only Market Party that could effectively solve the reliability need for which the Generator was committed or dispatched, or

ii when evaluating an SRE that was issued to address a reliability need that multiple Market Parties' Generators are capable of solving, the NYISO only received Bids from one Market Party (including its Affiliates), or

iii when evaluating a DARU, if the Market Party was notified of the need for the reliability commitment of its Generator prior to the close of the Day-Ahead Market.

23.3.1.2.3.3 The Bids or Bid components submitted for the Generator that were accepted outside the economic evaluation process to protect or maintain New York Control Area or local system reliability:

i exceeded the Generator's Minimum Generation Bid reference level by the greater of 10% or $10/MWh, or

ii. exceeded the Generator's Incremental Energy Bid reference level by the greater of 10% or $10/MWh, or

iii. exceeded the Generator's Start-Up Bid reference level by 10%, or

iv. exceeded the Generator's minimum run time, start-up time, and minimum down time reference levels by more than one hour in aggregate, or

v. exceeded the Generator's minimum generation MW reference level by more than 10%, or

vi. decreased the Generator's maximum number of stops per day below the Generator's reference level by more than one stop per day, or to one stop per day.

23.3.1.2.4 For In-City Generators committed in the Day-Ahead Market for local reliability, additional Mitigation Measures are specified in Section 23.5.2.1.

23.3.1.3 Thresholds for Identifying Uneconomic Production

23.3.1.3.1 The following threshold will be employed by the ISO to identify uneconomic production that may warrant the imposition of a mitigation measure:

23.3.1.3.1.1 Energy scheduled at an LBMP that is less than 20 percent of the applicable reference level and causes or contributes to transmission congestion; or

23.3.1.3.1.2 Real-time output from a Generator or generation resulting in real-time operation at a higher output level than would have been expected had the Market Party's and the Affiliate's Generator or generation followed the ISO's dispatch instructions, if such failure to follow ISO dispatch instructions in real-time causes or contributes to transmission congestion, and it results in an output difference that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator, or (iii) 200 MW of the total capability of a Market Party and its Affiliates.

23.3.1.4 Reference Levels

23.3.1.4.1 Except as provided in Sections 23.3.1.4.3 – 23.3.1.4.6 below, a reference level for each component of a Generator's Bid shall be calculated on the basis of the following methods, listed in the order of preference subject to the existence of sufficient data:

23.3.1.4.1.1 The lower of the mean or the median of a Generator's accepted Bids or Bid components, in hour beginning 6 to hour beginning 21 but excluding weekend and designated holiday hours, in competitive periods over the most recent 90 day period for which the necessary input data are available to the ISO's reference level calculation systems, adjusted for changes in fuel prices consistent with Section 23.3.1.4.6, below. To maintain appropriate reference levels (i) the ISO shall exclude all Incremental Energy and Minimum Generation Bids below $15/MWh from its development of Bid-based reference levels, (ii) the ISO shall exclude Minimum Generation Bids submitted for a Generator that was committed on the day prior to the Dispatch Day for the hours during the Dispatch Day that the Generator needs to operate in order to complete the minimum run time specified in the Bid it submitted for the hour in which it was committed, and (iii) the ISO may exclude other Bids that would cause a reference level to deviate substantially from a Generator's marginal cost when developing Bid-based reference levels;

23.3.1.4.1.2 Calculate incremental energy and minimum generation reference levels for a Generator using the mean of the LBMP at the Generator's location during the lowest-priced 50 percent of the hours that the Generator was dispatched over the most recent 90 day period for which the necessary LBMP data are available to the

ISO's reference level calculation systems, adjusted for changes in fuel prices consistent with Section 23.3.1.4.6, below. To maintain appropriate reference levels (i) the ISO shall exclude all LBMPs below $15/MWh from its development of LBMP-based reference levels, (ii) the ISO shall exclude LBMPs during hours when a Generator was scheduled as a Day-Ahead Reliability Unit or via a Supplemental Resource Evaluation or was Out-of-Merit Generation, from its development of that Generator's LBMP-based reference levels, (iii) for a Generator that was committed on the day prior to the Dispatch Day, the ISO shall exclude LBMPs for the hours during the Dispatch Day that the Generator needs to operate in order to complete the minimum run time specified in the Bid it submitted for the hour in which the Generator was committed from the ISO's development of that Generator's LBMP-based reference levels, and (iv) the ISO may exclude LBMPs that would cause a reference level to deviate substantially below a Generator's marginal cost when developing LBMP-based reference levels; or

23.3.1.4.1.3 A level determined in consultation with the Market Party submitting the Bid or Bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Party has provided data on a Generator's operating costs in accordance with specifications provided by the ISO.

The reference level for a Generator's Energy and Ancillary Service Bids are intended to reflect the Generator's marginal costs. The ISO's determination of a

Generator's Energy marginal costs shall include an assessment of the Generator's incremental operating costs in accordance with the following formula:

$$(heat\ rate * fuel\ costs) + (emissions\ rate * emissions\ allowance\ price) + (other\ variable\ operating\ and\ maintenance\ costs)$$

Reference levels shall also include such other factors or adjustments as the ISO shall reasonably determine to be appropriate based on such data as may be furnished by the Market Party or otherwise available to the ISO.

23.3.1.4.2 If sufficient data do not exist to calculate a reference level on the basis of either of the first two methods, or if the ISO determines that none of the three methods are applicable to a particular type of Bid component, or an attempt to determine a reference level in consultation with a Market Party has not been successful, or if the reference level produced does not reasonably approximate a Generator's marginal cost, the ISO shall determine a reference level on the basis of:

23.3.1.4.2.1 the ISO's estimate of the costs or physical parameters of an Electric Facility, taking into account available operating costs data, appropriate input from the Market Party, and the best information available to the ISO; or

23.3.1.4.2.2 an appropriate average of competitive bids of one or more similar Electric Facilities.

23.3.1.4.3 Notwithstanding the foregoing provisions, the reference level for Incremental Energy Bids for New Capacity for the three year and six month period following the New Capacity's first production of Energy while synchronously interconnected to the New York State Transmission System shall be the higher of (i) the amount determined in accordance with the provision of Section 23.3.1.4.1 or 23.3.1.4.2, or (ii) the average of the fuel price-adjusted peak LBMPs over the twelve months prior to the New Capacity's first production of Energy while synchronously interconnected to the New York State Transmission System of the New Capacity in the Load Zone in which the New Capacity is located during hours when Generators with operating characteristics similar to the New Capacity would be expected to run. For entities owning or otherwise controlling the output of capacity in the New York Control Area other than New Capacity, the provisions of this Section 23.3.1.4.3 shall apply only to net additions of capacity during the applicable three year and six month period.

23.3.1.4.4 Notwithstanding the foregoing provisions, a reference level for a Generator's start-up costs Bid shall be calculated on the basis of the following methods, listed in the order of preference subject to the existence of sufficient data:

23.3.1.4.4.1 If sufficient bidding histories under the applicable bidding rules for a given Generator's start-up costs Bids have been accumulated, the lower of the mean or the median of the Generator's accepted start-up costs Bids in competitive periods over the previous 90 days for similar down times, adjusted for changes in fuel prices consistent with Section 23.3.1.4.6 below. However, accepted Start-Up Bids that incorporate anticipated costs of operating on the day after the Dispatch Day in which the Generator is committed in order to permit the Generator to satisfy its minimum run time shall not be used to develop Bid-based start-up reference levels;

23.3.1.4.4.2 A level determined in consultation with the Market Party submitting the Bid or Bids at issue and intended to reflect the costs incurred for a Generator to achieve its specified minimum operating level from an offline state, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Party has provided data on the Generator's operating costs in accordance with specifications provided by the ISO; or

23.3.1.4.4.3 Generators committed in the Day-Ahead Market or via Supplemental Resource Evaluation that are not able to complete their minimum run time within the Dispatch Day in which they are committed are eligible to include in their Start-Up Bid expected net costs of operating on the day following the dispatch day at the minimum operating level (in MW) specified in the Generator's Bid for the commitment hour, for the hours necessary to complete the Generator's minimum run time. The NYISO will calculate a start-up reference level that incorporates the net costs the Generator is expected to incur on the day following the Dispatch Day as follows:

23.3.1.4.4.3.1 Calculation of a start-up reference level that includes expected net costs of operating on the day following the Dispatch Day

The NYISO will use the following calculation to develop a reference level that incorporates the costs that a Generator is expected to incur on the day following the Dispatch Day.

$$LateDayAdjusted_{g,i} = StrtUpRef_g + \max\left(0, MinGenRef_{g,i} * BidMinGen_{g,i} * \sum_{h=0}^{Z_{g,i}-1} SR_{g,h,i}\right)$$

Where:

$LateDayAdjusted_{g,i}$ = calculated start-up reference level for Generator g for hour i in $ (reflects the applicable start-up reference level ($StrtUpRef_g$), plus the expected net cost of operating on the day following the Dispatch Day)

$StrtUpRef_g$ = the start-up reference level for Generator g in $ that is in effect at the time the calculation is performed (does not include the expected net cost of operating on the day following the Dispatch Day)

$MinGenRef_{g,i}$ = the minimum generation cost reference level for Generator g for hour i in $/MW that is in effect at the time the calculation is performed

$BidMinGen_{g,i}$ = Generator g's Day-Ahead minimum operating level for hour i, in MW

$Z_{g,i}$ = the number of hours the Generator must operate during the day following the Dispatch Day in order to complete its minimum run time if it starts in hour i

$SR_{g,h,i}$ = shortfall ratio for Generator g that is bidding to start in hour i which must run during hour h in order to complete its minimum run time, calculated in accordance with Section 23.3.3.4.4.3.2, below

23.3.1.4.4.3.2 Calculation of the shortfall ratio for use in Section 23.3.1.4.4.3.1, above

$SR_{g,h,i}$ = the shortfall ratio calculated for Generator g that is bidding to start in hour i, and that must run during hour h to complete its minimum run time.

In all cases in which Generator g's Day-Ahead minimum operating level deviates from the average of the previous seven days' Day-Ahead minimum operating levels for the same hour by less than 5 MW (*i.e.*, if $|AvgBidMinGen_{g,h,i} - BidMinGen_{g,i}| < 5MW$) or by less than 10% (*i.e.*, if both $BidMinGen_{g,i} < 1.1 * AvgBidMinGen_{g,h,i}$ and $BidMinGen_{g,i} > 0.9 * AvgBidMinGen_{g,h,i}$),

Where:

$AvgBidMinGen_{g,h,i}$ = The average minimum operating level submitted in the Day-Ahead Market for hour h on the seven days preceding the day containing hour i, in MW, excluding any days for which a minimum operating level was not submitted in the Day-Ahead Market for Generator g, for hour h; and

$BidMinGen_{g,i}$ = The minimum operating level submitted in the Day-Ahead Market for Generator g for hour i, in MW

and in all cases in which $AvgBidMinGen_{g,h,i}$ cannot be calculated because minimum operating levels were not submitted for Generator g in the Day-Ahead Market for hour h on any of the seven days preceding the day containing hour i, the $SR_{g,h,i}$ value will be calculated using the primary method. Otherwise, the $SR_{g,h,i}$ value will be calculated using the alternative method.

Primary Method of Calculating the Shortfall Ratio

$$SR_{g,h,i} = 1 - \frac{1}{7} * \sum_{d=1}^{7} \frac{LBMP_{g,h,i,d}}{MinGenRef_{g,h,i,d}}$$

Where:

$LBMP_{g,h,i,d}$ = Day ahead LBMP at the location of Generator g in hour h of the Day-Ahead Market for the Dispatch Day that precedes the day containing hour i by d days, and

$MinGenRef_{g,h,i,d}$ = minimum generation cost reference level for Generator g in hour h of the Day-Ahead Market for the Dispatch Day that precedes the day containing hour i by d days

Alternative Method of Calculating the Shortfall Ratio

$$SR_{g,h,i} = 1 - \frac{AvgLBMP_{g,h,i}}{\left(AvgRefRate_{g,h,i} * \frac{RefRate2_{g,i}}{RefRate1_{g,h,i}}\right)}$$

Where:

$AvgLBMP_{g,h,i}$ = The average of the Day-Ahead LBMPs at the location of Generator *g* for hour *h* on the seven days preceding the day containing hour *i*, in $/MWh, excluding any days for which a minimum operating level was not submitted in the Day-Ahead Market for Generator *g* for hour *h*

$AvgRefRate_{g,h,i}$ = The average of the minimum generation reference levels for Generator *g* in hour *h* on the seven days preceding the day containing hour *i*, in $/MWh, excluding any days for which a minimum operating level was not submitted in the Day-Ahead Market for Generator *g* for hour *h*

$RefRate1_{g,h,i}$ = The minimum generation cost reference level in $/MWh for Generator *g* for hour *i*, calculated using the most current reference data, and assuming that the minimum operating level submitted in the Day-Ahead Market for Generator *g* in hour *i* corresponds to the MWs reflected in the $AvgBidMinGen_{g,h,i}$

$RefRate2_{g,i}$ = The minimum generation cost reference level in $/MWh for Generator *g* for hour *i*, calculated using the most current reference data, and incorporating the minimum operating level submitted in the Day-Ahead Market for Generator *g* in hour *i* that corresponds to the MWs reflected in the $BidMinGen_{g,i}$

Notwithstanding the above, in all cases where the denominator of the equation for calculating $SR_{g,h,i}$ is not greater than zero, $SR_{g,h,i}$ shall be set to zero, under both the primary and alternative methods.

23.3.1.4.4.4 The methods specified in Section 23.3.1.4.2.

23.3.1.4.5 The ISO is not required to calculate real-time reference levels for the three Operating Reserve products (Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves) because Generators that are capable of providing these products and that are submitting Bids into the Real-Time Market are automatically assigned a real-time Operating Reserves Availability Bid of zero for the amount of Operating Reserves they are capable of providing.

The ISO shall calculate real-time reference levels for Regulation Capacity in accordance with Sections 23.3.1.4.1.1, 23.3.1.4.1.3 or 23.3.1.4.2 of these Mitigation Measures. The ISO shall calculate real-time reference levels for Regulation Movement in accordance with Sections 23.3.1.4.1.3 or 23.3.1.4.2.1 of these Mitigation Measures and shall not calculate real-time Reference levels for Regulation Movement in accordance with Section 23.3.1.4.1.1.

The ISO shall calculate Day-Ahead reference levels for the three Operating Reserves products in accordance with Sections 23.3.1.4.1.1, 23.3.1.4.1.3 or 23.3.1.4.2 of these Mitigation Measures. The ISO shall calculate Day-Ahead reference levels for Regulation Capacity in accordance with Sections 23.3.1.4.1.1, 23.3.1.4.1.3 or 23.3.1.4.2 of these Mitigation Measures. The ISO shall calculate Day-Ahead reference levels for Regulation Movement in accordance with Sections 23.3.1.4.1.3 or 23.3.1.4.2.1 of these Mitigation Measures and shall not calculate Day-Ahead Reference levels for Regulation Movement in accordance with Section 23.3.1.4.1.1.

23.3.1.4.6 Reflecting Fuel Costs in Reference Levels. The ISO shall use the best fuel cost information available to it to adjust reference levels to reflect appropriate fuel costs.

23.3.1.4.6.1 ISO Reporting Obligation. If the ISO did not utilize the best fuel cost information available to it when it adjusted reference levels to reflect appropriate fuel costs, and the ISO's failure to utilize the best fuel cost information available to it affected market clearing prices or had an impact on guarantee payments that cannot be corrected, then the ISO shall report any market clearing price and uncorrected guarantee payment impacts to FERC staff and to its Market Participants. The ISO is not required to report, or to otherwise act, if no market impact is identified.

23.3.1.4.6.2 Market Parties shall monitor Generator reference levels and shall endeavor to timely (as that term is defined in Section 23.3.1.4.6.8 below) contact the ISO to request an adjustment to a Generator's reference level(s) when the Generator's fuel type or fuel price change.

23.3.1.4.6.2.1 Subject to the exceptions set forth in Section 23.3.1.4.6.2.1.2 below, the ISO shall not permit charges for unauthorized natural gas use to be included as a component in the development of a Generator's reference levels and Market Parties shall not be eligible to recover costs associated with unauthorized natural gas use.

23.3.1.4.6.2.1.1 What constitutes "unauthorized" natural gas use is specified in each natural gas pipeline's or local distribution company's ("LDC's") applicable tariff, rate schedule or customer contract. Unauthorized natural gas use may result from, but is not limited to, the following circumstances: (i) consumption of natural gas in violation of the terms of an Operational Flow Order ("OFO") issued by the relevant natural gas LDC or pipeline; (ii) violation of instructions issued by the relevant natural gas LDC or pipeline restricting consumption of natural gas or use of natural gas imbalance service, when such instructions are issued consistent with the LDC's or pipeline's authority under a tariff, rate schedule or contract; (iii) consumption of natural gas during a period of authorized interruption of service by the relevant natural gas LDC or pipeline, determined in accordance with the terms of the applicable tariff, rate schedule or contract; or (iv) use of natural gas balancing services that are explicitly identified in the relevant natural gas LDC's or pipeline's applicable tariff, rate schedule or contract as unauthorized use or penalty gas.

23.3.1.4.6.2.1.2 If and to the extent a Market Party has obtained specific authorization from the relevant natural gas LDC or pipeline to use gas that would otherwise be unauthorized, such use shall not be considered unauthorized use by the ISO. Market Parties shall make every effort to clearly document authorization they obtain from the LDC or pipeline. Documentation obtained after the fact will be considered.

23.3.1.4.6.3 Screening of fuel type and fuel price information. The ISO may use automated processes and/or require manual review of fuel type and fuel price information submitted by Market Parties to test the accuracy of the information submitted in order to prevent market clearing prices and guarantee payments from being incorrectly calculated.

23.3.1.4.6.4 Consistent with the rules specified in this Section 23.3.1.4.6 of the Mitigation Measures and the procedures that the ISO develops to implement these rules, Market Parties shall notify the ISO of changes in fuel type or fuel price by (i) submitting revised fuel type or fuel price information to the ISO's Market Information System along with the Generator's Bid(s), or (ii) by directly contacting the ISO to request a reference level update consistent with ISO procedures, or (iii) by utilizing both of the available notification methods. Revised fuel type or fuel price information that exceeds, or is rejected based upon, the thresholds that the ISO uses to automatically screen fuel type or fuel price information that is submitted to the ISO's Market Information System along with a Generator's Bid(s) shall be submitted by directly contacting the ISO to request a reference level update, consistent with ISO procedures.

23.3.1.4.6.5 Following the completion of the ISO's automated and/or manual screening processes, the ISO shall use fuel type and fuel price information that Market Parties or their representatives submit to develop Generator reference levels unless (i) the information submitted is inaccurate, or (ii) the information was not timely submitted, and the Market Party's failure to timely submit the information is not excused by the ISO in accordance with Section 23.3.1.4.6.8 below, or (iii) consistent with Section 23.3.1.4.6.9 below.

23.3.1.4.6.6 The ISO may not always have sufficient time to complete its screening of proposed fuel type or fuel price changes prior to the relevant Day-Ahead Market day or Real-Time Market hour. *If* fuel type or fuel price information (i) is timely submitted or, where untimely, the submission of fuel type or fuel price information is excused in accordance with Section 23.3.1.4.6.8 below, and (ii) the fuel type or fuel price information that the Market Party submitted is proven to have been accurate or to have understated the actual cost incurred for that component, and (iii) the Bid(s) were tested using reference levels that reflected outdated fuel type and/or fuel price information and the Bid(s) were mitigated or a sanction was imposed pursuant to Section 23.4.3 of these Mitigation Measures, *then* the ISO shall (a) re-perform any test(s) that resulted in a sanction being imposed pursuant to Section 23.4.3 of these Mitigation Measures, using the accurate fuel type and/or fuel price information and use the revised results to calculate the appropriate sanction (if any), and (b) determine if the Bids for the Generator would have failed the relevant conduct test(s) if accurate fuel type and/or fuel price information had been used to develop reference levels. The ISO shall then restore any original (as-submitted) Bid(s) that would not have failed the relevant conduct test(s) if accurate fuel type and/or fuel price information had been used to develop the Generator's reference levels, and use the restored Bid(s) to determine a settlement. Otherwise the ISO shall use the Generator's correct or corrected reference level(s) to determine a settlement.

23.3.1.4.6.7 The ISO shall publicly post the thresholds it employs to automatically screen fuel type and fuel price information that is submitted to the ISO's Market Information System for potentially inaccurate fuel type and fuel price data inputs.

23.3.1.4.6.8 For purposes of this Section 23.3.1.4.6, "timely" notice or submission to the Real-Time Market shall mean the submission of fuel type and/or fuel price information using the methods specified in Section 23.3.1.4.6.4 of these Mitigation Measures prior to market close for the relevant Real-Time Market hour. For purposes of this Section 23.3.1.4.6, "timely" notice or submission to the Day-Ahead Market shall mean the submission of fuel type and/or fuel price information using the methods specified in Section 23.3.1.4.6.4 of these Mitigation Measures at least 15 minutes prior to the close of the Day-Ahead Market (*i.e.*, by 4:45 a.m.). Market Parties are not expected to submit invoices or other supporting data with their Day-Ahead Market or Real-Time Market fuel type and fuel price information, but are expected to retain invoices and other supporting data consistent with the data retention requirements set forth in the Plan, and to be able to produce such information within a reasonable timeframe when asked to do so by the ISO or by its Market Monitoring Unit.

It may not always be possible for a Market Party to timely update a Generator's fuel type or fuel price to reflect unexpected real-time changes or events in advance of the first affected market-hour. Upon a showing of extraordinary circumstances, the ISO may retroactively reflect in Real-Time Market reference levels fuel type or fuel price information that was not timely submitted by a Market Party. While it should ordinarily be possible for a Market Party to timely submit updated fuel type and fuel price information for use in developing a Generator's Day-Ahead Market reference levels, the ISO may retroactively accept and utilize late-submitted Day-Ahead Market fuel type or fuel price information upon a showing of extraordinary circumstances.

23.3.1.4.6.9 If (i) the ISO determines, following consultation with the Market Party and review by the Market Monitoring Unit, that the Market Party or its representative has, over a time period of at least one week, submitted inaccurate fuel type or fuel price information that was biased in the Market Party's favor, or (ii) if a Market Party is subject to a penalty or sanction under Section 23.4.3.3.3 of these Mitigation Measures for submitting inaccurate fuel price or fuel type information, *then* the ISO shall cease using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Generator's Bid(s) to develop reference levels for the affected Generator(s) in the relevant (Day-Ahead or real-time) market for the duration(s) set forth below.

23.3.1.4.6.9.1 The first time the ISO ceases using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Bid(s) for a Generator to develop Day-Ahead or real-time reference levels for that Generator, it shall do so for 60 days. The 60 day period shall start two business days after the date that the ISO provides written notice of its determination that the application of mitigation is required.

23.3.1.4.6.9.2 Any subsequent time the ISO ceases using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Bid(s) for a Generator to develop Day-Ahead or real-time reference levels for that

Generator, it shall do so for 180 days. The 180 day period shall start two business days after the date that the ISO provides written notice of its determination that the application of mitigation is required.

23.3.1.4.6.9.3 If the bidders of a Generator that has previously been mitigated under this Section 23.3.1.4.6.9 becomes and remains continuously eligible to submit fuel type and fuel price information in the Day-Ahead or Real-Time Market (as appropriate) for a period of one year or more, then the ISO shall apply the mitigation measure set forth in Section 23.3.1.4.6.9 of the Mitigation Measures as if the Generator had not previously been subject to the mitigation measure.

23.3.1.4.6.9.4 Market Parties that transfer, sell, assign, or grant to another Market Party the right or ability to Bid a Generator that is subject to the mitigation measure described in this Section 23.3.1.4.6.9 are required to inform the new Market Party that the Generator has been mitigated under this measure, and to inform the new Market Party of the expected duration of such mitigation.

23.3.1.4.6.9.5 For purposes of this Section 23.3.1.4.6.9, submitted fuel type information shall be considered biased in a Market Party's favor if (a) the fuel type that a Market Party submits for a Generator is not the most economic fuel type available to the Generator, taking into consideration fuel availability, operating conditions, and relevant regulatory or reliability requirements, and (b) as a result of the change(s) in fuel type, the fuel prices that the ISO uses to develop reference levels for a Generator exceeded the fuel price that the ISO would have used to develop reference levels for that Generator by greater than 10%, on average, over a seven-day period. For purposes of calculating the seven day average, only hours in which the Market Party changed the Generator's fuel type to a more expensive fuel type will be considered. The Day-Ahead and Real-Time Markets shall be considered separately for purposes of this analysis.

23.3.1.4.6.9.6 For purposes of this Section 23.3.1.4.6.9, submitted fuel price information shall be considered biased in a Market Party's favor if the fuel price that the Market Party submitted to the ISO's Market Information System for use in developing reference levels for a Generator exceeded the greater of the actual fuel price (as substantiated by supplier quotes or invoices) or the ISO's indexed fuel price, by greater than 10%, on average, over a seven-day period. For purposes of calculating the seven-day average, only hours in which the fuel price submitted exceeds the ISO's indexed fuel price will be considered. The Day-Ahead and Real-Time Markets shall be considered separately for purposes of this analysis.

23.3.1.4.6.9.7 The responsibilities of the Market Monitoring Unit that are addressed in Section 23.3.1.4.6.9 of the Mitigation Measures are also addressed in Section 30.4.6.2.3 of the Plan.

23.3.1.4.6.10 In order to adjust (i) Bid-based incremental energy, minimum generation and start-up reference levels, and (ii) LBMP-based incremental energy and minimum generation reference levels to more accurately reflect fuel costs, the ISO may calculate distinct Bid- and LBMP-based reference levels for each fuel type or blend of fuel types that a Generator is capable of burning, and shall fuel index each of the distinct Bid- or LBMP-based reference levels that it calculates for fuel types that are amenable to fuel indexing. Where a Generator can draw on multiple natural gas sources that each have distinct, posted, market clearing prices, the ISO may calculate distinct Bid-Based or LBMP-based reference levels for each such available supply source.

23.3.1.4.7 Except as otherwise authorized in accordance with Section 23.3.1.4.6.8 above, Market Parties shall timely report significant changes to the cost components used to develop their Generator's reference levels to the ISO in order to permit the revised costs to be timely reflected in the Generator reference levels. However, if the ISO uses published index prices to fuel index a Generator's reference level when that Generator is burning a fuel type that is amenable to fuel indexing (which may include a blend of two indexed fuel types), the Market Party is not required to report fuel prices that are less than the published index price that the ISO relies on.

23.3.2 Material Price Effects or Changes in Guarantee Payments

23.3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Administered Markets, Mitigation Measures shall not be imposed unless conduct identified as specified above (i) causes or contributes to a material change in one or more prices in an ISO Administered Market, or (ii) substantially increases guarantee payments to participants in the New York Electric Market. Initially, the thresholds to be used by the ISO to determine a material price effect or change in guarantee payments shall be:

23.3.2.1.1 an increase of 200 percent or $100 per MWh, whichever is lower, in the hourly Day-Ahead or Real-Time Energy LBMP at any location, or of any other price in an ISO Administered Market; or

23.3.2.1.2 an increase of 200 percent, or 50 percent for Generators in a Constrained Area in Bid Production Cost guarantee payments to a Market Party for a Generator for a day; or

23.3.2.1.3 for a Constrained Area Generator subject to either a Real-Time Market or Day-Ahead Market conduct threshold, as specified above in Sections 23.3.1.1.1, 23.3.1.2.2.1, or 23.3.1.2.2.3: for all Constrained Hours (as defined in Section 23.3.1.2.2.1 for the Real-Time Market and in Section 23.3.1.2.2.3 for the Day-Ahead Market) for the unit being Bid, a threshold determined in accordance with the formula specified in Section 23.3.1.2.2.1 for the Real-Time Market or Section 23.3.1.2.2.3 for the Day-Ahead Market.

23.3.2.2 Price Impact Analysis

23.3.2.2.1 When it has the capability to do so, the ISO shall determine the effect on prices or guarantee payments of questioned conduct through the use of sensitivity analyses performed using the ISO's SCUC, RTC and RTD computer models, and such other computer modeling or analytic methods as the ISO shall deem appropriate following consultation with its Market Monitoring Unit. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.4 of Attachment O.

23.3.2.2.2 Pending development of the capability to use automated market models, the ISO, following consultation with its Market Monitoring Unit, shall determine the effect on prices or guarantee payments of questioned conduct using the best available data and such models and methods as they shall deem appropriate. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.5 of Attachment O.

23.3.2.2.3 The ISO shall implement automated procedures within the SCUC for Constrained Areas, and within RTC for Constrained Areas. Such automated procedures will: (i) determine whether any Day-Ahead or Real-Time Energy Bids, including start-up costs Bids and Minimum Generation Bids but excluding Ancillary Services Bids, that have not been adequately justified to the ISO exceed the thresholds for economic withholding specified in Section 23.3.1.2 above; and, if so, (ii) determine whether such Bids would cause material price effects or changes in guarantee payments as specified in Section 23.3.2.1.

23.3.2.2.4 The ISO shall forgo performance of the additional SCUC and RTC passes necessary for automated mitigation of Bids in a given Day-Ahead Market or Real-Time Market if evaluation of unmitigated Bids results in prices at levels at which it is unlikely that the thresholds for Bid mitigation will be triggered.

23.3.2.3 Section 205 Filings

The ISO shall make a filing under § 205 with the Commission seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections 23.3.1.1 through 23.3.1.3 above if that conduct has a significant effect on market prices or guarantee payments as specified below, unless the ISO determines, from information provided by the Market Party or Parties (which may include a Demand Side Resource participating in the Operating Reserves or Regulation Service Markets) that would be subject to mitigation, or from other information available to the ISO that the conduct and associated price or guarantee payment effect(s) are attributable to legitimate competitive market forces or incentives. For purposes of this section, conduct shall be deemed to have an effect on market prices or guarantee payments that is significant if it exceeds one of the following thresholds:

23.3.2.3.1 an increase of 100 percent in the hourly day-ahead or real-time energy LBMP at any location, or of any other price in an ISO Administered Market; or

23.3.2.3.2 an increase of 100 percent in Bid Production Cost guarantee payments to a Market Party for a Generator for a day, or an increase of 100 percent in any other guarantee payment over the time period used by the ISO to calculate the guarantee payment.

23.3.3 Consultation with a Market Party

23.3.3.1 Consultation Process

23.3.3.1.1 *Consultation initiated by the ISO to determine if mitigation is appropriate:* Applies to Market-Party-specific and/or Generator-specific mitigation, but not to mitigation that is applied pursuant to Sections 23.3.1.2.3, 23.3.2.2.3, or 23.5.2 of these mitigation measures. If through the application of an appropriate index or screen or other monitoring of market conditions, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified above, on one or more prices or guarantee payments in an ISO Administered Market, the ISO shall, as and to the extent specified in Attachment O or in Section 23.3.3.2 of these Mitigation Measures, contact the Market Party engaging in the identified conduct to request an explanation of the conduct.

23.3.3.1.2 *Consultation initiated by a Market Party when it anticipates that its Generator's marginal costs or other Bid parameters may exceed the Generator's reference level(s) by more than the relevant threshold(s).* If a Market Party anticipates submitting Bids in a market administered by the ISO that will exceed the thresholds specified in Section 23.3.1 above for identifying conduct inconsistent with competition, the Market Party may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Party's Bids.

23.3.3.1.3 *Results of consultation process addressing Bids.* If a Market Party's explanation of the reasons for its bidding indicates to the satisfaction of the ISO that the questioned conduct is consistent with competitive behavior, no further action will be taken. A preliminary determination by the ISO shall be provided to the Market Monitoring Unit for its review and comment.

23.3.3.1.4 *Consultation initiated by a Market Party regarding reference levels.* Upon request, the ISO shall consult with a Market Party or its representative with respect to the information and analysis used to determine reference levels under Section 23.3.1.4 for that Market Party's Generator(s). If cost data or other information submitted by a Market Party's Generator(s) indicates to the satisfaction of the ISO that the reference levels for that Market Party should be changed, revised reference levels shall be proposed by the ISO, communicated to the Market Monitoring Unit for its review and comment and, following the ISO's consideration of any recommendations that the Market Monitoring Unit is able to timely provide, communicated to the Market Party, and implemented by the ISO as soon as practicable. Changes to the reference levels addressed pursuant to the terms of this Section 23.3.3.1.4 shall be implemented on a going-forward basis commencing no earlier than the date that the Market

Party's consultation request is received. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.6 of Attachment O.

23.3.3.1.5 *Information required to support consultation regarding Bids and reference levels.* Market Parties shall ensure that the information they submit to the ISO, including but not limited to fuel price and fuel type information, is accurate. Except as set forth in Section 23.3.1.4.6.8, the ISO may not retroactively revise a reference level to reflect additional fuel costs if a Market Party or its representative did not timely submit accurate fuel cost information. Unsupported speculation by a Market Party does not present a valid basis for the ISO to determine that Bids that a Market Party submitted are consistent with competitive behavior, or to determine that submitted costs are appropriate for inclusion in the ISO's development of reference levels. Consistent with Sections 30.6.2.2 and 30.6.3.2 of the Plan, the Market Party shall retain the documents and information supporting its Bids and the costs it proposes to include in reference levels.

23.3.3.2 Consultation Requirements

23.3.3.2.1 The ISO shall make a reasonable attempt to contact and consult with the relevant Market Party about the Market Party's reference level(s) before imposing conduct and impact mitigation, other than conduct and impact mitigation imposed through the automated procedures described in Section 23.3.2.2.3 of these Mitigation Measures. The ISO shall keep records documenting its efforts to contact and consult with the Market Party.

23.3.3.2.2 Consultation regarding both real-time guarantee payment mitigation and mitigation of Generators committed outside the economic evaluation process in the Day-Ahead or Real-Time Markets to protect or preserve system reliability in accordance with Section 23.3.1.2.3 of these Mitigation Measures is addressed in Section 23.3.3.3, below. Consultation regarding Day-Ahead guarantee payment mitigation of Generators, other than mitigation imposed through the automated procedures described in Section 23.3.2.2.3 of these Mitigation Measures, shall be conducted in accordance with Sections 23.3.3.1 and 23.3.3.2 of these Mitigation Measures.

23.3.3.3 Consultation Rules for Real-Time Guarantee Payment Mitigation

23.3.3.3.1 Real-Time Guarantee Payment Consultation Process

23.3.3.3.1.1 For real-time guarantee payment mitigation determined pursuant to Sections 23.3.1.2.1 or 23.3.1.2.2, and 23.3.2.1.2 of these Mitigation Measures, the ISO shall electronically post settlement results informing Market Parties of Bid(s) that failed the real-time guarantee payment impact test. The settlement results posting shall include the adjustment to the guarantee payment and the mitigated Bid(s). The initial posting of settlement results ordinarily occurs two days after the relevant real-time market day.

23.3.3.3.1.2 For real-time guarantee payment mitigation determined pursuant to Sections 23.3.1.2.1 or 23.3.1.2.2, and 23.3.2.1.2 of these Mitigation Measures, no more than two business days after new or revised real-time guarantee payment impact test settlement results are posted, the ISO will send an e-mail or other notification to all potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures.

23.3.3.3.1.2.1 Although the ISO is authorized to take up to two business days to provide notification to all potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures, the ISO shall undertake reasonable efforts to provide notification to such Market Parties within one business day after new or revised real-time guarantee payment impact test settlement results are posted.

23.3.3.3.1.2.2 A Market Party that desires to receive notification from the ISO must provide one e-mail address to the ISO for real-time guarantee payment mitigation notices. Each Market Party is responsible for maintaining and monitoring the e-mail address it provides, and informing the ISO of any change(s) to that e-mail address in order to continue to receive e-mail notification. E-mail will be the ISOs primary method of providing notice to Market Parties.

23.3.3.3.1.2.3 Regardless of whether a Market Party chooses to receive notification from the ISO, each Market Party is responsible for reviewing its posted real-time guarantee payment impact test settlement results and for contacting the ISO to request a consultation if and when appropriate.

23.3.3.3.1.3 The following notice rules apply to guarantee payment mitigation determined pursuant to Section 23.3.1.2.3 of these Mitigation Measures.

23.3.3.3.1.3.1 For mitigation of a Generator’s Minimum Generation Bid, Start-Up Bid or Incremental Energy Bid resulting from its DARU or SRE commitment, the ISO shall send an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures within ten business days after the relevant market day, and shall undertake reasonable efforts to provide notification to such Market Parties within two business days after the relevant market day. The e-mail shall identify the date of the proposed mitigation and the Bid(s) or Bid components that the NYISO proposes to mitigate for all or part of the relevant market day.

As soon as it is able to do so, the NYISO will commence electronically posting settlement results informing Market Parties of Bid(s) that failed the Section 23.3.1.2.3 test and sending an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures. The settlement results posting shall include the mitigated bid(s). The posting of settlement results ordinarily occurs two days after the relevant real-time market day.

23.3.3.3.1.3.2 For mitigation of a Generator's Minimum Generation Bid, Start-Up Bid or Incremental Energy Bid resulting from an Out-of-Merit dispatch above the Generator's DARU or SRE commitment, the ISO shall send an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures within 10 business days after the relevant market day. The e-mail shall identify the date of the proposed mitigation and the bid(s) or bid components that the NYISO proposes to mitigate for all or part of the relevant market day.

23.3.3.3.1.3.3 For mitigation based on a Generator's minimum run time, start-up time, minimum down time, minimum generation MWs, or maximum number of stops per day, the ISO shall send an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these

Mitigation Measures within 10 business days after the relevant market day. The e-mail shall identify the date of the proposed mitigation and the conduct failing Bid(s) or Bid components.

23.3.3.3.1.4 Market Parties that want to consult with the ISO regarding real-time guarantee payment impact test results, or regarding mitigation applied in accordance with Section 23.3.1.2.3 of these Mitigation Measures, for a particular market day must submit a written request to initiate the consultation process that specifies the market day and Bid(s) for which consultation is being requested (for purposes of this Section 23.3.3.3.1, a “Consultation Request”).

23.3.3.3.1.4.1 Consultation Requests must be received by the ISO’s customer relations department within 15 business days after the ISO (i) posts new or revised real-time guarantee payment impact test settlement results, or (ii) either posts new or revised real-time guarantee payment impact test settlement results or sends an e-mail informing a Market Party of the results of a test performed pursuant to Section 23.3.1.2.3 of these Mitigation Measures for the relevant market day. Consultation Requests received outside the 15 business day period shall be rejected by the ISO.

23.3.3.3.1.4.2 The ISO may send more than one notice informing a Market Party of the same instance of mitigation. Notices that identify real-time guarantee payment impact test or Section 23.3.1.2.3 mitigation settlement results that are not new (for which the Market Party has already received a notice from the ISO) and that do not reflect revised mitigation (for which the dollar impact of the real-time guarantee payment mitigation has not changed) shall not present an additional opportunity, or temporally extend the opportunity, for the Market Party to initiate consultation.

23.3.3.3.1.4.3 If consultation was timely requested and completed addressing a particular set of real-time guarantee payment impact test results, or addressing a particular instance of mitigation applied in accordance with Section 23.3.1.2.3 of these Mitigation Measures, a Market Party may not again request consultation regarding the same real-time guarantee payment impact test results, or the same application of Section 23.3.1.2.3 mitigation, unless revised settlement results, that are not due to the previously completed consultation and that change the dollar impact of the relevant instance of mitigation, are posted.

23.3.3.3.1.5 The Consultation Request may include: (i) an explanation of the reason(s) why the Market Party believes some or all of the reference levels used by the ISO for the market day(s) in question are inappropriate, or why some or all of the Market Party's Bids on the market day(s) in question were otherwise consistent with competitive behavior; and (ii) supporting documents, data and other relevant information (collectively, for purposes of this Section 23.3.3.3.1, "Data"), including proof of any cost(s) claimed.

23.3.3.3.1.5.1 Market Parties shall ensure that the information they submit to the ISO, including but not limited to fuel price and fuel type information, is accurate. Except as set forth in Section 23.3.1.4.6.8, the ISO may not retroactively revise a reference level to reflect additional fuel costs if a Market Party or its representative did not timely submit accurate fuel cost information.

23.3.3.3.1.6 If the Market Party is not able to provide (i) an explanation of the reason(s) why the Market Party believes some or all of the reference levels used by the ISO for the market day(s) in question are inappropriate, or why some or all of the Market Party's Bids on the market day(s) in question were otherwise consistent with competitive behavior, or (ii) all supporting Data, at the time a Consultation Request is submitted, the Market Party should specifically identify any additional explanation or Data it intends to submit in support of its Consultation Request and provide an estimate of the date by which it will provide the additional explanation or Data to the ISO.

23.3.3.3.1.7 Following the submission of a Consultation Request that satisfies the timing and Bid identification requirements of Section 23.3.3.3.1.4, above, consultation shall be performed in accordance with Section 23.3.3.1 of these Mitigation Measures, as supplemented by the following rules:

23.3.3.3.1.7.1 The ISO shall consult with the Market Party to determine whether the information available to the ISO presents an appropriate basis for (i) modifying the reference levels used to perform real-time guarantee payment mitigation for the market day in question, or (ii) determining that the Market Party's Bid(s) on the market day in question were consistent with competitive behavior. The ISO shall only modify the reference levels used to perform mitigation, or determine that the Market Party's Bid(s) on the market day that is the subject of the Consultation Request were consistent with competitive behavior, if the ISO has in its possession Data that is sufficient to support such a decision.

23.3.3.3.1.7.2 A preliminary determination by the ISO shall be provided to the Market Monitoring Unit for its review and comment, and the ISO shall consider the Market Monitoring Unit's recommendations in reaching its decision. The ISO shall inform the Market Party of its decision, in writing, as soon as reasonably practicable, but in no event later than (i) 50 business days after the new or revised real-time guarantee payment impact test settlement results for the relevant market day were posted, or (ii) 50 business days after the earlier of the posting of new or revised Section 23.3.1.2.3 mitigation settlement results for the relevant market day, or the issuance of an e-mail in accordance with Section 23.3.3.3.1.3, above. If the ISO does not affirmatively determine that it is appropriate to modify the Bid(s) that are the subject of the Consultation Request within 50 business days, the Bid(s) shall remain mitigated. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.7 of Attachment O.

23.3.3.3.1.7.3 The ISO may, as soon as practicable, but at any time within the consultation period, request Data from the Market Party. The Market Party is expected to undertake all reasonable efforts to provide the requested Data as promptly as possible, to inform the ISO of the date by which it expects to provide requested Data, and to promptly inform the ISO if the Market Party does not intend to, or cannot, provide Data that has been requested by the ISO.

23.3.3.3.1.8 This Section 23.3.3.3.1 addresses Consultation Requests. It is not intended to limit, alter or modify a Market Party's ability to submit or proceed with a billing dispute pursuant to Section 7.4 of the ISO Services Tariff or Section 2.7.4.1 of the ISO OATT.

23.3.3.3.2 Revising Reference Levels of Certain Generators Committed Out-of-Merit or via Supplemental Resource Evaluation for Conducting Real-Time Guarantee Payment Conduct and Impact Tests and Applying Mitigation in Accordance with Section 23.3.1.2.3 of these Mitigation Measures

23.3.3.3.2.1 Consistent with and subject to all of the requirements of Section 23.3.3.3.1 of these Mitigation Measures, Generators that (i) are committed Out-of-Merit or via a Supplemental Resource Evaluation after the DAM has posted, and (ii) for which the NYISO has posted real-time guarantee payment impact test settlement results, or identified possible mitigation under Section 23.3.1.2.3 of these Mitigation Measures may contact the ISO within 15 business days after new or revised impact test settlement results are posted, or possible mitigation under Section 23.3.1.2.3 of these Mitigation Measures is identified, to request that the reference levels used to perform the testing and mitigation be adjusted to include any of the following verifiable costs:

23.3.3.3.2.1.1 procuring fuel at prices that exceed the index prices used to calculate the Generator’s reference level;

23.3.3.3.2.1.2 burning a type of fuel or blend of fuels that is not reflected in the Generator’s reference level;

23.3.3.3.2.1.3 permitted gas balancing charges;

23.3.3.3.2.1.4 compliance with operational flow orders; and

23.3.3.3.2.1.5 purchasing additional emissions allowances that are necessary to satisfy the Generator’s Supplemental Resource Evaluation or Out-of-Merit schedule.

23.3.3.3.2.2 The five categories of verifiable costs specified above shall be used to modify the requesting Generator's reference level(s) subject to the following prerequisites:

23.3.3.3.2.2.1 the Generator must specifically and accurately identify and document the extraordinary costs it has incurred to operate during the hours of its Supplemental Resource Evaluation or Out-of-Merit commitment; and

23.3.3.3.2.2.2 the costs must not already be reflected in the Generator's reference levels or be recovered from the ISO through other means.

As soon as practicable after the Market Party demonstrates to the ISO's reasonable satisfaction that one or more of the five categories of extraordinary costs have been incurred, but in no event later than the deadline set forth in Section 23.3.3.3.1.7.2 of these Mitigation Measures, the ISO shall adjust the affected Generator's reference levels and re-perform the real-time guarantee payment conduct and impact tests, or the Section 23.3.1.2.3 test, as appropriate, for the affected day. Only the reference levels used to perform real-time guarantee payment mitigation and/or mitigation pursuant to Section 23.3.1.2.3 of these Mitigation Measures, will be adjusted.

23.3.3.3.2.3 If, at some point prior to the issuance of a Close-Out Settlement for the relevant service month, the ISO or the Commission determine that some or all of the costs claimed by the Market Party during the consultation process described above were not, in fact, incurred over the course of the Out-of-Merit or Supplemental Resource Evaluation commitment, or were recovered from the ISO through other means, the ISO shall re-perform the appropriate test(s) using reference levels that reflect the verifiable costs that the Generator incurred and shall apply mitigation if the Generator's Bids fail conduct and impact, or the Section 23.3.1.2.3 test, at the corrected reference levels.

23.3.3.3.2.4 Generators may contact the ISO to request the inclusion of costs other than the five types identified above in their reference levels. The ISO shall consider such requests in accordance with Sections 23.3.1.4, or 23.3.3.3.1 of these Mitigation Measures, as appropriate.

23.4 Mitigation Measures

23.4.1 Purpose and Terms

If conduct is detected that meets the criteria specified in Section 23.3, the appropriate mitigation measure described in this Section shall be applied by the ISO. The conduct specified in Sections 23.3.1.1 to 23.3.1.3 shall be remedied by (1) the prospective application of a default bid measure, or (2) the application of a default bid to correct guarantee payments, as further described in Section 23.4.2.2.4, below. If a Market Party or its Affiliates engage in physical withholding by providing the ISO false information regarding the derating or outage of an Electric Facility or does not operate a Generator in conformance with ISO dispatch instructions such that the prospective application of a default bid is not feasible, or if otherwise appropriate to deter either physical or economic withholding, the ISO shall apply the sanction described in Section 23.4.3.

Terms with initial capitalization not defined in Section 23.4 shall have the meaning set forth in the Open Access Transmission Tariff.

23.4.2 Default Bid

23.4.2.1 Purpose

A default bid shall be designed to cause a Market Party to Bid as if it faced workable competition during a period when (i) the Market Party does not face workable competition, and (b) has responded to such condition by engaging in the physical or economic withholding of an Electric Facility. In designing and implementing default bids, the ISO shall seek to avoid causing an Electric Facility to Bid below its marginal cost.

23.4.2.2 Implementation

23.4.2.2.1 If the criteria contained in Section 23.3 are met, the ISO may substitute a default bid or bid parameter for a Bid or bid parameter submitted for an Electric Facility, or require the Market Party to use the default bid or bid parameter in the Bids it submits for an Electric Facility. The default bid or bid parameter shall establish a maximum or minimum value for one or more components of the submitted Bid or Bid parameters, equal to a reference level for that component determined as specified in Section 23.3.1.4.

23.4.2.2.2 An Electric Facility subject to a default bid shall be paid the LBMP or other market clearing price applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the LBMP or other market clearing price applicable to that facility.

23.4.2.2.3 If an Electric Facility is mitigated using the automated mitigation procedures described in Section 23.3.2.2.3 of these mitigation measures to a default bid for an Incremental Energy Bid other than a default bid determined as specified in Section 23.3.1.4, the Electric Facility shall receive an additional payment for each interval in which such mitigation occurs equal to the product of: (i) the amount of Energy in that interval scheduled or dispatched to which the incorrect default bid was applied; (ii) the difference between (a) the lesser of the applicable unmitigated bid and a default bid determined in accordance with Section 23.3.1.4, and (b) the applicable LBMP or other relevant market price in each such interval, if (a) greater than (b), or zero otherwise; and (iii) the length of that interval.

If an Electric Facility is mitigated to a default bid for a Start-Up Bid or a Minimum Generation Bid other than a default bid determined as specified in Section 23.3.1.4 of these Mitigation Measures, or if an Electric Facility is mitigated to a default bid for an Incremental Energy Bid other than a default bid determined as specified in Section 23.3.1.4 of these Mitigation Measures based on mitigation procedures other than the automated mitigation procedures described in Section 23.3.2.2.3 of these Mitigation Measures, then the ISO shall determine if the Bids would have failed the relevant conduct test(s) if correctly determined default bids had been used. The ISO shall then restore any original (as-submitted) Bid(s) that would not have failed the relevant conduct test(s) if correctly determined default bids had been used, and use the restored Bid(s) to determine a settlement. Otherwise, the ISO shall use the Generator's correct or corrected default bid(s) to determine a settlement.

23.4.2.2.4 Except as may be specifically authorized by the Commission:

23.4.2.2.4.1 The ISO shall not use a default bid to determine revised market clearing prices for periods prior to the imposition of the default bid.

23.4.2.2.4.2 The ISO shall only be permitted to apply default bids to determine revised real-time guarantee payments to a Market Party in accordance with the provisions of Section 23.3.3.3 of these Mitigation Measures.

23.4.2.2.5 Automated implementation of default bid mitigation measures shall be subject to the following requirements.

23.4.2.2.5.1 Automated mitigation measures shall not be applied if the price effects of the measures would cause the average day-ahead energy price in the mitigated locations or zones to rise over the entire day.

23.4.2.2.5.2 Automated mitigation measures as specified in Section 23.3.2.2.3 shall be applied to Minimum Generation Bids and start-up costs Bids meeting the applicable conduct and impact tests. When mitigation of Minimum Generation Bids is warranted, mitigation shall be imposed from the first hour in which the impact test is met to the last hour in which the impact test is met, or for the duration of the mitigated Generator's minimum run time, whichever is longer.

23.4.2.2.5.3 The posting of the Day-Ahead schedule may be delayed if necessary for the completion of automated mitigation procedures.

23.4.2.2.5.4 Bids not mitigated under automated procedures shall remain subject to mitigation by other procedures specified herein as may be appropriate.

23.4.2.2.5.5 The role of automated mitigation measures in the determination of Day-Ahead market clearing prices is described in Section 17.1.3 of Attachment B of the ISO Services Tariff.

23.4.2.2.6 A Real-Time automated mitigation measure shall remain in effect for the duration of any hour in which there is an RTC interval for which such mitigation is deemed warranted.

23.4.2.2.7 A default bid shall not be imposed on a Generator that is not in the New York Control Area and that is electrically interconnected with another Control Area.

23.4.3 Sanctions

23.4.3.1 Types of Sanctions

The ISO may impose financial penalties on a Market Party in amounts determined as specified below.

23.4.3.2 Imposition

The ISO shall impose financial penalties as provided in this Section 23.4.3, if the ISO determines in accordance with the thresholds and other standards specified in this Attachment H that*:* (i) a Market Party has engaged in physical withholding, including providing the ISO false information regarding the derating or outage of an Electric Facility; or (ii) a Market Party or its Affiliates have failed to follow the ISOs dispatch instructions in real-time, resulting in a different output level than would have been expected had the Market Party's or the Affiliate's generation followed the ISO's dispatch instructions, and such conduct has caused a material increase in one or more prices or guarantee payments in an ISO Administered Market; or (iii) a Market Party has made unjustifiable changes to one or more operating parameters of a Generator that reduce its ability to provide Energy or Ancillary Services; or (iv) a Load Serving Entity has been subjected to a Penalty Level payment in accordance with Section 23.4.4 below; or (v) a Market Party has submitted inaccurate fuel type or fuel price information that is used by the ISO in the development of a Generator's reference level, where the inaccurate reference level that is developed, in turn, directly or indirectly impacts guarantee payments or market clearing prices paid to the Market Party; or (vi) the opportunity to submit Incremental Energy Bids into the real-time market that exceed Incremental Energy Bids made in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, has been revoked for a Market Party's Generator pursuant to Sections 23.4.7.2 and 23.4.7.3 of these Mitigation Measures.

23.4.3.3 Base Penalty Amount

23.4.3.3.1 Except for financial penalties determined pursuant to Sections 23.4.3.3.2, 23.4.3.3.3, and 23.4.3.3.4 below, financial penalties shall be determined by the product of the Base Penalty Amount, as specified below, times the appropriate multiplier specified in Section 23.4.3.4:

MW meeting the standards for mitigation during Mitigated Hours * Penalty market-clearing price.

23.4.3.3.1.1 For purposes of determining a Base Penalty Amount, the term "Mitigated Hours" shall mean: (i) for a Day-Ahead Market, the hours in which MW were withheld; (ii) for a Real-Time Market, the hours in the calendar day in which MW were withheld; and (iii) for load Bids, the hours giving rise to Penalty Level payments.

23.4.3.3.1.2 For purposes of determining a Base Penalty Amount, the term "Penalty market-clearing price" shall mean: (i) for a withholding seller, the LBMP or other market-clearing price at the generator bus of the withheld resource (or in the relevant Load Zone, if a clearing price is not calculated at the generator bus); and (ii) for a Load Serving Entity, its zonal LBMP.

23.4.3.3.2 The financial penalty for failure to follow ISOs dispatch instructions in real-time, resulting in real-time operation at a different output level than would have been expected had the Market Party's or the Affiliate's generation followed the ISO's dispatch instructions, if the conduct violates the thresholds set forth in Sections 23.3.1.1.1.2, or 23.3.1.3.1.2 of these Mitigation Measures, and if a Market Party or its Affiliates, or at least one Generator, is determined to have had impact in accordance with Section 23.3.2.1 of these Mitigation Measures, shall be:

One and a half times the estimated additional real time LBMP and Ancillary Services revenues earned by the Generator, or Market Party and its Affiliates, meeting the standards for impact during intervals in which MW were not provided or were overproduced.

23.4.3.3.3 If inaccurate fuel type and/or fuel price information was submitted by or for a Market Party, and the reference level that the ISO developed based on that inaccurate information impacted guarantee payments or market clearing prices paid to the Market Party in a manner that violates the thresholds specified in this Section 23.4.3.3.3, then, following consultation with the Market Party regarding the appropriate fuel type and/or fuel price, the ISO shall apply the penalty set forth below, unless: (i) the Market Party shows that the information was submitted in compliance with the requirements of Section 4.1.9 of the ISO Services Tariff (Incremental Cost Recovery for Units Responding to Local Reliability Rule I-R3 or I-R5), or (ii) the total penalty calculated for a particular Day-Ahead or Real-Time Market day is less than $5,000, in which case the ISO will not apply a penalty.

23.4.3.3.3.1 Day-Ahead Conduct and Market Impact Tests

23.4.3.3.3.1.1 Day-Ahead Conduct Test

Using the higher of (a) a revised reference level calculated using the Generator’s actual fuel costs, or (b) the reference level that would have been in place for the Generator but for the submission of inaccurate fuel type and/or fuel price information, test the Bids to determine if they violate the relevant conduct threshold in accordance with the appropriate provision(s) of Section 23.3.1.2 of these Mitigation Measures.

23.4.3.3.3.1.2 Day-Ahead Impact Test

Using the higher of (a) a revised reference level calculated using the Generator's actual fuel costs, or (b) the reference level that would have been in place for the Generator but for the submission of inaccurate fuel type and/or fuel price information, test the Bids for both LBMP and guarantee payment impact in accordance with the appropriate provisions of Section 23.3.2.1 of these Mitigation measures. However, the ISO shall perform the Day-Ahead guarantee payment impact test for Generators that are committed in the Day-Ahead Market for local reliability, and that are not located in a Constrained Area, at the 50% increase Constrained Area threshold specified in Section 23.3.2.1.2 of these Mitigation Measures.

23.4.3.3.3.1.3 Day-Ahead Reliability Commitments in a Constrained Area Consistent with Section 23.5.2 of these Mitigation Measures, the conduct and impact thresholds for In-City Generators committed in the Day-Ahead Market for local reliability shall each be zero.

23.4.3.3.3.2 Real-Time Conduct and Market Impact Tests

23.4.3.3.3.2.1 Real-Time Conduct Test

Using the higher of (a) a revised reference level calculated using the Generator's actual fuel costs, or (b) the reference level that would have been in place for the Generator but for the submission of inaccurate fuel type and/or fuel price information, test the Bids to determine if they violate the relevant conduct threshold in accordance with the appropriate provision(s) of Section 23.3.1.2 of these Mitigation Measures

23.4.3.3.3.2.2 Real-Time LBMP Impact Test

Each of the Market Party's Bids for a Generator will be treated as having a Real-Time Market LBMP impact if (1) the higher of (a) a revised reference level calculated using the Generator's actual fuel costs, or (b) the reference level that would have been in place for the Generator but for a Market Party's submission of inaccurate fuel type and/or fuel price information, is less than or equal to the real-time LBMP at the PTID that represents the Generator's location, and (2) the lesser of (x) the Generator's Bid, or (y) the reference level that was actually used to test the Bid for LBMP impact in the Real-Time Market for that hour, is greater than or equal to the real-time LBMP at the PTID that represents the Generator's location.

23.4.3.3.3.2.3 Real-Time Guarantee Payment Impact Test

Using the greater of (a) a revised reference level calculated using the Generator's actual fuel costs, or (b) the reference level that would have been in place for the Generator but for the submission of inaccurate fuel type and/or fuel price information, test the Bids for guarantee payment impact in accordance with the appropriate provisions of Section 23.3.2.1 of these Mitigation Measures. However, the ISO shall perform the real-time guarantee payment impact test for Generators that are committed outside the ISO's economic merit order selection process via a SRE, and that are not located in a Constrained Area, at the 50%

increase Constrained Area threshold specified in Section 23.3.2.1.2 of these Mitigation Measures.

23.4.3.3.3.3 Day-Ahead Market Penalty Calculation

If the results of the Day-Ahead Market impact test indicate that the Market Party's Bid had either LBMP or guarantee payment impact then the ISO shall charge the Market Party a penalty, calculated for each penalized day, for each of its Generators, for each hour of the day, as follows:

Daily Penalty = max [(Multiplier * [Σ_g ▲ Day-Ahead BPCG payment$_g$] + (Multiplier) Σ_h Σ_g ([Market Party MWh$_{gh}$] x [▲ Day Ahead LBMP@PTID$_{gh}$]) + max [Σ_h TCC Revenue Calc for Market Party$_h$, 0]), 0]

Where:

g = an index running across all the Market Party's Generators

h = for purposes of this Section 23.4.3.3.3, h is an index running across all hours of the day

Multiplier = a factor of 1.0 or 1.5. The ISO shall use a 1.0 Multiplier if the Market Party has not been penalized for inaccurately reporting fuel type or fuel price information in the Day-Ahead Market over the 6 months prior to the market-day for which the penalty is being calculated. In all other cases the ISO shall use a 1.5 Multiplier.

▲ Day-Ahead BPCG payment$_g$ = the change in the Day-Ahead Market guarantee payment that the Market Party receives for Generator g determined when the ISO performs the Day Ahead Market guarantee payment impact test in accordance with Section 23.3.2.1.2 of these Mitigation Measures

Market Party MWh_{gh} = the MWh of Energy scheduled in the Day-Ahead Market for Generator g in hour h

▲ Day Ahead LBMP@$PTID_{gh}$ = the change in the Day-Ahead Market LBMP for hour h at the location of Generator g, as determined when the ISO performs the relevant Day Ahead Market LBMP impact test in accordance with Section 23.3.2.1.1 or 23.3.2.1.3 of these Mitigation Measures

TCC Revenue Calc for Market $Party_h$ = the change in TCC Revenues that the Market Party receives for hour h, determined when the ISO performs the relevant Day Ahead Market LBMP impact test

23.4.3.3.3.4 Real-Time Market Penalty Calculation

If the results of either of the Real-Time Market impact tests indicate that the Minimum Generation Bid or Incremental Energy Bid submitted for a Market Party's Generator had either LBMP or guarantee payment impact then the ISO shall charge the Market Party a penalty, calculated for each penalized day, for each of its Generators, for each hour of the day, as follows:

Daily Penalty = Max [(Multiplier * Σ_g [▲ simplified guarantee $payment_g$]) + Σ_h Σ_g (Multiplier * [original reference $level_{gh}$ – updated reference $level_{gh}$]) * max [MWh DAM_{gh}, MWh RT_{gh}, Market Party MWh_{gh}, 0], 0]

Where

g = an index running across all the Market Party's Generators

h = an index running across all hours of the day in which inaccurate fuel type or fuel price information was supplied for any of the Market Party's Generators; provided that one of the Bids in that hour "h" for at least one of the Market

Party's Generators must have had a Real Time Market LBMP or guarantee payment impact in accordance with Sections 23.4.3.3.3.2.2 or 23.4.3.3.3.2.3 of these Mitigation Measures

Multiplier = a factor of 1.0 or 1.5. The ISO shall use a 1.0 Multiplier if the Market Party has not been penalized for inaccurately reporting fuel type or fuel price information in the Real-Time Market over the 6 months prior to the market-day for which the penalty is being calculated. In all other cases the ISO shall use a 1.5 Multiplier.

Updated reference level$_{gh}$ = greater of a revised reference level calculated using the actual fuel costs of Generator g in hour h, or the reference level that would have been in place for the Generator in hour h, but for the Market Party's submission of inaccurate fuel type and/or fuel price information

Original reference level$_{gh}$ = the lesser of the Market Party's Bids or the reference level for Generator g in hour h actually used in the Real-Time Market to perform conduct and impact testing of the Market Party's Bids

MWh DAM$_{gh}$ = the MWh that Generator g was scheduled to produce in the Day-Ahead Market in hour h

MWh RT$_{gh}$ = the MWh that Generator g was scheduled to produce in the Real-Time Market in hour h

Market Party MWh$_{gh}$ = MWh produced by Market Party's Generator g that was scheduled to produce energy in hour h in the Real-Time Market

▲ simplified guarantee payment$_{g}$ = the change in the Real-Time Market guarantee payment that the Market Party receives for Generator g, determined when the ISO performs a simplified Bid Production Cost guarantee payment impact test using the threshold specified in Section 23.3.2.1.2 of these Mitigation Measures. The simplified guarantee payment shall be based upon actual Real-Time Bids, actual Real-Time Generator LBMPs, and reference levels that are the greater of (a) a revised reference level calculated using the Generator's actual fuel costs, or (b) the reference level that would have been in place for the Generator but for the submission of inaccurate fuel type and/or fuel price information

23.4.3.3.4 If the opportunity to submit Incremental Energy Bids into the real-time market that exceed Incremental Energy Bids made in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, has been revoked on a Market Party's Generator pursuant to Sections 23.4.7.2 and 23.4.7.3 of these Mitigation Measures, then the following virtual market penalty may be imposed on the Market Party:

Virtual market penalty = (Virtual Load MWs) * (Amount by which the hourly integrated real-time LBMP exceeds the day-ahead LBMP applicable to the Virtual Load MWs)

WHERE:

Virtual Load MWs are the scheduled MWs of Virtual Load Bid by the Market Party in the hour for which an increased real-time Bid for the Market Party's Generator failed the test specified in Section 23.4.7.2 of these Mitigation Measures; and

LBMP is the LBMP at which the Virtual Load MWs settled in the Day-Ahead and real-time Markets.

23.4.3.3.5 Real-Time LBMPs shall not be revised as a result of the imposition of a financial obligation as specified in this Section 23.4.3.3, except as may be specifically authorized by the Commission.

23.4.3.4 Multipliers

The Base Penalty Amount specified in Section 23.4.3.3.1 shall be subject to the following multipliers:

23.4.3.4.1 For the first instance of a type of conduct by a Market Party meeting the standards for mitigation, the multiplier shall be one (1).

23.4.3.4.2 For the second instance within the current or the two immediately previous capability periods of substantially similar conduct in the same market by a Market Party or its Affiliates, the multiplier shall be one (1),

23.4.3.4.3 For the third instance within the current or the two immediately previous capability periods of substantially similar conduct in the same market by a Market Party or its Affiliates, the multiplier shall be two (2),

23.4.3.4.4 For the fourth or any additional instance within the current or immediately previous capability period of substantially similar conduct in the same market by a Market Party or its Affiliates, the multiplier shall be three (3).

23.4.3.5 Dispute Resolution

23.4.3.5.1 Parties with of disputes arising from or relating to the imposition of a sanction under this Section 23.4.3 may utilize the dispute resolution provisions of the ISO Services Tariff. The scope of any such proceeding shall include resolution of any dispute as to legitimate justifications, under applicable legal, regulatory or policy standards, for any conduct that is asserted to warrant a penalty. Any or all of the issues in any such proceeding may be resolved by agreement of the parties.

23.4.3.5.2 Payment of a financial penalty may be withheld pending conclusion of any arbitration or other alternate dispute resolution proceeding instituted pursuant to the preceding paragraph and any petition to FERC for review under the Federal Power Act of the determination in such dispute resolution proceeding; provided, however, that interest at the ISO's average cost of borrowing shall be payable on any part of the penalty that is withheld, and that is determined to be payable at the conclusion of the dispute resolution/FERC review process from the date of the infraction giving rise to the penalty to the date of payment. The exclusive remedy for the inappropriate imposition of a financial penalty, to the exclusion of any claim for damages or any other form of relief, shall be a determination that a penalty should not have been imposed, and a refund with interest of paid amounts of a penalty determined to have been improperly imposed, as may be determined in the applicable dispute resolution proceedings.

23.4.3.5.3 This Section 23.4.3 shall not be deemed to provide any right to damages or any other form of relief that would otherwise be barred by Section 30.11 of Attachment O or Section 23.6 of this Attachment H.

23.4.3.5.4 This Section 23.4.3 shall not restrict the right of any party to make such filing with the Commission as may otherwise be appropriate under the Federal Power Act.

23.4.3.6 Disposition of Penalty Funds

Except as specified in Section 23.4.4.3.2, amounts collected as a result of the imposition of financial penalties shall be credited against costs collectable under Rate Schedule 1 of the ISO Services Tariff.

23.4.4 Load Bid Measure

23.4.4.1 Purpose

As initially implemented, the ISO market rules allow loads to choose to purchase power in either the Day-Ahead Market or in the Real-Time Market, but provide other Market Parties less flexibility in opting to sell their output in the Real-Time Market. As a result of this and other design features, certain bidding practices may cause Day-Ahead LBMPs not to achieve the degree of convergence with Real-Time LBMPs that would be expected in a workably competitive market. A temporary mitigation measure is specified below as an interim remedy if conditions warrant action by the ISO until such time as the ISO develops and implements an effective long-term remedy, if needed. These measures shall only be imposed if persistent unscheduled load causes operational problems, including but not limited to an inability to meet unscheduled load with available resources. The ISO shall post a description of any such operational problem on its web site.

23.4.4.2 Implementation

23.4.4.2.1 Day-Ahead LBMPs and Real-Time LBMPs in each load zone shall be monitored to determine whether there is a persistent hourly deviation between them in any zone that would not be expected in a workably competitive market. Monitoring of Day-Ahead and real-time LBMPs shall include examination of the following two metrics (along with any additional monitoring tools and procedures that the ISO determines to be appropriate to achieve the purpose of this Section 23.4.4):

(1) The ISO shall compute a rolling average of the hourly deviation of real-time zonal LBMPs from Day-Ahead zonal LBMPs. The hourly deviation shall be measured as: (zonal $\text{LBMP}_{\text{real time}}$ - zonal $\text{LBMP}_{\text{day ahead}}$). Each observation of the rolling-average time series shall be a simple average of all the hourly deviations over the previous four weeks, or such other averaging period determined by the ISO to be appropriate to achieve the purpose of this Section 23.4.4.

(2) The ISO shall also compute the rolling average *percentage* deviation of real-time zonal LBMPs from Day-Ahead zonal LBMPs. This percentage deviation shall be calculated by dividing the rolling-average hourly deviation (defined in Section 23.4.4.2.1 (1) above) by the rolling-average level of Day-Ahead zonal LBMP over the same time period, using the averaging period(s) described in Section 23.4.4.2.1 (1), above.

23.4.4.2.2 The ISO shall also estimate and monitor the average percentage of each Load Serving Entity's load scheduled in the Day-Ahead Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as the ISO deems practicable. The average percentage will be computed over a specified time period determined by the ISO to be appropriate to achieve the purpose of this mitigation measure.

23.4.4.2.3 If the ISO determines that (i) the relationship between zonal LBMPs in a zone in the Day-Ahead Market and the Real-Time Market is not what would be expected under conditions of workable competition, (ii) one or more Load

Serving Entities have been meeting a substantial portion of their loads with purchases in the Real-Time Market, and (iii) that this practice has contributed to an unwarranted divergence of LBMP between the two markets, then the following mitigation measure may be imposed. Any such measure shall be rescinded upon a determination by the ISO that any one or more of the foregoing conditions is not met.

23.4.4.3 Description of the Measure

23.4.4.3.1 The ISO may require a Load Serving Entity engaging in the purchasing practice described above to purchase or schedule all of its expected power requirements in the Day-Ahead Market. A Load Serving Entity subject to this requirement may purchase up to a specified portion of it actual load requirements (the “Allowance Level”) in the Real-Time Market without penalty, as determined by the ISO to be appropriate in recognition of the uncertainty of load forecasting.

23.4.4.3.2 Effective with the imposition of the foregoing requirement, all purchases in the Real-Time Market in excess of this Allowance Level (the “Penalty Level”) shall be settled at a specified premium over the applicable zone LBMP. Revenues from such premiums, if any, shall be rebated on a pro *rata* basis to the Market Parties that scheduled energy for delivery to load within New York in the Day-Ahead Market for the day in which the revenues were collected.

23.4.4.3.3 The Allowance Level and the Penalty Level shall be established by the ISO at levels deemed effective and appropriate to mitigate the market effects described in this Section 23.4.4. In addition, the Penalty Level payments shall be waived in any hour in which the Allowance Level is exceeded because of unexpected system conditions.

23.4.5 Installed Capacity Market Mitigation Measures

23.4.5.1 If and to the extent that sufficient installed capacity is not under a contractual obligation to be available to serve load in New York and if physical or economic withholding of installed capacity would be likely to result in a material change in the price for installed capacity in all or some portion of New York, the ISO, in consideration of the comments of the Market Parties and other interested parties, shall amend this Attachment H, in accordance with the procedures and requirements for amending the Plan, to implement appropriate mitigation measures for installed capacity markets.

23.4.5.2 Offers to sell Mitigated UCAP in an ICAP Spot Market Auction shall not be higher than the higher of (a) the UCAP Offer Reference Level for the applicable ICAP Spot Market Auction, or (b) the Going-Forward Costs of the Installed Capacity Supplier supplying the Mitigated UCAP. Where an Installed Capacity Supplier is a Pivotal Supplier in some, but not all, Mitigated Capacity Zones in which it has Resources, such Installed Capacity Supplier's offer to sell Mitigated UCAP in any ICAP Spot Market Auction for any Resource for which it is a Pivotal Supplier shall not be higher than the higher of (a) the lowest of the UCAP Offer Reference Levels for each Mitigated Capacity Zone in which such Installed Capacity Supplier has Resources; or (b) if an Offer for a Resource has an applicable Going-Forward Cost, such Going-Forward Cost.

23.4.5.3 An Installed Capacity Supplier's Going-Forward Costs for an ICAP Spot Market Auction shall be determined upon the request of the Responsible Market Party for that Installed Capacity Supplier. The Going-Forward Costs shall be determined by the ISO after consultation with the Responsible Market Party, provided such consultation is requested by the Responsible Market Party not later than 50 business days prior to the deadline for offers to sell Unforced Capacity in such auction, and provided such request is supported by a submission showing the Installed Capacity Supplier's relevant costs in accordance with specifications provided by the ISO. Such submission shall show (1) the nature, amount and determination of any claimed Going-Forward Cost, and (2) that the cost would be avoided if the Installed Capacity Supplier is taken out of service or retired, as applicable. If the foregoing requirements are met, the ISO shall determine the level of the Installed Capacity Supplier's Going-Forward Costs and shall seasonally adjust such costs not later than 7 days prior to the deadline for submitting offers to sell Unforced Capacity in such auction. A Responsible Market Party shall request an updated determination of an Installed Capacity Supplier's Going-Forward Costs not less often than annually, in the absence of which request the Installed Capacity Supplier's offer cap shall revert to the UCAP Offer Reference Level. An updated determination of Going-Forward Costs may be undertaken by the ISO at any time on its own initiative after consulting with the Responsible Market Party. Any redetermination of an Installed Capacity Supplier's Going-Forward Costs shall conform to the consultation and determination schedule specified in this paragraph. The costs that an Installed Capacity Supplier would avoid as a result of retiring should only be included in its Going-Forward Costs if the owner or operator of that Installed Capacity Supplier actually plans to mothball or retire it if the Installed Capacity revenues it receives are not sufficient to cover those costs.

23.4.5.4 Mitigated UCAP shall be offered in each ICAP Spot Market Auction in accordance with Section 5.14.1.1 of the ISO Services Tariff and applicable ISO procedures, unless (a) it has been exported to an External Control Area or sold to meet Installed Capacity requirements outside the Mitigated Capacity Zone in which the ICAP Supplier is a Pivotal Supplier is located in a transaction that does not constitute physical withholding under the standards specified below, or (b) it is Net Unforced Capacity of a Behind-the-Meter Net Generation Resource that is sold to its Host Load in a transaction that does not constitute physical withholding under the standards specified in Section 23.4.5.4.1(b).

23.4.5.4.1 (a) An export to an External Control Area or sale to meet an Installed Capacity requirement outside the Mitigated Capacity Zone in which the ICAP Supplier or Generator with CRIS MW is electrically located (either of the foregoing being referred to as "External Sale of Capacity") may be subject to audit and review by the ISO to assess whether such action constituted physical withholding of UCAP from a Mitigated Capacity Zone. "External Sale UCAP" shall mean the UCAP equivalent of the External Sale of Capacity if known, or otherwise the reasonably projected UCAP equivalent as determined by the ISO. External Sale UCAP shall be deemed to have been physically withheld on the basis of a comparison between the net revenues from UCAP sales that would have been earned by the sale of the External Sale UCAP in a Mitigated Capacity Zone and the net revenues earned from the External Sale of Capacity. The comparison shall be made for the period for which capacity is committed (the "Comparison

Period") in each of the shortest term organized capacity markets (the "External Reconfiguration Markets") for the area and during the period in which the External Sale of Capacity occurred. External Sale UCAP shall be deemed to have been withheld from a Mitigated Capacity Zone if: (1) the Responsible Market Party for the External Sale UCAP could have made all or a portion of the External Sale UCAP available to be offered in the Mitigated Capacity Zone by buying out of its external capacity obligation through participation in an External Reconfiguration Market and timely meeting the requirements to be qualified as an Installed Capacity Supplier; (2) the net revenues over the Comparison Period from sale in the Mitigated Capacity Zone of the External Sale UCAP that could have been made available for sale in that Locality would have been greater by 15% or more, provided that the net revenues were at least $2.00/kilowatt-month more than the net UCAP revenues from that portion of the External Sale UCAP over the Comparison Period; and (3) the Responsible Market Party for the External Sale UCAP is a Pivotal Supplier, or would otherwise have been deemed a Pivotal Supplier if the External Sale UCAP had been available to be offered in the Mitigated Capacity Zone for the Comparison Period.

(b) Any Mitigated UCAP that is Net Unforced Capacity of a Behind-the-Meter Net Generation Resource that is not offered into the ICAP Spot Market Auction in accordance with Section 23.4.5.2 may be subject to audit and review by the ISO, and shall be deemed to have been physically withheld unless (i) the Responsible Market Party has obtained a determination from the ISO pursuant to Section 23.4.5.4.3(b) that the sale to its Host Load would not constitute physical withholding, and (ii) the Mitigated UCAP that was the subject of the determination pursuant to Section 23.4.5.4.3(b) is actually sold to its Host Load.

23.4.5.4.2 If Mitigated UCAP or External Sale UCAP is not offered or sold as specified above, the Responsible Market Party for such Installed Capacity Supplier or Generator electrically located in a MCZ Import Constrained Locality shall pay the ISO an amount equal to the product of (A) 1.5 times the difference between the Market-Clearing Price for the Mitigated Capacity Zone in the ICAP Spot Market Auction with and without the inclusion of the Mitigated UCAP or External Sale UCAP and (B) the total of (1) the amount of Mitigated UCAP or External Sale UCAP not offered or sold as specified above, and (2) all other megawatts of Unforced Capacity in the Mitigated Capacity Zone under common Control with such Mitigated UCAP or External Sale UCAP. If the failure to offer was associated with the same period as an External Sale of Capacity, and the failure caused or contributed to an increase in UCAP prices in the Mitigated Capacity Zone of 15 percent or more, provided such increase is at least $2.00/kilowatt-month, the Responsible Market Party for such Generator or UDR project electrically located in a MCZ Import Constrained Locality shall be required to pay to the ISO an amount equal to 1.5 times the difference between the average Market-Clearing Price for the Mitigated Capacity Zone in the ICAP Spot Market Auctions for the relevant Comparison Period with and without the External Sale of Capacity in those auctions, times the total of (1) the amount of External Sale UCAP not offered or sold as specified above, and (2) all other megawatts of Unforced Capacity in the Mitigated Capacity Zone under common

Control with such External Sale UCAP. The ISO will distribute any amounts recovered in accordance with the foregoing provisions among the LSEs serving Loads in regions affected by the withholding in accordance with ISO Procedures.

23.4.5.4.3 (a) Reasonably in advance of the deadline for submitting offers in an External Reconfiguration Market the Responsible Market Party for External Sale UCAP may request the ISO to provide a projection of ICAP Spot Auction clearing prices for the Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market. Such requests, and the ISO's response, shall be made in accordance with the deadlines specified in ISO Procedures. Prior to completing its projection of ICAP Spot Auction clearing prices for the Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market, the ISO shall consult with the Market Monitoring Unit regarding such price projection. The Responsible Market Party shall be exempt from a physical withholding penalty as specified in Section 23.4.5.4.2, below, if at the time of the deadline for submitting offers in an External Reconfiguration Market its offers, if accepted, would reasonably be expected to produce net revenues from the External Sale of Capacity that exceed the net revenues that would have been realized from sale of the External Sale UCAP in the Mitigated Capacity Zone at the ICAP Spot Auction prices projected by the ISO. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.8(a) of Attachment O to this Services Tariff.

(b) At least fifteen business days in advance of the opening of the ICAP Spot Market Auction, a Behind-the-Meter Net Generation Resource can request that the ISO make a determination that the sale of Net Unforced Capacity in a Mitigated Capacity Zone to its Host Load does not constitute physical withholding. The Responsible Market Party shall be exempt from a physical withholding penalty as specified in Section 23.4.5.4.2 if the ISO determines that the Behind-the-Meter Net Generation Resource has demonstrated that the Host Load's actual consumption is planned to exceed its Adjusted Host Load, and it has a documented transaction to provide Net Unforced Capacity to its Host Load. Prior to reaching its decision on a request by a Behind-the-Meter Net Generation Resource that its sale of Net Unforced Capacity to its Host Load would not constitute physical withholding, the ISO shall provide its preliminary determination to the Market Monitoring Unit for review and comment. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.8(b) of Attachment O.

23.4.5.5 Control of Unforced Capacity shall be rebuttably presumed from (i) ownership of an Installed Capacity Supplier, or (ii) status as the Responsible Market Party for an Installed Capacity Supplier, but may also be determined on the basis of other evidence. For purposes of determining if a Responsible Market Party is a Pivotal Supplier in a Mitigated Capacity Zone, the presumption of Control of Unforced Capacity can be rebutted by demonstrating to the reasonable satisfaction of the ISO that the ability to determine the price and quantity of offers to supply Unforced Capacity has been conveyed to a person or entity that is not an Affiliated Entity without limitation or condition, but cannot be rebutted by the sale of Unforced Capacity in a Capability Period or Monthly Auction. For any Mitigated Capacity Zone, if the presumption has not been rebutted, and if two or more Market Parties each have rights or obligations with respect to Unforced Capacity from an Installed Capacity Supplier that could reasonably be anticipated to affect the quantity or price of Unforced Capacity transactions in an ICAP Spot Market Auction, the ISO may attribute Control of the affected MW of Unforced Capacity from the Installed Capacity Supplier to each such Market Party. Prior to reaching its decision regarding whether the presumption of control of Unforced Capacity has been rebutted, the ISO shall provide its preliminary determination to the Market Monitoring Unit for review and comment. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.9 of Attachment O.

23.4.5.6 Audit, Review, and Penalties for Physical Withholding to Increase Market-Clearing Prices

23.4.5.6.1 Audit and Review of Proposals or Decisions to Remove or Derate Installed Capacity from a Mitigated Capacity Zone

Any proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone Unforced Capacity market, or to de-rate the amount of Installed Capacity available from such supplier, may be subject to audit and review by the ISO if the ISO determines that such action could reasonably be expected to affect Market-Clearing Prices in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone in which the Resource(s) that is the subject of the proposal or decision is located, subsequent to such action; provided, however, no audit and review shall be necessary if the Installed Capacity Supplier is a Generator that is being retired or removed from a Mitigated Capacity Zone as the result of a Forced Outage that began on or after May 1, 2015 that was determined by the ISO to be a Catastrophic Failure. Such an audit or review shall assess whether the proposal or decision has a legitimate economic justification or is based on an effort to withhold Installed Capacity physically in order to affect prices. The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.10 of Attachment O.

23.4.5.6.2 Audit and Review of the Reclassification of a Generator in a Mitigated Capacity Zone From a Forced Outage to an ICAP Ineligible Forced Outage

This Section 23.4.5.6.2 shall apply to a Market Party whose Installed Capacity Supplier is a Generator that began a Forced Outage on or after May 1, 2015.

23.4.5.6.2.1 Any reclassification of an Installed Capacity Supplier that is a Generator in a Mitigated Capacity Zone from a Forced Outage to an ICAP Ineligible Forced Outage by a Market Party or otherwise, pursuant to the terms of Section 5.18.2.1 of this Services Tariff, may be subject to audit and review by the ISO if the ISO determines that such reclassification could reasonably be expected to affect the Market-Clearing Price in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone in which the Generator(s) that is the subject of the reclassification is located, subsequent to such action; provided, however, if the Market Party's Generator experienced the Forced Outage as a result of a Catastrophic Failure, the reclassification of a Generator in a Mitigated Capacity Zone from a Forced

Outage to an ICAP Ineligible Forced Outage shall not be subject to audit and review pursuant to this Section 23.4.5.6.2.

The audit and review pursuant to the above paragraph shall assess whether the reclassification of the Generator in a Mitigated Capacity Zone from a Forced Outage to an ICAP Ineligible Forced Outage had a legitimate economic justification or is based on an effort to withhold Installed Capacity physically in order to affect prices.

The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.10 of Attachment O to this Services Tariff.

23.4.5.6.2.2 The audit and review pursuant to Section 23.4.5.6.2.1 shall be deferred by the ISO beyond the time period established in ISO Procedures for the audit and review of a reclassification of a Generator from a Forced Outage to an ICAP Ineligible Forced Outage if the Generator was in a Forced Outage for at least 180 days before the reclassification and one or more Exceptional Circumstances delayed the acquisition of data necessary for the ISO's audit and review.

The ISO shall conduct the audit and review after its receipt of data that it determines is necessary for the audit and review; provided, however, if, at the time the ISO acquires the necessary data, the Market Party has Commenced Repair of the Generator, or the Generator is determined by the ISO to have had a Catastrophic Failure, the Market Party shall not be subject to an audit and review pursuant to Section 23.4.5.6.2.1 of this Services Tariff. A Generator that Commenced Repair while in an ICAP Ineligible Forced Outage but that ceased or unreasonably delayed that repair shall be subject to audit and review by the ISO pursuant to Section 23.4.5.6.2.1 of this Services Tariff.

The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.10 of Attachment O.

23.4.5.6.2.3 The audit and review of the removal of a Generator from a Forced Outage to an ICAP Ineligible Forced Outage, and the determinations of Catastrophic Failure and Exceptional Circumstances, will be pursuant to specific timelines established in ISO Procedures.

23.4.5.6.2.4 The audit and review pursuant to Sections 23.4.5.6.2.1, and 23.4.5.6.2.2 shall be conducted to determine whether the decision not to repair a Generator had a legitimate economic justification, consistent with competitive behavior; that is, whether the cost of repair, including the risk-adjusted cost of capital, could not reasonably be expected to be recouped over the reasonably anticipated remaining life of the generator. The elements of such audit and review may include, as appropriate, the historical revenue and maintenance cost data for the purpose of the baseline, the duration of the repair, the costs including, but not limited to, capital expenditures necessary to comply with federal or state environmental, safety or reliability requirements that must be met in order to operate the Generator, the anticipated capacity, energy and ancillary services revenues following the repair, the projected costs of operating the Generator following the repair, any benefits that would be foregone from using the site for a purpose other than as the existing Generator (e.g., repowering), and other relevant data.

The criteria for the audit and review provided in this Services Tariff Section 23.4.5.6.2.4 may be incorporated, as appropriate, in an audit and review required to be conducted pursuant to other provisions in this Services Tariff Section 23.4.

23.4.5.6.2.5 For a requesting Market Party, a determination that the Market Party has experienced Exceptional Circumstances shall be made by the ISO by the 160th day of the Generator's Forced Outage. The ISO shall use reasonable efforts to issue a determination that a Market Party has experienced Exceptional Circumstances after it has Commenced Repair and requests reclassification to an ICAP Ineligible Force Outage by the 40th day after the ISO's receipt of data necessary to conduct the analysis.

For a requesting Market Party, a determination that a Generator has experienced a Catastrophic Failure shall be made by the ISO by the 160th day of the Forced Outage. If the ISO has determined that Exceptional Circumstances will delay the submission of data necessary for the ISO to perform an audit and review pursuant to Section 23.4.5.6.2.1 or 23.4.5.6.2, the ISO shall use reasonable efforts to issue a determination that the Generator has experienced a Catastrophic Failure by the 40th day after receipt of data necessary to conduct the analysis.

23.4.5.6.3 Penalties for Withholding Installed Capacity Physically In Order To Affect Prices

If the ISO determines that either: i) pursuant to Section 23.4.5.6.1, the proposal or decision by a Market Party to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone, or to de-rate the amount of Installed Capacity available from such supplier, or ii) pursuant to Section 23.4.5.6.2, the ISO determines that the reclassification of an Installed Capacity Supplier that is a Generator from a Forced Outage to an ICAP Ineligible Forced Outage constitutes physical withholding, and would increase the Market-Clearing Price in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone by five percent or more, provided such increase is at least $.50/kilowatt-month, for each such violation of the above requirements the Market Party shall be assessed an amount equal to the product of (A) 1.5 times the difference between the Market Clearing Price for the Mitigated Capacity Zone in the ICAP Spot Market Auctions with and without the inclusion of the withheld UCAP in those auctions, and (B) the total of (1) the number of megawatts withheld in the month and (2) all other megawatts of Installed Capacity in the Mitigated Capacity Zone under common Control with such withheld megawatts in the month. The requirement to pay such amounts shall continue until the Market Party demonstrates that the removal from service, retirement, or de-rate, as described in Section 23.4.5.6.1, or reclassification as described in Section 23.4.5.6.2 is justified by economic considerations other than the effect of such action on Market-Clearing Prices in the ICAP Spot Market Auctions for the Mitigated Capacity Zone. The ISO will distribute any amount recovered in accordance with the foregoing provisions among the LSEs serving Loads in the Mitigated Capacity Zone(s) wherein the Market-Clearing Price was affected for the month corresponding to the penalty accordance with ISO Procedures.

23.4.5.7 Unless exempt as specified below, offers to supply Unforced Capacity from a Mitigated Capacity Zone Installed Capacity Supplier: (i) shall equal or exceed the applicable Offer Floor; and (ii) can only be offered in the ICAP Spot Market Auctions. Except for Offer Floors applied pursuant to Section 23.4.5.7.9.5.2 (*i.e.*, after the revocation of a Competitive Entry Exemption), the ISP UCAP MW, or when the Installed Capacity Supplier is an RMR Generator, the Offer Floor shall apply to offers for Unforced Capacity from the Installed Capacity Supplier, if it is not a Special Case Resource, starting with the Capability Period for which the Installed Capacity Supplier first offers to supply UCAP. Offer Floors applied pursuant to Section 23.4.5.7.9.5.2 shall apply to offers for Unforced Capacity from an Installed Capacity Supplier starting with all ICAP auction activity subsequent to the date of the revocation. Offer Floors shall cease to apply to that portion of a resource's UCAP (rounded down to the nearest tenth of a MW) that has cleared for any twelve, not-necessarily-consecutive, months (such cleared amount, "Cleared UCAP") in which the resource's MW were not ISP UCAP MW or MW of an RMR Generator. Offer Floors shall also cease to apply for the period an Installed Capacity Supplier is an Interim Service Provider but only in the amount of its ISP UCAP MW, or an RMR Generator in which case the Installed Capacity Supplier's offers of UCAP shall be as set forth in Section 23.4.5.7.12. Offer Floors shall be adjusted annually using the most recent inflation rate that is the twelve month percentage change in the index for the general component of the escalation factor ("Inflation Rate") that is the most recent of (a) the Inflation Rate identified in the index accepted by the Commission after a periodic review in an ICAP Demand Curve Reset Filing Year, as of October 1 of the ICAP Demand Curve Reset Filing Year, and (b) the Inflation Rate in the Annual Update of the relevant effective ICAP Demand Curves published under Section 5.14.1.2.2.1 of the Services Tariff.

23.4.5.7.1 Unforced Capacity from an Installed Capacity Supplier that is subject to an Offer Floor may not be used to satisfy any LSE Unforced Capacity Obligation for Mitigated Capacity Zone Load unless such Unforced Capacity is obtained through participation in an ICAP Spot Market Auction.

23.4.5.7.2 An Installed Capacity Supplier, in a Mitigated Capacity Zone for which the Commission has accepted an ICAP Demand Curve, shall be exempt from an Offer Floor if: (a) the price that is equal to the (x) average of the ICAP Spot Market Auction price for each month in the two Capability Periods, beginning with the Summer Capability Period commencing three years from the start of the year of the Class Year (the "Starting Capability Period") is projected by the ISO, in accordance with Section 23.4.5.7.15, to be higher than (y) the numerical value equal to 75 percent of the Mitigation Net CONE that would be applicable to such supplier in the same two (2) Capability Periods (utilized to compute (x)), (b) the price that is equal to the average of the ICAP Spot Market Auction prices in the six Capability Periods beginning with the Starting Capability Period is projected by the ISO, in accordance with Section 23.4.5.7.15, to be higher than the reasonably anticipated Unit Net CONE of the Installed Capacity Supplier, or (c) it has been determined to be exempt pursuant to Section 23.4.5.7.9 (the "Competitive Entry Exemption"). For purposes of the determinations pursuant to

(a) and (b) of this section, (I) if the Class Year is not bifurcated under OATT Section 25.5.10 (referred to herein as "not Bifurcated") or if the Class Year is so bifurcated (referred to herein a "Bifurcated Class Year", "Class Year X-1", and "Class Year X-2") and the Examined Facility remains in the Class Year through Class Year X-2, the ISO shall identify Unit Net CONE and the projected ICAP Spot Market Auction prices in accordance with Section 23.4.5.7.15, for each Examined Facility promptly after it (i) has accepted its Project Cost Allocation (as defined below) and deliverable MW, if any, from the Final Decision Round and (ii) along with all other remaining members, has posted any associated security pursuant to OATT Section 25 (OATT Attachment S) (for purposes of Section 23.4, a project that "remains a member of the completed Class Year"), and if a Class Year that is not Bifurcated, it shall do so concurrently for an Expected CRIS Transferee (as defined in 23.4.5.7.3); and (II) if the Examined Facility is a member of a Bifurcated Class Year and the Examined Facility (i) completes the decision and settlement phase as part of Class Year X-1 and has accepted its Project Cost Allocation and deliverable MW, if any, and (ii) along with all other members of Class Year X-1 has posted any associated Security pursuant to OATT Section 25 (OATT Attachment S), the ISO shall include in the Unit Net CONE of an Examined Facility with a Project Cost Allocation for shared upgrade facilities the amount required if all the Class Year projects accept their Project Cost Allocations and post Security, and identify the Unit Net CONE and the relevant projected ICAP Demand Curve price to be used no later than the date the ISO reports to all Class Year Developers all of the Acceptance Notices and

Non-Acceptance Notices that were received from all of the Developers in the Class Year X-1.

For purposes of Section 23.4.5.7 *et seq*, "Project Cost Allocation" shall mean the singular Project Cost Allocation or two Project Cost Allocations (*i.e.*, one for System Deliverability Upgrades ("SDUs") and one for System Upgrade Facilities, as applicable, from the Final Decision Round.

The first year value of an Examined Facility's Unit Net CONE calculated pursuant to Section 23.4.5.7 and Section 23.4.5.7.3.2 will be established in accordance with Section 23.4.5.7.3.7 at the time such Examined Facility first offers UCAP, and will be used by the ISO in subsequent mitigation exemption or Offer Floor determinations for Additional CRIS MW. A Unit Net CONE determination received pursuant to this Section 23.4.5.7.2, Section 23.4.5.7.6 or 23.4.5.7.7 shall only be final for the relevant Examined Facility (A) if the Examined Facility accepts its Project Cost Allocation or deliverable MW, if any, and the Examined Facility remains a member of the completed Class Year (whether it is Bifurcated, Class Year X-1, or Class Year X-2 or at the time of the completion of its applicable Class Year is an Expected CRIS Transferee, (B) on the date the ISO issues a notice to stakeholders that the Class Year decisional process of which the Examined Facility is a member has been completed, and (C) as specified in the ISO's notice to the Examined Facility of the final exemption and Offer Floor determination for the quantity of CRIS MW accepted in such Class Year at the time of its completion (or transferred CRIS if an Expected CRIS Transferee).

23.4.5.7.2.1 Promptly after Commission acceptance of the first ICAP Demand Curve to apply to a Mitigated Capacity Zone, the ISO shall make an exemption and Offer Floor determination for any NCZ Examined Project that remains a member of the completed Class Year, or was evaluated concurrently for transferred CRIS at the same location, and has received CRIS, unless exempt pursuant to section 23.4.5.7.6 or 23.4.5.7.8.

23.4.5.7.2.2 The ISO shall make an "Indicative Buyer-Side Mitigation Exemption Determination" for any NCZ Examined Project if (i) the Commission has accepted an ICAP Demand Curve for the Mitigated Capacity Zone that will become effective when the Mitigated Capacity Zone is first effective, or (ii) if the Commission has not accepted the first ICAP Demand Curve to apply specifically to the Mitigated Capacity Zone in which the NCZ Examined Project is located, provided the ISO has filed an ICAP Demand Curve pursuant to Services Tariff Section 5.14.1.2.2.4.11. The Indicative Buyer-Side Mitigation Exemption Determination shall be computed using such ICAP Demand Curve for the Mitigated Capacity Zone concurrent with the determinations the ISO makes for Examined Facilities pursuant to Sections 23.4.5.7.3.2 and 23.4.5.7.3.3.2 through 23.4.5.7.3.3.5. The ISO shall recompute the Indicative Buyer-Side Mitigation Exemption Determination promptly after Commission acceptance of the first ICAP Demand Curve for the applicable Locality provided that such NCZ Examined Project (i) received CRIS if the Class Year completed at the time the Commission accepts the Demand Curve, or (ii) has not been removed from the Class Year Deliverability Study if the Class Year is not completed. The

Indicative Buyer-Side Mitigation Exemption Determination is for informational purposes only. The exemption or Offer Floor for an NCZ Examined Project to which this Section applies shall be determined for such projects receiving CRIS using the Commission-accepted Locality ICAP Demand Curve.

23.4.5.7.2.3 Any NCZ Examined Project not exempt pursuant to 23.4.5.7.8 shall provide data and information requested by the ISO by the date specified by the ISO, in accordance with the ISO Procedures.

23.4.5.7.2.3.1 The ISO shall compute the reasonably anticipated ICAP Spot Market Auction forecast price in accordance with Section 23.4.5.7.15.

23.4.5.7.2.4 When the ISO is evaluating more than one NCZ Examined Project concurrently, the ISO shall recognize in its computation of the anticipated ICAP Spot Market Auction forecast price that Generators or UDR projects will clear from lowest to highest, using for each NCZ Examined Project the lower of (i) the first year value of its Unit Net CONE, or (ii) the numerical value equal to 75 percent of the Mitigation Net Cone, then inflated in accordance with 23.4.5.7 for each of the year two and year three of the Mitigation Study Period.

23.4.5.7.2.5 When evaluating NCZ Examined Projects pursuant to Sections 23.4.5.7.2.1 or 23.4.5.7.2.2, the ISO shall seek comment from the Market Monitoring Unit on matters relating to the determination of price projections and cost calculations. The ISO shall inform the NCZ Examined Project of the Offer Floor or Offer Floor exemption determination or Indicative Buyer-Side Mitigation Exemption Determination promptly. The responsibilities of the Market

Monitoring Unit that are addressed in this Section 23.4.5.7.2.5 are also addressed in Section 30.4.6.2.12 of Attachment O.

23.4.5.7.2.6 If an NCZ Examined Project under the criteria in 23.4.5.7.2.1 or 23.4.5.7.2.2 does not provide all of the requested data by the date specified by the ISO, the MW of CRIS received at that time by the project shall be subject to the Mitigation Net CONE Offer Floor for the period determined by the ISO in accordance with Section 23.4.5.7.

23.4.5.7.2.7 An NCZ Examined Project or Examined Facility located in more than one Mitigated Capacity Zone shall be evaluated pursuant to the tests in Section 23.4.5.7.2 (a) and (b) or 23.4.5.7.3 (as applicable), calculating Mitigation Net CONE for the smallest Mitigated Capacity Zone that contains the Load Zone in which such NCZ Examined Project or Examined Facility is electrically located.

23.4.5.7.3 The ISO shall make such exemption and Unit Net CONE determination for each "Examined Facility" (collectively "Examined Facilities") which term shall mean (I) each proposed new Generator and proposed new UDR project, and each existing Generator that has ERIS only and no CRIS, that is a member of the Class Year that requested CRIS, or that requested an evaluation of the transfer of CRIS rights from another location, in the Class Year Facilities Study commencing in the calendar year in which the Class Year Facility Study determination is being made (the Capability Periods of expected entry as further described below in this Section, the "Mitigation Study Period") and (II) each (i) existing Generator that did not have CRIS rights, and (ii) proposed new Generator and proposed new UDR project, provided such Generator under Subsection (i) or (ii) is an expected recipient of transferred CRIS rights at the same location regarding which the ISO has been notified by the transferor or the transferee of a transfer pursuant to OATT Attachment S Section 25.9.4 that will be effective on a date within the Mitigation Study Period ("Expected CRIS Transferee").

23.4.5.7.3.1 **[Reserved for future use]**

23.4.5.7.3.2 The ISO shall compute the reasonably anticipated ICAP Spot Market Auction forecast price for any Mitigated Capacity Zone in accordance with Section 23.4.5.7.15. In the case of a Bifurcated Class Year, for Examined Facilities that remain a member of the completed Class Year X-1 and Expected CRIS Transferees, the determination issued prior to the commencement of the Bifurcated Decision Period shall be the same as the final determination; therefore, the determinations will reflect all Examined Facilities in the Class Year at the time such first determination is issued. In computations made for Examined Facilities that remain in Class Year X-2, the ISO shall treat Examined Facilities that complete the decision and settlement phase as part of Class Year X-1in the same manner as Examined Facilities in a prior Class Year that remained a member of the completed Class Year.

When the ISO is evaluating more than one Examined Facility concurrently, the ISO shall recognize in its computation of the anticipated ICAP Spot Market Auction forecast price that Generators or UDR projects will clear from lowest to highest, using for each Examined Facility the lower of (i) the first year value of its Unit Net CONE, or (ii) the numerical value equal to 75 percent of the Mitigation Net Cone, then inflated in accordance with 23.4.5.7 for each of the year two and year three of the Mitigation Study Period.

23.4.5.7.3.3 [Intentionally Left Blank]

23.4.5.7.3.3.1 All developers, Interconnection Customers, and Installed Capacity Suppliers for any Examined Facility that do not request CRIS shall provide data and information requested by the ISO by the date specified by the ISO, in accordance with the ISO Procedures. For any such Examined Facility that is in a Class Year on the date the ISO issues a notice to stakeholders that the Class Year decisional process of which the Examined Facility is a member has been completed but that only has ERIS rights, the ISO shall utilize the data first provided in its analysis of the Unit Net CONE in its review of the project in any future Class Year in which the Generator or UDR project requests CRIS.

23.4.5.7.3.3.2 In the case of a Class Year for which the ISO issues a Notice of SDUs Requiring Additional Studies, the ISO will issue to the Examined Facilities that are Class Year Project Developers that received a notice under Section 25.5.10.2 of the OATT the following preliminary determinations, as applicable: Unit Net CONE determination and determination of an exemption pursuant to Section 23.4.5.7.2(a) or (b), regarding a request for a Competitive Entry Exemption or the Offer Floor. This preliminary information will be provided to such Examined Facilities on the same date that the ISO issues the notice pursuant to Section 25.5.10.2 of the OATT.

23.4.5.7.3.3.3 In the case of a Class Year that is Bifurcated, the ISO shall determine the reasonably anticipated Unit Net CONE with the costs as then determined in the

Project Cost Allocation, and additional SDUs from preliminary Class Year Study results, as applicable, prior to the commencement of the Bifurcated Decision Period for the Class Year, and shall provide to the Examined Facility the ISO's initial determination of an exemption or the Offer Floor.

23.4.5.7.3.3.4 For a Class Year that is not Bifurcated and for a Class Year X-2, on or before the three (3) days prior to the ISO's issuance of the Project Cost Allocation or Revised Project Cost Allocation, as applicable, the ISO will issue (or as applicable, revise) its forecast of ICAP Spot Market Auction prices for the Capability Periods in the Mitigation Study Period based on the Examined Facilities that remain in the Class Year for CRIS and the Examined Facilities that meet 23.4.5.7.3 (II). The ISO shall provide to each project its price forecast and an initial determination (incorporating its revised Project Cost Allocation) prior to the commencement of the Initial Decision Period and each Subsequent Decision Period no later than the ISO's issuance of a Revised Project Cost Allocation.

23.4.5.7.3.3.5 If a project remains a member of the completed Class Year, the ISO shall inform the project of the final determination of the Offer Floor or the Offer Floor exemption as soon as practicable after the date the ISO issues a notice to stakeholders that the Class Year decisional process has been completed, in accordance with methods and procedures specified in ISO Procedures. If a project remains a member of the completed Class Year X-1or is an Expected CRIS Transferee, the final determination shall be the same as the initial determination issued prior to the commencement of the Bifurcated Decision Period and shall apply to the quantity of CRIS MW that the Examined Facility accepts at the time it remains a member of the completed Class Year X-1 or the MW of the proposed CRIS transfer.

23.4.5.7.3.3.6 When evaluating Examined Facilities pursuant to this Section 23.4.5.7, the ISO shall seek comment from the Market Monitoring Unit on matters relating to the determination of price projections and cost calculations. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.12 of Attachment O.

23.4.5.7.3.4 If an Examined Facility under the criteria in 23.4.5.7.3 (II) has not provided written notice to the ISO on or before the date specified by the ISO, or any Examined Facility required to be reviewed does not provide all of the requested data by the date specified by the ISO, the proposed Capacity shall be subject to the Mitigation Net CONE Offer Floor for the period determined by the ISO in accordance with Section 23.4.5.7.

23.4.5.7.3.5 Except as specified in Section 23.4.5.7.6 with respect to Additional CRIS MW, an Examined Facility for which an exemption or Offer Floor determination has been rendered may only be reevaluated for an exemption or Offer Floor determination if it meets the criteria in Section 23.4.5.7.3 (I) and either (a) enters a new Class Year for CRIS or (b) intends to receive transferred CRIS rights at the same location. The restriction on redeterminations also means that the Offer Floor or exemption determination for an Examined Facility that remains a member of the Class Year X-1 at the time of its completion will not be revised for any reason. An Examined Facility under the criteria in 23.4.5.7.3 (II) that did receive CRIS will be bound by the determination rendered and will not be reevaluated. An Examined Facility under the criteria that had been set forth in 23.4.5.7.3 (III) prior to May 19, 2016, will not be reevaluated.

23.4.5.7.3.6 **[Reserved for future use]**

23.4.5.7.3.7 If the Installed Capacity Supplier first offers UCAP prior to the first Capability Year of the Mitigation Study Period for which it was evaluated, its Offer Floor shall be reduced using the same numerical value for the inflation index that was used in the final determination issued under Section 23.4.5.7.4 (*i.e.*, when the Examined Facility remains a member of the completed Class Year as identified in Section 23.4.5.7.4. If the Installed Capacity Supplier first offers UCAP after the first Capability Year of the Mitigation Study Period for which it was evaluated, its Offer Floor shall be increased using the inflation rate identified in 23.4.5.7.

23.4.5.7.3.8 Net Energy and Ancillary Services Revenue Projections for UDR Projects

For the purposes of making an exemption determination or Unit Net CONE determination pursuant to Section 23.4.5.7 for a UDR project, the ISO will determine the likely projected net Energy and Ancillary Services revenues utilizing a methodology that reflects, as applicable, but is not limited to, the guiding principles set forth in Section 23.4.5.7.3.8.1. The ISO will implement this Section 23.4.5.7.3.8 in accordance with Section 23.4.5.7.3.8.2.

23.4.5.7.3.8.1 The methodology used for a specific UDR project shall reflect the following guiding principles, where applicable:

(a) The design and characteristics of the UDR project as proposed in the Class Year, including whether it is proposed to be uni-directional or bi-directional.

(b) The market structure, scheduling rules, price formation rules, and other relevant characteristics and rules of the Control Area at each terminus of the UDR project.

(c) The reasonably projected effects of transactions utilizing the UDR project on NYCA and External Control Areas prices, including proxy bus prices.

(d) The reasonably projected cost to purchase energy, capacity, and ancillary services that would be transmitted into, and if the UDR project is proposed in the Class Year to be bi-directional also from, the Mitigated Capacity Zone, utilizing the UDR project at the rate determined by: (i) market-based clearing price mechanisms to the extent that the External Control Area uses them, or ISO market prices if an internal UDR project; (ii) a reasonable substitute, in the ISO's judgment, to the extent that the External Control Area does not use market-based clearing price mechanisms to determine prices. The costs to purchase energy and capacity, and any other products associated therewith, shall not be based on advantages or sources of revenue that would not reflect arm's-length transactions, or that are not in ordinary course of business for a competitive energy market participant.

(e) The reasonably anticipated fees for transmitting the ISO-projected energy, capacity, and ancillary services transactions utilizing the UDR project. These fees shall include any export fees, transmission services charges, ancillary services fees, scheduling fees, and other fees and costs.

(f) The reasonably projected opportunity costs (including fees) of selling energy, capacity, and any other products associated with the sale of energy, into an

External Control Area in lieu of a sale transaction into the Mitigated Capacity Zone.

(g) The reasonably projected revenues from the sale of energy and ancillary services that would be transmitted into, and if the UDR project is proposed in the Class Year to be bi-directional also from, the Mitigated Capacity Zone, utilizing the UDR project at the rate determined by: (i) market-based clearing price mechanisms to the extent that the External Control Areas uses them, or ISO market prices if an internal UDR project; (ii) a reasonable substitute, in the ISO's judgment, to the extent that the External Control Area does not use market-based clearing price mechanisms to determine prices. The revenues from the sale of energy, capacity, and any other products associated with the sale thereof, into an External Control Area shall not be based on advantages or sources of revenue that do not reflect arm's-length transactions, or that are not in ordinary course of business for a competitive energy market participant.

(h) The effect of scheduling uncertainty and imperfect arbitrage on the projected costs and revenues from the purchase and sale of energy and ancillary services that are reasonably projected to be transmitted into, and if the UDR project is proposed in the Class Year to be bi-directional also from, the Mitigated Capacity Zone, utilizing the UDR project.

23.4.5.7.3.8.2 Implementation

(a) The ISO shall seek comment from the Market Monitoring Unit on the methodology the ISO will use to project net Energy and Ancillary Services for each UDR project, and the inputs used to perform the calculation. The responsibilities of the Market Monitoring Unit that are addressed in this section are also addressed in Section 30.4.6.2.12 of Attachment O.

(b) The ISO shall post on its website a description of the methodology used for each UDR project, subject to any restrictions on the disclosure of Confidential Information or Critical Energy Infrastructure Information.

(c) If a UDR project that is an Examined Facility or an NCZ Examined Project withdraws from a Class Year and then enters another Class Year (regardless of whether it has the same or a different interconnection queue position,) the ISO may utilize a different methodology than it previously used, provided it reflects, where applicable, the guiding principles set forth in Section 23.4.5.7.3.8.1 and implemented in accordance with Section 23.4.5.7.3.8.2(a) and (b).

23.4.5.7.4 For purposes of Sections 23.4.5.7.2(b) and 23.4.5.7.6(b), the ISO shall identify the Unit Net CONE projected for a Mitigation Study Period using: the most recent inflation index. For purposes of Section 23.4.5.7.4, the inflation index shall mean the average of the most recently published median Headline Consumer Price Index (CPI) and Headline Personal Consumption Expenditures (PCE) long-term annual averages for inflation over the ten years that includes the last year of the Mitigation Study Period, as reported by the Survey of Professional Forecasters, unless this index is eliminated, replaced or otherwise terminated by the publisher thereof. In such circumstance, the ISO shall utilize the replacement or successor index established by the publisher, if any, or, in the absence of a replacement or successor index, shall select as a replacement a substantially similar index.

23.4.5.7.5 A Mitigated Capacity Zone Installed Capacity Supplier that is a Special Case Resource shall be subject to an Offer Floor beginning with the month of its initial offer to supply Installed Capacity, and until its offers of Installed Capacity have been accepted in the ICAP Spot Market Auction at a price at or above its Offer Floor for a total of twelve, not necessarily consecutive, months. A Special Case Resource shall be exempt from the Offer Floor if (a) it is located in a Mitigated Capacity Zone except New York City and is enrolled as a Special Case Resource with the ISO for any month within the Capability Year that includes March 31 in an ICAP Demand Curve Reset Filing Year in which the ISO proposes a New Capacity Zone that includes the location of the Special Case Resource, or (b) the ISO projects that the ICAP Spot Market Auction price will exceed the Special Case Resource's Offer Floor for the first twelve months that the Special Case Resource reasonably anticipated to offer to supply UCAP. If a Responsible Interface Party fails to provide Special Case Resource data that the ISO needs to conduct the calculations described in the two preceding sentences by the deadline established in ISO Procedures, the Special Case Resource will cease to be eligible to offer or sell Installed Capacity. The Offer Floor for a Special Case Resource shall be equal to the minimum monthly payment for providing Installed Capacity payable by its Responsible Interface Party, plus the monthly value of any payments or other benefits the Special Case Resource receives from a third party for providing Installed Capacity, or that is received by the Responsible Interface Party for the provision of Installed Capacity by the Special Case Resource. The Offer Floor calculation shall include any payment or the value of other benefits that are awarded for offering or supplying Mitigated Capacity Zone Capacity except for payments or the value of other benefits provided under programs administered or approved by New York State or a government instrumentality of New York State. Offers by a Responsible Interface Party at a PTID shall be not lower than the highest Offer Floor applicable to a Special Case Resource providing Installed Capacity at that PTID. Such offers may comprise a set of points for which prices may vary with the quantity offered. If this set includes megawatts from a Special Case Resource(s) with an Offer Floor, then at least the quantity of megawatts in the offer associated with each Special Case Resource must be offered at or above the Special Case Resource's Offer Floor. Offers by a Responsible Interface Party shall be subject to audit to determine whether they conformed to the foregoing Offer Floor requirements. If a Responsible Interface Party together with its Affiliated Entities submits one or more offers below the applicable Offer Floor, and such offer or offers cause or contribute to a decrease in UCAP prices in the Mitigated Capacity Zone of 5 percent or more, provided such decrease is at least $.50/kilowatt-month, the Responsible Interface Party shall be required to pay to the ISO an amount equal to 1.5 times the difference between the Market-Clearing Price for the Mitigated Capacity Zone in the ICAP Spot Auction for which the offers below the Offer Floor were submitted with and without such offers being set to the Offer Floor, times the total amount of UCAP sold by the Responsible Interface Party and its Affiliated Entities in such ICAP Spot Auction. If an offer is submitted below the applicable Offer Floor, the ISO will notify the Responsible Market

Party and the notification will identify the offer, the Special Case Resource, the price impact, and the penalty amount. The ISO will provide the notice reasonably in advance of imposing such penalty. The ISO shall distribute any amounts recovered in accordance with the foregoing provisions among the entities, other than the entity subject to the foregoing payment requirement, supplying Installed Capacity in regions affected by one or more offers below an applicable Offer Floor in accordance with ISO Procedures.

23.4.5.7.6 Exemptions for Additional CRIS MW: All requests for Additional CRIS MW located in a Mitigated Capacity Zone, in a Class Year or through a transfer, shall be evaluated for a buyer-side mitigation exemption or Offer Floor in accordance with this Section. Additional CRIS MW obtained in a Class Year or obtained through a transfer at the same location shall be exempt from an Offer Floor (a) if the price that is equal to (x) the average of the ICAP Spot Market Auction price for each month in the two Capability Periods, beginning with the Summer Capability Period commencing three years from the start of the Class Year (the “Starting Capability Period”) is projected by the ISO, in accordance with Section 23.4.5.7.15, to be higher than (y) the highest Offer Floor based on the Mitigation Net CONE that would be applicable to such Additional CRIS MW in the same two (2) Capability Periods (utilized to compute (x)); or (b) if the price that is equal to the average of the ICAP Spot Market Auction prices in the six Capability Periods beginning with the Starting Capability Period is projected by the ISO, in accordance with Section 23.4.5.7.15, to be higher than the reasonably anticipated Unit Net CONE computed in accordance with (i) and (ii) of Section 23.4.5.7.6.1 for the Installed Capacity Supplier's Additional CRIS MW.

23.4.5.7.6.1 For Additional CRIS MW that have an exemption or Offer Floor determined pursuant to this Section 23.4.5.7.6, the ISO shall compute Unit Net CONE as follows:

(i) Unit Net CONE for the Additional CRIS MW shall be based on the Additional CRIS MW and the costs and revenues of and associated with the Additional CRIS MW if:

(a) the most recent prior determination concluded that the Capacity for which the Examined Facility accepted CRIS was exempt from the Offer Floor pursuant to Section 23.4.5.7.2(b), 23.4.5.7.6(b), 23.4.5.7.7, or 23.4.5.7.8; or

(b) at the time of an Examined Facility's request for Additional CRIS MW: (1) it has accepted CRIS MW equal to, or greater than, 95 percent of the Examined Facility's maximum MW of electrical capability, net of auxiliary load, at an ambient temperature of 93° F as determined in accordance with ISO Procedures and (2) the amount of Cleared UCAP is greater than or equal to the amount of UCAP calculated pursuant to Section 23.4.5.7.6.3; or

(c) the Examined Facility's Total Evaluated CRIS MW includes exempted CRIS MW for which the Examined Facility did not receive a Unit Net CONE determination and thus did not provide data to the ISO because the determination for the exempt CRIS MW received was not based on Unit Net CONE and was made prior to November 27, 2010.

(ii) or in all other cases, Unit Net CONE, shall be the greater of two values, one based on the Total Evaluated CRIS MW, and the costs and revenues of the Total Evaluated CRIS MW, and one based on the Additional CRIS MW, and the costs and revenues of the Additional CRIS MW.

23.4.5.7.6.2 When calculating the Unit Net CONE of the Total Evaluated CRIS MW for an Examined Facility, the ISO shall utilize the Examined Facility's first year Unit Net CONE determined pursuant to Section 23.4.5.7 and Section 23.4.5.7.3.2, adjusted to the year's dollars at the time of an Examined Facility's request for Additional CRIS MW using: (i) the relevant value from the price index for non-farm business output published in the Survey of Current Business by the Department of Commerce's Bureau of Economic Analysis ("BEA Non-Farm Price Index"), or its successor; or (ii) the most recent inflation rate determined pursuant to Section 5.14.1.2.2.4.11 for any future year which is beyond the published BEA Non-Farm Price Index, or its successor.

23.4.5.7.6.3 For purposes of making the determination pursuant to Section 23.4.5.7.6.1(i)(b)(2), the amount of Cleared UCAP shall be compared to an amount of UCAP calculated as the product of the CRIS MW held by the Examined Facility immediately prior to its request for Additional CRIS MW and (1-EFORd). Except as specified in the next paragraph, for purposes of this calculation, if the Examined Facility is a Generator, its EFORd shall be derived using the data in the 5-year average NERC-GADS Generating Availability Report, or its successor, for the main class of the unit (hereinafter the "Class Average EFORd") that is current at the time of the request for Additional CRIS

MW, when available. If the Examined Facility is an Intermittent Power Resource or Limited Control Run-of-River Hydro Resource, the ISO shall apply a 5-year average derating factor based on ISO data to establish the EFORd to be utilized in the calculation pursuant to this paragraph. In all other cases, the ISO will apply the 5-year average derating factor from the ICAP/UCAP translation, for the smallest Mitigated Capacity Zone in which the resource is located at the time of the request. The EFORd applied by the ISO at the time that the Examined Facility first offers or certifies UCAP in an Installed Capacity auction ("Initial Entry EFORd") shall be used instead of Class Average EFORd when it is higher (*i.e.*, a greater outage rate) than the Class Average EFORd calculated at the time of the Examined Facility's request for Additional CRIS MW.

23.4.5.7.6.4 Additional CRIS MW shall be subject to the Mitigation Net CONE Offer Floor for the period specified in Section 23.4.5.7, for any Examined Facility whose Total Evaluated CRIS MW includes CRIS MW that are or have ever been subject to the Mitigation Net CONE Offer Floor, pursuant to Section 23.4.5.7.3.4.

23.4.5.7.6.5 The Offer Floor for Additional CRIS MW shall be equal to the lesser of: (a) the Unit Net CONE for the Additional CRIS MW; or (b) a numerical value equal to 75 percent of the Mitigation Net CONE translated into a seasonally adjusted monthly UCAP value for the Additional CRIS MW.

23.4.5.7.6.6 The results of this exemption determination shall apply only to the Additional CRIS MW and shall not alter or affect any prior exemption or Offer Floor determination for the Examined Facility. The Additional CRIS MW for which CRIS is received shall be bound by the determination rendered and will not be reevaluated unless the Examined Facility enters a new Class Year for the Additional CRIS MW.

23.4.5.7.6.7 When the ISO makes a mitigation exemption or Offer Floor determination for an Examined Facility's Additional CRIS MW for an Installed Capacity Supplier other than that to which the Unit Net CONE determination for the Examined Facility was rendered, the ISO shall provide such Installed Capacity Supplier with the Examined Facility's first year Unit Net CONE value if the Installed Capacity Supplier (a) requests that information, and (b) represents that it: (i) will use that information solely for purposes of considering a request for Additional CRIS MW for the Examined Facility, and (ii) will not share that information with or make it available to any other person except those that are assisting it in considering a request for Additional CRIS MW.

23.4.5.7.6.8 The ISO shall post on its website the determination of whether the project is exempt or non-exempt from an Offer Floor as soon as the determination is final. Concurrent with the ISO's posting, the Market Monitoring Unit shall publish a report on the ISO's determination, as further specified in Section 30.4.6.2.12 and 30.10.4 of Attachment O to this Services Tariff.

23.4.5.7.7 (a) An In-City Installed Capacity Supplier that is not a Special Case Resource shall be exempt from an Offer Floor if it was an existing facility on or before March 7, 2008. (b) A Generator or UDR project that was an existing facility on or before June 29, 2012, which: (i) is in a Mitigated Capacity Zone except New York City, and (ii) was grandfathered from the deliverability requirement at a certain quantity of MW of CRIS pursuant to Section 25.9.3.1 of

OATT Attachment S ("Deliverability Grandfathering Process") shall be exempt from an Offer Floor for the MW quantity of CRIS that was provided through the Deliverability Grandfathering Process plus an additional 2 MW obtained through Section 30.3.2.6 of Attachment X to the OATT. If the Generator or UDR project subsequently received CRIS above the quantity established through the Deliverability Grandfathering Process, this exemption shall not apply to any such increase above the 2 MW allowed in Section 30.3.2.6 of Attachment X to the OATT.

23.4.5.7.8 For any Mitigated Capacity Zone except New York City:

(I) Any existing or proposed Generator or UDR project that has the characteristics specified in this Section 23.4.5.7.8(I) shall be exempt from an Offer Floor with respect to the MW of CRIS that it received at the time, or for which it satisfied the specific CRIS transfer requirements stated in this Section. To be eligible for an exemption under this Section: (a) the existing or proposed Generator or UDR project's location must be included in the ISO's March 31 Filing in the ICAP Demand Curve Reset Filing Year in which a Mitigated Capacity Zone is first applied to such location; (b) prior to that March 31 Filing the existing or proposed Generator or UDR project must have both: (i) Commenced Construction and (ii) either (1) received the MW of CRIS in a Class Year that was completed or (2) submitted to the ISO an Interconnection Request that specifically states that the Generator or UDR project will be requesting or has requested a transfer of a specific MW quantity of CRIS at the same location in accordance with Section 25.9.4 of OATT Attachment S (provided that the transfer is ultimately approved by the ISO and consummated); and (c) the existing or proposed Generator or UDR project must demonstrate to the ISO no later than the deadline established by the ISO that it satisfies the requirements of (b) (i) and (ii) above; and

(II) An existing or proposed Generator or UDR project that is not subject to a deliverability requirement (and therefore, is not in a Class Year and does not receive CRIS MW) shall be exempt from an Offer Floor if it meets the following requirements prior to the ISO's March 31 Filing in an ICAP Demand Curve Reset Filing Year in which a Mitigated Capacity Zone is first applied to such location: (a) has Commenced Construction, (b) has an effective interconnection agreement, and (c) provides specific written notification to the ISO that it meets requirements (a) and (b) of this subsection 23.4.5.7.8(II) no later than the deadline established by the ISO.

The ISO shall consult with the Market Monitoring Unit prior to determining whether an existing or proposed Generator or UDR project has Commenced Construction. Prior to the ISO making its determination, the Market Monitoring Unit shall provide the ISO a written opinion and recommendation regarding whether an existing or proposed Generator or UDR project Commenced Construction. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.12 of Attachment O. The ISO shall only make a determination pursuant to this Section for an existing or proposed Generator or UDR project for the Mitigated Capacity Zone's first application to the location of the project. The

Market Monitoring Unit shall also provide a public report on its assessment of an ISO determination that an existing or proposed Generator or UDR project is exempt from an Offer Floor pursuant to this Section 23.4.5.7.8.

23.4.5.7.9 Competitive Entry Exemption

23.4.5.7.9.1 Eligibility

23.4.5.7.9.1.1 A proposed new Generator or UDR project that becomes a member of a Class Year after Class Year 2012 may request to be evaluated for a "Competitive Entry Exemption" for its CRIS MW and shall qualify for such exemption if the ISO determines that the proposed Generator or UDR project meets each of the following requirements: (a) does not have, and at no time before the Generator first produces or the UDR project first transmits energy (for purposes of this Section 23.4.5.7.9, the "Entry Date") shall have, (i) a direct or indirect "non-qualifying contractual relationship," as defined in Section 23.4.5.7.9.1.2, with a Transmission Owner, a Public Power Entity, or any other entity with a Transmission District in the NYCA, or an agency or instrumentality of New York State or a political subdivision thereof, (collectively "Non-Qualifying Entry Sponsors"); or (ii) an unexecuted agreement, written or unwritten, with a Non-Qualifying Entry Sponsor that would support the development of the project, except those agreements that would not constitute a "non-qualifying contractual relationship," as set forth in Section 23.4.5.7.9.1.3(i) – (viii), (b) is not itself, and is not an Affiliate of, a Non-Qualifying Entry Sponsor.

23.4.5.7.9.1.2 For purposes of Section 23.4.5.7.9, a direct "non-qualifying contractual relationship" shall include but not be limited to any contract, agreement, arrangement, or relationship (for the purposes of this Section 23.4.5.7.9, a "contract") that: (a) directly relates to the planning, siting, interconnection, operation, or construction of the Generator or UDR project that is the subject of the request for the Competitive Entry Exemption; (b) is for the energy or capacity produced by or delivered from or by the Generator or UDR project, including an agreement for rights to schedule or use a UDR; or (c) provides services, financial support, or tangible goods to a Generator or UDR project. For purposes of Section 23.4.5.7.9, an indirect "non-qualifying contractual relationship" is any contract between the Generator or UDR project and an entity (for purposes of this Section 23.4.5.7.9, a "third party") if the third party has a non-qualifying contractual relationship with a Non-Qualifying Entry Sponsor, the recital, purpose, or subject of which includes, or has the effect of including, this Generator or UDR project.

23.4.5.7.9.1.3 A contract with a Non-Qualifying Entry Sponsor shall not constitute a "non-qualifying contractual relationship" if it is (i) an Interconnection Agreement; (ii) an agreement for the construction or use of interconnection facilities or transmission or distribution facilities, or directly connected joint use transmission or distribution facilities (including contracts required for compliance with Articles VII or X of the New York State Public Service Law or orders issued pursuant to Articles VII or X); (iii) a grant of permission by any department, agency, instrumentality, or political subdivision of New York State to bury, lay, erect or construct wires, cables or other conductors, with the necessary poles, pipes or other fixtures in, on, over or under public property; (iv) a contract for the sale or lease of real property to or from a Non-Qualifying Entry Sponsor at or above fair market value as of the date of the agreement was executed, such value demonstrated by an independent appraisal at the time of execution prepared by an accountant or appraiser with specific experience in such valuations; (v) an easement or license to use real property; (vi) a contract, with any department, agency, instrumentality, or political subdivision of New York State providing for a payment-in-lieu of taxes (*i.e.*, a "PILOT" agreement) or industrial or commercial siting incentives, such as tax abatements or financing incentives, provided the PILOT agreement or incentives are generally available to industrial or commercial entities; (vii) a service agreement for natural gas entered into under a tariff accepted by a regulatory body with jurisdiction over that service; or (viii) a service agreement entered into under a tariff accepted by a regulatory body with jurisdiction over that service at a regulated rate for electric Station Power, or steam service, excluding an agreement for a rate that is a negotiated rate pursuant to any such regulated electric, or steam tariff. Notwithstanding the foregoing, a contract with a Non-Qualifying Entry Sponsor that includes a provision that is a non-qualifying contractual relationship will render the entire contract described in (i) through (viii) of this Section a non-qualifying contractual relationship.

23.4.5.7.9.1.4 The ISO shall determine whether a Generator or UDR project is eligible for a Competitive Entry Exemption based on its review of the certifications required by Section 23.4.5.7.9.2, below, and any other supporting data requested by the ISO. When evaluating eligibility for a Competitive Entry Exemption, the ISO shall consult with the Market Monitoring Unit. The responsibilities of the

Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.12 of Attachment O.

23.4.5.7.9.2 Certifications and Acknowledgements

23.4.5.7.9.2.1 A Generator or UDR project requesting a Competitive Entry Exemption shall submit to the ISO in accordance with ISO Procedures, and shall be legally bound by, the following Certification and Acknowledgement form executed by a duly authorized officer:

CERTIFICATION AND ACKNOWLEDGMENT

I [NAME & TITLE] hereby certify on behalf of myself, [NAME OF PROJECT], and [NAME OF DEVELOPER] that each of the following statements is true and correct:

1. I am an officer whose responsibilities include the development of the [EXAMINED FACILITY], New York Independent System Operator, Inc.'s ("NYISO") Interconnection queue position Number [INSERT NUMBER] (the "Project").

2. I am duly authorized to make representations concerning the Project, including each of the certifications and acknowledgements that I have made in this document.

3. I hereby [REQUEST ON BEHALF OF/ACKNOWLEDGE THE PRIOR SUBMISSION IN THIS CLASS YEAR BY] the Developer a Competitive Entry Exemption for the Project.

4. I have reviewed and I understand the requirements established under the NYISO Market Administration and Control Area Services Tariff ("Services Tariff") related to a "Competitive Entry Exemption" pursuant to Section 23.4.5.7.9.

5. I have personal knowledge of the facts and circumstances supporting the Project's request and eligibility for a Competitive Entry Exemption as of the date of this Certification and Acknowledgment, including all data and other information submitted by the Project to the NYISO.

6. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification there [ARE/ARE NOT ANY**]** direct or indirect contractual relationships for the Project with a "Non-Qualifying Entry Sponsor," as those terms are defined in Section 23.4.5.7.9 of the Services Tariff. I have listed all contracts with Non-Qualifying Entry Sponsors on Schedule 1 to this Certification.

7. If the Answer to (6) is that there are one or more direct or indirect contractual relationships for the Project with a Non-Qualifying Entry Sponsor, then I certify that to the best of my knowledge and having conducted due diligence that they are "allowable contracts" as set forth in Section 23.4.5.7.9.1.3(i) – (viii) of the Services Tariff.

8. To the best of my knowledge and having conducted due diligence that is current as of the date of this Certification, (a) no unexecuted agreements, written or unwritten, with a Non-Qualifying Entry Sponsor exist that would support the development of the Project except those agreements that would not constitute a non-qualifying contractual relationship, as set forth in Section 23.4.5.7.9.1.3(i) – (viii) of the Services Tariff, and (b) all agreements that would not constitute a non-qualifying contractual relationship are on Schedule 1 to this certification.

9. To the best of my knowledge and having conducted due diligence, the Project is not a Non-Qualifying Entry Sponsor, and it is not an "Affiliate" (as Affiliate is defined in Section 2.1 of the Services Tariff) of, a Non-Qualifying Entry Sponsor.

10. The Project shall provide any information or cooperation requested by the NYISO in connection with the Project's request for a Competitive Entry Exemption.

11. All parents or Affiliates of the Project shall provide any information or cooperation requested by the ISO.

I hereby acknowledge on behalf of myself, [INSERT NAME OF PROJECT], and [NAME OF DEVELOPER] that:

a. The submission of false, misleading, or inaccurate information, or the failure to submit information requested by the NYISO related to the Project's request for a Competitive Entry Exemption, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Project, shall constitute a violation of Section 4.1.7 of the Services Tariff, and subject to the Commission's review, a violation of the Commission's regulations and Section 316A of the Federal Power Act.

b. If the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO, including but not limited to information contained or submitted in this Certification and Acknowledgement on behalf of the Project, it shall cease to be eligible for a Competitive Entry Exemption and, if the Project has already received a Competitive Entry Exemption, that exemption shall be subject to revocation by the NYISO or the Commission after which the Project shall be subject to an Offer Floor set at the Mitigation Net CONE Offer Floor (such value calculated based on the date it first Offers UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of the Services Tariff,) starting with the date of the revocation pursuant to Section 23.4.5.7.9.5.3 of the Services Tariff.

c. If the Project submits false, misleading, or inaccurate information, or fails to submit requested information to the NYISO, including but not limited to information contained or submitted in the Certification and Acknowledgement on behalf of the Project, it may be subject to civil penalties that may be imposed by the Commission for violations of Section 4.1.7 of Services Tariff, the Commission's rules, and/or Section 316A of the Federal Power Act.

____
[PRINT NAME]
[DATE]

Subscribed and sworn to before me
this [ ] day of [MONTH] [YEAR].

____
Notary Public

My commission expires: ______________________

PROJECT NAME] SCHEDULE 1 CERTIFICATION AND ACKNOWLEDGEMENT **[DATE]**

Parties to agreement	Date Executed	Effective Date	Date Performance Commences

23.4.5.7.9.2.2 A duly authorized officer of the Generator or UDR project shall also submit a certification acknowledging that parents or Affiliates shall provide any information or cooperation requested by the ISO.

23.4.5.7.9.2.3 The certifying officers must have knowledge of the facts and circumstances supporting the request and qualification for a Generator's or UDR project's Competitive Entry Exemption.

23.4.5.7.9.2.4 Such certifications shall be submitted concurrent with the request for a Competitive Entry Exemption and each time the ISO requests a resubmittal of a certification, until the Generator's or UDR project's Entry Date.

23.4.5.7.9.2.5 The Generator or UDR project must notify the ISO if information in a certification ceases to be true, promptly upon such occurrence or learning information previously provided was not true.

23.4.5.7.9.2.6 Failure to provide, without prior notification, information or cooperation consistent with any certification shall be considered a false, misleading, or inaccurate submission for purposes of Section 23.4.5.7.9.5.

23.4.5.7.9.2.7 Where a notification is provided to the ISO, within 2 business days of receipt of a request from the ISO for information or cooperation, that the information or cooperation requested will not be provided, such refusal will not be considered a false, misleading, or inaccurate submission for purposes of Section 23.4.5.7.9.5 as long as the information is provided by the earlier of a mutually agreed upon deadline or thirty (30) calendar days. A refusal to provide information or any other failure to provide information by that deadline will make the Generator or UDR project requesting a Competitive Entry Exemption ineligible for such exemption, and such Generator or UDR project shall be subject to the Mitigation Net CONE Offer Floor (such value based on the date it first offers UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of the Services Tariff.)

23.4.5.7.9.3 Timing for Requests, Required Submittals, and Withdrawals

23.4.5.7.9.3.1 The executed Certification and Acknowledgement form required by Section 23.4.5.7.9.2 shall be submitted concurrent with a request for a Competitive Entry Exemption. The ISO may request additional information and updated certifications at any time prior to a Generator's or UDR project's Entry Date. A Generator or UDR project that is granted an exemption pursuant to this Section 23.4.5.7.9, shall be required to submit an executed Certification and Acknowledgement form set forth in Section 23.4.5.7.9.2 of the Services Tariff, updated as appropriate, upon its Entry Date.

23.4.5.7.9.3.2 Requests for Competitive Entry Exemptions for Generators or UDR projects in Class Years subsequent to Class Year 2012 must be received by the ISO no later than the deadline by which a facility must notify the ISO of its election to enter the Class Year, such date as set forth in Section 25.5.9 OATT Attachment S. A Generator or UDR project that remains a member of the completed Class Year if such Class Year is Class Year 2012 or prior Class Year, shall not be eligible to request or receive a Competitive Entry Exemption. The ISO shall determine whether a Generator or UDR project is exempt, subject to any required further submissions of information, or not exempt under the Competitive Entry Exemption, prior to the Initial Decision Period within which a Developer must provide an Acceptance Notice or Non-Acceptance Notice to the ISO in response to the first Project Cost Allocation issued by the ISO to the Developer.

23.4.5.7.9.3.3 A Generator or UDR project that submits a request for a Competitive Entry Exemption, including the required Certification and Acknowledgement, responses to information requests, and resubmittal, but (a) enters into a "non-qualifying contractual relationship" or (b) enters into an unexecuted agreement, written or unwritten, with a Non-Qualifying Entry Sponsor that would support the development of the Project, except those agreements identified in 23.4.5.7. 9.1.3 that would not constitute a "non-qualifying contractual relationship, may withdraw such request, provided that it notifies the ISO that it has entered into such "non-qualifying contractual relationship" within 2 business days of doing so. A Generator or UDR project seeking to withdraw its request pursuant to this section 23.4.5.7.9.3.3 shall be subject to the Mitigation Net CONE Offer Floor (such value calculated based on its the date it first offers UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of the Services Tariff,) but will not be subject to the provisions of Section 23.4.5.7.9.5.

23.4.5.7.9.4 Notifications

23.4.5.7.9.4.1 The ISO shall post on its website a list of each Generator or UDR project that requests a Competitive Entry Exemption that becomes a member of the Class Year, promptly after the deadline set forth in Section 30.8.1 of the OATT (Attachment X) (by which the ISO must receive the Developer's executed Class Year Interconnection Facilities Study Agreement and deposit.) The ISO shall update the list as necessary. The ISO shall also post on its website whether a request for a Competitive Entry Exemption was denied, or granted, as soon as its determination is final.

23.4.5.7.9.4.2 Concurrent with the ISO posting of its final determination, the Market Monitoring Unit shall publish a report on the ISO's determination in accordance with Sections 30.4.6.2.12 and 30.10.4 of Attachment O to the Services Tariff.

23.4.5.7.9.5 Revocation

23.4.5.7.9.5.1 The submission of false, misleading, or inaccurate information, or the failure to submit requested information in connection with a request for a Competitive Entry Exemption shall constitute a violation of the Services Tariff. Such violation shall be reported, by the ISO, to the Market Monitoring Unit and to the Commission's Office of Enforcement (or any successor to its responsibilities).

23.4.5.7.9.5.2 Where the ISO reasonably believes that a request for a Competitive Entry Exemption was granted based on false, misleading, or inaccurate information, the ISO shall notify the Generator or UDR project that its Competitive Entry Exemption may be revoked, and provided 30 days written notice has been given to the Generator or UDR project (such notice to the extent practicable,) the ISO may revoke the Competitive Entry Exemption and apply the Mitigation Net CONE Offer Floor (such value calculated based on the date it first offers UCAP, in accordance with Section 23.4.5.7.3.7, and adjusted annually in accordance with Section 23.4.5.7 of the Services Tariff.) Prior to the revocation of a Competitive Entry Exemption and the submission of a report to the Commission's Office of Enforcement (or any successor to its responsibilities,) the ISO shall provide the Generator or UDR project an opportunity to explain any statement, information, or action. The ISO cannot revoke the Competitive Entry Exemption until after the

30 days written notice period has expired, unless ordered to do so by the Commission.

23.4.5.7.10 The ISO shall post on its website the identity of the project in a Mitigated Capacity Zone and the determination of either exempt or non-exempt as soon as the determination is final. Concurrent with the ISO's posting, the Market Monitoring Unit shall publish a report on the ISO's determinations, as further specified in Section 30.4.6.2.12 of Attachment O to this Services Tariff.

23.4.5.7.11 Mitigated UCAP that is subject to an Offer Floor shall remain subject to the requirements of Section 23.4.5.4, and if the Offer Floor is higher than the applicable offer cap shall submit offers not lower than the applicable Offer Floor, except as set forth in 23.4.5.7.12.

23.4.5.7.12 An Interim Service Provider that has UCAP subject to an Offer Floor shall offer all ISP UCAP MW in each ICAP Spot Market Auction at $0.00/kW-month. For an RMR Generator that has UCAP subject to an Offer Floor, the UCAP subject to the Offer Floor shall be offered at $0.00/kW-month.

23.4.5.7.15 Forecasts Under the Buyer Side Market Power Mitigation Measures

The rules set forth in this Section 23.4.5.7.15 apply to (i) the ISO's determinations pursuant to Section 23.4.5.7, *et seq*. of ICAP Spot Market Auction forecast prices ("BSM ICAP Forecast") and (ii) Energy and Ancillary Services revenues when determining Unit Net CONE under Sections 23.4.5.7, *et seq*. (collectively for purposes of this Section, a "BSM Forecast"). Before the commencement of the Initial Decision Period for a Class Year that is not Bifurcated or Class Year X-2, and before the Bifurcated Decision Period in a Bifurcated Class Year, the ISO shall post on its website the BSM Forecast inputs determined in accordance with this Section

23.4.5.7.15, subject to any restrictions on the disclosure of Confidential Information or Critical Energy Infrastructure Information. This posting will include sources of or references for publicly available information "demonstrating with reasonable certainty," as defined in Section 23.4.5.7.15.2, used to develop the BSM Forecast.

23.4.5.7.15.1 For the purposes of Section 23.4.5.7.15, a "positive indicator" that a Generator or UDR project will repair and return to service includes indications that a return to service is, in the ISO's judgment, likely and imminent, such as visible site activity, executed labor or fuel supply arrangements, or unit testing.

23.4.5.7.15.2 For the purposes of Section 23.4.5.7.15, publicly available information "demonstrating with reasonable certainty" shall be limited to information that has been released, authorized, capitulated, or endorsed by an individual or entity having the authority or right to take specific, definitive, actions; and – if such information is contested, to take unilateral actions regarding the operational status of the facility.

23.4.5.7.15.3 When establishing a BSM Forecast, the ISO shall incorporate the parameters and inputs identified in the following subsections. The ISO shall make assumptions necessary to account for any other value or input not expressly addressed in the following subsections in accordance with ISO Procedures.

23.4.5.7.15.3.1 When establishing a BSM Forecast, the ISO shall include Existing Units and Additional Units, as defined in Sections 23.4.5.7.15.4 and .5, less Excluded Units, as defined in Section 23.4.5.7.15.6.

23.4.5.7.15.3.2 When establishing a BSM Forecast, the ISO shall utilize the Load forecast as set forth in the most recently published Load and Capacity Data (Gold Book), or as most recently posted to the ISO's public website and in accordance with ISO Procedures.

23.4.5.7.15.3.3 When determining a BSM ICAP Forecast, the ISO shall reflect Special Case Resource enrollment at a level consistent with average enrollment over the 3 prior Capability Years.

23.4.5.7.15.3.4 When determining a BSM ICAP Forecast, the ISO shall identify the projected ICAP Demand Curve by applying the "inflation index" as defined in Section 23.4.5.7.4. When determining a BSM ICAP Forecast for an Indicative Buyer-Side Mitigation Exemption Determination under Sections 23.4.5.7.2.2 and 23.4.5.7.2.4 when the Commission has not yet accepted the first ICAP Demand Curve to apply specifically to the Mitigated Capacity Zone in which the NCZ Examined Project is located, such inflation rate shall be applied to the ICAP Demand Curve the ISO filed pursuant to Services Tariff Section 5.14.1.2.2.4.11.

23.4.5.7.15.4 Existing Units

Except for the Generators and UDR projects that are excluded without limitation under an exception set forth in Section 23.4.5.7.15.7, the ISO shall identify "Existing Units" as the set of Generators and UDR projects identified in the ISO's most-recently published Gold Book that have CRIS, and are operating at the time that the ISO determines the forecast; including but not limited to Generators in Forced Outage or Inactive Reserve status.

23.4.5.7.15.5 Additional Units

Subject to the exceptions set forth in Section 23.4.5.7.15.7, the ISO shall identify "Additional Units" as each Generator and UDR project that: (i) has previously offered to supply UCAP, (ii) has CRIS, (iii) is not in Existing Units, and (iv) if a Generator, is in an ICAP Ineligible Forced Outage, Mothball Outage, or Retired; if either: (a) the ISO concludes in its sole judgment that there are sufficient positive indicators that the Generator or UDR project will repair and return to service, or (b) the ISO determines that a return to service of the Generator or UDR project would have a positive Net Present Value as set forth in Section 23.4.5.7.15.8.

23.4.5.7.15.5.1 When establishing a BSM Forecast, the inclusion of Generators and UDR projects identified pursuant to Section 23.4.5.7.15.5 (b) as Additional Units shall reflect the persistence of their operation as being contingent on the projected recovery of their forecasted Going Forward Costs.

23.4.5.7.15.6 Excluded Units

Subject to the exceptions set forth in Section 23.4.5.7.15.7, the ISO shall identify "Excluded Units" as the set of Generators and UDR projects that meet the criteria in the following subsections.

23.4.5.7.15.6.1 Generators and UDR projects (i) that have transferred CRIS; (ii) for which the CRIS has expired; (iii) that have CRIS for which a request has been received by the ISO for an evaluation of a CRIS transfer from another location in the Class Year Facilities Study commencing in a calendar year in or preceding the Mitigation Study Period; or (iv) that are an expected transferor of transferred CRIS at the same location. For any CRIS transfer described in (iii) or (iv) of this Section, the transferor or the transferee must have notified the ISO of the transfer pursuant to OATT Attachment S Section 25.9.4 and the transfer must be reasonably expected to be effective on a date within the Mitigation Study Period.

23.4.5.7.15.6.2 Generators in ICAP Ineligible Forced Outages (even if resulting from Catastrophic Failures), Mothball Outages, or that are Retired; provided they are not identified under Section 23.4.5.7.15.5 as an Additional Unit or an exception under Section 23.4.5.7.15.7.

23.4.5.7.15.6.3 Generators that have submitted a Generation Deactivation Notice, beginning with the proposed deactivation date identified in such notice, provided that: (i) the ISO does not identify sufficient positive indicators that the Generator will repair and return to service and (ii) the ISO determines that a return to service or continued operation of the Generator does not have a positive Net Present Value as set forth in Section 23.4.5.7.15.8.

23.4.5.7.15.7 Exceptions

The rules set forth in the following subsections take precedence over the rules described elsewhere in Section 23.4.5.7.15 under the facts and circumstances defined therein.

23.4.5.7.15.7.1 Generators that have submitted a Generation Deactivation Notice, for which the ISO has not yet completed its Generation Deactivation Assessment, shall not be identified by the ISO as Excluded Units, unless there is publicly available information demonstrating with reasonable certainty that the Generator or UDR project will indefinitely cease operation.

23.4.5.7.15.7.2 Initiating Generators with an associated Generator Deactivation Reliability Need for which a Generator Deactivation Solution has not yet been identified, RMR Generators, and Interim Service Providers, shall be included in Existing Units for the expected duration of such Reliability Need with which they are associated. Such Generators shall also be included in Existing Units beyond the expected duration of the Reliability Need if either: (a) the ISO determines, in its sole judgment, that a return to service or continued operation of the Generator has a positive Net Present Value as set forth in Section 23.4.5.7.15.8, or (b) there is publicly available information demonstrating with reasonable certainty that the Generator will continue operation.

23.4.5.7.15.7.3 Except for those included in Existing Units pursuant to Section 23.4.5.7.15.7.2, Generators and UDR projects for which there is publicly available information demonstrating with reasonable certainty that they will indefinitely cease operation, shall be identified as Excluded Capacity beginning with the date determined by the ISO to be consistent with the expected cessation of operations.

23.4.5.7.15.7.4 Generators and UDR projects for which there is publicly available information demonstrating with reasonable certainty that (a) they will return to service shall be included in Additional Units beginning with the date determined by the ISO to be consistent with its expected return to service, or (b) they will continue operations shall be included in Additional Units until the date determined by the ISO to be consistent with its expected continuation of operations.

23.4.5.7.15.7.5 Where determined by the ISO in its sole judgment to be reasonable, the additional capability associated with the repair of a Generator or UDR project that has been operating under a long term partial derate (such as due to the delay or deferral of repairs) may be treated as if it were in and of itself a separate Generator or UDR project in an ICAP Ineligible Forced Outage for the purposes of Section 23.4.5.7.15. In such instances, the net present value of the investment required to for the Generator or UDR facility to return to its original capability or capability prior to the long term partial derate shall be evaluated in place of the cost of returning to service.

23.4.5.7.15.7.6 The ISO shall not be required pursuant to Section 23.4.5.7.15 to determine whether a return to service or continued operation would have a positive Net Present Value as set forth in Section 23.4.5.7.15.8 for: (i) Generators in ICAP Ineligible Forced Outages that the ISO determined to have resulted from a Catastrophic Failure; and (ii)

Generators that are Retired, provided that in the case of (ii), in the ISO's sole judgment, (a) the Generator was subject to actions that rendered it permanently inoperable, (b) the reversal of such actions would be a nontrivial undertaking, and (c) the ISO has received confirmation from it that it has permanently ceased operations.

23.4.5.7.15.7.7 The production and sale of energy from Generators and UDR projects that only have ERIS and no CRIS, or that will have ERIS only after a transfer of CRIS, for which the ISO has received notice or made a determination in the Class Year as described in the next sentence, shall be modeled in the BSM Forecasts, but such units shall be excluded from the BSM ICAP Forecast. In accordance with Attachment S of the OATT, the ISO must have received notice that the transaction is final if a transfer of CRIS at the same location, or have determined the facility receiving the transfer is deliverable and such transferee is either in the Class Year being examined, or remained in a prior Class Year at the time of its completion, if a transfer of CRIS from a different location.

23.4.5.7.15.8 Net Present Value Analysis

Where required by Section 23.4.5.7.15, the ISO shall determine if a Generator or UDR project that potentially could return to service or continue in operation would have a positive net present value under ISO-predicted market conditions and recognizing the entry of projects in the current Class Year and those that remained in prior Class Years at the time of their completion, in accordance with ISO Procedures. If the ISO-estimated net present value is greater than zero, then the criterion of this Section will be considered to have been met.

23.4.5.7.15.8.1 The ISO's net present value analysis shall consider, at a minimum: (a) the ISO-estimated costs and opportunity costs associated with returning a Generator or UDR project to service if the unit is not currently operating, and of continued operation through the end of the Mitigation Study Period, or the end of the investment horizon as reasonably determined by the ISO, whichever is of greater length (including, if applicable, the expected lost revenues of the rest of the portfolio of the Installed Capacity Supplier attributable to reductions in ICAP Spot Market Auction prices caused by the Generator or UDR project's return to service); (b) the ISO-estimated revenues, over the same time period, from the production and sale of Energy, Ancillary Services, and capacity, and (c) the effect that additional risk associated with the age, condition, and location of the Generator or UDR project may have on the required return on investment.

23.4.5.7.15.8.2 The ISO's net present value analysis shall be for a period beginning after the reasonably anticipated commencement of the Initial Decision Period but before the starting Capability Period of the Mitigation Study Period, through the end of Mitigation Study Period, or until the investment horizon as reasonably assumed by the ISO, whichever is of greater length.

23.4.5.7.15.8.3 The ISO shall consider data received from the Generator and UDR project for which it is performing a net present value analysis pursuant to this Section 23.4.5.7.15.8, and information received pursuant to Section 30.25 of the OATT, along with any new, updated, or relevant information that the ISO, in its sole judgment and in accordance with ISO Procedures, has verified is reasonable and accurate. If the ISO has not timely received sufficient information from the owner or representative of a Generator or UDR project, or if the ISO has received information but determined it is not suitable or reliable to be used for the purposes of a net present value analysis pursuant to Section 23.4.5.7.8, the ISO can substitute suitable estimated data, or identify the Generator or UDR project as Excluded Units.

23.4.5.8 RMR Agreement Capacity Price and Offer Requirements

23.4.5.8.1 All ISP UCAP MW shall be offered in each ICAP Spot Market Auction. All UCAP from an RMR Generator shall be offered in each ICAP Spot Market Auction, except if and only to the extent expressly authorized in an RMR Agreement due to the existence of a commitment under a bilateral agreement that (a) was effective at the time the RMR Agreement became effective and (b) is effective and executory, requiring the provision of UCAP, for the Obligation Procurement Period.

23.4.5.8.2 Except as provided in Section 23.4.5.7.12, all UCAP offered by an RMR Generator shall be offered at $0.00/kW-month.

23.4.6 Virtual Bidding Measures

23.4.6.1 Purpose

The provisions of this Section 23.4.6 specify the market monitoring and mitigation measures applicable to "Virtual Bids." "Virtual Bids" are bids to purchase or supply energy that are not backed by physical load or generation that are submitted in the ISO Day-Ahead Market in accordance with the procedures and requirements specified in the ISO Services Tariff.

To implement the mitigation measures set forth in this Section 23.4.6, the ISO shall monitor and assess the impact of Virtual Bidding on the ISO Administered Markets.

23.4.6.2 Implementation

23.4.6.2.1 Day-Ahead LBMPs and Real-Time LBMPs in each load zone shall be monitored to determine whether there is a persistent hourly deviation between them in any zone that would not be expected in a workably competitive market. Monitoring of Day-Ahead and real-time LBMPs shall include examination of the following two metrics (along with any additional monitoring tools and procedures that the ISO determines to be appropriate to achieve the purpose of this Section 23.4.6):

(1) The ISO shall compute a rolling average of the hourly deviation of real-time zonal LBMPs from Day-Ahead zonal LBMPs. The hourly deviation shall be measured as: (zonal $\text{LBMP}_{\text{real time}}$ - zonal $\text{LBMP}_{\text{day ahead}}$). Each observation of the rolling-average time series shall be a simple average of all the hourly deviations over the previous four weeks, or such other averaging period determined by the ISO to be appropriate to achieve the purpose of this Section 23.4.6.

(2) The ISO shall also compute the rolling average *percentage* deviation of real-time zonal LBMPs from Day-Ahead zonal LBMPs. This percentage deviation shall be calculated by dividing the rolling-average hourly deviation (defined in Section 23.4.6.2.1 (1) above) by the rolling-average level of Day-Ahead zonal LBMP over the same time period, using the averaging period(s) described in Section 23.4.6.2.1 (1), above.

23.4.6.2.2 If the ISO determines that (i) the relationship between zonal LBMPs in a zone in the Day-Ahead Market and the Real-Time Market is not what would be expected under conditions of workable competition, and that (ii) the Virtual Bidding practices of one or more Market Participants has contributed to an unwarranted divergence of LBMPs between the two markets, then the following mitigation measure may be imposed. Any such measure shall be rescinded upon a determination by the ISO that the foregoing conditions are not met.

23.4.6.3 Description of the Measure

23.4.6.3.1 If the ISO determines that the conditions specified in Section 23.4.6.2 exist, the ISO may limit the hourly quantities of Virtual Bids for supply or load that may be offered in a zone by a Market Participant whose Virtual Bidding practices have been determined to contribute to an unwarranted divergence of LBMPs between the Day-Ahead and Real-Time Markets. Any such limitation shall be set at such level that, and shall remain in place for such period as, in the best judgment of the ISO, would be sufficient to prevent any unwarranted divergence between Day-Ahead and Real-Time LBMPs.

23.4.6.3.2 As part of the foregoing determination, the ISO shall request explanations of the relevant Virtual Bidding practices from any Market Participant submitting such Bids. Prior to imposing a Virtual Bidding quantity limitation as specified above, the ISO shall notify the affected Market Participant of the limitation.

23.4.6.4 Limitation of Virtual Bidding

If the ISO determines that such action is necessary to avoid substantial deviations of LBMPs between the Day-Ahead and Real-Time Markets, the ISO may impose limits on the quantities of Virtual Bids that may be offered by all Market Participants. Any such restriction shall limit the quantity of Virtual Bids for supply or load that may be offered by each Market Participant by hour and by zone. Any such limit shall remain in place for the minimum period necessary to avoid substantial deviations of LBMPs between the Day-Ahead and Real-Time Markets, or to maintain the reliability of the New York Control Area.

23.4.7 Increasing Bids in Real-Time for Day-Ahead Scheduled Incremental Energy

23.4.7.1 Purpose

This Section 23.4.7 specifies the monitoring applicable and the mitigation measures that may be applicable to a Market Party with submitted Incremental Energy Bids in the real-time market that exceed the Incremental Energy Bids made in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriated, for a portion of the Capacity of one or more of its Generators that has been scheduled in the Day-Ahead Market.

The purpose of the Services Tariff rules authorizing the submission of Incremental Energy Bids in the real-time market that exceed the Incremental Energy Bids made in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, of the portion of the Capacity of a Market Party's Generator that was scheduled in the Day-Ahead Market is to permit the inclusion of additional costs of providing incremental Energy in real-time Incremental Energy Bids for Generators scheduled in the Day-Ahead Market, where the additional costs of providing incremental Energy were not known prior to the close of the Day-Ahead Market.

23.4.7.2 Monitoring and Implementation

The ISO will monitor Market Parties for unjustified interactions between a Market Party's virtual bidding and the submission of real-time Incremental Energy Bids that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of a Generator's Capacity that was scheduled in the Day-Ahead Market.

If the Market Party has a scheduled Virtual Load Bid for the same hour of the Dispatch Day as the hour for which submitted real-time Incremental Energy Bids exceeded the Incremental Energy Bids submitted in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, for a portion of its Generator's Capacity that was scheduled in the Day-Ahead Market, and any such real-time Incremental Energy Bids exceed the reference level for those Bids that can be justified after-the-fact by more than:

(i) the lower of $100/MWh or 300%

(ii) If the Market Party's Generator is located in a Constrained Area for intervals in which an interface or facility into the area in which the Generator or generation is located has a Shadow Price greater than zero, then a threshold calculated in accordance with Sections 23.3.1.2.2.1 and 23.3.1.2.2.2 of these Mitigation Measures;

and a calculation of a virtual market penalty pursuant to the formula set forth in Section 23.4.3.3.4 of these Mitigation Measures for the Market Party would produce a penalty in excess of $1000, then the mitigation measure specified below in Section 23.4.7.3.1 shall be imposed for the Market Party's Generator, along with a penalty calculated in accordance with Section 23.4.3.3.4 of these Mitigation Measures. The application of a penalty under Section 23.4.3.3.4 of these Mitigation Measures shall not preclude the simultaneous application of a penalty pursuant to Section 23.4.3.3.3 of these Mitigation Measures.

23.4.7.3 Mitigation Measure

23.4.7.3.1 If the ISO determines that the conditions specified in Section 23.4.7.2 exist the ISO shall revoke the opportunity for any bidder of that Generator to submit Incremental Energy Bids in the real-time market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of that Generator's Capacity that were scheduled Day-Ahead.

23.4.7.3.1.1 The first time the ISO revokes the opportunity for bidders of a Generator to submit Incremental Energy Bids in the Real-Time Market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of that Generator's Capacity that were scheduled Day-Ahead, mitigation shall be imposed for 90 days. The 90 day period shall start two business days after the date that the ISO provides written notice of its determination that the application of mitigation is required.

23.4.7.3.1.2 Any subsequent time the ISO revoked the opportunity for bidders of a Generator to submit Incremental Energy Bids in the Real-Time Market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of that Generator's Capacity that were scheduled Day-Ahead, mitigation shall be imposed for 180 days. The 180 day period shall start two business days after the date that the ISO provides written notice of its determination that the application of mitigation is required.

23.4.7.3.1.3 If bidders of a Generator that has previously been mitigated under this Section 23.4.7.3 become and remain continuously eligible to submit Incremental Energy Bids in the Real-Time Market that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of that Generator's Capacity that were scheduled Day-Ahead, for a period of one year or more, then the ISO shall apply the mitigation measure set forth in Section 23.4.7.3 of the Mitigation Measures as if the Generator had not previously been subject to this mitigation measure.

23.4.7.3.1.4 Market Parties that transfer, sell, assign, or grant to another Market Party the right or ability to Bid a Generator that is subject to the mitigation measure in this Section 23.4.7.3 are required to inform the new Market Party that the Generator is subject to mitigation under this measure, and to inform the new Market Party of the expected duration of such mitigation.

23.4.8 Duration of Mitigation Measures

Except as specified in Section 23.4.5 of this Attachment H, any mitigation measure imposed as specified above shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the ISO.

23.5 Other Mitigation Measures

23.5.1 Facilitation of Real-Time Mitigation in Constrained Areas

To facilitate the application of the Real-Time mitigation measures specified in this Attachment H for Constrained Areas, all Generators located in a Constrained Area that are capable of doing so shall respond to RTD Base Point Signals, unless such a Generator is subject to contractual obligations in existence prior to June 1, 2002 that would preclude such operation.

23.5.2 Market Power Mitigation Measures Applicable to In-City Unit Commitments for Local Reliability

23.5.2.1 If an In-City Generator is scheduled in any hour in the Day-Ahead Market to meet the reliability needs of a local system, the ISO will set the In-City Generator's Start-Up Bid to the lower of the Bid or the applicable reference level, which may include a Start-Up reference level calculated in accordance with Section 23.3.1.4.4.3 of these Mitigation Measures. In each hour an In-City Generator is scheduled in the Day-Ahead Market to meet the reliability needs of a local system, the ISO will set the In-City Generator's Minimum Generation Bid to the lower of the Bid or the applicable reference level.

23.5.3 Market Power Mitigation Measures Applicable to Sales of Spinning Reserves

23.5.3.1 Local reliability rules require that specified amounts of Spinning Reserves be provided by In-City Generators. The Spinning Reserve-capable portion of each Generator located in New York City must be made available to the ISO for purposes of meeting the New York City Spinning Reserve requirement.

23.5.3.2 The market power mitigation measures applicable to Spinning Reserves will be implemented when the ISO's least-cost dispatch requires that one or more of the Generators located in New York City be committed to meet the In-City Spinning Reserve requirement. For any day that an In-City Generator is committed to meet the In-City Spinning Reserve requirement under circumstances where the Generator would not otherwise have been committed under the ISO's least-cost dispatch, the market power mitigation measures applicable to unit commitments, as described in Section 23.5.2, would apply.

23.5.4 FERC-Ordered Measures

In addition to any mitigation measures specified above, the ISO shall administer, and apply when appropriate in accordance with their terms, such other mitigation measures as it may be directed to implement by order of the FERC.

23.6 RMR Generator and Interim Service Provider Energy and Ancillary Service Market Participation Rules

23.6.1 Submission of Bids for RMR Generators and Interim Service Providers

23.6.1.1 A Market Party shall Bid into the Day-Ahead and Real-Time Markets all of the Energy, Operating Reserves and Regulation each RMR Generator or Interim Service Provider is capable of providing by submitting ISO-committed flexible Bids at or below (equally restrictive to or less restrictive than for non-dollar parameters) the Generator's reference levels.

23.6.1.1.1 The ISO develops reference levels for Bids and Bid parameters, including Bid parameters that are not denominated in dollars. *See, e.g.*, Sections 23.3.1.2 and 23.3.1.2.3.3 of these Mitigation Measures. A Market Party must submit Bids for RMR Generators and Interim Service Providers that are consistent with ***all*** reference levels determined by the ISO, including all non-dollar Bid parameters that have been set as reference levels by the ISO.

23.6.1.1.2 If an RMR Generator or Interim Service Provider is not able to operate to a reference level that has been set by the ISO, the Market Party must timely contact the ISO in accordance with ISO Procedures to request a change and explain the need there for.

23.6.1.1.3 If an RMR Generator is not capable of providing all or a portion of its capability flexibly, the ISO and Generator Owner (as defined in Section 38.1 of the OATT) shall specify the restriction in the RMR Agreement. If a new operating constraint arises during the term of an RMR Agreement that prevents the Market Party from offering all or a portion of a RMR Generator's capability via an ISO-committed flexible Bid, then the Market Party must obtain written permission from the ISO to change how it offers the RMR Generator into the ISO Administered Markets. If a new operating constraint arises while a Generator is an Interim Service Provider that prevents the Market Party from offering all or a portion of the Generator's capability via an ISO-committed flexible Bid, the Market Party shall promptly inform the ISO of the change, shall provide all documentation requested by the ISO or by the Market Monitoring Unit, and shall permit the ISO and/or the Market Monitoring Unit to inspect the affected Generator (including all requested plant records) on five days prior notice.

23.6.1.1.4 Market Parties are not required to submit hourly Bids in the Real-Time Market for an RMR Generator or Interim Service Provider that is not capable of being committed by RTC if the RMR Generator or Interim Service Provider was not committed Day-Ahead. If such an RMR Generator or Interim Service Provider was committed Day-Ahead, then the Generator shall be Bid in real-time for the hours of its Day-Ahead schedule and for additional real-time hours consistent with the Generator's operating capabilities.

23.6.1.1.5 Market Parties shall timely respond to a Supplemental Resource Evaluation ("SRE") or an Out-of-Merit ("OOM") commitment request issued by the ISO or by a Transmission Owner for an RMR Generator or Interim Service Provider.

23.6.1.1.6 If and to the extent a RMR Generator or Interim Service Provider is not available, or is not fully available, the Market Party shall timely notify the ISO of the outage or derate in accordance with ISO Procedures and accurately reflect each RMR Generator's or Interim Service Provider's availability in its Bids.

23.6.1.1.7 The ISO shall monitor Bids that are submitted at prices below an RMR Generator's or Interim Service Provider's reference levels for possible uneconomic overproduction. *See* Section 23.3.1.3. RMR Generators and Interim Service Providers are compensated at the lesser of their Bid or the appropriate Reference Level in accordance with Rate Schedule 8 to the Services Tariff.

23.6.1.2 RMR Generators and Interim Service Providers that are not Installed Capacity Suppliers, or that have not sold all of their Unforced Capacity, are still required to offer all of the Energy, Operating Reserves and Regulation each Generator is capable of providing into each Day-Ahead Market.

23.6.1.3 RMR Generators that provide Voltage Support Services or Restoration Services shall do so in compliance with the relevant provisions of the ISO Tariffs and their RMR Agreement. Interim Service Providers shall provide Voltage Support Services and/or Restoration Services if they provided the service at any point during the 365 days prior to submitting a Generator Deactivation Notice and are physically capable of providing the service.

23.6.1.4 Market Parties shall not schedule Bilateral Transactions for an RMR Generator's output, unless the Bilateral Transaction is expressly permitted under the relevant RMR Agreement. Market Parties shall not schedule Bilateral Transactions for an Interim Service Provider's output unless they were under an ongoing contractual obligation to do so at the time the Generator Deactivation Notice was submitted.

23.6.1.5 Market Parties may only self-schedule an RMR Generator or Interim Service Provider if they are authorized to do so by the ISO.

23.6.1.6 The responsibilities of the Market Monitoring Unit that are specified in Section 23.6.1 of the Mitigation Measures are also addressed in Section 30.4.6.2.13 of Attachment O.

23.6.2 RMR Generator and Interim Service Provider Energy and Ancillary Service Reference Levels

23.6.2.1 RMR Generator reference levels shall be developed in accordance with the rules specified in these Mitigation Measures, including the provisions of this Section 23.6.2.

23.6.2.2 Interim Service Provider reference levels shall be developed in accordance with the reference level development rules specified in these Mitigation Measures, including the additional rules and authority that are ***expressly*** applied to Interim Service Providers in this Section 23.6.2. The ISO, in consultation with the Market Monitoring Unit, may review and update an Interim Service Provider's reference levels. The Generator Owner may propose updates to its Interim Service Provider's reference levels. The ISO shall make the ultimate determination with regard to each reference level.

23.6.2.3 In advance of the execution of an RMR Agreement, the ISO, in consultation with the Market Monitoring Unit and Generator Owner, shall review and update the reference levels for each such Generator. The ISO shall make the ultimate determination with regard to each reference level.

23.6.2.3.1 If a possible RMR Generator or Interim Service Provider faces operational constraints the ISO, in consultation with the Market Monitoring Unit and Generator Owner, will develop reference levels that will permit the Generator to operate consistent with the identified constraints, while ensuring that the

Generator will be available (a) to resolve the Reliability Need the Generator is being retained to address, and (b) for economic commitment when appropriate.

23.6.2.4 If an RMR Agreement is executed after the reference level review and update process described above is completed, then during the term of the RMR Agreement, the ISO's authority to change the RMR Generator's reference levels will be limited to the following circumstances:

23.6.2.4.1 Reference levels may be adjusted based on season, the RMR Generator's remaining availability or other factors, to address operational constraints;

23.6.2.4.2 The costs used to develop a reference level (*e.g.*, fuel, emissions, variable operation and maintenance expenses) may be revised whenever the ISO obtains updated or more accurate cost information;

23.6.2.4.3 Opportunity costs may be updated based on actual operating experience during the term of the RMR Agreement;

23.6.2.4.4 If a physical change to the RMR Generator occurs that alters the RMR Generator's capabilities (*e.g.*, damage to the RMR Generator or Capital Expenditures that alter an RMR Generator's capabilities), then the ISO shall determine revised reference levels in consultation with the Market Monitoring Unit and Generator Owner; and

23.6.2.4.5 The ISO and Generator Owner, in consultation with the Market Monitoring Unit, may mutually agree to a reference level change that they expect will better reflect an RMR Generator's actual operating characteristics or variable costs.

23.6.2.5 The Market Party shall timely submit fuel price updates and fuel type updates to the ISO so that they can be incorporated to develop accurate reference levels for each RMR Generator or Interim Service Provider.

23.6.2.5.1 If a Market Party fails to timely submit fuel price updates and fuel type updates for an RMR Generator or Interim Service Provider, then the compensation paid for the RMR Generator's operation may be limited by the reference levels that were in place.

23.6.2.5.2 If a Market Party fails to timely update an RMR Generator's or Interim Service Provider's reference levels to reflect cost reductions that are not *de minimis*, and that are required to be reflected, then the ISO may recalculate the Generator's reference levels and true-up the Variable Costs paid to the Generator under Rate Schedule 8 to the Services Tariff consistent with the Generator's demonstrated costs. The ISO shall inform the Market Monitoring Unit if it performs such a true-up.

23.6.2.6 The responsibilities of the Market Monitoring Unit that are specified in Section 23.6.2 of the Mitigation Measures are also addressed in Section 30.4.6.2.13 of Attachment O.

23.6.3 Mitigation of RMR Generators and Interim Service Providers

23.6.3.1 RMR Generators and Interim Service Providers are required to Bid at or below their reference levels. The ISO shall mitigate all dollar-denominated Bids that exceed a RMR Generator's or Interim Service Provider's currently effective reference levels.

23.6.3.2 If a Market Party submits unit commitment data or non-dollar Bid parameters for an RMR Generator or Interim Service Provider that is/are not consistent with the Generator's reference levels without first requesting an adjustment to the Generator's reference levels from the ISO, then the ISO shall inform the Market Monitoring Unit of the Market Party's behavior and apply all Tariff-authorized mitigation measures, which may include the application of financial penalties in accordance with Section 23.4.3 of these Mitigation Measures.

23.6.3.3 The ISO shall apply all other Tariff-authorized mitigation measures to RMR Generators and Interim Service Providers consistent with the Mitigation Measures.

23.6.4 Other Energy and Ancillary Service Market Rules

23.6.4.1 On and after the execution of an RMR Agreement, and for the duration of its term, a Market Party shall not enter into any new agreement or extend any other agreement that impairs or otherwise diminishes an RMR Generator's ability to comply with obligation under an RMR Agreement, or that limits the ability of an RMR Generator to provide Energy or Ancillary Services directly to the ISO Administered Markets.

23.6.4.2 A Market Party shall not enter into any new agreement or extend any other agreement that impairs, diminishes or limits the ability of an Interim Service Provider to provide Energy or Ancillary Services directly to the ISO Administered Markets.

23.6.4.3 Market Parties shall not enter into, renew or extend bilateral agreements for Energy or Ancillary Services from an RMR Generator during the term of an RMR Agreement.

23.6.4.4 Market Parties shall not enter into, renew or extend bilateral agreements for Energy or Ancillary Services from an Interim Service Provider.

23.6.4.5 RMR Generators and Interim Service Providers are not eligible to receive Energy, Operating Reserves, Regulation or ICAP market revenues. Instead, RMR Generators and Interim Service Providers are compensated in accordance with Rate Schedule 8 to the Services Tariff and associated Tariff Rules for their participation in the ISO Administered Markets.

23.6.5 ISO Authority to Terminate RMR Agreement with Under-Performing RMR Generator and Cease Reimbursing Capital Expenditures

23.6.5.1 The ISO may terminate an RMR Agreement, or may terminate an RMR Agreement with regard to one of the RMR Generators that is subject to an RMR Agreement if any of the following conditions occur:

(a) Owner (as defined in the *Form of Reliability Must Run Agreement* set forth in Appendix C of Attachment FF to the ISO OATT) defaults under the RMR Agreement and fails to timely cure its default;

(b) The RMR Generator fails to meet one or more of the Minimum Operating Standards set forth in the RMR Agreement (the Minimum Availability Standard, or the Minimum Performance Standard, or the Operation to Address the Reliability Need Standard); or

(c) The RMR Generator fails to operate as requested when it is called upon by the ISO or by a Transmission Owner to address the Reliability Need that it was retained to address on three or more occasions over the term of an RMR Agreement.

23.6.5.2 If the ISO terminates an RMR Agreement for one of the reasons specified in Section 23.6.5.1 above, then it shall cease repaying the cost of any Capital Expenditures that were incurred at or for the terminated RMR Generator(s) unless the ISO is otherwise instructed by the Commission.

23.6.5.3 Rules for concluding the obligations of an Interim Service Provider early are set forth in Section 38.13 of the OATT.

23.7 Dispute Resolution

If a Market Party has reasonable grounds to believe that it has been adversely affected because a Mitigation Measure has been improperly applied or withheld, it may utilize the dispute resolution provisions of the ISO Services Tariff to determine whether, under the standards and procedures specified above and in the Plan, the imposition of a Mitigation Measure was or would have been appropriate. In no event, however, shall the ISO be liable to a Market Party or any other person or entity for money damages or any other remedy or relief except and to the extent specified in the Plan.

23.8 Effective Date

These Mitigation Measures shall be effective as of the date they are approved by the FERC.

24 Attachment I

Reserved for future use.

25 Attachment J – Determination of Day-Ahead Margin Assurance Payments and Import Curtailment Guarantee Payments

25.1 Introduction

If a Supplier that is eligible pursuant to Section 25.2 of this Attachment J buys out of a Day-Ahead Energy, Regulation Service or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin it shall receive a Day-Ahead Margin Assurance Payment, except as noted in Sections 25.4, and 25.5 of this Attachment J. The purpose of such payments is to protect Suppliers' Day-Ahead Margins associated with real-time reductions after accounting for: (i) any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve schedules; and (ii) any Supplier-requested real-time de-rate granted by the ISO.

In addition, a Supplier may be eligible to receive an Import Curtailment Guarantee Payment if its Import is curtailed at the request of the ISO as determined pursuant to Section 25.6 of this Attachment J.

25.2 Eligibility for Receiving Day-Ahead Margin Assurance Payments

25.2.1 General Eligibility Requirements for Suppliers to Receive Day-Ahead Margin Assurance Payments

Subject to Section 25.2.2 of this Attachment J, the following categories of Resources bid by Suppliers shall be eligible to receive Day-Ahead Margin Assurance Payments: (i) all Self-Committed Flexible and ISO-Committed Flexible Generators that are either online and dispatched by RTD or available for commitment by RTC; (ii) Demand Side Resources committed to provide Operating Reserves or Regulation Service; (iii) any Resource that is scheduled out of economic merit order by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; (iv) any Resource internal to the NYCA that is derated or decommitted by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; and (v) Energy Limited Resources with an ISO-approved real-time reduction in scheduled output from its Day-Ahead schedule.

25.2.2 Exceptions

Notwithstanding Section 25.2.1 of this Attachment J, no Day-Ahead Margin Assurance Payment shall be paid to:

25.2.2.1 a Resource, otherwise eligible for a Day-Ahead Margin Assurance Payment, in hours in which the NYISO has increased the Resource's real-time minimum operating level above the Resource's Day-Ahead Market Energy schedule either: (i) at the Resource's request including through an adjustment to the Resource's self-commitment schedule; or (ii) in order to reconcile the ISO's dispatch with the Resource's actual output or to address reliability concerns that arise because the Resource is not following Base Point Signals; or (iii) an Intermittent Power Resource that depends on wind as its fuel.

25.2.2.2 a Resource, otherwise eligible for Day-Ahead Margin Assurance Payments, in hours in which the NYISO has increased the Resource's real-time minimum operating level at the Resource's request, including through an adjustment to the Resource's self-commitment schedule, above the MW level determined by subtracting the Resource's Day-Ahead Market Regulation Service schedule from its Day-Ahead Market Energy schedule.

25.2.2.3 a Resource, otherwise eligible for Day-Ahead Margin Assurance Payments, in hours in which the Resource reduces the MW quantity specified in its real-time Regulation Capacity Bid below its Day-Ahead Market Regulation Service schedule.

25.2.2.4 a Generator, otherwise eligible for Day-Ahead Margin Assurance Payments, for (i) any hour in which the Incremental Energy Bids submitted in the real-time market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) in which the Incremental Energy Bids submitted in the real-time market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market.

25.2.2.5 A Generator that is available for commitment by RTC and otherwise eligible for Day-Ahead Margin Assurance Payments, for (i) any hour in which the Start-Up Bids submitted in the real-time market for that Generator exceed the Start-Up Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Start-Up Bids where appropriate, and that Generator was scheduled for Energy or Regulation Service in that hour in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) in which the Start-Up Bids submitted in the real-time market for that Generator exceed the Start-Up Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Start-Up Bids where appropriate, and that Generator was scheduled for Energy or Regulation Service in that hour in the Day-Ahead Market.

25.3 Calculation of Day-Ahead Margin Assurance Payments

25.3.1 Formula for Day-Ahead Margin Assurance Payments for Generators, Except for Limited Energy Storage Resources

Subject to Sections 25.4 and 25.5 of this Attachment J, Day-Ahead Margin Assurance Payments for Generators, except for Limited Energy Storage Resources, shall be determined by applying the following equations to each individual Generator using the terms as defined in Section 25.3.4:

$$DMAP_{hu} = max\left(0, \sum_{i \in h} CDMAP_{iu}\right)$$

where:

$$CDMAP_{iu} = CDMAPen_{iu} + \sum_{P} CDMAPres_{iup} + CDMAPreg_{iu}$$

If the Generator's real-time Energy schedule is lower than its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = \left((DASen_{hu} - LL_{iu}) * RTPen_{iu} - \int_{LL_{iu}}^{DASen_{hu}} DABen_{hu} \right) * \frac{Seconds_i}{3600}$$

If the Generator's real-time Energy schedule is greater than or equal to its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = min\left[\left((DASen_{hu} - UL_{iu}) * RTPen_{iu} + \int_{DASen_{hu}}^{UL_{iu}} RTBen_{iu} \right) * \frac{Seconds_i}{3600}, 0\right]$$

If the Generator's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTPres_{iup} - DABres_{hup}\right)\right] * \frac{Seconds_i}{3600}$$

If the Generator's real-time schedule for a given Operating Reserve product, p, is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTPres_{iup}\right)\right] * \frac{Seconds_i}{3600}$$

If the Generator's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})] * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

If the Generator's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) * max\left((RTPreg_{iu} - RTBreg_{iu}), 0\right)\right] * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

25.3.2 Formula for Day-Ahead Margin Assurance Payments for Demand Side Resources

25.3.2.1 Formula for Day-Ahead Margin Assurance Payment for Demand Side Resources

Subject to Section 25.5 of this Attachment J, Day-Ahead Margin Assurance Payments for Demand Side resources scheduled to provide Operating Reserves or Regulation Service shall be determined by applying the following equations to each individual Demand Side Resource using the terms as defined in Section 25.3.4, except for RPIiu, which is defined in Section 25.3.2.2:

$$DMAP_{hu} = max\left(0, \sum_{i \in h} CDMAP_{iu}\right)$$

where:

$$CDMAP_{iu} = \sum_{p} CDMAPres_{iup} + CDMAPreg_{iu}$$

If the Demand Side Resource's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTPres_{iup} - DABres_{hup}\right)\right] * RPI_{iu} * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time schedule for a given Operating Reserve product, p, is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTSPres_{iup}\right)\right] * RPI_{iu} * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$\begin{aligned} CDMAPreg_{iu} = {} & [(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})] * \frac{Seconds_i}{3600} \\ & + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})] \end{aligned}$$

If the Demand Side Resource's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$\begin{aligned} CDMAPreg_{iu} = {} & \left[(DASreg_{hu} - RTSreg_{iu}) * max\left((RTPreg_{iu} - RTBreg_{iu}), 0\right)\right] * \frac{Seconds_i}{3600} \\ & + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})] \end{aligned}$$

25.3.2.2 Reserve Performance Index for Demand Side Resource Suppliers of Operating Reserves

The ISO shall produce a Reserve Performance Index for purposes of calculating a Day Ahead Margin Assurance Payment for a Demand Side Resource providing Operating Reserves. The Reserve Performance Index shall take account of the actual Demand Reduction achieved by the Supplier of Operating Reserves following the ISO's instruction to convert Operating Reserves to Demand Reduction.

The Reserve Performance Index shall be a factor with a value between 0.0 and 1.0 inclusive. For each interval in which the ISO has not instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction, the Reserve Performance Index shall have a value of one. For each interval in which the ISO has instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction the Reserve Performance Index shall be calculated pursuant to the following formula, provided however when UAGi is zero or less, the Reserve Performance Index shall be set to zero:

$$RPI_{iu} = min[(UAG_i \,/\, ADG_i + \ .1), 1]$$

Where:

RPI_{iu}	=	Reserve Performance Index in interval *i* for Demand Side Resource *u*;
UAG_i	=	average actual Demand Reduction for interval *i*, represented as a positive generation value; and
ADG_i	=	average scheduled Demand Reduction for interval *i*, represented as a positive generation base point.

25.3.3 Formula for Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources

Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources scheduled to provide Regulation Service shall be determined by applying the following equations to each Resource using the terms as defined in Section 25.3.4; *provided*, *however*, that a Day-Ahead Margin Assurance Payment is payable only for intervals in which the NYISO has reduced the real-time Regulation Service offer (in MWs) of a Limited Energy Storage Resource and the NYISO is not pursuing LESR Energy Management for such Resource for such interval, pursuant to ISO Procedures:

If the LESR's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule and the real-time Regulation Capacity Market Price is greater than the Day-Ahead Regulation Capacity Bid price then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})] * K_p * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

If the LESR's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule and the real-time Regulation Capacity Market price is less than or equal to the Day-Ahead Regulation Capacity Bid price then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})] * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

If the LESR's real-time Regulation Service schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) * max\left((RTPreg_{iu} - RTBreg_{iu}), 0\right)\right] * \frac{Seconds_i}{3600} + \left[(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})\right]$$

25.3. 4 Terms Used in this Attachment J

The terms used in the formulas in this Attachment J shall be defined as follows:

h is the hour that includes interval *i*;

$DMAP_{hu}$ = the Day-Ahead Margin Assurance Payment attributable in any hour *h* to any Supplier *u*;

$CDMAP_{iu}$ = the contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;

$CDMAPen_{iu}$ = the Energy contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;

$CDMAPreg_{iu}$ = the Regulation Service contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;

$CDMAPres_{iup}$ = the Operating Reserve contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u* determined separately for each Operating Reserve product *p*;

$DASen_{hu}$ = Day-Ahead Energy schedule for Supplier *u* in hour *h*;

$DASreg_{hu}$ = Day-Ahead schedule for Regulation Service for Supplier *u* in hour *h*;

$DASres_{hup}$ = Day-Ahead schedule for Operating Reserve product p, for Supplier *u* in hour *h*;

$DABen_{hu}$ = Day-Ahead Energy Bid cost for Supplier *u* in hour *h*, including the Minimum Generation Bid and Incremental Energy Bids;

$DABreg_{hu}$ = Day-Ahead Regulation Capacity Bid price for Supplier *u* in hour *h*;

$DABres_{hup}$ = Day-Ahead Availability Bid for Operating Reserve product *p* for Supplier *u* in hour *h*;

$RTSen_{iu}$ = real-time Energy scheduled for Supplier *u* in interval *i*, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Supplier *u* during the course of interval *i*;

$RTSreg_{iu}$ = real-time schedule for Regulation Service for Supplier *u* in interval *i*.

$RTSres_{iup}$ = real-time schedule for Operating Reserve product *p* for Supplier *u* in interval *i*.

$RTBreg_{iu}$ = real-time Regulation Capacity Bid price for Supplier *u* in interval *i*.

$RTBen_{iu}$ = real-time Energy Bid cost for Supplier *u* in interval *i*, including the Minimum Generation Bid and Incremental Energy Bids.

$RTBregm_{iu}$ = real-time Regulation Movement Bid price for Supplier *u* in interval *i*.

$RTMreg_{iu}$ = real-time Regulation Movement MWs for Supplier *u* in interval *i;*

AEI_{iu} = average Actual Energy Injection by Supplier *u* in interval *i* but not more than $RTSen_{iu}$ plus Compensable Overgeneration;

$RTPen_{iu}$ = real-time price of Energy at the location of Supplier *u* in interval *i*;

$RTPreg_{iu}$ = real-time price of Regulation Capacity at the location of Supplier *u* in interval *i*;

$RTPres_{iup}$ = real-time price of Operating Reserve product *p* at the location of Supplier *u* in interval *i*;

$RTPregm_{iu}$ = real-time Regulation Movement Market Price at the location of Supplier *u* in interval *i;*

LL_{iu} = either, as the case may be:

(a) $if\ RTSen_{iu} < EOP_{iu}, then\ LL_{iu} = min\left(max\left(RTSen_{iu}, min(AEI_{iu}, EOP_{iu})\right), DASen_{hu}\right)$; or

(b) $if\ RTSen_{iu} \geq EOP_{iu}, then\ LL_{iu} = min(RTSen_{iu}, max(AEI_{iu}, EOP_{iu}), DASen_{hu})$

UL_{iu} = either, as the case may be:

(a) $if\ RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}, then\ UL_{iu} = max\left(min\ \left(RTSen_{iu}, max\ (AEI_{iu}, EOP_{iu})\right), DASen_{hu}\right)$; or

(b) otherwise, then $UL_{iu} = max(RTSen_{iu}, min(AEI_{iu}, EOP_{iu}), DASen_{hu})$;

EOP_{iu} = the Economic Operating Point of Supplier *u* in interval *i* calculated without regard to ramp rates;

$Seconds_i$ = number of seconds in interval *i*

KPI_{pi} = the factor derived from the Regulation Service Performance index for Resource *u* for interval *i* as defined in Rate Schedule 3 of this Services Tariff.

25.4 Exception for Generators Lagging Behind RTD Base Point Signals

If an otherwise eligible Generator's average Actual Energy Injection in an RTD interval (*i.e.*, its Actual Energy Injections averaged over the RTD interval) is less than or equal to its penalty limit for under-generation value for that interval, as computed below, it shall not be eligible for Day-Ahead Margin Assurance Payments for that interval.

The penalty limit for under-generation value is the tolerance described in Section 15.3A.1 of Rate Schedule 3-A of this ISO Services Tariff, which is used in the calculation of the persistent under-generation charge applicable to Generators that are not providing Regulation Service.

25.5 Rules Applicable to Supplier Derates

Suppliers that request and are granted a derate of their real-time Operating Capacity, but that are otherwise eligible to receive Day-Ahead Margin Assurance Payments may receive a payment up to a Capacity level consistent with their revised Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable. The foregoing rule shall also apply to a Generator otherwise eligible for a Day-Ahead Margin Assurance Payment in hours in which the ISO has derated the Generator's Operating Capacity in order to reconcile the ISO's dispatch with the Generator's actual output, or to address reliability concerns that arise because the Generator is not following Base Point Signals. If a Supplier's derated real-time Operating Capacity is lower than the sum of its Day-Ahead Energy, Regulation Services, and Operating Reserve schedules then when the ISO conducts the calculations described in Section 25.3 above, the DASen, DASeg and $DASres_p$ variables will be reduced by REDen, REDreg and $REDres_p$ respectively. REDen, REDreg and $REDres_p$ shall be calculated using the formulas below:

$$REDtot_{iu} = max\left(DASen_{hu} + DASreg_{hu} + \sum_p DASres_{hup} - RTUOL_{iu}, 0\right)$$

$$POTREDen_{iu} = max(DASen_{hu} - RTSen_{iu}, 0)$$

$$POTREDreg_{iu} = max(DASreg_{hu} - RTSreg_{iu}, 0)$$

$$POTREDres_{iup} = max\left(DASres_{hup} - RTSres_{iup}, 0\right)$$

$$REDen_{iu} = \left(POTREDen_{iu} / \left(POTREDen_{iu} + POTREDreg_{iu} + \sum_p POTREDres_{iup}\right)\right) * REDtot_{iu}$$

$$REDreg_{iu} = \left(POTREDreg_{iu} / \left(POTREDen_{iu} + POTREDreg_{iu} + \sum_p POTREDres_{iup}\right)\right) * REDtot_{iu}$$

$$REDres_{iup} = \left(POTREDres_{iup} / \left(POTREDen_{iu} + POTREDreg_{iu} + \sum_p POTREDres_{iup}\right)\right) * REDtot_{iu}$$

where:

$RTUOL_{iu}$ = The real-time Emergency Upper Operating Limit or Normal Upper Operating Limit whichever is applicable of Supplier *u* in interval *i*

$REDtot_{iu}$ = The total amount in MW that Day-Ahead schedules need to be reduced to account for the derate of Supplier *u* in interval *i*

$REDen_{iu}$ = The amount in MW that the Day-Ahead Energy schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*

$REDreg_{iu}$ = The amount in MW that Supplier *u*'s Day-Ahead Regulation Service schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval *i*

$REDres_{iup}$ = The amount in MW that Supplier *u*'s Day-Ahead Operating Reserve schedule for Operating Reserves product *p* is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval *i*

$POTREDen_{iu}$ = The potential amount in MW that Supplier *u*'s Day-Ahead Energy schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*

$POTREDreg_{iu}$ = The potential amount in MW that Supplier *u*'s Day-Ahead Regulation Service schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*

$POTREDres_{iup}$ = The potential amount in MW that Supplier *u*'s Day-Ahead Operating Reserve Schedule for Operating Reserve product *p* could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*

All other variables are as defined above.

25.6 Import Curtailment Guarantee Payments

25.6.1 Eligibility for an Import Curtailment Guarantee Payment for an Import Curtailed by the ISO

In the event that the Energy injections for an Import scheduled by RTC or RTD at a Proxy Generator Bus, other than a CTS Enabled Proxy Generator Bus, are Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible for an Import Curtailment Guarantee Payment as determined in Section 25.6.2 of this Attachment J. Suppliers scheduling Imports at CTS Enabled Proxy Generator Buses shall not be eligible for Import Curtailment Guarantee payments for those Transactions.

25.6.2 Formula for an Import Curtailment Guarantee Payment for a Supplier Whose Import Was Curtailed by the ISO

A Supplier eligible under Section 25.6.1 of this Attachment J shall receive an Import Curtailment Guarantee Payment for its curtailed Energy injections that is equal to the daily sum of the hourly payments which, for each hour of Import t, is calculated as the greater of the interval payments determined for the hour or zero as seen in the formula below.

Import Curtailment Guarantee Payment to Supplier u in association with Import t =

$$\sum_{h=1}^{N} max\left(\sum_{i=1}^{H}\big(RTLBMP_{ti} - max(DADecBid_{ti}, 0)\big) * (DAen_{ti} - RTDen_{ti}) * \frac{S_i}{3600}, 0\right)$$

Where

N = the number of hours in the Dispatch Day

H = the number of intervals in hour *h*

i = the relevant interval in hour *h*;

S_i = number of seconds in interval *i*;

$RTLBMP_{t,i}$ = the real-time LBMP, in $/MWh, for interval *i* at the Proxy Generator Bus which is the source of the Import *t*.

$DADecBid_{t,i}$ = the Day Ahead Decremental Bid price associated with the Day-Ahead energy schedule, in $/MWh, for Import *t* in hour h containing interval *i*;

$DAen_{t,i}$ = the Day Ahead scheduled Energy injections, in MWh, for Import t in hour *h* containing interval *i* as determined by Security Constrained Unit Commitment (SCUC); and

$RTDen_{t,i}$ = the scheduled Energy injections, in MWh, for Import *t* in interval *i* as determined by Real-Time Dispatch (RTD).

26 Attachment K - Creditworthiness Requirements For Customers

This Attachment K applies to all Customers and all applicants seeking to become Customers. "Customer," as used in this Attachment K, shall also mean an applicant seeking to become a Customer.

26.1 Minimum Participation Criteria

26.1.1 General

To participate in the ISO-Administered Markets, in addition to satisfying any other eligibility requirements set forth in the ISO Tariffs, each Customer must satisfy, and at all times remain in compliance with, the following requirements:

(a) Risk Management. Customer shall maintain current, written risk management policies and procedures that address those risks that could materially and adversely affect Customer's ability to pay its ISO invoices when due, including, but not limited to, credit risks, liquidity risks, and market risks.

(b) Training. Each employee and agent that Bids or schedules in the ISO-Administered Markets on behalf of Customer shall have appropriate training and/or experience to transact on behalf of Customer in the ISO-Administered Markets. In addition, each employee and agent that Bids on Virtual Transactions or TCCs on behalf of Customer shall successfully complete the designated ISO-administered online training course on Virtual Transactions and/or TCCs one time, as applicable; *provided, however*, this requirement does not apply to a Transmission Owner as a result of its receipt of Net Auction Revenue.

(c) Operational Capabilities. Customer shall have appropriate personnel resources and technical abilities to promptly and effectively respond to all ISO communications and directions related to settlements, billing, credit requirements, and other financial matters.

(d) Capitalization. Customer, or its guarantor with the provision of an unlimited guaranty in compliance with Section 26.5.4 of this Attachment K, shall meet the minimum capitalization criteria set forth below or post additional security in accordance with the following:

i. Maintain at least US $10 million in assets or at least US $1 million in tangible net worth as evidenced by Customer's or its guarantor's most recent audited annual financial statements; or

ii. If Customer is unable to meet the minimum capitalization criteria set forth in Section 26.1.1(d)i of this Attachment K, post with the ISO either (1) $200,000 to participate in any/all of the ISO-Administered Markets other than the TCC market, which security Customer may not use to support any ISO credit requirements, or (2) $500,000 to participate in any/all of the ISO-Administered Markets including the TCC market, which security the Customer may not use to support any ISO credit requirements.

The ISO will independently verify that adequate capitalization is being maintained on an annual basis. In addition, if at any time a Customer that satisfied the capitalization requirement set forth in Section 26.1.1(d) above by demonstrating compliance with the criteria set forth in Section 26.1.1(d)i experiences a change in financial position such that Customer no longer satisfies these criteria, Customer shall notify the ISO promptly of this change in financial position and post the appropriate amount of security in accordance with Section 26.1.1(d)ii of this Attachment K.

26.1.2 Annual Certification

Each Customer must demonstrate ongoing compliance with the minimum participation requirements set forth in Section 26.1.1 of this Attachment K by submitting to the ISO on or before April 30 of each year a notarized officer's certificate, signed by an authorized officer of Customer with signatory authority, in a form acceptable to the ISO, certifying that Customer is in compliance with each of the minimum participation requirements. Each NYISO applicant must submit an initial notarized officer's certificate with its Completed Application.

26.1.3 Verification of Risk Management Policies and Procedures

26.1.3.1 Scope

(a) Each applicant applying to participate in the TCC market shall submit its risk management policies and procedures for verification prior to commencing any activity in the TCC market.

(b) Each Customer that participates in the TCC market, except those Customers that solely own Grandfathered Rights, Grandfathered TCCs and/or Fixed Price TCCs, shall submit its risk management policies and procedures to the ISO annually by no later than April 30 of each calendar year.

(c) Each Customer that participates in the TCC market and meets the criteria below shall be subject to annual verification:

i. does not solely own Grandfathered Rights, Grandfathered TCCs and/or Fixed Price TCCs, and

ii. has, for any month in the immediately preceding 36 months, had a concentration of negative or low positive TCCs. For purposes of this Section 26.1.3.1(c)(ii), a Customer shall be deemed to have a concentration of negative or low positive TCCs if the net amount owed by the Customer to the ISO for "TCC Congestions Rents" on its consolidated invoices for the month is greater than $0 or the net amount owed by the ISO to the Customer for "TCC Congestion Rents" on its consolidated invoices for the month is less than or equal to $50,000.

(d) For Customers that are not already subject to verification as detailed in Section 26.1.3.1(c), the ISO may select 10-20% of those Customers per year for review on a random basis. Customers randomly selected for risk management verification and satisfactorily verified shall be excluded from such verification based on a random selection for the subsequent two years.

(e) A Customer notified by the ISO that it will be subject to verification shall, within two (2) business days of the Customer's receipt of the ISO's notice, submit to the ISO a copy of its current governing risk management policies and procedures.

(f) Where a Customer has not made any material changes to its risk management policies and procedures since its last submission to the ISO, the Customer may submit a certificate to the ISO in lieu of resubmission of its risk management policies and procedures. The certificate must be in a form acceptable to the ISO, be signed by an authorized officer of the Customer, and state that the Customer's risk management policies and procedures have not materially changed since its last submission.

26.1.3.2 Verification Standards and Process

The ISO will assess the Customer's (or applicant's) risk management policies and procedures to confirm those policies and procedures conform to the risk management standards and practices set forth in this Section 26.1.3.2. Through such assessment, the ISO will verify that:

1. Customer's risk management framework is documented in a risk policy addressing market, credit and liquidity risks that have been approved by the Customer's risk management function, which includes appropriate corporate persons or bodies that are independent of the Customer's trading functions, such as a risk management committee, a designated risk officer, a Customer's board of directors or board committee, or, if applicable, a board of directors or board committee of a Customer's parent company.

2. Customer maintains an organizational structure with clearly defined roles and responsibilities that appropriately, and to the extent practical, segregate trading functions from risk management functions (*e.g*, segregation of front, middle, and back office functions).

3. Customer has established delegations of authority specifying the transactions into which its traders are allowed to enter.

4. Customer ensures that its traders have adequate training and/or experience relative to their delegations of authority in the systems and markets in which they transact.

5. As appropriate, risk limits are in place to control risk exposures.

6. Reporting is in place to ensure that risks are adequately communicated throughout the organization.

7. Processes are in place for qualified independent review of trading activities.

8. As appropriate, there is periodic valuation or mark-to-market of risk positions.

A Customer subject to risk management verification and satisfactorily verified by the ISO shall inform the ISO of any material change in its risk management policies and procedures within five (5) business days of such change.

For each Customer subject to risk management verification, continued eligibility to participate in the ISO-Administered Markets is conditioned upon the ISO notifying the Customer of successful completion of the ISO's verification; *provided, however,* that if the ISO notifies the Customer in writing that the Customer's risk management policies and procedures did not satisfy the standards set forth in this Section 26.1.3.2, the Customer shall have 30 calendar days to submit revised risk management policies and procedures, which have been revised to address any deficiencies identified by the ISO, prior to the ISO declaring the Customer in default for failure to comply with the creditworthiness requirements of the ISO Tariffs. If, prior to the expiration of such 30 calendar days, the Customer demonstrates to the ISO that it has filed with the Commission an appeal of the ISO's risk management verification determination, then the Customer shall retain its transaction rights and not be declared in default for failure to comply with the creditworthiness requirements of the ISO Tariffs, pending the Commission's determination on the Customer's appeal.

The ISO may retain a third party to perform the review and verification function described in this Section 26.1.3.2. The ISO and any third party it may retain will treat as

Confidential Information the documentation provided by a Customer under this Section 26.1.3.2, consistent with the applicable provisions of Attachment F to the ISO OATT.

The ISO shall have the right to charge a Customer subject to verification under this Section 26.1.3 for any costs incurred by the ISO related to the ISO's verification of the Customer's risk management policies and procedures.

26.1.4 Additional Information

Each Customer shall submit to the ISO, upon request, any information or documentation reasonably required for the ISO to monitor and evaluate Customer's creditworthiness and compliance with requirements set forth in the ISO Tariffs, ISO Procedures, and/or ISO Agreements related to settlements, billing, credit requirements, and other financial matters.

26.2 Reporting Requirements

26.2.1 All Customers shall be required to comply with the reporting requirements in this Section 26.2.1

26.2.1.1 References

The ISO may require a Customer to provide references from one (1) bank and up to three (3) utilities. A Customer that does not have utility references, may substitute trade payable vendor references.

26.2.1.2 Prior Bankruptcy or Default

A Customer shall inform the ISO of any prior bankruptcy declarations or material defaults by the Customer or its predecessors, subsidiaries, or Affiliates occurring within the previous five (5) years.

26.2.1.3 Investigations

A Customer shall inform the ISO of the existence of any ongoing investigations of which the Customer is aware by the Securities and Exchange Commission, the Department of Justice, the Federal Energy Regulatory Commission, or the New York Public Service Commission which could have a material impact on the Customer's financial condition.

26.2.1.4 Material Change in Financial Status

A Customer shall inform the ISO of any material change in its financial status within five (5) business days, including but not limited to: (a) a downgrade of a long- or short-term debt rating by any ISO-approved rating agency; (b) placement on a negative credit watch by any ISO-approved rating agency; (c) a bankruptcy filing, insolvency, or a default under any financing agreement; (d) resignation or termination of a key officer; (e) initiation of a lawsuit that could materially and adversely impact current or future financial performance; or (f) restatement of prior financial statements.

26.2.1.5 Change in Peak Load

A Load Serving Entity shall inform the ISO as soon as practicable if it expects its peak Load to increase by fifteen percent (15%) or more above its peak Load during the Prior Equivalent Capability Period.

26.2.1.6 Financial Statements

Customer shall keep on file with the ISO its most recent annual financial statements (including, but not limited to, balance sheet and income statement), which shall be submitted to the ISO annually within ten (10) days of such statements becoming available and within ninety (90) days of the end of the fiscal year of such Customer. If such financial statements are not audited, Customer shall submit with the financial statements a certification from an officer of the Customer, in a form acceptable to the ISO, certifying the accuracy of the financial statements.

If a Customer does not routinely prepare financial statements, Customer shall submit equivalent financial information annually, as required in the paragraph above, with a certification from an officer of the Customer certifying the accuracy of the financial information submitted, in forms acceptable to the ISO.

The ISO may grant an extension for the provision of the required financial information under this Section 26.2.1.6 upon a showing of good cause.

26.2.2 Customers Requesting Unsecured Credit

In addition to the reporting requirements in Section 26.2.1., above, a Customer requesting Unsecured Credit, including a request for an Equivalency Rating, shall be required to comply with the reporting requirements of this Section 26.2.2.

26.2.2.1 Financial Statements

A Customer requesting Unsecured Credit shall provide to the ISO audited annual financial statements from the most recent three (3) years and its recent quarterly financial statement. Thereafter, the Customer shall provide audited annual financial statements to the ISO within ten (10) days of such statements becoming available and within ninety (90) days of the end of each fiscal year and shall provide quarterly financial statements to the ISO within sixty (60) days of the end of each quarter. The ISO may grant an extension for the provision of quarterly and annual financial statements upon a showing of good cause.

26.2.2.2 Publicly-Traded Customer

A publicly-traded Customer shall provide financial statements on Form 10-K and 10-Q, respectively. A publicly-traded Customer shall also provide Form 8-K reports within five (5) business days of their issuance. Information available on EDGAR shall be deemed provided by a Customer that directs the ISO to obtain it there.

26.2.2.3 Privately-Held Customer

A Customer that is not publicly-traded shall provide financial statements that include a balance sheet including a statement of stockholders' equity, an income statement, a statement of cash flow, notes to the financial statement, and an unqualified auditor's opinion.

26.2.2.4 Government Entities

Notwithstanding Section 26.2.2.1 of this Attachment K, government entities that do not normally prepare quarterly financial statements shall not be required to provide them to qualify for Unsecured Credit.

26.3 Investment Grade Customers

26.3.1 Senior Long-Term Unsecured Debt Rating

A Customer shall be deemed an Investment Grade Customer if its senior long-term unsecured debt rating is BBB- or higher by Standard & Poor's or Fitch, or Baa3 or higher by Moody's. If a Customer has been rated by two of these agencies, the ISO shall use the lower of the two ratings. If a Customer is rated by all three of these rating agencies, and one rating agency differs in its rating of a Customer from the other two, the ISO shall use the matching ratings. If a Customer is rated differently by all three of these rating agencies, the ISO shall use the middle rating. A Customer that has not been rated by any of the three above-named rating agencies may use a rating from Dominion. Notwithstanding the above, a Customer with a senior long-term unsecured debt rating from any of the approved rating agencies below BBB- (or Baa3) shall be deemed to be a Non-Investment Grade Customer.

26.3.2 Issuer Rating

If a Customer does not have a senior long-term unsecured debt rating from Standard & Poor's, Fitch, Moody's or Dominion, the Customer shall nevertheless be deemed an Investment Grade Customer if it has an issuer rating of BBB or higher from Standard & Poor's, Fitch, or Dominion, or Baa2 or higher from Moody's.

A Customer that has a senior long-term unsecured debt rating from Standard & Poor's, Fitch, Moody's or Dominion shall not be permitted to substitute an issuer rating. The rules established in Section 26.3.1 of this Attachment K regarding conflicting ratings and the use of a Dominion rating shall apply to issuer ratings. Notwithstanding the above, a Customer with an issuer rating from any of the approved rating agencies below BBB (or Baa2) shall be deemed to be a Non-Investment Grade Customer.

26.3.3 Equivalency Rating

A Customer that has not received a senior long-term unsecured debt rating or an issuer rating from Standard & Poor's, Moody's, Fitch, or Dominion may request that the ISO assign it an Equivalency Rating. The ISO shall determine an Equivalency Rating using Moody's KMV RiskCalc™. A Customer with an Equivalency Rating of BBB or higher shall be deemed to be an Investment Grade Customer. The ISO shall review a Customer's Equivalency Rating at least once each quarter. A Customer may not use an Equivalency Rating in the event that it is rated by an ISO-approved rating agency.

26.4 Operating Requirement and Bidding Requirement

26.4.1 Purpose and Function

The Operating Requirement is a measure of a Customer's expected financial obligations to the ISO based on the nature and extent of that Customer's participation in ISO-Administered Markets. A Customer shall be required to allocate Unsecured Credit, where allowed, and/or provide collateral in an amount equal to or greater than its Operating Requirement. Upon a Customer's written request, the ISO will provide a written explanation for any changes in the Customer's Operating Requirement.

The Bidding Requirement is a measure of a Customer's potential financial obligation to the ISO based upon the bids that Customer seeks to submit in an ISO-administered TCC or ICAP auction. A Customer shall be required to allocate Unsecured Credit, where allowed, and/or provide collateral in an amount equal to or greater than its Bidding Requirement prior to submitting bids in an ISO-administered TCC or ICAP auction.

26.4.2 Calculation of Operating Requirement

The Operating Requirement shall be equal to the sum of (i) the Energy and Ancillary Services Component; (ii) the External Transaction Component; (iii) the UCAP Component; (iv) the TCC Component; (v) the WTSC Component; (vi) the Virtual Transaction Component; (vii) the DADRP Component; (viii) the DSASP Component; (ix) the Projected True-Up Exposure Component; and (x) the Former RMR Generator Component, where:

26.4.2.1 Energy and Ancillary Services Component

The Energy and Ancillary Services Component shall be equal to:

(a) For Customers without a prepayment agreement, the greater of either:

$$\frac{Basis\ Amount\ for\ Energy\ and\ Ancillary\ Services}{Days\ in\ Basis\ Month} * 16$$

- or -

$$\frac{\substack{Total\ Charges\ Incurred\ for\ Energy\ and \\ Ancillary\ Services\ for\ Previous\ Ten\ (10) Days}}{10} * 16$$

(b) For Customers that qualify for a prepayment agreement, subject to the ISO's credit analysis and approval, and execute a prepayment agreement in the form provided in Appendix K-1, the greater of either:

$$\frac{Basis\ Amount\ for\ Energy\ and\ Ancillary\ Services}{Days\ in\ Basis\ Month} * 3$$

-or-

$$\frac{\substack{Total\ Charges\ Incurred\ for\ Energy\ and \\ Ancillary\ Services\ for\ Previous\ Ten\ (10) Days}}{10} * 3$$

(c) For new Customers, the ISO shall determine a substitute for the Basis Amount for Energy and Ancillary Services for use in the appropriate formula above equal to:

$$EPL * 720 * AEP$$

where:

EPL = estimated peak Load for the Capability Period; and

AEP = average Energy and Ancillary Services price during the Prior Equivalent Capability Period after applying the Price Adjustment.

26.4.2.2 External Transaction Component

The External Transaction Component shall equal the sum of the Customer's (i) Import Credit Requirement, (ii) Export Credit Requirement, (iii) Wheels Through Credit Requirement, and (iv) the net amount owed to the ISO for the settled External Transaction Component Transactions.

26.4.2.2.1 Import Credit Requirement

For a given month, the Import Credit Requirement shall apply to any Customer that Bids to Import in the Day-Ahead Market ("DAM") unless (i) the Customer has at least 50 scheduled Day-Ahead Import Bids in the three-month period ending on the 15th day of the preceding month (or the six-month period ending on the 15th day of the preceding month if the Customer has fewer than 50 scheduled Day-Ahead Import Bids in the immediately preceding three-month period), and (ii) fewer than 25% of the MWhs of such scheduled Day-Ahead Import Bids were settled at a loss to the Customer.

The Import Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Import Bid until posting of the applicable DAM schedule/price.

The ISO will calculate the required credit support for pending DAM Import Bids for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for DAM Import Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The ISO will categorize each Import Bid into one of the 18 Import Price Differential (IPD) groups set forth in the IPD chart in Section 26.4.2.2.5 below, as appropriate, based upon the season and time-of-day of the Import Bid. The amount of credit support required in $/MWh that applies to an Import Bid shall equal the 97th percentile level of the following: the hourly average Energy price calculated in the Real-Time Market at the location associated with the Import Bid, minus the Energy price calculated in the DAM at the same location and time, with the dataset used to perform this calculation consisting of all hours that are in the same IPD group as the hour to which the Import Bid applies, and that occurred no earlier than April 1, 2005 nor later than the end of the calendar month preceding the month to which the Import Bid applies. The amount of credit support required in $/MWh shall not be less than $0/MWh.

The credit requirement for each Import Bid shall be calculated as follows:

$$Bid_{MWhB} * Max\ (IPD_{CS}, 0)$$

Where:

Bid_{MWhB}	=	the total quantity of MWhs that a Customer Bids to Import in a particular hour and at a particular location.
IPD_{CS}	=	the amount of credit support required, in $/MWh, for an Import Bid as described above, for the location associated with the Import Bid and for the IPD group that contains the hour to which the Import Bid applies.

(2) Upon posting of the applicable DAM schedule/price until completion of the hour Bid in real-time for a DAM Import Bid.

The credit requirement for each Import Bid shall be calculated as follows:

$$SchBid_{MWhI} * Max(IPD_{CS}, 0)$$

Where:

$SchBid_{MWhI}$	=	the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Import Bid.
IPD_{CS}	=	the amount of credit support required, in $/MWh, for an Import Bid as described above, for the location associated with the Import Bid and for the IPD group that contains the hour to which the Import Bid applies.

(3) Upon completion of the hour Bid in real-time for a DAM Import Bid until the net amount owed to the ISO is determined for settled External Transactions.

The credit requirement for each Import Bid shall be calculated as follows:

$$Max\big((BalPay_{\$} - DAMPay_{\$}), 0\big)$$

Where:

$BalPay_{\$}$	=	$(SchBid_{MWhI} – Actual_{MWhI})$ * RT $LBMP_I$
$DAMPay_{\$}$	=	$SchBid_{MWhI}$ * DAM $LBMP_I$
$SchBid_{MWhI}$	=	the total quantity of MWhs that is scheduled in the DAM in a particular hour at a particular location as a result of the Customer's Import Bid.
$Actual_{MWhI}$	=	the total quantity of MWhs that is scheduled in real-time associated with the Customer's Import Bid in a particular hour and at a particular location for the hour completed.
DAM $LBMP_I$	=	the Day-Ahead LBMP in a particular hour and at a particular location associated with the Customer's Import Bid.
RT $LBMP_I$	=	the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Import Bid.

26.4.2.2.2 Export Credit Requirement

The Export Credit Requirement shall apply to any Customer that Bids to Export from the DAM or Hour-Ahead Market ("HAM").

The Export Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Export Bid until posting of the applicable DAM schedule/price.

The ISO will calculate the required credit support for pending DAM Export Bids for a market day three days prior to the DAM market close for that market day. The ISO will calculate the required credit support for DAM Export Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The ISO will categorize each Export Bid into one of the 18 Export Price Differential (EPD) groups set forth in the EPD chart in Section 26.4.2.2.5 below, as appropriate, based upon the season and time-of-day of the Export Bid. The amount of credit support required in $/MWh that applies to an Export Bid shall equal the 97th percentile level of the following: the Energy price calculated in the DAM at the location associated with the Export Bid, minus the hourly average Energy price calculated in the Real-Time Market at the same location and time, with the dataset used to perform this calculation consisting of all hours that are in the same EPD group as the hour to which the Export Bid applies, and that occurred no earlier than April 1, 2005 nor later than the end of the calendar month preceding the month to which the Export Bid applies. The amount of credit support required in $/MWh shall not be less than $0/MWh.

The credit requirement for all DAM Export Bids with the same hour/date and location shall be calculated as follows:

$$\left(Max\left(\left(Max_N(Bid_{MWh} * Bid_{\$E})\right), \left(BidMax_{MWhB} * EPD_{CS}\right)\right)\right)$$

Where:

Bid_{MWh}	=	the total quantity of MWhs that a Customer Bids to Export in the DAM in a particular hour and at a particular location at or below each Bid Price.
$Bid_{\$E}$	=	the Bid Price in $/MWh at which the Customer Bids to purchase the Bid_{MWh} of Exports in a particular hour and at a particular location.
N	=	the set of hourly Export Bid Prices in a particular hour and at a particular location.
$BidMax_{MWhB}$	=	the total quantity of MWhs that a Customer Bids to Export in the DAM in a particular hour and at a particular location.
EPD_{CS}	=	the amount of credit support required, in $/MWh, for an Export Bid as described above, for the location associated with the Export Bid and for the EPD group that contains the hour to which the Export Bid applies.

(2) Upon posting of the applicable DAM schedule/price until completion of hour Bid in real-time for a DAM Export Bid.

The credit requirement for each Export Bid shall be calculated as follows:

$$\left(SchBid_{MWhE} * \left(Max(EPD_{CS}, DAM\ LBMP_{E})\right)\right)$$

Where:

$SchBid_{MWhE}$	=	the total quantity of MWhs that is scheduled in the DAM in a particular hour at a particular location as a result of the Customer's Export Bid.
EPD_{CS}	=	the amount of credit support required, in $/MWh, for an Export Bid as described above, for the location associated with the Export Bid and for the EPD group that contains the hour to which the Export Bid applies.
DAM $LBMP_{E}$	=	the Day-Ahead LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

(3) From submission of a HAM Export Bid until completion of the hour Bid in real-time.

i. Non-CTS Interface Bids to Export .

The ISO will calculate the required credit support for pending HAM non-CTS Interface Bids to Export for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for HAM non-CTS Interface Bids to Export that are submitted after the commencement of the initial credit evaluation upon Bid submission. The amount of credit support required in $/MWh that applies to HAM non-CTS Interface Bids Export in the same hour/date and at the same location shall equal the maximum amount of the payment potentially due to the ISO based on the MWhs of Exports Bid for purchase at each bid price in a particular hour and at a particular location.

The credit requirement for all HAM non-CTS Interface Bids to Export with the same hour/date and location shall be calculated as follows:

$$\left(Max_{N}\left(\left(Max(Bid_{MWhE}, 0)\right) * Bid_{\$E}\right)\right)$$

Where:

Bid_{MWhE}	=	the total quantity of MWhs that a Customer Bids to Export in the HAM in a particular hour and at a particular location at or below each bid price minus the MWhs of Exports scheduled in the DAM in the same hour at the same location.
$Bid_{\$E}$	=	the bid price in \$/MWh at which the Customer Bids to purchase the Bid_{MWhE} of Exports in a particular hour and at a particular location.
N	=	the set of hourly Export bid prices in a particular hour and at a particular location.

ii. CTS Interface Bids to Export.

For CTS Interface Bids to Export credit support will be calculated at HAM close.The amount of credit support required in $/MWh that applies to such bid shall equal the sum of the time-weighted hourly RTC price for each of the 15-minute intervals within the bid hour, not to be less than zero.

The credit requirement for each CTS Interface Bid to Export shall be calculated as follows:

$$Max\left(\sum\nolimits_{N}\left(RTC_{\$/MWhcts} * Bid_{MWhscts} * Hourly\ Weight\right), 0\right)$$

Where:

N	=	each 15-minute interval within the bid hour.
$RTC_{\$/MWhcts}$	=	most recently available RTC price for N in \$/MWh at the location associated with the CTS Interface Bid to Export
$Bid_{MWhscts}$	=	the total quantity of MWhs in a Customer's CTS Interface Bid to Export for N in a particular hour and at a particular location minus the MWhs of Exports scheduled in the DAM in same hour at the same location.
Hourly Weight	=	0.25

(4) Upon completion of the hour Bid in real-time for an Export Bid until the net amount owed to the ISO is determined for settled External Transactions.

The amount of credit support required will equal the sum of the Day-Ahead Credit Calculation and Real-Time Credit Calculation for each completed hour.

The credit requirement for each Export Bid shall be calculated as follows:

Day-Ahead Credit Calculation + Real-Time Credit Calculation

The Day-Ahead Credit Calculation only applies to DAM Export Bids and the Real-Time Credit Calculation applies to all HAM Export Bids including HAM Bids associated with a DAM Bid.

Where:

Day-Ahead Credit Calculation = Max (Adjusted Export Day-Ahead Credit Calculation, 0)

Adjusted Export Day-Ahead Credit Calculation = the credit requirement calculated in accordance with section 26.4.2.2.2(2) minus the Balancing Payment.

$$Balancing\ Payment = Max\big((SchBid_{MWhE} - Actual_{MWhE}), 0\big) * RT\ LBMP_E$$

$SchBid_{MWhE}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Export Bid.

$Actual_{MWhE}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Export Bid in a particular hour and at a particular location for the hour completed.

$RT\ LBMP_E$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

$$Real\text{-}Time\ Credit\ Calculation = Max\Big(\big(Max\big((Actual_{MWhE} - SchBid_{MWhE}), 0\big) * RT\ LBMP_E\big), 0\Big)$$

$Actual_{MWhE}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Export Bid in a particular hour and at a particular location for the hour completed.

$SchBid_{MWhE}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Export Bid.

$RT\ LBMP_E$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

26.4.2.2.3 Wheels Through Credit Requirement

The Wheels Through Credit Requirement shall apply to any Customer that Bids to Wheel Through in the DAM or HAM.

The Wheels Through Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Wheels Through Bid until posting of the applicable DAM schedule/price.

The ISO will calculate the required credit support for pending DAM Wheels Through Bids for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for DAM Wheels Through Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The amount of credit support required in \$/MWh that applies to the DAM Wheels Through Bid shall equal the maximum payment potentially due to the ISO based on the Customer's Bid Prices on the Bid curve. The credit requirement for each Wheels Through Bid shall be calculated as follows:

$$Max\left(Max_N\left(BidPt_{MWhN} * Bid\$_{\$/MWhN}\right), 0\right)$$

Where:

N = each Bid Price on the Bid curve.

$BidPt_{MWhN}$ = the MWhs associated with the Bid Price on the Bid curve.

$Bid\$_{\$/MWhN}$ = the amount that the customer is willing to pay for congestion in \$/MWh on the Bid curve associated with the Customer's Wheels Through Bid.

(2) Upon posting of the applicable Wheels Through DAM schedule/price until completion of the hour Bid in real-time.

The credit requirement for each DAM Wheels Through Bid shall be calculated as follows:

$$Max(SchBid_{MWhW} * (DAM\ LBMP_{POW} - DAM\ LBMP_{POI}), 0)$$

Where:

$SchBid_{MWhW}$ = the total quantity of MWhs scheduled in the DAM as a result of the Customer's Bid to schedule Wheels Through.

$DAM\ LBMP_{POI}$ = the Day-Ahead LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

$DAM\ LBMP_{POW}$ = the Day-Ahead LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

(3) Upon creation of a HAM Wheels Through Bid until the completion of the hour Bid in real-time.

The ISO will calculate the required credit support for pending HAM Wheels Through Bids for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for HAM Wheels Through Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The amount of credit support required in \$/MWh that applies to HAM Wheels Through Bid shall equal the price of the maximum value of exposure based on bid prices on the Bid curve.

The credit requirement for each Wheels Through Bid shall be calculated as follows:

$$Max\left(Max_N\left(Max(BidPt_{MWhW}, 0) * Bid\$_{\$/MWhN}\right), 0\right)$$

Where:

N = each bid price on the Bid curve.

$BidPt_{MWhW}$ = the MWhs associated with the bid price on the Bid curve minus the MWhs of the DAM Bid with same hour/date, location and Bid transaction ID.

$Bid\$_{\$/MWhN}$ = the amount that the customer is willing to pay for congestion in \$/MWh on the Bid curve associated with the Customer's Wheels Through Bid.

(4) Upon completion of the hour Bid in real-time for a Wheels Through Bid until the net amount owed to the ISO is determined for settled External Transactions.

The amount of credit support required will equal the sum of the Day-Ahead Credit Calculation and Real-Time Credit Calculation for each completed hour. The credit requirement for each Wheels Through Bid shall be calculated as follows:

Day-Ahead Credit Calculation + Real-Time Credit Calculation

The Day-Ahead Credit Calculation only applies to DAM Wheels Through Bids and the Real-Time Credit Calculation applies to all HAM Wheels Through Bids including HAM Bids associated with a DAM Bid.

Where:

Day-Ahead Credit Calculation = Max (Adjusted Wheels Through Day-Ahead Credit Calculation, 0)

Adjusted Wheels Through Day-Ahead Credit Calculation = the credit requirement calculated in section 26.4.2.2.3(2) minus the Balancing Payment.

$$Balancing\ Payment = Max\big((SchBid_{MWhW} - Actual_{MWhW}), 0\big) * (RT\ LBMP_{POW} - RT\ LBMP_{POI})$$

$SchBid_{MWhW}$ = the total quantity of MWhs that is scheduled in the DAM as a result of the Customer's Wheels Through Bid.

$Actual_{MWhW}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Wheels Through Bid for the hour completed.

$RT\ LBMP_{POI}$ = the Real-Time LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

$RT\ LBMP_{POW}$ = the Real-Time LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

$$Real\text{-}Time\ Credit\ Calculation = Max\Big(Max\big((Actual_{MWhW} - SchBid_{MWhW}), 0\big) * (RT\ LBMP_{POW} - RT\ LBMP_{POI}), 0\Big)$$

$SchBid_{MWhW}$ = the total quantity of MWhs that is scheduled in the DAM as a result of the Customer's Bid to Wheel Through Energy.

$Actual_{MWhW}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Wheels Through Bid for the hour completed.

$RT\ LBMP_{POI}$ = the Real-Time LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

$RT\ LBMP_{POW}$ = the Real-Time LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

26.4.2.2. 4 Calculation of Price Differentials

Import Price Differential (IPD) Groups

Summer	**For each Proxy Generator Bus**
HB07–10	IPD-1
HB11–14	IPD-2
HB15–18	IPD-3
HB19–22	IPD-4
Weekend/ Holiday (HB07–22)	IPD-5
Night (HB23–06)	IPD-6
Winter	
HB07–10	IPD-7
HB11–14	IPD-8
HB15–18	IPD-9
HB19–22	IPD-10
Weekend/ Holiday (HB07–22)	IPD-11
Night (HB23–06)	IPD-12
Rest-of-Year	
HB07–10	IPD-13
HB11–14	IPD-14
HB15–18	IPD-15
HB19–22	IPD-16
Weekend/ Holiday (HB07–22)	IPD-17
Night (HB23–06)	IPD-18

Where:

Summer = May, June, July, and August

Winter = December, January, and February

Rest-of-Year = March, April, September, October, and November

HB07–10 = weekday hours beginning 07:00–10:00

HB11–14 = weekday hours beginning 11:00–14:00

HB15–18 = weekday hours beginning 15:00–18:00

HB19–22 = weekday hours beginning 19:00– 22:00

Weekend/Holiday	=	weekend and holiday hours beginning 07:00–22:00
Night	=	all hours beginning 23:00– 06:00

Export Price Differential (EPD) Groups

Summer	**For each Proxy Generator Bus**
HB07–10	EPD-1
HB11–14	EPD-2
HB15–18	EPD-3
HB19–22	EPD-4
Weekend/ Holiday (HB07–22)	EPD-5
Night (HB23–06)	EPD-6
Winter	
HB07–10	EPD-7
HB11–14	EPD-8
HB15–18	EPD-9
HB19–22	EPD-10
Weekend/ Holiday (HB07–22)	EPD-11
Night (HB23–06)	EPD-12
Rest-of-Year	
HB07–10	EPD-13
HB11–14	EPD-14
HB15–18	EPD-15
HB19–22	EPD-16
Weekend/ Holiday (HB07–22)	EPD-17
Night (HB23–06)	EPD-18

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
HB07–10	=	weekday hours beginning 07:00–10:00
HB11–14	=	weekday hours beginning 11:00–14:00
HB15–18	=	weekday hours beginning 15:00–18:00
HB19–22	=	weekday hours beginning 19:00– 22:00
Weekend/Holiday	=	weekend and holiday hours beginning 07:00–22:00
Night	=	all hours beginning 23:00– 06:00

26.4.2.3 UCAP Component

The UCAP Component shall be equal to the total of all amounts then-owed (billed and unbilled) for UCAP purchased in the ISO-administered markets.

26.4.2.4 TCC Component

The TCC Component shall be equal to the greater of either (a) the amount calculated in accordance with Section 26.4.2.4.1 (Auction TCC Holding Requirement) or Section 26.4.2.4.2 (Fixed Price TCC Holding Requirement), as appropriate, or (b) Section 26.4.2.4.3 (Mark-to-Market Calculation) below; *provided however*, that upon initial award of a TCC until the ISO receives payment for the TCC (or payment for the first year of a two-year TCC), the ISO will hold the greater of the payment obligation for the TCC or the credit requirement for the TCC calculated in accordance with this Section 26.4.2.4.

26.4.2.4.1 Auction TCC Holding Requirement

This Section 26.4.2.4.1 applies to TCCs awarded in the Centralized TCC Auction and Balance-of-Period Auction.

The credit requirement pursuant to this Section 26.4.2.4.1 shall equal the sum of the amounts calculated in accordance with the appropriate per TCC term-based formulas listed below. The ISO will not impose a credit requirement on TCCs that have been sold by a Market Participant in the Centralized TCC Auction or Balance-of-Period Auction.

26.4.2.4.1.1 Two-Year TCCs:

(1) upon initial award of a two-year TCC until completion of the final round of the current two-year Sub-Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC.

Second Year:

$$+1.909\sqrt{e^{10.9729 + .6514\left(ln\left(\left|P_{ijt}\right| + e\right)\right) + .6633 * Zone\ J + 1.1607 * Zone\ K}}$$

where:

P_{ijt} = market clearing price of that two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

(2) upon completion of the final round of the current two-year Sub-Auction until completion of the final round of the current one-year Sub-Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

Second Year:

$$+1.909\sqrt{e^{10.9729\,+\,.6514\left(ln\left(\left|P_{ijt}\right|\,+\,e\right)\right)\,+\,.6633\,*\,Zone\ J\,+\,1.1607\,*\,Zone\ K}}$$

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the current two-year Sub-Auction with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

(3) upon completion of the final round of the current one-year Sub-Auction until completion of the Balance-of-Period Auction for the first month of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the two-year TCC

Second Year:

$$+1.909\sqrt{e^{10.9729\,+\,.6514\left(ln\left(\left|P_{ijt}\right|\,+\,e\right)\right)\,+\,.6633\,*\,Zone\ J\,+\,1.1607\,*\,Zone\ K}}$$

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the current two-year Sub-Auction with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the two-year TCC

(4) upon completion of the Balance-of-Period Auction for the first month of the two-year TCC until completion of the final round of the six-month Sub-Auction in the next Centralized TCC Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formulas set forth in Section 26.4.2.4.1.6 below

Second Year:

$$+1.909\sqrt{e^{10.9729\,+\,.6514\left(ln\left(|P_{ijt}|\,+\,e\right)\right)\,+\,.6633\,*\,Zone\ J\,+\,1.1607\,*\,Zone\ K}}$$

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the two-year Sub-Auction in which the TCC was purchased with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction that directly followed the two-year Sub-Auction in which the TCC was purchased with the same POI and POW combination as the two-year TCC

(5) upon completion of the final round of the six-month Sub-Auction for the final six months of the first year of the two-year TCC until completion of the Balance-of-Period Auction immediately preceding the final six months of the first year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the six-month Sub-Auction with the same POI and POW combination as the one-year TCC

Second Year:

$$+1.909\sqrt{e^{10.9729 + .6514\left(ln\left(|P_{ijt}| + e\right)\right) + .6633 * Zone\ J + 1.1607 * Zone\ K}}$$

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the two-year Sub-Auction in which the TCC was purchased with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction that directly followed the two-year Sub-Auction in which the TCC was purchased with the same POI and POW combination as the two-year TCC

(6) upon completion of the Balance-of-Period Auction immediately preceding the final six months of the first year of the two-year TCC until ISO receipt of payment for the second year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period TCC Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

$$+1.909\sqrt{e^{10.9729 + .6514\left(ln\left(|P_{ijt}| + e\right)\right) + .6633 * Zone\ J + 1.1607 * Zone\ K}}$$

where:

Pijt = market clearing price of a two-year TCC in the final round of the two-year Sub-Auction in which the TCC was purchased with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction that directly followed the two-year Sub-Auction in which the TCC was purchased with the same POI and POW combination as the two-year TCC

(7) upon ISO receipt of payment for the second year of the two-year TCC until completion of the final round of the one-year Sub-Auction in the next Centralized TCC Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior equivalent Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

(8) upon completion of the final round of the one-year Sub-Auction for the second year of the two-year TCC until completion of the Balance-of-Period Auction for the first month of the second year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows::

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the most recently completed one-year Sub-Auction with the same POI and POW combination as the two-year TCC

(9) upon completion of the Balance-of-Period Auction for the first month of the second year of the two-year TCC until completion of the final round of the six-month Sub-Auction in the next Centralized TCC Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

(10) upon completion of the final round of the six-month Sub-Auction for the final six months of the two-year TCC until completion of the Balance-of-Period Auction immediately preceding the final six months of the two-year TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the most recently completed six-month Sub-Auction with the same POI and POW combination as the two-year TCC

(11) upon completion of the Balance-of-Period Auction for the first month of the final six months of a two-year TCC:

the amount calculated in accordance with the Balance-of-Period TCC formulas set forth in Section 26.4.2.4.1.5 below

26.4.2.4.1.2 One-Year TCCs:

(1) upon initial award of a one-year TCC until completion of the final round of the current one-year Sub-Auction:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

(2) upon completion of the final round of the current one-year Sub-Auction until completion of the Balance-of-Period Auction for the first month of the one-year TCC:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the one-year TCC

(3) upon completion of the Balance-of-Period Auction for the first month of the one-year TCC until completion of the final round of the six month Sub-Auction in the next Centralized TCC Auction:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

(4) upon completion of the final round of the six-month Sub-Auction for the final six months of a one-year TCC until completion of the Balance-of-Period Auction immediately preceding the final six months of a one-year TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the most recently completed six-month Sub-Auction with the same POI and POW combination as the one-year TCC

(5) upon completion of the Balance-of-Period Auction for the first month of the final six months of a one-year TCC:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirementformula set forth in Section 26.4.2.4.1.6 below

26.4.2.4.1.3 Six-Month TCCs:

(1) upon initial award of a six-month TCC until completion of the final round of the current six-month Sub-Auction:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

(2) upon completion of the final round of the current six-month Sub-Auction until completion of the Balance-of-Period Auction for the first month of a six-month TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the current six-month Sub-Auction with the same POI and POW combination as the one-year TCC

(3) upon completion of the Balance-of-Period Auction for the first month of a six-month TCC:

the amount calculated in accordance with the Balance-of-Period Auction formula set forth in Section 26.4.2.4.1.6.1 below

26.4.2.4.1.4 One-Month TCCs:

upon initial award of a one-month TCC:

the amount calculated in accordance with the Balance-of-Period TCC Auction holding requirementformula set forth in Section 26.4.2.4.1.6.1 below

26.4.2.4.1.5 Centralized TCC Auction – Holding Requirement Formulas:

for one-year TCCs, representing a 5% probability curve:

$$+1.909\sqrt{e^{10.9729+.6514\left(ln\left(|P_{ijt}|+e\right)\right)+.6633*Zone\,J+1.1607*Zone\,K}-1}\;P_{ijt}$$

for six-month TCCs, representing a 3% probability curve:

$$+2.565\sqrt{e^{11.6866+.4749\left(ln\left(|P_{ijt}|+e\right)\right)+.4856*Zone\,J+.8498*Zone\,K-.0373\,Summer}-1}\;P_{ijt}$$

where:

P_{ijt}	=	market clearing price of i to j TCC in round t of the auction in which the TCC was purchased;
Zone J	=	1 if TCC sources or sinks but not both in Zone J, zero otherwise;
Zone K	=	1 if TCC sources or sinks but not both in Zone K and does not source or sink in Zone J, 0 otherwise;
Summer	=	1 for six-month TCCs sold in the spring auction, 0 otherwise; and

Further, when calculating "Pijt" in Section 26.4.2.4.1, in the event there is no market clearing price for a two-year, one-year, or six-month TCC in the appropriate prior Capability Period Centralized TCC Auction with the same POI and POW combination as the awarded two-year, one-year, or six-month TCC, as appropriate, then the market clearing price shall equal a proxy price, assigned by the ISO, for a TCC with like characteristics.

Further, the NYISO may adjust any of the Zone K multipliers in Section 26.4.2.4.1 if, for TCCs of the same duration, the percentage ratio between collateral and congestion rents for Zone K TCCs deviates from the percentage ratio for Zone J TCCs by more than ten percent (10.0%).

26.4.2.4.1.6 Balance-of-Period Auction – Holding Requirement Formulas:

During the Balance-of-Period Auction, a TCC awarded in the Centralized TCC Auction (or the remaining segments of a TCC awarded in a prior Centralized TCC Auction) is segmented, as appropriate, into (i) a monthly segment, corresponding to the months within the current Capability Period, (ii) a future six-month segment, corresponding to the next Capability Period, and (iii) a one-year segment, corresponding to the next Capability Year, such that the sum of segments (i), (ii), and (iii) covers the entire remaining duration of the TCC. The credit holding requirement for the monthly segments and the future six-month segment are calculated in accordance with the formulas below.

26.4.2.4.1.6.1 Monthly Segment

Monthly Segment ($) = [(Monthly Margin ($) ×Monthly Index Ratio×Monthly Factor) −TCC Price ($)]×MWs

where:

Monthly Margin is calculated based on a methodology approved by Market Participants and posted to the ISO's website

Monthly Index Ratio as determined from time to time by the ISO based on historical data and a methodology approved by Market Participants and posted to the ISO's website

Monthly Factor as determined from time to time by the ISO based on historical data and a methodology approved by Market Participants and posted to the ISO's website

TCC Price is the market clearing price for the respective Capability Period month in the most recent Balance-of-Period Auction

MWs is the number of awarded TCC MWs

26.4.2.4.1.6.2 Future Six-Month Segment

Future Six-Month Segment ($) = (Six-Month Margin ($)−TCC Price ($))×MWs

where:

Six-Month Margin is calculated based on a methodology approved by Market Participants and posted on the ISO's website

TCC Price is the market clearing price, using the same POI/POW combination, resulting from the

(1) Market clearing price from the final round of the most recent one-year TCC Sub-Auction, less the

(2) Market clearing price from the second round of the most recent six-month TCC Sub-Auction

MWs is the number of awarded TCC MWs

26.4.2.4.2 Fixed Price TCC Holding Requirement:

Upon award of a Fixed Price TCC, and for the duration of the Fixed Price TCC, the credit holding requirement will equal the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.1.5; provided, however, the market clearing price (P_{ijt}) shall be replaced by the fixed price associated with that Fixed Price TCC, as determined in accordance with, as appropriate, OATT Section 19.2.1 or OATT Section 19.2.2.

26.4.2.4.3 Mark-to-Market Calculation

The projected amount of the Primary Holder's payment obligation to the NYISO, if any, considering the net mark-to-market value of all TCCs in the Primary Holder's portfolio, as defined for these purposes, according to the formula below:

$$\sum_{n \epsilon N} \left\{ \frac{NAP_n}{90} * RD_n \right\} + \sum_{n \epsilon N} ACR_n$$

where:

NAP = the net amount of Congestion Rents between the POI and POW composing each TCC_n during the previous ninety days

RD = the remaining number of days in the life of TCC_n; *provided, however*, that in the case of Grandfathered TCCs, RD shall equal the remaining number of days in the life of the longest duration TCC sold in an ISO-administered auction then outstanding;

N = the set of TCCs held by the Primary Holder; and

ACR = the net amount owed to the ISO for Congestion Rents between the POI and POW composing each TCC_n.

26.4.2.5 WTSC Component

The WTSC Component shall be equal to the greater of either:

$$\frac{\begin{array}{c}Greatest\ Amount\ Owed\ for\ WTSC\ During\ Any\\ Single\ Month\ in\ the\ Prior\ Equivalent\ Capability\ Period\end{array}}{Days\ in\ Month} * 50$$

- or –

$$\frac{\begin{array}{c}Total\ Charges\ Incurred\ for\ WTSC\ Based\ Upon\ the\ Most\\ Recent\ Monthly\ Data\ Provided\ by\ the\ Transmission\ Owner\end{array}}{Days\ in\ Month} * 50$$

26.4.2.6 Virtual Transaction Component

The Virtual Transaction Component shall be equal to the sum of the Customer's (i) Virtual Supply credit requirement ("VSCR") for all outstanding Virtual Supply Bids, plus (ii) Virtual Load credit requirement ("VLCR") for all outstanding Virtual Load Bids, plus (iii) net amount owed to the ISO for settled Virtual Transactions.

Where:

VSCR = $\sum(VSG_{MWh} * VSG_{CS})$

VLCR = $\sum(VLG_{MWh} * VLG_{CS})$

Where:

VSG_{MWh} = the total quantity of MWhs of Virtual Supply that a Customer Bids for all Virtual Supply positions in the Virtual Supply group

VSG_{CS} = the amount of credit support required in $/MWh for the Virtual Supply group

VLG_{MWh} = the total quantity of MWhs of Virtual Load that a Customer Bids for all Virtual Load positions in the Virtual Load group

VLG_{CS} = the amount of credit support required in $/MWh for the Virtual Load group

The ISO will categorize each Virtual Supply Bid into one of the 72 Virtual Supply groups set forth in the Virtual Supply chart below, as appropriate, based upon the season, Load Zone, and time-of-day of the Virtual Supply Bid. The amount of credit support required in $/MWh for a Virtual Transaction in a particular Virtual Supply group shall equal the price differential between the Energy price in the Day-Ahead Market and the Energy price in the Real-Time Market, at the 97th percentile, based upon all possible Virtual Supply positions in the Virtual Supply group for the period of time from April 1, 2005, through the end of the preceding calendar month.

The ISO will categorize each Virtual Load Bid into one of the 30 Virtual Load groups set forth in the Virtual Load chart below, as appropriate, based upon the season, Load Zone, and time-of-day of the Virtual Load Bid. The amount of credit support required in $/MWh for a Virtual Transaction in a particular Virtual Load group shall equal the price differential between the Energy price in the Day-Ahead Market and the Energy price in the Real-Time Market, at the 97th percentile, based upon all possible Virtual Load positions in the Virtual Load group for the period of time from April 1, 2005, through the end of the preceding calendar month.

If a Customer submits Bids for both Virtual Load and Virtual Supply for the same day, hour, and Load Zone, then for those Bids, until such time as those Bids have been evaluated by SCUC, only the greater of the Customer's (i) VLCR for the total MWhs Bid for Virtual Load, or (ii) VSCR for the total MWhs Bid for Virtual Supply will be included when calculating the Customer's Virtual Transaction Component. After evaluation of those Bids by SCUC, then only the credit requirement for the net position of the accepted Bids (in MWhs of Virtual Load or

Virtual Supply) will be included when calculating the Customer's Virtual Transaction Component.

Virtual Supply Groups

Summer	**Load Zones A–F**	**Load Zones G–I**	**Load Zone J**	**Load Zone K**
HB07–10	VSG-1	VSG-7	VSG-13	VSG-19
HB11–14	VSG-2	VSG-8	VSG-14	VSG-20
HB15–18	VSG-3	VSG-9	VSG-15	VSG-21
HB19–22	VSG-4	VSG-10	VSG-16	VSG-22
Weekend/ Holiday (HB07–22)	VSG-5	VSG-11	VSG-17	VSG-23
Night (HB23–06)	VSG-6	VSG-12	VSG-18	VSG-24
Winter				
HB07–10	VSG-25	VSG-31	VSG-37	VSG-43
HB11–14	VSG-26	VSG-32	VSG-38	VSG-44
HB15–18	VSG-27	VSG-33	VSG-39	VSG-45
HB19–22	VSG-28	VSG-34	VSG-40	VSG-46
Weekend/ Holiday (HB07–22)	VSG-29	VSG-35	VSG-41	VSG-47
Night (HB23–06)	VSG-30	VSG-36	VSG-42	VSG-48
Rest-of-Year				
HB07–10	VSG-49	VSG-55	VSG-61	VSG-67
HB11–14	VSG-50	VSG-56	VSG-62	VSG-68
HB15–18	VSG-51	VSG-57	VSG-63	VSG-69
HB19–22	VSG-52	VSG-58	VSG-64	VSG-70
Weekend/ Holiday (HB07–22)	VSG-53	VSG-59	VSG-65	VSG-71
Night (HB23–06)	VSG-54	VSG-60	VSG-66	VSG-72

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
HB07–10	=	weekday hours beginning 07:00–10:00
HB11–14	=	weekday hours beginning 11:00–14:00
HB15–18	=	weekday hours beginning 15:00–18:00
HB19–22	=	weekday hours beginning 19:00– 22:00
Weekend/Holiday	=	weekend and holiday hours beginning 07:00–22:00

Night = all hours beginning 23:00– 06:00

Virtual Load Groups

Summer	**Load Zones A–F**	**Load Zones G–I**	**Load Zone J**	**Load Zone K**
HB07–10	VLG-1	VLG-4	VLG-8	VLG-12
HB11–14	VLG-2	VLG-5	VLG-9	VLG-13
HB15–18	VLG-2	VLG-6	VLG-10	VLG-14
HB19–22	VLG-1	VLG-4	VLG-8	VLG-15
Weekend/ Holiday (HB07–22)	VLG-3	VLG-4	VLG-8	VLG-16
Night (HB23–06)	VLG-1	VLG-7	VLG-11	VLG-12
Winter				
HB07–10	VLG-17	VLG-19	VLG-21	VLG-23
HB11–14	VLG-17	VLG-20	VLG-21	VLG-23
HB15–18	VLG-18	VLG-19	VLG-22	VLG-24
HB19–22	VLG-17	VLG-20	VLG-21	VLG-24
Weekend/ Holiday (HB07–22)	VLG-17	VLG-20	VLG-21	VLG-23
Night (HB23–06)	VLG-17	VLG-20	VLG-21	VLG-23
Rest-of-Year				
HB07–10	VLG-25	VLG-26	VLG-27	VLG-29
HB11–14	VLG-25	VLG-26	VLG-28	VLG-29
HB15–18	VLG-25	VLG-26	VLG-28	VLG-30
HB19–22	VLG-25	VLG-26	VLG-27	VLG-30
Weekend/ Holiday (HB07–22)	VLG-25	VLG-26	VLG-27	VLG-30
Night (HB23–06)	VLG-25	VLG-26	VLG-27	VLG-29

Where:

Summer = May, June, July, and August

Winter = December, January, and February

Rest-of-Year = March, April, September, October, and November

HB07–10 = weekday hours beginning 07:00–10:00

HB11–14 = weekday hours beginning 11:00–14:00

HB15–18 = weekday hours beginning 15:00–18:00

HB19–22 = weekday hours beginning 19:00– 22:00

Weekend/Holiday = weekend and holiday hours beginning 07:00–22:00

Night = all hours beginning 23:00– 06:00

26.4.2.7 DADRP Component

The DADRP Component shall be equal to the product of: (i) the Demand Reduction Provider's monthly average of MWh of accepted Demand Reduction Bids during the prior summer Capability Period or, where the Demand Reduction Provider does not have a history of accepted Demand Reduction bids, a projected monthly average of the Demand Reduction Provider's accepted Demand Reduction bids; (ii) the average Day-Ahead LBMP at the NYISO Reference Bus during the prior summer Capability Period; (iii) twenty percent (20%); and (iv) a factor of four (4). The ISO shall adjust the amount of Unsecured Credit and/or collateral that a Demand Reduction Provider is required to provide whenever the DADRP Component increases or decreases by ten percent (10%) or more.

26.4.2.8 DSASP Component

The DSASP Component is calculated every two months based on the Demand Side Resource's Operating Capacity available for the scheduling of such services, the delta between the Day-Ahead and hourly market clearing prices for such products in the like two-month period of the previous year, and the location of the Demand Side Resource. Resources located East of Central-East shall pay the Eastern reserves credit support requirement and Resources located West of Central-East shall pay the Western reserves credit support requirement. The DSASP Component shall be equal to:

(a) For Demand Side Resources eligible to offer only Operating Reserves, the product of (i) the maximum hourly Operating Capacity (MW) for which the Demand Side Resource may be scheduled to provide Operating Reserves, (ii) the amount of Eastern or Western reserves credit support, as appropriate, in $/MW per day, and (iii) three (3) days.

Where:

The amount of Eastern reserves credit support ($/MW/day) for each two-month period	=	Eastern Price Differential for the same two-month period in the previous year * the higher of two (2) or the maximum number of daily Reserve Activations for the same two-month period in the previous year
The amount of Western reserves credit support ($/MW/day) for each two-month period	=	Western Price Differential for the same two-month period in the previous year * the higher of two (2) or the maximum number of daily Reserve Activations for the same two-month period in the previous year
Two-month periods:	=	January and February March and April May and June July and August September and October November and December
MCP_{SRh}	=	Hourly, time-weighted Market Clearing Price for Spinning Reserves
Eastern Price Differential	=	The hourly differential at the 97th percentile of all hourly differentials between the Day-Ahead and Real-Time MCPSRh for Eastern Spinning Reserves for hours in the two-month period of the previous year when the Real-Time MCPSRh for Eastern Spinning Reserves exceeded the Day-Ahead MCPSRh for Eastern Spinning Reserves
Western Price Differential	=	The hourly differential at the 97th percentile of all hourly differentials between the Day-Ahead and Real-Time MCPsSRh for Western Spinning Reserves for hours in the two-month period of the previous year when the Real-Time MCPSRh for Western Spinning Reserves exceeded the Day-Ahead MCPSRh for Western Spinning Reserves
Reserve Activations	=	The number of reserve activations at the 97th percentile of daily reserve activations for days in each two month period of the previous year that had reserve activations.

(b) For Demand Side Resources eligible to offer only Regulation Service, or Operating Reserves and Regulation Service, the product of (i) the maximum hourly Operating Capacity (MW) for which the Demand Side Resource may be scheduled to provide Regulation Service and Operating Reserves, (ii) the amount of regulation credit support, as appropriate, in $/MW per day, and (iii) three (3) days.

Where:

The amount of regulation credit support ($/MW/day) for each two-month period	=	Price Differential for the same two-month period in the previous year * 24 hours
Two-month periods:	=	January and February March and April May and June July and August September and October November and December
MCP_{Regh}	=	Hourly, time-weighted Market Clearing Price for Regulation Services
Price Differential	=	The hourly differential at the 97^{th} percentile of all hourly differentials between the Day-Ahead and Hour-Ahead MCPRegh for hours in the two-month period of the previous year when the Real-Time MCP exceeded the Day-Ahead MCP

26.4.2.9 Projected True-Up Exposure Component

The Projected True-Up Exposure Component shall apply to any Customer whose four-month true-ups over the most recently invoiced four months average percentage credit exposure to the NYISO is greater than ten percent of the initial invoice settlements for the associated months. Customers subject to the Projected True-Up Exposure Component shall be required to provide secured credit to satisfy the requirement. The Projected True-Up Exposure Component shall be determined according to the following formula:

$$PTE = \left[\sum_{N4}(Avg4TrueUp * Initial4Month)\right] + \left[\sum_{NF}(AvgFinalTrueUp * InitialFinal)\right]$$

Where:

PTE	=	The amount of secured credit support required for the Projected True-Up Exposure Component
N4	=	Each month with an initial settlement without an associated 4 month settlement
NF	=	Each month with an initial settlement without an associated final bill close-out
Avg4TrueUp	=	Most recent six month rolling average percentage credit exposure of 4 month settlements to associated initial settlements, not to exceed a market-wide maximum percentage reasonably determined by the ISO
AvgFinalTrueUp	=	Most recent six month rolling average percentage credit exposure of final bill close-outs to associated 4 month settlements, not to exceed a market-wide maximum percentage reasonably determined by the ISO
Initial 4 Month	=	Initial settlement for the month N4
Initial Final	=	Initial settlement for the month NF

26.4.2.10 Former RMR Generator Component

The Former RMR Generator Component shall apply to any Customer that is the financially responsible party under the ISO Tariffs for a former RMR Generator or former Interim Service Provider that is subject to a Monthly Repayment Obligation. The Former RMR Generator Component will apply until either (a) the Monthly Repayment Obligation associated with the former RMR Generator or former Interim Service Provider is paid in full, or (b) the former RMR Generator or former Interim Service Provider is not subject to a Monthly Repayment Obligation. Customers subject to the Former RMR Generator Component shall be required to provide collateral to satisfy the requirement.

The Former RMR Generator Component shall be calculated as follows:

$$\sum_{G \in S} MRO_G \times Term_G$$

S = the set of former RMR Generators and former Interim Service Providers for which Customer is the financially responsible party under the ISO Tariffs

G = a former RMR Generator or former Interim Service Provider in set S

MRO_G = the Monthly Repayment Obligation (as defined in Section 15.8.7 of Rate Schedule 8 to the Services Tariff) for Generator *G*

$Term_G$ = the lesser of 8 or the number of months remaining in the repayment term that the ISO determines in accordance with Rate Schedule 8 to the Services Tariff for Generator *G*

26.4.3 Calculation of Bidding Requirement

The Bidding Requirement shall be an amount equal to the sum of:

(i) the amount of bidding authorization that the Customer has requested for use in or during, as appropriate, an upcoming ISO-administered TCC auction, which shall at least cover the sum of all positive bids to purchase TCCs, plus the absolute value of the sum of all negative offers to sell TCCs; *provided, however,* that the amount of credit required for each TCC that the Customer bids to purchase, whether positive, negative, or zero shall not be less than (a) $3,000 per MW for two-year TCCs, (b) $1,500 per MW for one-year TCCs, (c) $2,000 per MW for six-month TCCs, (d) $1,800 per MW for five-month TCCs, (e) $1,500 per MW for four-month TCCs, (f) $1,200 per MW for three-month TCCs, (g) $900 per MW for two-month TCCs, and (h) $600 per MW for one-month TCCs;

(ii) the approximate amount that the Customer may owe following an upcoming TCC auction as a result of converting expired ETAs into Historic Fixed Price TCCs pursuant to Section 19.2.1 of Attachment M to the OATT, which shall be calculated in accordance with the provisions of Section 19.2.1 regarding the purchase of TCCs with a duration of ten years;

(iii) the amount of bidding authorization that the Customer has requested for use in an upcoming ISO-administered ICAP auction; and

(iv) five (5) days prior to any ICAP Spot Market Auction, the amount that the Customer may be required to pay for UCAP in the auction, calculated as follows:

$$\sum_{L \in S}\left[(ICPM_L * 1000 * \ Deficiency_L) + \left(ICPM_L * 1000 * (ZDOMW_L * -1)\right) + \ \left(ICPM_L * 1000 * \left(\frac{ZCP_L - 1}{2}\right) * \ RQT_L\right)\right]$$

Where:

S equals a set containing the following locations: each Locality and Rest of State,

L equals a location in the set *S*,

$ICPM_L$ equals the lesser of $UBRP_L$ or LM_L,

$UBRP_L$ equals the UCAP based reference point (in $/kW-Month) for location *L*, as determined on the ICAP Demand Curve for that location (or for NYCA, if *L* is Rest of State) for the applicable Obligation Procurement Period,

LM_L equals (1) for any Locality *L* that is contained within another Locality *X*, the greater of CPM_L or CPM_X, or (2) for any other Locality or Rest of State, CPM_L,

CPM_L equals for location *L*, (1 + $Margin_L$)*MCP_L ,

CPM_X equals for location *X*, (1 + $Margin_X$)*MCP_X ,

$Margin_L$ equals 25% if location *L* is New York City and 100% if location *L* is G-J Locality, Long Island or Rest of State,

MCP_L equals the Market-Clearing Price for location *L* in the most recent Monthly Auction that established such a price for the month covered by the ICAP Spot Market Auction, measured in dollars per kilowatt-month,

$Deficiency_L$ equals the number of megawatts of Unforced Capacity that are to be procured in location *L* on behalf of that Customer in the ICAP Spot Market Auction in order to cover any deficiency for that Customer that exists in that location after the certification deadline for that ICAP Spot Market Auction less any deficiency calculated for that Customer for any Localities contained within location *L*, such value not to be less than zero,

$ZDOMW_L$ equals the number of megawatts of unsold Unforced Capacity in location *L* that the Customer committed as zero dollar offered megawatts for that ICAP Spot Market Auction,

ZCP_L equals the percentage determined in accordance with Services Tariff Section 5.14.1.2 for the applicable ICAP Demand Curves as established at the $0.00 point for the appropriate Capability Year, and

RQT_L equals (1) if *L* is New York City or Long Island, that Customer's share of the Locational Minimum Unforced Capacity Requirement for location *L* or (2) if *L* is G-J Locality, that Customer's share of the Locational Minimum Unforced Capacity Requirement for the G-J Locality that remains after reducing this amount by its share of the Locational Minimum Unforced Capacity Requirements for New York City or, (3) if *L* is Rest of State, that Customer's share of the NYCA Minimum Unforced Capacity Requirement that remains after reducing this amount by (a) its share of the Locational Minimum Unforced Capacity Requirements for New York City and Long Island and (b) that Customer's share of the Locational Minimum Unforced Capacity Requirement for the G-J Locality remaining after accounting for New York City, as calculated in (2) above; such value not to be less than zero.

26.5 Unsecured Credit

A Customer may use Unsecured Credit to satisfy any part of its Operating Requirement or Bidding Requirement other than (i) any credit requirement for bidding on or holding TCCs, (ii) the Projected True-Up Exposure Component, (iii) the Former RMR Generator Component, or (iv) a withdrawing Customer's required collateral. Affiliate guarantees are considered a form of Unsecured Credit.

Upon written request of a Customer, the ISO shall determine the amount of Unsecured Credit to be granted to the Customer, if any, in accordance with the ISO's creditworthiness requirements. Upon a Customer's written request, the ISO will provide a written explanation for any changes in the amount of the Customer's Unsecured Credit.

26.5.1 Eligibility

A Customer may be eligible to receive Unsecured Credit if the Customer meets the following criteria:

(i) Creditworthiness

(a) is an Investment Grade Customer,

(b) is an Unrated Customer that is deemed an Investment Grade Customer pursuant to an Equivalency Rating, or

(c) provides an Affiliate guarantee in compliance with Section 26.5.4 of this Attachment K;

AND

(ii) Payment History

(a) has actively participated in the ISO-Administered markets and paid when due all of its invoices during the immediately preceding six months, or

(b) has actively participated in the markets of another independent system operator or regional transmission organization and has paid when due all of its invoices during the immediately preceding six months. Any Customer relying on its payment history in another market to fulfill the requirement of this Section 26.5.1(ii) must provide evidence satisfactory to the ISO of such payment history.

Notwithstanding the foregoing, a Customer otherwise eligible for Unsecured Credit that fails to respond to the ISO's request to update the Customer's list of Affiliates, within the time frame provided by Section 9.2 of the ISO Services Tariff, shall not be eligible for Unsecured Credit.

26.5.2 Market Concentration Cap

A Customer's Unsecured Credit shall not exceed fifty million dollars ($50M) (the "Market Concentration Cap"). Moreover, the maximum amount of Unsecured Credit extended to a group of Customers that are Affiliates shall not exceed, in the aggregate, the Market Concentration Cap.

26.5.3 Determination of Unsecured Credit

26.5.3.1 Starting Point

The starting point for determining the amount of Unsecured Credit to be granted to an Investment Grade Customer, except as provided otherwise in Section 26.5.3.6 of this Attachment

K, shall be a percentage of its Tangible Net Worth, as indicated on the matrix contained in Table K-1, subject to the Market Concentration Cap.

26.5.3.2 Adjustment to Starting Point

The ISO shall conduct a Credit Assessment of the Customer and shall determine the amount of Unsecured Credit that it shall grant to the Customer by adjusting the Customer's starting point in accordance with the following table:

Starting Point Adjustment

Score Bucket	Public Score Range	Private Score Range	Starting Point Adjustment
1	0.00 – 0.33	0.00 – 0.31	0%
2	0.34 – 0.40	0.32 – 0.39	-20%
3	0.41 – 0.45	0.40 – 0.43	-50%
4	0.46 – 0.50	0.44 – 0.48	-80%
5	0.51+	0.49+	-100%

26.5.3.3 Adjustment to Unsecured Credit

(a) In the event of a change in a Customer's (1) Tangible Net Worth, and/or (2) agency rating, the ISO shall recalculate the Customer's starting point and Unsecured Credit amount in accordance with Sections 26.5.3.1 and 26.5.3.2 of this Attachment K.

(b) The ISO may conduct a Credit Assessment of a Customer at any time and adjust the amount of Unsecured Credit granted to the Customer in accordance with the following table:

Unsecured Credit Adjustment

Current Credit Assessment Score Bucket

Prior Credit Assessment Score Bucket	**Score Bucket**	**1**	**2**	**3**	**4**	**5**
	1	0%	-20%	-50%	-80%	-100%
	2	25%	0%	-38%	-75%	-100%
	3	100%	60%	0%	-60%	-100%
	4	400%	300%	150%	0%	-100%
	5	N/A	N/A	N/A	N/A	N/A

26.5.3.4 Restoration of Unsecured Credit

A Customer that is subject to a 100% reduction of Unsecured Credit shall not be eligible for Unsecured Credit again until the Customer demonstrates two consecutive quarters of financial performance that would otherwise have qualified the Customer for Unsecured Credit in accordance with Sections 26.5.3.1 and 26.5.3.2 of this Attachment K.

26.5.3.5 Credit Assessment

(a) In performing a Credit Assessment, the ISO shall evaluate specified indicators of credit risk pertaining to a Customer, which indicators will vary depending on whether the Customer is categorized by the ISO as a private entity or a public entity. The ISO shall categorize a Customer as private or public, for Credit Assessment purposes, in accordance with the following criteria:

Primary Criteria	**Secondary Criteria**	**Credit Assessment Category**
Standalone public trading company	None	Public
Subsidiary of a public company with its parent company as guarantor	None	Public
Subsidiary of a public company	With assets greater than US$10B	Public
Subsidiary of a public company	Contributes 50% or more of its parent company's revenues or accounts for 50% or more of its assets	Public
Subsidiary of a public company	Contributes less than 50% of its parent company's revenues or represents less than 50% of its assets	Private
Does not satisfy the criteria listed above	None	Private

(b) The ISO shall determine the Credit Assessment score for a Customer based upon the market and financial indicators and weightings, as appropriate, set forth below.

Public Entity Indicators **Weight**

- Market Indicators
  - Absolute CDS Spread 21.3%
  - Relative Stock Decline from 3 month high 4.3%

• Stock Return Volatility (3 month std. deviation)	12.7%
▪ Performance	
• Revenue/Market Cap	12.7%
• Retained Earnings/Assets	8.5%
▪ Debt Coverage	
• Total Debt/EBITDA	12.7%
▪ Leverage	
• Debt/(Total Debt + Equity)	8.5%
▪ Liquidity	
• Cash/Assets	4.3%
▪ Qualitative Assessment	15.0%

Private Entity Indicators	**Weight**
▪ Performance	
• Return on Assets	17.5%
• Profit Margin	10.5%
▪ Debt Coverage	
• Total Debt/EBITDA	17.5%
▪ Leverage	
• Total Debt/Total Assets	17.5%
▪ Liquidity	
• Cash/Assets	7.0%
▪ Qualitative Assessment	30.0%

(c) If one or more of the indicators listed above does not exist for a Customer, then the ISO shall, in its sole discretion, reallocate the weight attributed to that indicator either (1) to the remaining indicators proportionately, or (2) entirely to the qualitative assessment indicator.

(d) The qualitative areas evaluated shall include, but shall not be limited to, the following (as applicable): (1) Affiliate financial and market indicators, (2) ratemaking ability and legal right to fully recover end-user costs, (3) industry characteristics, (4) risk policies and procedures, (5) management quality, (6) ability to access funding in difficult market conditions, and (7) historical relationship and payment history with the ISO. A Transmission Owner that can recover end-user costs pursuant to authority granted by the PSC will receive a qualitative assessment score of no worse than five.

26.5.3.6 Public Power Entities

The following additional provisions shall apply to the determination of a Customer's Unsecured Credit:

(a) A Public Power Entity shall qualify for one million dollars ($1M) in Unsecured Credit, without regard for its Tangible Net Worth or Credit Assessment. Municipal electric systems that operate through a joint action agency or a similar municipal affiliation agreement may aggregate their Unsecured Credit amounts of one million dollars ($1M) per member such that the joint action agency will have an Unsecured Credit amount, subject to the Market Concentration Cap, equal to the total of the Unsecured Credit amounts of each individual member. Each such agency will qualify for such aggregated Unsecured Credit treatment subject to the ISO's review of the particular affiliation agreement and the ISO's review of documentation submitted by the agency to demonstrate that it has been formed under the pertinent sections of the New York State Municipal Law.

(b) In lieu of a one million dollar ($1M) grant of Unsecured Credit, a Public Power Entity may request Unsecured Credit based on its Tangible Net Worth and Credit Assessment. In such case, the ISO will consider the Public Power Entity a private entity for Credit Assessment purposes.

26.5.4 Affiliate Guarantees

26.5.4.1 Eligibility

An Affiliate guarantor shall be subject to the ISO's financial assurance requirements as if the Affiliate guarantor were a Customer and shall be assigned a level of Unsecured Credit, if any.

26.5.4.2 Use for Satisfaction of Minimum Capitalization Requirements

A Customer may use an Affiliate guarantor's financial statements to satisfy the capitalization requirement set forth in Section 26.1.1(d) of this Attachment K if (i) no other Customer relies on the Affiliate guarantor's financial statements to satisfy the capitalization requirement, and (ii) the Customer provides an unlimited Affiliate guarantee that satisfies the requirements set forth in Section 26.5.4.3 of this Attachment K. If a Customer provides an Affiliate guarantee solely to satisfy its capitalization requirement, the Affiliate guarantor, notwithstanding Section 26.5.4.1 of this Attachment K, shall not be subject to the ISO financial assurance requirements.

26.5.4.3 Form of Affiliate Guarantee

An Affiliate guarantee must be in a form acceptable to the ISO and issued by an Investment Grade U.S. or Canadian Affiliate. A Customer's failure to provide a source of collateral in an amount sufficient to (i) secure its obligations to the ISO and/or (ii) as applicable, secure its capitalization requirement pursuant to Section 26.1.1(d) of this Attachment K, fifty (50) days prior to the termination of an Affiliate guarantee, which source of collateral shall be guaranteed to remain in effect for a period of not less than one (1) year, shall be a condition of default enabling the ISO to immediately demand payment under the Affiliate guarantee in the amount required to meet Customer's ISO credit requirements, and/or, as applicable, the amount required to secure Customer's capitalization requirement.

26.5.5 Requests for Changes, Appeals

Requests for changes to the amount of a Customer's Unsecured Credit shall be made in writing to the ISO Credit Manager. Appeals of any decision regarding a Customer's Unsecured Credit shall be made in writing to the ISO's Chief Financial Officer and shall include all necessary supporting documentation. The Chief Financial Officer shall determine all appeals within ten (10) business days.

26.6 Collateral Requirements

As security for the prompt payment of a Customer's obligations to the ISO arising under the Services Tariff or the OATT, including without limitation an obligation to (i) satisfy any credit requirement for bidding on or holding TCCs, and (ii) to the extent that its Operating Requirement and/or Bidding Requirement exceed(s) the total of its Unsecured Credit plus any posted collateral, Customer shall provide to the ISO collateral in an acceptable form in accordance with Section 26.6.1 hereof.

26.6.1 Acceptable Collateral

26.6.1.1 Cash deposit

A cash deposit shall be held in escrow by the ISO, with actual interest earned on the deposit accrued to the Customer's account.

26.6.1.2 Letter of credit

A letter of credit shall be in a form acceptable to the ISO and issued or guaranteed by an approved U.S. or Canadian commercial bank, or an approved U.S. or Canadian branch of a foreign bank, with a minimum "A" rating from Standard & Poor's, Fitch, Moody's, or Dominion. A Customer's failure to provide acceptable collateral in an amount sufficient to secure its obligations to the ISO fifty (50) days prior to the termination of a letter of credit, which collateral shall be guaranteed to remain in effect for a period of not less than one (1) year, shall be a condition of default enabling the ISO to immediately draw upon the full value of the letter of credit.

26.6.1.3 Surety Bonds

A surety bond shall be in a form acceptable to the ISO, payable immediately upon demand without prior demonstration of the validity of the demand, and issued by a U.S. Treasury-listed surety with a minimum "A" rating from A.M. Best. A Customer's failure to provide acceptable collateral in an amount sufficient to secure its obligations to the ISO fifty (50) days prior to the termination of a surety bond, which collateral shall be guaranteed to remain in effect for a period of not less than one (1) year, shall be a condition of default enabling the ISO to immediately demand payment of the full value of the surety bond.

26.6.1.4 Netting of Amounts Receivable

A Customer may elect to treat as cash collateral the amount that the ISO determines will be owed to the Customer as of the day after the next regular weekly payment to the Customer and that will be payable to the Customer in the following regular weekly payment; *provided*, *however*, that (i) any such payment to the Customer may be adjusted by the ISO as necessary to correct for any error in this determination, and (ii) the Customer first enter into a security agreement with the ISO in a form acceptable to the ISO. At a minimum, the security agreement must grant to the ISO a continuing, first priority security interest in the Customer's ISO receivables and authorize the ISO to file financing statements, as necessary, at Customer's expense, to protect the ISO's interest.

26.6.3 Alternative Security Arrangements

Alternative security arrangements substantially similar to the credit requirements set forth in this Attachment K may be made in exigent circumstances to protect the financial position of the ISO if proposed by the Customer and approved by the ISO.

26.7 Additional Financial Assurance Policies for External Transactions

26.7.1 ISO Monitoring

The ISO shall monitor the External Transaction Bids submitted by a Customer. If the credit support required for any batch of External Transaction Bids submitted by a Customer exceeds the amount of the Customer's available credit support for External Transactions, then all of the Customer's External Transaction Bids in that batch of Bids shall be rejected by the ISO.

26.7.2 Suspension

If, at any time, the net amount owed to the ISO by a Customer as a result of External Transactions reaches fifty percent (50%) of the credit support provided by the Customer to support its External Transactions, then the ISO shall attempt to contact the Customer to request either payment or additional credit support in the amount then owed by the Customer as a result of its External Transactions.

If the day of the ISO's request stated above falls on a business day and the Customer fails to make payment or provide additional collateral as described above by 4:00 p.m. Eastern Time on the same day as the ISO's request, then the ISO may immediately suspend the Customer's authorization to engage in External Transactions until payment or provision of its required amount of credit support using Unsecured Credit and/or collateral.

If the day of the ISO's request stated above does not fall on a business day, then the ISO may issue a demand for credit support and immediately suspend the Customer's authorization to engage in External Transactions until the Customer makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

If, at any time, the amount owed to the ISO by a Customer as a result of its External Transactions reaches one hundred percent (100%) of the credit support provided by the

Customer to support its External Transactions, then the ISO may cancel any pending Day-Ahead Bids before they are accepted and may immediately suspend the Customer's authorization to engage in External Transactions until the Customer makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

26.8 Additional Financial Assurance Policies for TCCs

26.8.1 Suspension

If, at any time, the net amount owed by a Customer to the ISO for Congestion Rents reaches fifty percent (50%) of the collateral posted by the Customer to satisfy the TCC Component of its Operating Requirement then the ISO shall attempt to contact the Customer to request either payment or additional collateral in the net amount of the Congestion Rents then owed by the Customer.

If the Customer fails to make payment or provide additional collateral as described above by 4:00 p.m. Eastern Time on the same day as the ISO's request, then the ISO may cancel any pending Bids on TCCs and may immediately suspend the Customer's authorization to Bid on TCCs until the Customer makes payment or provides the required amount of collateral.

26.9 Additional Financial Assurance Policies for Virtual Transactions

26.9.1 ISO Monitoring

The ISO shall monitor the Virtual Transaction Bids submitted by a Customer. If the credit support required for any batch of Virtual Transaction Bids submitted by a Customer exceeds the amount of the Customer's available credit support for Virtual Transactions, then all of the Customer's Virtual Transaction Bids in that batch of Bids shall be rejected by the ISO.

26.9.2 Suspension

If, at any time, the net amount owed to the ISO by a Customer as a result of Virtual Transactions reaches fifty percent (50%) of the credit support provided by the Customer to support its Virtual Transactions, then the ISO shall attempt to contact the Customer to request either payment or additional credit support in the amount then owed by the Customer as a result of its Virtual Transactions.

If the day after the ISO's request stated above falls on a business day and the Customer fails to make payment or provide additional credit support as described above by 4:00 p.m. on that next business day, then the ISO may immediately suspend the Customer's authorization to engage in Virtual Transactions until payment or provision of its required amount of credit support using Unsecured Credit and/or collateral.

If the day after the ISO's request does not fall on a business day, then the ISO may issue a demand for credit support and immediately suspend the Customer's authorization to engage in Virtual Transactions until the Customer makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

If, at any time, the amount owed to the ISO by a Customer as a result of its Virtual Transactions reaches one hundred percent (100%) of the credit support provided by the

Customer to support its Virtual Transactions, then the ISO may cancel any pending Day-Ahead Bids before they are accepted and may immediately suspend the Customer's authorization to engage in Virtual Transactions until the Customer makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

26.10 Additional Financial Assurance Policies for Demand Side Resources Offering Ancillary Services

26.10.1 Suspension

(i) If, at any time, the amount owed to the ISO by a Demand Side Resource offering Ancillary Services as a result of its market activity reaches fifty percent (50%) of the credit support provided by the Demand Side Resource offering Ancillary Services to support its market transactions, the ISO shall attempt to contact the Demand Side Resource to request either payment or additional credit support in the amount then owed by the Demand Side Resource to support its market transactions.

(ii) If the day after the ISO's request described above falls on a business day and the Demand Side Resource fails to make payment or provide additional credit support as described above by 4:00 p.m. on the day after the ISO's request described above, the ISO may immediately suspend the Demand Side Resource's authorization to engage in market transactions until payment or provision of its required amount of credit support using Unsecured Credit and/or collateral.

(iii) If the day after the ISO's request does not fall on a business day, the ISO may issue a demand for credit support and immediately suspend the Demand Side Resource's authorization to engage in market transactions until the Demand Side Resource makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

(iv) If, at any time, the amount owed to the ISO by a Demand Side Resource as a result of its market transactions reaches one hundred percent (100%) of the credit support provided by the Demand Side Resource to support its market transactions, the ISO may cancel any pending Day-Ahead bids and may immediately suspend the Demand Side Resource's authorization to engage in market transactions until the Demand Side Resource makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.

26.11 Additional Financial Assurance Policies for Wholesale Transmission Service Charges

26.11.1 Application of Security

In the event a Transmission Owner declares a certain WTSC overdue and satisfies the requirements specified in Section 26.11.2 below, the NYISO will reimburse the Transmission Owner for part, or all, of the unpaid amount.

To the extent a Market Participant's Unsecured Credit does not satisfy the Market Participant's Operating Requirement, the NYISO will collect and hold collateral calculated pursuant to the WTSC Component of the Operating Requirement to secure payments owed by Customers to Transmission Owners. Any security held by the ISO for a Customer in excess of the amount collected pursuant to the WTSC Component of the Operating Requirement shall be available to secure WTSC only to the extent the ISO determines that such collateral will not be necessary to secure any payment obligations to the ISO, including true-up payments and other anticipated invoice adjustments. The ISO shall have access to any collateral collected pursuant to the WTSC Component of the Operating Requirement only to the extent that the ISO determines such collateral is not necessary to secure WTSC payment obligations to Transmission Owners.

26.11.2 Prerequisites to NYISO Action

The following conditions must be fully satisfied before the NYISO takes action to address a WTSC nonpayment:

26.11.2.1 The WTSC payment must be at least ten (10) days overdue, as measured from the due date on the invoice sent to the Customer by the Transmission Owner;

26.11.2.2 The Transmission Owner must have issued a late notice and demand letter to the Customer specifying both the amount and period by which the WTSC payment is overdue;

26.11.2.3 The Transmission Owner must have made an additional, informal attempt to collect the overdue WTSC payment from the Customer which may be, without limitation, a telephone call or meeting with appropriate personnel (the method of such additional informal attempt shall be at the Transmission Owner's discretion); and

26.11.2.4 The Transmission Owner must provide to the ISO, by certified mail or other verifiable delivery method, a copy of the initial invoice sent to the Customer, a copy of the late notice and demand letter with proof of receipt by the Customer, an indemnification of the ISO regarding the liabilities discussed in Section 26.11.3 below, a request that the NYISO draw upon available collateral to satisfy the default, and a sworn statement by an officer of the Transmission Owner stating: (a) that the WTSC payment is due and owing, (b) the period by which the WTSC payment is overdue, (c) a recitation of the Transmission Owner's collection efforts (including the additional, informal attempt to collect the debt).

26.11.3 NYISO Action

On the first business day after the ISO has received the notice that satisfies the requirements listed in Section 26.11.2.4 above, the ISO: (i) shall send a final demand for payment of the WTSC to the Customer within two (2) business days; (ii) shall initiate a draw upon available collateral for the benefit of the affected Transmission Owner if the WTSC due is not paid within two (2) business days of the letter; and (iii) may begin termination proceedings in accordance with the NYISO tariffs.

26.11.4 Transmission Owner Indemnification to the NYISO

As a prerequisite for ISO action listed in Section 26.11.3 above, the Transmission Owner will indemnify and hold the ISO harmless against liability arising out of the use of security to satisfy a WTSC nonpayment, any proceeding to terminate service, or termination of service to a customer except to the extent the dispute arises out of the ISO's reporting to the Transmission Owner of whether the underlying wheel through, internal wheel or export transaction(s) actually occurred and the details of the transaction.

26.12 Request for Additional Credit Support

If, at any time, the ISO requests additional credit support from a Customer to meet a shortfall, the Customer shall, within two (2) business days from the date of the request, or any shorter time period specified by the ISO or otherwise required by the ISO Tariffs, allocate Unsecured Credit and/or post collateral in an amount sufficient to cover the shortfall.

26.13 Withdrawing Customer's Collateral

Upon a Customer's withdrawal from the LBMP Market(s) and/or all of the ISO-Administered Markets to secure the Customer's estimated remaining financial obligations, including, but not limited to, true-up payments or other invoice adjustments, the Customer shall be required to provide secured credit according to the following formula:

$$RCC = [\sum_{N4} (\text{Avg 4TrueUp} * \text{Initial 4 Month})] + [\sum_{NF} (\text{AvgFinalTrueUp} * \text{Initial Final})]$$

Where:

RCC	=	The amount of secured credit to be required following a Customer's withdrawal
N4	=	Each month with an initial settlement without an associated 4 month settlement
NF	=	Each month with an initial settlement without an associated final bill close-out
Avg4TrueUp	=	Most recent six month rolling average percentage credit exposure of 4 month settlements to associated initial settlements, not to exceed a market-wide maximum percentage reasonably determined by the ISO
AvgFinalTrueUp	=	Most recent six month rolling average percentage credit exposure of final bill close-outs to associated 4 month settlements, not to exceed a market-wide maximum percentage reasonably determined by the ISO
Initial 4 Month	=	Initial settlement for the month N4
Initial Final	=	Initial settlement for the month NF

26.14 Material Adverse Change

The amount of Unsecured Credit granted to a Customer, if any, and the amount of the Customer's Operating Requirement shall be subject to change, at the discretion of the ISO, in the event that there is a material adverse change affecting the risk of nonpayment by the Customer, which includes, but is not limited to: (a) a material change in financial status pursuant to Section 26.2.1.4 of this Attachment K, (b) Customer's failure to timely cure its default under the ISO Tariffs or the tariffs of another independent system operator or regional transmission organization, (c) the issuance of a notice of alleged violation or show cause order, imposition of a sanction or other administrative order by the Federal Energy Regulatory Commission, the Commodity Futures Trading Commission, Environmental Protection Agency, New York State Public Service Commission, New York State Department of Environmental Conservation or any other regulatory body, independent system operator, or regional transmission organization, including the ISO, which could have a material adverse effect on the Customer's financial condition, (d) a downgrade of an Equivalency Rating, (e) a significant change in the Customer's "Expected Default Frequency (EDF)" as determined by Moody's KMV CreditEdge, (f) a significant variation in the Customer's credit evaluation, (g) a significant increase in a Customer's credit default swap (CDS) spreads, or (h) a significant decline in a Customer's market capitalization. In the event the ISO invokes its rights pursuant to this Section 26.14, the ISO will provide the affected Customer with a written explanation of the reasons the ISO declared a material adverse change.

Table K-1 Tangible Net Worth Credit Matrix

Customer Rating	Starting Point for Determining Unsecured Credit

Senior Long-term Unsecured Debt Rating		Issuer Rating or Equivalency Rating		(% of Tangible Net Worth)
S&P, Fitch, and Dominion	Moody's	S&P, Fitch, Dominion, and NYISO	Moody's	
A+ or higher	A1 or higher	AA- or higher	Aa3 or higher	7.5%
A	A2	A+	A1	6.5%
A-	A3	A	A2	5.0%
BBB+	Baa1	A-	A3	4.0%
BBB	Baa2	BBB+	Baa1	2.5%
BBB-	Baa3	BBB	Baa2	1.5%
BB+ or lower	Ba1 or lower	BBB- or lower	Baa3 or lower	0%

Appendix K-1 - Form Of Customer Prepayment Agreement

THIS PREPAYMENT AGREEMENT, effective as of **[date]** ("Prepayment Agreement") is entered into by and between the New York Independent System Operator, Inc. ("NYISO") and **[full legal name of customer]** ("Customer"). Capitalized terms used and not otherwise defined herein shall have the meaning ascribed to those terms in the Open Access Transmission Tariff ("OATT") or the Market Administration and Control Area Services Tariff ("Services Tariff"), as context requires.

1. Prepayment to Reduce Operating Requirement. Customer agrees to make a payment each week for purchases of Energy and Ancillary Services ("Prepayment") in order to reduce the Energy and Ancillary Services Component of its Operating Requirement pursuant to Section 26.4.2.1 of Attachment K of the Services Tariff.

2. Prepayment Amount. The amount of each Prepayment ("Prepayment Amount") shall be the NYISO's reasonable estimate, based on the charges incurred by Customer during the previous week, of the charges that Customer will incur during the following week for purchases of Energy and Ancillary Services in the NYISO-administered markets. The initial Prepayment Amount is $**[amount]**. NYISO shall inform Customer of any change in the Prepayment Amount not later than 11:00 A.M. EST on the last business day prior to the day on which the next Prepayment is due. Amounts owed to Customer by NYISO in regular weekly settlements shall not reduce or offset the Prepayment Amount.

3. Manner and Timing of Payment. Customer shall make each Prepayment not later than 4:00 P.M. EST on the second business day after the NYISO requests Prepayment by wire transfer, or other payment method, if any, authorized by ISO Procedures, to the account designated by NYISO.

4. Supplemental Payment. In the event that NYISO determines that a Prepayment is less than the charges incurred or estimated to be incurred by Customer for purchases of Energy and Ancillary Services in the week for which the Prepayment is made, Customer shall make a supplemental payment upon written demand by NYISO. NYISO shall specify in its demand the amount of the supplemental payment and the time for such payment to be made; *provided, however*, that the payment shall not be due sooner than 4:00 P.M. EST on the next business day.

5. Overpayment. In the event that NYISO determines that a Prepayment exceeds the charges incurred or estimated to be incurred by Customer for purchases of Energy and Ancillary Services in the week for which the Prepayment is made, NYISO shall credit the difference toward Customer's next Prepayment and shall notify Customer of the revised Prepayment Amount.

6. Termination. Customer may terminate this Prepayment Agreement upon ten (10) days written notice to NYISO. NYISO may terminate this Prepayment Agreement immediately upon written notice to the Customer in the event that Customer fails to perform in strict accordance with the terms hereof. In addition, this Prepayment Agreement shall terminate upon any amendment of the OATT or the Services

Tariff that eliminates the prepayment mechanism thereunder or requires material modification of this Prepayment Agreement.

7. Regular Weekly Settlements. Nothing in this Prepayment Agreement shall alter the obligation of Customer or NYISO to pay amounts owed in accordance with the NYISO's regular weekly settlement process pursuant to the terms of the OATT and the Services Tariff, which amounts shall be net of payments made pursuant to this Prepayment Agreement.

8. Interest. Customer shall not earn interest on its Prepayments. NYISO shall apply any interest actually earned on Prepayments to offset NYISO costs otherwise recovered through Schedule 1 of the OATT and Rate Schedule 1 of the Services Tariff.

9. Communications. All communications pursuant to this Prepayment Agreement shall be in writing, deemed effective when received, and delivered by hand with receipt of delivery, registered mail, or facsimile with confirmation of receipt to the following addresses:

NYISO:

Attn: Credit Manager

New York Independent System Operator, Inc.

10 Krey Boulevard

Rensselaer, New York 12144

Fax: (518) 356-7505

Customer:

Attn: ______________________

____

____

Fax: _______________________

NYISO or Customer may change the address provided for receipt of communications pursuant to this Prepayment Agreement by providing written notice to the other party.

10. Expenses. Customer shall pay all reasonable costs incurred by NYISO to enforce this Prepayment Agreement, including attorney fees and expenses.

11. Amendment and Waiver. The terms and provisions of this Prepayment Agreement may not be amended or waived except in writing and signed by NYISO and Customer.

12. Entire Agreement. This Prepayment Agreement embodies the entire agreement between NYISO and Customer with respect to the matters set forth herein, and supersedes all prior such agreements.

13. Severability. Should any provision of this Prepayment Agreement be determined by a court of competent jurisdiction to be unenforceable, all of the other provisions shall remain effective.

14. Choice of Law; Jurisdiction; Venue; and Service of Process. This Prepayment Agreement shall be governed by the laws of the State of New York without regard to conflict of laws principles. Customer irrevocably submits to the jurisdiction of any New York court or any United States court sitting in New York over any action or proceeding arising out of or relating to this Prepayment Agreement and irrevocably agrees that all claims in such action or proceeding may be heard and determined by such court. Customer agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Customer waives any objection to venue on the basis of forum non conveniens. Customer irrevocably consents to the service of process in any action or proceeding by the mailing of copies of such process to Customer at its address set forth herein. Customer agrees that any action or proceeding brought against NYISO shall be brought only in a New York court or a United States court sitting in New York. Nothing herein shall affect the right of NYISO to bring any action or proceeding against the Customer or its property in the courts of any other jurisdictions.

15. Waiver of Jury Trial. CUSTOMER IRREVOCABLY, VOLUNTARILY, AND WITH ADVICE OF COUNSEL WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN ANY ACTION ARISING IN CONNECTION WITH THIS PREPAYMENT AGREEMENT.

IN WITNESS WHEREOF, NYISO and Customer have caused this Prepayment Agreement to be executed by their respective authorized officials.

New York Independent System Operator, Inc.

By:

Name:

Title:

[Customer]

By:

Name:

Title:

27 Attachment L

Reserved for future use.

28 Reserved for future use

29 Attachment N – External Transactions at The Proxy Generator Buses Associated With The Cross-Sound Scheduled Line, Neptune Scheduled Line, Linden VFT Scheduled Line, and HTP Scheduled Line

29.1 Supremacy of Attachment N

External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, and the HTP Scheduled Line shall be Bid and scheduled pursuant to the provisions of the ISO Services Tariff and the ISO OATT, and in accordance with this Attachment N. In the event of a conflict between the provisions of this Attachment N and any other provision of the ISO OATT, the ISO Services Tariff, or any of their attachments and schedules, with regard to External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line, the provisions of this Attachment N shall prevail.

29.2 Transmission Reservations on the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, and the HTP Scheduled Line

Customers scheduling External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line must first hold an Advance Reservation on the appropriate Scheduled Line sufficient to support the proposed External Transaction. Advance Reservations must be obtained in accordance with (a) the Cross-Sound Scheduled Line release procedures that are set forth in Schedule 18 and the Schedule 18 Implementation Rule of the ISO New England Inc. Transmission, Markets and Services Tariff, or any successors thereto, or (b) the Neptune release procedures that are established pursuant to Section 38 of the PJM Interconnection, L.L.C. (“PJM”) Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Open Access Transmission Tariff, or (c) the Linden VFT Scheduled Line release procedures that are established pursuant to Section 38 of the PJM Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Open Access Transmission Tariff, or (d) the HTP Scheduled Line release procedures that are established pursuant to Section 38 of the PJM Open Access Transmission Tariff and set forth in a separate service schedule under the PJM Open Access Transmission Tariff.

Customers that have obtained Advance Reservations and wish to schedule External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line must (a) schedule an External Transaction with the ISO by submitting appropriate bids for economic evaluation, and (b) correspondingly schedule a transaction over the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line (as appropriate) in accordance with all applicable tariffs and market rules of the Control Area in which the Scheduled Line is located.

If a Customer scheduling External Transactions at the Proxy Generator Buses that are associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line inaccurately claims to hold an Advance Reservation or Advance Reservations that are adequate to support its Bid(s), or falsely implies that it has an Advance Reservation or Advance Reservations that are adequate to support its Bid(s) by scheduling such an External Transaction, the ISO may inform the Commission and take other appropriate action.

29.3 Additional Scheduling Rules for the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, and the HTP Scheduled Line

29.3.1 Bid Submission and E-Tags for Day-Ahead Transactions

Customers seeking to Schedule Day-Ahead transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line (a) shall comply with all applicable ISO Procedures, and (b) shall submit bids that reference valid NERC E-Tags for their transaction(s) no later than 10 minutes prior to the close of the DAM.

29.3.2 Bids and E-Tags for Real Time Transactions

Customers seeking to schedule Real-Time Market transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line (a) shall comply with all applicable ISO Procedures, and (b) shall submit Bids that reference valid NERC E-Tags for their transaction(s) at least 85 minutes before the start of each dispatch hour.

29.3.3 E-Tags Shall Each Reference One Advance Reservation ID

NERC E-Tags for External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line shall each reference no more than one (a) Cross-Sound Scheduled Line Advance Reservation ID or “assignment reference number” from the Cross-Sound Cable, LLC node of the ISO-NE OASIS, or (b) assignment reference number or other designation associated with the grant of scheduling rights over the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line (as appropriate).

30 Attachment O - Market Monitoring Plan

30.1 INTRODUCTION AND PURPOSE

30.1.1 Purposes and Objectives

This Market Monitoring Plan is intended to provide for the independent, impartial and effective monitoring of and reporting on: (1) the competitive structure, performance and economic efficiency of the New York Electric Markets; (2) the conduct of Market Parties, including but not limited to any exercise or attempt to exercise market power or restrain competition in any New York Electric Market by any Market Party or group of Market Parties; (3) the operation and use of the New York State Transmission System as such system affects or may affect competitive conditions in or the economic efficiency of any of the New York Electric Markets, including but not limited to the nature, extent and causes of any congestion on such system and the costs of or charges for such congestion; (4) the adequacy and effectiveness of any tariff or services agreement, or any rule, standard or procedure, or any market power mitigation or other remedial measures, implemented, administered or overseen by the New York Independent System Operator, Inc. ("ISO") and that affects or could affect the competitiveness or economic efficiency of any of the New York Electric Markets; and (5) any other condition, function or action affecting the foregoing.

Attachment O provides for review and evaluation by the Market Monitoring Unit of the ISO's: (i) Tariffs and market rules, including the ISO's imposition of appropriate measures for the mitigation of market power and imposition of appropriate sanctions or other remedial measures for actions or inaction that the ISO is authorized to address or remedy in its Tariffs; and (ii) administration of the New York Electric Markets. In addition, Attachment O requires the Market Monitoring Unit to timely: (a) report any failure by a Market Party or by the ISO to comply with any tariff or services agreement, or any law, regulation, rule, standard or procedure, including any market power mitigation or other remedial measure, if such violation or failure to comply impairs or threatens to impair the competitiveness or economic efficiency of any of the New York Electric Markets; (b) submit to the FERC, or other appropriate regulatory or enforcement agency, evidence of possible violation of state or federal law for the preservation of competition (including violations of FERC's regulations and the ISO Tariff rules); and (c) report on perceived market design flaws that the Market Monitoring Unit believes could be effectively remedied by rule or tariff changes. Attachment O is intended to minimize interference with open and competitive markets.

30.1.2 Implementation of Attachment O

All persons or entities responsible for the implementation of Attachment O shall do so in a manner consistent with and intended to achieve both: (i) the creation and operation of New York Electric Markets that are robust, competitive, efficient and non-discriminatory; and (ii) the safe and reliable operation of the electric system in New York Control Area.

30.1.3 Persons and Entities Subject to Attachment O

The ISO, the Market Monitoring Unit, and any person or entity participating in any of the New York Electric Markets or that takes service under or is a party to any tariff or agreement administered by the ISO, shall be subject to the terms, conditions and obligations of Attachment O. Entities that are subject to Attachment O may also be held responsible for actions or inaction by their Affiliates.

30.2 Definitions

For purposes of Attachment O, capitalized terms shall have the meanings specified below, or in the New York Independent System Operator Agreement or Market Administration and Control Area Services Tariff:

Affiliate

For purposes of Attachment O, "Affiliate" includes both Affiliates, as defined in the ISO Services Tariff and, where appropriate, Affiliated Entities, as defined in the Market Mitigation Measures.

Board

"Board" shall mean the Board of Directors of the New York Independent System Operator, a not-for-profit New York corporation.

Core Market Monitoring Functions

"Core Market Monitoring Functions" or "Core Functions" shall mean the duties that the FERC determined the Market Monitoring Unit must be responsible for performing in Order 719. The Core Functions are set forth in Section 30.4.5 of Attachment O.

Interested Government Agencies

"Interested Government Agencies" shall mean the FERC and the New York Public Service Commission.

ISO Market Power Mitigation Measures

"ISO Market Power Mitigation Measures" or "Market Mitigation Measures" shall mean Attachment H to the ISO's Market Administration and Control Area Services Tariff, or any successor provisions thereto.

Market Mitigation and Analysis Department

"Market Mitigation and Analysis Department" or "MMA" shall mean a department, internal to the ISO that is responsible for participating in the ISO's administration of its Tariffs. The MMA's duties are described in Section 30.3, below.

Market Monitoring Unit

"Market Monitoring Unit" shall mean the consulting or other professional services firm, or other similar entity, retained by the Board, as specified in Section 30.4.2 of Attachment O, that is responsible for carrying out the Core Market Monitoring Functions and the other functions that are assigned to it in Attachment O. The Market Monitoring Unit shall recommend Tariff and market rule changes, but shall not participate in the administration of the ISO's Tariffs, except as specifically authorized in Attachment O.

Market Party

"Market Party" shall mean any person or entity that is a buyer or a seller in, or that makes bids or offers to buy or sell in, or that schedules or seeks to schedule transactions with the ISO in or affecting, any of the New York Electric Markets, or any combination of the foregoing. Under Attachment O and the ISO's Market Mitigation Measures, Market Parties may be held responsible for the actions of, or inaction by, their Affiliates.

Market Violation

"Market Violation" shall mean any of (i) a tariff violation, (ii) violation of a Commission-accepted or approved order, rule or regulation including, but not limited to, violations of FERC's Market Behavior Rules, 18 CFR § 35.41, or any successor provisions thereto, (iii) market manipulation (*see* 18 CFR § 1c.2, or any successor provision thereto), or (iv) inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

New York Electric Markets

"New York Electric Markets" shall mean the LBMP Market, the Wholesale Market, any market for the purchase or sale of TCCs, and any other market administered, coordinated or facilitated by, or involving transmission or other services scheduled or otherwise provided by, the ISO.

Order 719

"Order 719" shall mean the Order issued by the FERC on October, 17, 2008 in Docket Nos. RM07-19-000 and AD07-7-000, including the regulations adopted by FERC in that Order, as amended by any subsequent orders issued by the FERC or by a Federal court of appeals.

Other State Commission

"Other State Commission" shall mean the State regulatory agencies other than the New York Public Service Commission that possess primary jurisdiction over (a) the construction and siting of electric transmission and generating facilities, and/or (b) the regulation of retail electric rates, within their respective State.

Plan (Attachment O)

"Plan" shall mean this ISO Market Monitoring Plan (Attachment O).

Protected Information

"Protected Information" shall mean: (a) information that is confidential, proprietary, commercially valuable or competitively sensitive or is a trade secret, (b) information that is Confidential Information under Attachment F to the ISO OATT, (c) information that the Market

Monitoring Unit or the ISO is obligated by tariff, regulation or law to protect, (d) information which, if revealed, would present opportunities for collusion or other anticompetitive conduct, or that could facilitate conduct that is inconsistent with economic efficiency, (e) information relating to ongoing investigations and monitoring activities (including the identity of the person or Market Party that requested or is the subject of an investigation, unless such party consents to disclosure), (f) information subject to the attorney-client privilege, the attorney work product doctrine, or concerning pending or threatened litigation, or (g) information that has been designated as such in writing by the party supplying the information to the ISO or to its Market Monitoring Unit, or by the ISO or its Market Monitoring Unit, provided that such designation is consistent with the ISO's tariffs and this Plan.

30.3 NYISO Market Mitigation And Analysis Department

30.3.1 Establishment

The ISO shall establish, and provide appropriate staffing and resources for, its internal Market Mitigation and Analysis Department ("MMA").

30.3.2 Staffing

The MMA shall be comprised of full-time employees of the ISO having the experience and qualifications necessary to assist the ISO's efforts to implement its obligations under its Tariffs and under Attachment O, including providing support to the ISO's external Market Monitoring Unit where and when needed. In carrying out its responsibilities, the MMA, may retain such consultants and other experts as the ISO deems appropriate to the effective implementation of Attachment O, subject to the management oversight of the Chief Executive Officer ("CEO") or the CEO's designee, the Chief Operating Officer ("COO"). Such consultants or other experts shall comply with applicable ISO policies on conflicts of interest or other standards of conduct.

30.3.3 Duties of MMA

The MMA shall not be responsible for carrying out any of the Core Functions. Rather, the MMA is responsible for working collaboratively with the Market Monitoring Unit and other ISO departments to assist the ISO's efforts to carry out its Tariff responsibilities, including the ISO's obligation to provide adequate data and support to its Market Monitoring Unit. The MMA's duties shall include: (1) administering mitigation in accordance with the ISO's Tariffs, which will include performing daily monitoring of the ISO's markets to identify potential violations of the Market Mitigation Measures, (2) assisting the ISO's efforts to accurately and effectively implement the requirements of its Tariffs and its intended market design,

(3) responding to information and data requests the ISO receives from the FERC's Office of Enforcement staff and from the staff of the New York Department of Public Service, consistent with the provisions of Attachment O, the ISO's Code of Conduct, and any other provisions of the ISO's Tariffs that address the protection of Protected Information, (4) providing data and other assistance to support the Market Monitoring Unit, (5) working collaboratively with other ISO departments to analyze market outcomes, and (6) bringing to the Market Monitoring Unit's attention market-related concerns (including, but not limited to, possible Market Violations) it identifies while carrying out its responsibilities; and (7) participate in and review the ISO's development, implementation and administration of RMR Agreements and associated tariff provisions.

30.3.4 Accountability

The MMA shall act at the direction of the CEO or the CEO's designee, the COO, who shall be accountable for the ISO's implementation of Attachment O.

The CEO or the CEO's designee, the COO, shall ensure that the MMA has adequate employees, funding and other resources, access to required information, and the cooperation of other ISO staff, as necessary for it to perform its duties under Attachment O and under the ISO's Market Mitigation Measures.

30.4 Market Monitoring Unit

30.4.1 Mission of the Market Monitoring Unit

The Market Monitoring Unit's goals are (1) to ensure that the markets administered by the ISO function efficiently and appropriately, and (2) to protect both consumers and participants in the markets administered by the ISO by identifying and reporting Market Violations, market design flaws and market power abuses to the Commission in accordance with Sections 30.4.5.3 and 30.4.5.4 below.

30.4.2 Retention and Oversight of the Market Monitoring Unit

The Board shall retain a consulting or other professional services firm, or other similar entity, to advise it on the matters encompassed by Attachment O and to carry out the responsibilities that are assigned to the Market Monitoring Unit in Attachment O. The Market Monitoring Unit selected by the Board shall have experience and expertise appropriate to the analysis of competitive conditions in markets for electric capacity, energy and ancillary services, and financial instruments such as TCCs, and to such other responsibilities as are assigned to the Market Monitoring Unit under Attachment O, and must also have sufficient resources and personnel to be able to perform the Core Functions and other assigned functions.

The Market Monitoring Unit shall be accountable to the non-management members of the Board, and shall serve at the pleasure of the non-management members of the Board.

30.4.3 Market Monitoring Unit Ethics Standards

The Market Monitoring Unit, including all persons employed thereby, shall comply at all times with the ethics standards set forth below. The Market Monitoring Unit ethics standards set forth below shall apply in place of the standards set forth in the ISO's OATT Attachment F Code of Conduct, and/or the more general policies and standards that apply to consultants retained by the ISO.

30.4.3.1 The Market Monitoring Unit and its employees must have no material affiliation with any Market Party or Affiliate of any Market Party.

30.4.3.2 The Market Monitoring Unit and its employees must not serve as an officer, employee, or partner of a Market Party.

30.4.3.3 The Market Monitoring Unit and its employees must have no material financial interest in any Market Party or Affiliate of a Market Party. Ownership of mutual funds by Market Monitoring Units and their employees that contain investments in Market Parties or their Affiliates is permitted so long as: (a) the fund is publicly traded; (b) the fund's prospectus does not indicate the objective or practice of concentrating its investment in Market Parties or their Affiliates; and (c) the Market Monitoring Unit/Market Monitoring Unit employee does not exercise or have the ability to exercise control over the financial interests held by the fund.

30.4.3.4 The Market Monitoring Unit and its employees are prohibited from engaging in transactions in the markets administered by the ISO, other than in the performance of duties under the ISO's Tariffs. This provision shall not, however, prevent the Market Monitoring Unit, or its employees, from purchasing electricity, power and Energy as retail customers for their own account and consumption.

30.4.3.5 The Market Monitoring Unit and its employees must not be compensated, other than by the ISO, for any expert witness testimony or other commercial services, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or to the markets that the ISO administers.

30.4.3.6 The Market Monitoring Unit and its employees may not accept anything that is of more than *de minimis* value from a Market Party.

30.4.3.7 The Market Monitoring Unit and its employees must advise the Board in the event they seek employment with a Market Party, and must disqualify themselves from participating in any matter that could have an effect on the financial interests of that Market Party until the outcome of the matter is determined.

30.4.3.8 If the Market Monitoring Unit or any of its employees provide services to entities other than the ISO, the Market Monitoring Unit shall provide to the ISO's Board, and shall regularly update, a list of such entities and services. When the Market Monitoring Unit issues an opinion, report or recommendation to, for or addressing the ISO or the markets it administers that relates to, or could reasonably be expected to affect, an entity (other than the ISO) to which the Market Monitoring Unit or its employees provide services, the Market Monitoring Unit shall inform the ISO's Board of the opinion, report or recommendation it has issued, and that its opinion, report or recommendation relates to, or could reasonably be expected to affect, an entity to which the Market Monitoring Unit or its employees provide services.

30.4.4 Duties of the Market Monitoring Unit

The Market Monitoring Unit shall advise the Board, shall perform the Core Functions specified in Section 30.4.5 of Attachment O, and shall have such other duties and responsibilities as are specified in Attachment O. The Market Monitoring Unit may, at any time, bring any matter to the attention of the Board that the Market Monitoring Unit may deem necessary or appropriate for achieving the purposes, objectives and effective implementation of Attachment O.

The Market Monitoring Unit shall not participate in the administration of the ISO's Tariffs, except for performing its duties under Attachment O. The Market Monitoring Unit shall not be responsible for performing purely administrative duties, such as enforcement of late fees or Market Party reporting obligations, that are not specified in Attachment O. The Market Monitoring Unit may (i) provide, or assist the ISO's efforts to develop, the inputs required to conduct mitigation, and (ii) assist the ISO's efforts to conduct "retrospective" mitigation (*see* Order 719 at PP. 369, 375) that does not change bids or offers (including physical bid or offer parameters) at or before the time such bids or offers (including physical bid or offer parameters) are considered in the ISO's market solution.

30.4.5 Core Market Monitoring Functions

The Market Monitoring Unit shall be responsible for performing the following Core Functions:

30.4.5.1 Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the ISO, to the Commission's Office of Energy Market Regulation staff, and to other interested entities, including the New York Public Service Commission, and participants in the ISO's stakeholder governance process. Provided that:

30.4.5.1.1 The Market Monitoring Unit is not responsible for systematic review of every tariff and market rule; its role is monitoring, not audit.

30.4.5.1.2 The Market Monitoring Unit is not to effectuate its proposed market design itself.

30.4.5.1.3 The Market Monitoring Unit's role in recommending proposed rule and Tariff changes is advisory in nature, unless a Tariff provision specifically concerns actions to be undertaken by the Market Monitoring Unit itself.

30.4.5.1.4 The Market Monitoring Unit must limit distribution of issues or concerns it identifies, and its recommendations to the ISO and to Commission staff in the event it believes broader dissemination could lead to exploitation. Limited distributions should include an explanation of why further dissemination should be avoided at that time.

30.4.5.2 Review and report on the performance of the wholesale markets to the ISO, the Commission, and other interested entities such as the New York Public Service Commission and participants in its stakeholder governance process on at least a quarterly basis, and issue a more comprehensive annual state of the market report. The Market Monitoring Unit may issue additional reports as necessary.

30.4.5.2.1 In order to perform the Core Functions, the Market Monitoring Unit shall perform daily monitoring of the markets that the ISO administers. The Market Monitoring Unit's daily monitoring shall include monitoring of virtual bidding.

30.4.5.2.2 The Market Monitoring Unit shall submit drafts of each of its reports to the ISO for review and comment sufficiently in advance of the report's issuance to provide an effective opportunity for review and comment by the ISO. The Market Monitoring Unit may disregard any suggestions with which it disagrees. The ISO may not alter the reports prepared by the Market Monitoring Unit, nor dictate the Market Monitoring Unit's conclusions.

30.4.5.3 Identify and notify the Commission staff of instances in which a Market Party's or the ISO's behavior may require investigation, including, but not limited to, suspected Market Violations.

30.4.5.3.1 Except as provided in Section 30.4.5.3.2 below, in compliance with § 35.28(g)(3)(iv) of the Commission's regulations (or any successor provisions thereto) the Market Monitoring Unit shall submit a non-public referral to the Commission in all instances where it has obtained sufficient credible information to believe a Market Violation has occurred. Once the Market Monitoring Unit has obtained sufficient credible information to warrant referral to the Commission, the Market Monitoring Unit shall immediately refer the matter to the Commission and desist from further investigation of independent action related to the alleged Market Violation, except at the express direction of the Commission or Commission staff. The Market Monitoring Unit may continue to monitor for repeated instances of the reported activity by the same or other entities and shall respond to requests from the Commission for additional information in connection with the alleged Market Violation it has referred.

30.4.5.3.2 The Market Monitoring Unit is not required to refer the actions (or failures to act) listed in this Section 30.4.5.3.2 to the Commission as Market Violations, because they have: (i) already been reported by the ISO as a Market Problem under Section 3.5.1 of the ISO Services Tariff; and/or (ii) because they pertain to actions or failures that: (a) are expressly set forth in the ISO's Tariffs; (b) involve objectively identifiable behavior; and (c) trigger a sanction or other consequence that is expressly set forth in the ISO Tariffs and that is ultimately appealable to the Commission. The actions (or failures to act) that are exempt from mandatory referral to the Commission are:

30.4.5.3.2.1 failure to meet a Contract or Non-Contract CRIS MW Commitment pursuant to Sections 25.7.11.1.1 and 25.7.11.1.2 of Attachment S to the ISO OATT that results in a charge or other a sanction under Section 25.7.11.1.3 of Attachment S of the ISO OATT;

30.4.5.3.2.2 Black Start performance that results in reduction or forfeitures of payments under Rate Schedule 5 to the ISO Services Tariff;

30.4.5.3.2.3 any failure by the ISO to meet the deadlines for completing System Impact Studies, or any failure by a Transmission Owner to meet the deadlines for completing Facilities Studies, under Sections 3.7 and 4.5 of the ISO OATT that results in the filing of a notice and/or the imposition of sanctions under those provisions;

30.4.5.3.2.4 failure of a Market Party to comply with the ISO's creditworthiness requirements set forth in Attachment K of the ISO Services tariff, or other action, that triggers sanctions under Section 7.5 of the ISO Services Tariff or Section 2.7.5 of the ISO OATT, specifically: (i) failure of a Market Party to make timely payment under Section 7.2.2 of the ISO Services Tariff or Section 2.7.3.2 of the ISO OATT that triggers a sanction under Sections 7.5.3(i) or 7.5.3(iv) of the ISO Services Tariff, or Sections 2.7.5.3(i), 2.7.5.3(iv), or 2.7.5.4 of the ISO OATT; (ii) failure of a Market Party to comply with a demand for additional credit support under Section 26.6 of Attachment K of the ISO Services Tariff that triggers a sanction under Section 7.5.3(i) of the ISO Services Tariff or Section 2.7.5.3(i) of the ISO OATT; (iii) failure of a Market Party to cure a default in another ISO/RTO market under Sections 7.5.3(iii) of the ISO Services Tariff, or Section 2.7.5.3(iii) of the ISO OATT that triggers a sanction under either of those tariff provisions; (iv) failure of a Market Party that has entered into a Prepayment Agreement with the ISO under Appendix K-1 to Attachment K to the ISO Services Tariff to make payment in accordance with the terms of the Prepayment Agreement that triggers a sanction under the Prepayment Agreement or 7.5.3(i) of the ISO Services Tariff; and (v) failure of a Market Party to make timely payment on two occasions within a rolling twelve month period under Section 7.5.3(iv) of the ISO Services Tariff, or Section 2.7.5.3(iv) of the ISO OATT that triggers a sanction under either of those provisions.

30.4.5.3.2.5 bidding in a manner that results in a penalty under Section 23.4.3.3.4 of the Market Mitigation Measures.

30.4.5.3.2.6 submission of inaccurate fuel type information into the Day-Ahead Market that results in a penalty under Section 23.4.3.3.3.3 of the Market Mitigation Measures.

30.4.5.3.2.7 submission of inaccurate fuel type and/or fuel price information into the Real-Time Market that results in a penalty under Section 23.4.3.3.3.4 of the Market Mitigation Measures.

To the extent the above list enumerates specific Tariff provisions, the exclusions specified above shall also apply to re-numbered and/or successor provisions thereto. The Market Monitoring Unit is not precluded from referring any of the activities listed above to the

Commission.

30.4.5.4 Identify and notify the Commission staff of perceived market design flaws that could be effectively remedied by rule or tariff changes.

30.4.5.4.1 In compliance with § 35.28(g)(3)(v) of the Commission's regulations (or any successor provisions thereto) the Market Monitoring Unit shall submit a referral to the Commission when the Market Monitoring Unit has reason to believe that a market design flaw exists, that the Market Monitoring Unit believes could effectively be remedied by rule or tariff changes.

30.4.5.4.1.1 If the Market Monitoring Unit believes broader dissemination of the possible market design flaw, and its recommendation could lead to exploitation, the Market Monitoring Unit shall limit distribution of its referral to the ISO and to the Commission. The referral shall explain why further dissemination should be avoided.

30.4.5.4.1.2 Following referral of a possible market design flaw, the Market Monitoring Unit shall continue to provide to the Commission additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the Market Monitoring Unit's proposed market rule or tariff change, any recommendations made by the Market Monitoring Unit to the ISO, its stakeholders, Market Parties or state public service commissions regarding the perceived market design flaw, and any actions taken by the ISO regarding the perceived market design flaw.

30.4.6 Market Monitoring Unit Responsibilities Set Forth Elsewhere in the ISO's Tariffs

30.4.6.1 Supremacy of (Attachment O)

Provisions addressing the Market Monitoring Unit, its responsibilities and its authority, have been centralized in Attachment O. However, provisions that address the Market Monitoring Unit can also be found in the Market Mitigation Measures that are set forth in Attachment H to the ISO Services Tariff, and elsewhere in the ISO's Tariffs. In the event of any inconsistency between the provisions of Attachment O and any other provision of the ISO OATT, the ISO Services Tariff, or any of their attachments and schedules, with regard to the Market Monitoring Unit, its responsibilities and its authority, the provisions of Attachment O shall control.

30.4.6.2 Market Monitoring Unit responsibilities set forth in the Market Mitigation Measures

30.4.6.2.1 The ISO and its Market Monitoring Unit shall monitor the markets the ISO administers for conduct that the ISO or the Market Monitoring Unit determine constitutes an abuse of market power but that does not trigger the thresholds specified in the Market Mitigation Measures for the imposition of mitigation measures by the ISO. If the ISO identifies or is made aware of any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified in Section 23.3.2.3 of the Market Mitigation Measures, it shall make a filing under § 205 of the Federal Power Act, 16 U.S.C. § 824d (1999) ("§ 205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, shall incorporate or address the recommendation of its Market Monitoring Unit, and shall set forth the ISO's justification for imposing that mitigation measure. The Market Monitoring Unit's reporting obligations are specified in Sections 30.4.5.3 and 30.4.5.4 of Attachment O. *See* Market Mitigation Measures Section 23.1.2.

30.4.6.2.2 The ISO and the Market Monitoring Unit shall monitor the ISO Administered Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices or guarantee payments in an ISO Administered Market. *See* Market Mitigation Measures Section 23.2.4.4.

30.4.6.2.3 If (i) the ISO determines, following consultation with the Market Party and review by the Market Monitoring Unit, that the Market Party or its representative has, over a time period of at least one week, submitted inaccurate fuel type or fuel price information that was, taken as a whole, biased in the Market Party's favor, *then* the ISO shall cease using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Generator's Bid(s) to develop reference levels for the affected Generator(s) in the relevant (Day-Ahead or real-time) market for the durations specified in Sections 23.3.1.4.6.8.1, 23.3.1.4.6.8.2, and 23.3.1.4.6.8.3 of the Mitigation Measures. *See* Section 23.3.1.4.6.8 of the Market Mitigation Measures

30.4.6.2.4 When it has the capability to do so, the ISO shall determine the effect on prices or guarantee payments of questioned conduct through the use of sensitivity analyses performed using the ISO's SCUC, RTC and RTD computer models, and such other computer modeling or analytic methods as the ISO shall deem appropriate following consultation with its Market Monitoring Unit. *See* Market Mitigation Measures Section 23.3.2.2.1.

30.4.6.2.5 Pending development of the capability to use automated market models, the ISO, following consultation with its Market Monitoring Unit, shall determine the effect on prices or guarantee payments of questioned conduct using the best available data and such models and methods as they shall deem appropriate. *See* Market Mitigation Measures Section 23.3.2.2.2.

30.4.6.2.6 If through the application of an appropriate index or screen or other monitoring of market conditions, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified above, on one or more prices or guarantee payments in an ISO Administered Market, the ISO shall, as and to the extent specified in Attachment O or in Section 23.3.3.2 of the Market Mitigation Measures, contact the Market Party engaging in the identified conduct to request an explanation of the conduct. If a Market Party anticipates submitting bids in a market administered by the ISO that will exceed the thresholds specified in Section 23.3.1 of the Market Mitigation Measures for identifying conduct inconsistent with competition, the Market Party may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Party's bids. If a Market Party's explanation of the reasons for its bidding indicates to the satisfaction of the ISO that the questioned conduct is consistent with competitive behavior, no further action will be taken. Market Parties shall ensure that the information they submit to the ISO, including but not limited to fuel price and fuel type information, is accurate. Except as set forth in Section 23.3.1.4.6.7 of the Market Mitigation Measures, the ISO may not retroactively revise a reference level to reflect additional fuel costs if a Market Party or its representative did not timely submit accurate fuel cost information. Unsupported speculation by a Market Party does not present a valid basis for the ISO to determine that Bids that a Market Party submitted are consistent with competitive behavior, or to determine that submitted costs are appropriate for inclusion in the ISO's development of reference levels. Consistent with Sections 30.6.2.2 and 30.6.3.2 of the Plan, the Market Party shall retain the documents and information supporting its Bids and the costs it proposes to include in reference levels. A preliminary determination by the ISO shall be provided to the Market Monitoring Unit for its review and comment, and the ISO shall consider the Market Monitoring Unit's recommendations before the ISO issues its decision or determination to the Market Party. Upon request, the ISO shall consult with a Market Party or its representative with respect to the information and analysis used to determine reference levels under Section 23.3.1.4 of the Market Mitigation Measures for that Market Party's Generator(s). If cost data or other information submitted by a Market Party indicates to the satisfaction of the ISO that the reference levels for that Market Party's Generator(s) should be changed, revised reference levels shall be proposed by the ISO, communicated to the Market Monitoring Unit for its review and comment and, following the ISO's consideration of any recommendation that the Market Monitoring Unit is able to timely provide, communicated to the Market Party, and implemented by the ISO as soon as practicable. Changes to reference levels addressed pursuant to the terms of Section 23.3.3.1.4 of the Market Mitigation Measures shall be implemented on a going-forward basis commencing no earlier than the date that the Market Party's consultation request is received. *See* Market Mitigation Measures Sections 23.3.3.1.1 through 23.3.3.1.5.

30.4.6.2.7 With regard to a Market Party's request for consultation that satisfies the requirements of Sections 23.3.3.3.1.4 and 23.3.3.3.1.7 of the Market Mitigation Measures, and consistent with the duties assigned to the ISO in Section 23.3.3.3.1.7.1 of the Market Mitigation Measures, a preliminary determination by the ISO regarding the Market Party's consultation request shall be provided to the Market Monitoring Unit for its review and the ISO shall consider the Market Monitoring Unit's recommendations in reaching its decision. *See* Market Mitigation Measures Section 23.3.3.3.1.7.1 and 23.3.3.3.1.7.2.

30.4.6.2.8 Review pursuant to Market Mitigation Measures Section 23.4.5.4.3

(a) Reasonably in advance of the deadline for submitting offers in an External Reconfiguration Market and in accordance with the deadlines specified in ISO Procedures, the Responsible Market Party for External Sale UCAP may request the ISO to provide a projection of ICAP Spot Auction clearing prices for a Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market. Prior to completing its projection of ICAP Spot Auction clearing prices for a Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market, the ISO shall consult with the Market Monitoring Unit regarding such price projection. *See* Market Mitigation

Measures Section 23.4.5.4.3(a).

(b) At least fifteen Business Days in advance of the opening of the ICAP Spot Market Auction, the Responsible Market Party for a Behind-the-Meter Net Generation Resource may request the ISO to make a determination regarding physical withholding that the sale of Net Unforced Capacity in a Mitigated Capacity Zone to its Host Load does not constitute physical withholding. Prior to reaching its decision on such a request, the ISO shall provide its preliminary determination to the Market Monitoring Unit for review and comment. *See* Market Mitigation Measures Section 23.4.5.4.3(b).

30.4.6.2.9 Prior to reaching its decision regarding whether the presumption of control of Unforced Capacity has been rebutted, the ISO shall provide its preliminary determination to the Market Monitoring Unit for review and comment. *See* Market Mitigation Measures Section 23.4.5.5.

30.4.6.2.10 Any proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone Unforced Capacity market, or to de-rate the amount of Installed Capacity available from such supplier, may be subject to audit and review by the ISO if the ISO determines that such action could reasonably be expected to affect Market-Clearing Prices in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone subsequent to such action; provided, however, no audit and review shall be necessary if the Installed Capacity Supplier is a Generator that is being retired or removed from a Mitigated Capacity Zone as the result of a Forced Outage that began on or after the effective date of the amendments to Section

23.4.5.6.1 of this Services Tariff that was determined by the ISO to be a Catastrophic Failure. Such an audit or review shall assess whether the proposal or decision has a legitimate economic justification or is based on an effort to withhold Installed Capacity physically in order to affect prices. The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment. *See* Market Mitigation Measures Section 23.4.5.6.

30.4.6.2.11 Any reclassification of a an Installed Capacity Supplier that is a Generator in a Mitigated Capacity Zone from a Forced Outage that began on or after the effective date of Section 23.4.5.6.2 of this Services Tariff to an ICAP Ineligible Forced Outage by a Market Party or otherwise, pursuant to the terms of Section 5.18.2.1 of this Services Tariff, may be subject to audit and review by the ISO if the ISO determines that such reclassification could reasonably be expected to affect the Market-Clearing Price in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone in which the Generator(s) that is the subject of the reclassification is located, subsequent to such action; provided, however, if the Market Party's Generator experienced the Forced Outage as a result of a Catastrophic Failure, the reclassification of a Generator in a Mitigated Capacity Zone from a Forced Outage to an ICAP Ineligible Forced Outage shall not be subject to audit and review pursuant to Section 23.4.5.6.2 of this Services Tariff.

The audit and review pursuant to the above paragraph shall assess whether the reclassification of the Generator in a Mitigated Capacity Zone from a Forced Outage to an ICAP Ineligible Forced Outage had a legitimate economic justification or is based on an effort to withhold Installed Capacity physically in order to affect prices. The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment.

The audit and review pursuant to Section 23.4.5.6.2.1 of this Services Tariff shall be deferred by the ISO beyond the time period established in ISO Procedures for the audit and review until the ISO's receipt of data pursuant to Section 23.4.5.6.2.2 if the Generator was in a Forced Outage for at least 180 days before the reclassification and one or more Exceptional Circumstances delayed the acquisition of data necessary for the ISO's audit. If, at the time the ISO acquires the necessary data, the Market Party has Commenced Repair of the Generator, or the Generator is determined by the ISO to have had a Catastrophic Failure, the Market Party shall not be subject to an audit and review pursuant to Section 23.4.5.6.2.1 of this Services Tariff. The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment.

30.4.6.2.12 When evaluating an Examined Facility or NCZ Examined Project pursuant to Section 23.4.5.7 of the Market Mitigation Measures, the ISO shall seek comment from the Market Monitoring Unit on matters relating to the determination of price projections, cost calculations, and the methodology the ISO will use to project net Energy and Ancillary Services for each UDR project, and the inputs used to perform the calculation the ISO's draft list of recommended Exempt Renewable Technologies and the basis for the recommendation; requests pursuant to Section 23.4.5.7.14.1.2(e)(C) regarding whether a "contract" (as defined in Section 23.4.5.7.14.2(e) would make it ineligible to obtain or (if previously granted) retain a Self Supply Exemption. As required by Section 23.4.5.7 of Attachment H to this Services Tariff, the Market Monitoring Unit shall prepare a written report discussing factors that affect the ISO's mitigation exemption and Offer Floor determinations, and confirming whether the ISO's Offer Floor and exemption determinations and calculations conducted pursuant to Sections 23.4.5.7.2 and 23.4.5.7.6, the NYISO's determination of eligible or ineligible for an exemption pursuant to Section 23.4.5.7.9, 23.4.5.7.13, and 23.4.5.7.14 were conducted in accordance with the terms of the Services Tariff, and if not, identifying the flaws inherent in the ISO's approach. This report shall be presented concurrent with the ISO's posting of its mitigation exemption and Offer Floor determinations. Pursuant to Section 23.4.5.7.8 of the Market Mitigation Measures, the ISO shall also consult with the Market Monitoring Unit when evaluating whether any existing or proposed Generator or UDR project in a Mitigated Capacity Zone, except New York City, has Commenced Construction, and determinations of whether it shall be exempted from an Offer Floor under that Section. Prior to the ISO making an exemption determination pursuant to Section 23.4.5.7.8, the Market Monitoring Unit shall provide the ISO a written opinion and recommendation. The Market Monitoring Unit shall also provide a public report on its assessment of an ISO determination that an existing or proposed Generator or UDR project is exempt from an Offer Floor under Section 23.4.5.7.8. *See* Market Mitigation Measures Section 23.4.5.7.

30.4.6.2.13 RMR Generator Energy and Ancillary Service Market Participation Rules.

If a new operating constraint arises while a Generator is an Interim Service Provider that prevents the Market Party from offering all or a portion of the Generator's capability via an ISO-committed flexible Bid, the Market Party shall promptly inform the ISO of the change, shall provide all documentation requested by the ISO or by the Market Monitoring Unit, and shall permit the ISO and/or the Market Monitoring Unit to inspect the affected Generator (including all requested plant records) on five days prior notice. *See* Market Mitigation Measures Section 23.6.1.1.3.

The ISO, in consultation with the Market Monitoring Unit, may review and update an Interim Service Provider's reference levels. The Generator Owner may propose updates to its Interim Service Provider's reference levels. The ISO shall make the ultimate determination with regard to each reference level. *See* Market Mitigation Measures Section 23.6.2.2.

In advance of the execution of an RMR Agreement, the ISO, in consultation with the Market Monitoring Unit and the Generator Owner, shall review and update the reference levels for each affected Generator. The ISO shall make the ultimate determination with regard to each reference level. *See* Market Mitigation Measures Section 23.6.2.3.

If a possible RMR Generator or Interim Service Provider faces operational constraints the ISO, in consultation with the Market Monitoring Unit and the Generator Owner, will develop reference levels that will permit the Generator to operate consistent with the identified constraints, while ensuring that the Generator will be available (a) to resolve the Reliability Need the Generator is being retained to address, and (b) for economic commitment when appropriate. *See* Market Mitigation Measures Section 23.6.2.3.1.

If a physical change to the RMR Generator occurs that alters the RMR Generator's capabilities (*e.g.*, damage to the generator or Capital Expenditures that alter an RMR Generator's capabilities), then the ISO shall determine revised reference levels in consultation with the Market Monitoring Unit and the Generator Owner. *See* Market Mitigation Measures Section 23.6.2.4.4.

The ISO and the Generator Owner, in consultation with the Market Monitoring Unit, may mutually agree to a reference level change that they expect will better reflect an RMR Generator's actual operating characteristics or variable costs. *See* Market Mitigation Measures Section 23.6.2.4.5.

30.4.6.3 Market Monitoring Unit responsibilities set forth in the ISO Services Tariff

30.4.6.3.1 The ICAP Demand Curve periodic review schedule and procedures shall provide an opportunity for the Market Monitoring Unit to review and comment on the draft request for proposals, the independent consultant's report, and the ISO's proposed ICAP Demand Curves. *See* ISO Services Tariff Sections 5.14.1.2.1.5 and 5.14.1.2.2.4.5.

30.4.6.3.2 The new capacity zone periodic review shall provide an opportunity for the Market Monitoring Unit to review and comment on the NCZ Study, and any proposed NCZ tariff revisions. See ISO Services Tariff Sections 5.16.1.3 and 5.16.4.

30.4.6.4 Market Monitoring Unit responsibilities set forth in the Rate Schedules to the ISO Services Tariff.

30.4.6.4.1 Responsibilities related to the Regulation Service Demand Curve

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure Regulation Service at a quantity and/or price point different than those specified in Section 15.3.7 of Rate Schedule 3 to the ISO Services Tariff. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to 90 days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

After the first year the Regulation Service Demand Curve is in place, the ISO shall perform periodic reviews, subject to the scope requirement specified in Section 15.3.7 of Rate Schedule 3 to the ISO Services Tariff, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Regulation Service Demand Curve. *See* Section 15.3.7 of Rate Schedule 3 to the ISO Services Tariff.

30.4.6.4.2 Responsibilities related to the Operating Reserves Demand Curves and Scarcity Reserve Demand Curve

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure any Operating Reserve product at a quantity and/or price point different than those specified in Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified in Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to 90 days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

After the first year the Operating Reserves Demand Curves are in place, the ISO shall perform periodic reviews, subject to the scope requirement specified in Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve. *See* Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff.

30.4.6.5 Market Monitoring Unit responsibilities set forth in the Attachments to

the ISO Services Tariff (other than the Market Mitigation Measures).

30.4.6.5.1 Responsibilities related to Transmission Shortage Cost

The ISO may periodically evaluate the Transmission Shortage Cost to determine whether it is necessary to modify the Transmission Shortage Cost to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this evaluation.

If the ISO determines that it is necessary to modify the Transmission Shortage Cost in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to 90 days, provided however the ISO shall file such change with the Commission pursuant to § 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change. *See* Section 17.1.4 of Attachment B to the ISO Services Tariff.

30.4.6.6 Market Monitoring Unit responsibilities set forth in the ISO OATT

30.4.6.7 Market Monitoring Unit responsibilities set forth in the Rate Schedules to the ISO OATT

30.4.6.8 Market Monitoring Unit responsibilities set forth in the Attachments to the ISO OATT

30.4.6.8.1 Responsibilities related to implementing new scheduling path prohibitions

If the ISO, acting in consultation with its Market Monitoring Unit, identifies transmission scheduling paths that are being used to schedule External Transactions in a manner that is not consistent with the manner in which power is actually expected to flow, the ISO may submit a compliance filing in FERC Docket No. ER13-780 proposing to expand the list of prohibited scheduling paths included in Section 16.3.3.8 of the ISO OATT. The ISO's compliance filing will include, or be accompanied by, a discussion of the Market Monitoring Unit's position regarding the ISO's proposal to add a new prohibited scheduling path or new prohibited scheduling paths. The Market Monitoring Unit's position may be explained in the ISO's filing letter, be set forth in an accompanying affidavit, or be submitted by the Market Monitoring Unit as a companion filing or as comments on the ISO's compliance filing in Docket No. ER13-780. *See* Section 16.3.3.8 of Attachment J to the ISO OATT.

30.4.6.8.2 Responsibilities related to the draft Reliability Needs Assessment

Following the Management Committee vote, the draft Reliability Needs Assessment (RNA), with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft RNA will be provided to the Market Monitoring Unit for its review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. *See* Section 31.2.3.2 of Attachment Y to the ISO OATT.

30.4.6.8.3 Responsibilities related to the draft Comprehensive Reliability Plan

Following the Management Committee vote, the draft Comprehensive Reliability Plan (CRP), with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CRP will also be provided to the Market Monitoring Unit for its review and consideration of whether market rule changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. *See* Section 31.2.7.2 of Attachment Y to the ISO OATT.

30.4.6.8.4 Responsibilities related to the draft Congestion Analysis and Resource Integration Study

Following the Management Committee vote, the draft Congestion Analysis and Resource Integration Study (CARIS), with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CARIS will be provided to the Market Monitoring Unit for its review and consideration. *See* Section 31.3.2.2 of Attachment Y to the ISO OATT.

30.4.6.8.5 Responsibilities related to the draft Public Policy Transmission Planning Report

The ISO will provide the draft Public Policy Transmission Planning Report to the Market Monitoring Unit for its review and consideration of any impact on the ISO-administered markets of regulated transmission solutions proposed to satisfy a Public Policy Transmission Need. *See* Sections 31.4.9 and 31.4.10.1 of Attachment Y to the ISO OATT. The Market Monitoring Unit's evaluation will be provided to the Management Committee before the Management Committee's advisory vote. *See* Section 31.4.10.1 of Attachment Y. Following the Management Committee vote, the draft Public Policy Transmission Planning Report, with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrent with the submission to the ISO Board of the draft Public Policy Transmission Planning Report, the Market Monitoring Unit's evaluation will be provided to the ISO Board. *See* Section 31.4.7 of Attachment Y to the ISO OATT.

30.4.6.8.6 Responsibilities Related to Market Monitoring Unit Review of Reliability Must Run Costs and RMR Avoidable Cost Determinations

The ISO shall seek comments from the Market Monitoring Unit on matters relating to the inputs and the calculations the ISO performed pursuant to Section 38.8 of Attachment FF of the ISO OATT. *See* Section 38.8.2 of Attachment FF of the ISO OATT.

The ISO shall seek comments from the Market Monitoring Unit on its review of Proposed Additional Costs and its determinations of Substantiated Additional Costs under Section 38.16 of Attachment FF of the ISO OATT. *See* Section 38.16.2.2 of Attachment FF of the ISO OATT.

Concurrent with the ISO or a Generator filing with the Commission an RMR Agreement pursuant to Sections 38.11.3, 38.11.4 or 38.11.5 of Attachment FF to the ISO OATT, the Market Monitoring Unit shall publish a report. The report shall review the ISO's determination of the highest net present value offer (or more than one offer) to provide RMR service in accordance with Sections 38.8, 38.9 and 38.10 of Attachment FF to the ISO OATT. In the event that cost alone did not provide for a clear delineation between two or more RMR Service Offers, the report shall also review the ISO's consideration of the Generator Owner's proposed changes to the *Form of Reliability Must Run Agreement* and the operational, performance and market impacts, and the size of the Generators. If the RMR Agreement contains RMR Avoidable Costs and an Availability and Performance Rate, the report shall also review the inputs to, and ISO's calculation of, the RMR Avoidable Costs and the Availability and Performance Rate. *See* Section 38.18.3 of Attachment FF to the ISO OATT.

30.4.6.9 Market Monitoring Unit responsibilities set forth in other documents that have been formally filed with the Commission

30.4.6.10 Market Monitoring Unit responsibilities set forth in the *Form of Reliability Must Run Agreement, Appendix C to Attachment FF of the ISO OATT*

The ISO and the Market Monitoring Unit shall monitor deviations from each RMR Generator's historic planned outage schedules. Owner shall promptly respond to ISO and Market Monitoring Unit requests for explanations, information and data regarding or supporting outage schedules. *See* Section 7.1.3 of the *Form of Reliability Must Run Agreement.*

The ISO and the Market Monitoring Unit shall monitor deviations from each RMR Generator's historic forced outage rate. Owner shall promptly respond to ISO and Market Monitoring Unit requests for explanations, information and data regarding or supporting forced outages, including the time required to return from a Forced Outage. *See* Section 7.2.2 of the *Form of Reliability Must Run Agreement.*

30.4.6.11 Additional Market Monitoring Unit responsibilities related to Reliability Must Run Agreements

The Market Monitoring Unit shall review any Owner-Developed Rate that is filed with the Commission as described in Section 4.5 of the *Form of Reliability Must Run Agreement*. The Market Monitoring Unit shall intervene and participate in Commission proceedings concerning such filings. It shall submit, as appropriate, comments or a protest in such a proceeding describing its review and informing the Commission of whether it has found a proposed Owner Developed Rate to be consistent with, or in excess of, an RMR Generator's full cost of service. The Market Monitoring Unit shall also inform the Commission of whether: (i) it believes the proposed Owner Developed Rate, including its terms and conditions of service, is or is not just and reasonable; and (ii) it has any other concerns with the proposed Owner Developed Rate.

30.4.7 Availability of Data and Resources to Market Monitoring Unit

30.4.7.1 The ISO shall ensure that the Market Monitoring Unit has sufficient access to ISO resources, personnel and market data to enable the Market Monitoring Unit to carry out its functions under Attachment O. Consistent with Section 30.6.1 of Attachment O, the Market Monitoring Unit shall have complete access to the ISO's databases of market information.

30.4.7.2 Any data created by the Market Monitoring Unit, including but not limited to reconfiguration of the ISO's data, will be kept within the exclusive control of the Market Monitoring Unit. The Market Monitoring Unit may share the data it creates, subject to the limitations on distribution of and obligation to protect the confidentiality of Protected Information that are contained in Attachment O, the ISO Services Tariff, and the ISO's Code of Conduct.

30.4.7.3 Where data outside the ISO's geographic footprint would be helpful to the Market Monitoring Unit in carrying out its duties, the Market Monitoring Unit should seek out that data (with assistance from the ISO, where appropriate).

30.5 Monitoring Implementation And Responsibilities

30.5.1 Monitoring Methods, Procedures and Resources

30.5.1.1 Adequacy

The Market Monitoring Unit and MMA shall develop and implement methods, procedures, staffing and other resources for achieving the purposes and objectives of Attachment O. Such methods, procedures, staffing and other resources shall be appropriate to realizing the purposes and objectives and effective implementation of Attachment O, and shall be subject to review, modification and approval by the ISO's CEO or the CEO's designee, the COO, where the measures involve the MMA, or by the ISO's Board, where the measures involve the Market Monitoring Unit.

30.5.1.2 Conditions, Functions or Actions Monitored

The monitoring methods, procedures, staffing and other resources shall ensure, to the extent practicable, that the Market Monitoring Unit and the ISO (consistent with the division of duties specified above) are able to achieve the purposes and objectives of Attachment O through review and analysis of conditions, functions or actions affecting the competitiveness, economic efficiency and proper operation of any of the New York Electric Markets, including but not limited to the following, as and to the extent each may be deemed relevant to the purposes and objectives of Attachment O by the Market Monitoring Unit or by the ISO:

30.5.1.2.1 The nature, extent and causes of any undue concentration in the ownership or control of generation or other facilities in or affecting any of the New York Electric Markets;

30.5.1.2.2 Any evidence of or other information relating to collusive or other anticompetitive or inefficient behavior in or affecting any of the New York

Electric Markets;

30.5.1.2.3 The bids or offers submitted to each of the New York Electric Markets administered by the ISO, the evaluation of those bids or offers, and as appropriate the relationship of those bids or offers to marginal or other costs;

30.5.1.2.4 Schedules submitted to the ISO for bilateral or other transactions;

30.5.1.2.5 Unit commitment and dispatch in the New York Control Area;

30.5.1.2.6 The determination and level of LBMPs or other prices in the New York Electric Markets;

30.5.1.2.7 The provision of transmission services in the New York Control Area, including but not limited to auctions and other markets for TCCs;

30.5.1.2.8 The nature and extent, causes of, and costs of and charges for, transmission congestion on the New York State Transmission System or, to the extent practicable, transmission congestion on any other system that affects any of the New York Electric Markets;

30.5.1.2.9 Competitive or other market impacts of tariffs and agreements, or other rules, standards or procedures, governing or affecting any of the New York Electric Markets;

30.5.1.2.10 The need for and the implementation and efficacy of market power mitigation or other remedial measures for competitive or other market defects, including mitigation measures implemented in accordance with the provisions of Attachment O or other mitigation measures that the FERC has authorized or directed the ISO to implement;

30.5.1.2.11 The need for and the implementation and efficacy of appropriate sanctions or other remedial measures for violations of or other failures to comply with any tariff or services agreement, or any rule, standard or procedure, or any market power mitigation or other remedial measure, to the extent such violation or failure to comply impairs or threatens to impair the competitiveness or economic efficiency of any of the New York Electric Markets;

30.5.1.2.12 To the extent practicable, conditions or events outside the New York Control Area affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold in any of the New York Electric Markets; and

30.5.1.2.13 Such other conditions, functions or actions as may be approved by the CEO or the CEO's designee, the COO, or by the Board (as appropriate).

30.5.3 Legal Advice

The Market Monitoring Unit and MMA may consult legal counsel for the ISO for advice on antitrust, regulatory or other legal issues pertinent to Attachment O.

30.6 Data Collection and Disclosure

30.6.1 Access to ISO Data and Information

For purposes of carrying out their responsibilities under Attachment O, the Market Monitoring Unit and MMA shall have access to, and shall endeavor primarily to rely upon (but shall not be limited to), data or other information gathered or generated by the ISO in the course of its operations. This data and information shall include, but not be limited to, data or information gathered or generated by the ISO in connection with its scheduling, commitment and dispatch of generation, its determination of Locational Based Marginal Pricing, its operation or administration of the New York State Transmission System, and data or other information produced by, or required to be provided to the ISO under its Tariffs, the New York Independent System Operator Agreement, the New York State Reliability Council Agreement, or any other relevant tariffs or agreements.

30.6.2 Data from Market Parties

30.6.2.1 Data Requests

If the Market Monitoring Unit or MMA, determines that additional data or other information is required to accomplish the objectives of Attachment O or of the Market Mitigation Measures, the ISO may request the persons or entities possessing, having access to, or having the ability to generate or produce such data or other information to furnish it to the ISO or to its Market Monitoring Unit. Any such request shall be accompanied by an explanation of the need for such data or other information, a specification of the form or format in which the data is to be produced, and an acknowledgment of the obligation of the ISO and its Market Monitoring Unit to maintain the confidentiality of data or information appropriately designated as Protected Information by the party producing it.

A party receiving an information request from the ISO shall furnish all information, in the requested form or format, that is: (i) included on the below list of categories of data or information that it may routinely request from a Market Party; or (ii) reasonably necessary to achieve the purposes or objectives of Attachment O, not readily available from some other source that is more convenient, less burdensome and less expensive, and not subject to an attorney-client or other generally recognized evidentiary doctrine of confidentiality or privilege.

The categories data or information that may be routinely requested shall be limited to data or information the routine provision of which would not be unduly burdensome or expensive, and which has been reasonably determined by the ISO, in consultation with its Market Monitoring Unit, to be likely to be relevant to the purposes and objectives of Attachment O or the Market Mitigation Measures.

30.6.2.2 Categories of Data the ISO May Request from Market Parties

The following categories of data or information may be obtained by the ISO from Market Parties in accordance with Attachment O. Market Parties shall retain the following categories of data or information for the period specified in Section 30.6.3 of Attachment O.

30.6.2.2.1 Production costs – Data or information relating to the costs or operating a specified Electric Facility (for generating units such data or information shall include, but not be limited to, heat rates, start-up fuel requirements, fuel purchase costs, and operating and maintenance expenses) or data or information relating to the costs of providing load reductions from a specified facility participating as a Demand Side Resource in the ISO Operating Reserves or Regulation Service markets.

30.6.2.2.2 Opportunity costs – Data or information relating to a claim of opportunity costs, including, but not limited to, contracts or price quotes.

30.6.2.2.3 Logs – Data or information relating to the operating status of an Electric Facility, including, for generating units, generator logs showing the generating status of a specified unit or data or information relating to the operating status of a specified facility participating as a Demand Side Resource in the ISO Operating Reserves or Regulation Service markets. Such data or information shall include, but not be limited to, any information relating to the validity of a claimed forced outage or derating of a generating unit or other Electric Facility or a facility participating as a Demand Side Resource in the ISO Operating Reserves or Regulation Service markets.

30.6.2.2.4 Bidding or Capacity Agreements – Documents, data, or information relating to a Market Party or its Affiliate conveying to or receiving from another entity the ability: (i) to determine the bid/offer of (in any of the markets administered by the ISO); (ii) to determine the output level of; or (iii) to withhold; generation that is owned by another entity. At the request of the producing entity, the ISO may (but is not required to) permit the documents, data or information produced in response to the foregoing specification to be partially redacted, or the ISO may agree to other measures for the protection of confidential or commercially sensitive information, provided that the ISO receives the complete text of all provisions relating to the subjects specified in this Section 30.6.2.2.4

30.6.2.2.5 Other Cost and Risk Data Supporting Reference Levels or ICAP mitigation determinations or Going-Forward Costs – All data or information not specifically identified above that: (i) supports or relates to a Market Party's claimed, requested, or approved reference levels or Going-Forward Costs (as that term is defined in the Market Mitigation Measures) for a particular resource; or (ii) are necessary for the ISO to make a mitigation determination under Services Tariff Section 23.4.5.7, including data or information: (a) necessary to determine a Market Party's Unit Net CONE (as that term is defined in the Market Mitigation Measures) for a particular resource; or (b) required to evaluate a Market Party for a mitigation determination, including information from a Market Party's Affiliates, as appropriate.

30.6.2.2.6 Information Related to RMR Agreements -- All information that the NYISO is authorized to obtain under Appendix F to Attachment Y to the OATT.

30.6.2.2.7 Ownership and Control – Data or information identifying a Market Party's Affiliates.

30.6.2.3 Enforcement of Data Requests

30.6.2.3.1 A party receiving a request for data or information specified in Section 30.6.2.2 of Attachment O shall promptly provide it to the ISO, and may not contest the right of the ISO to obtain such data or information except to the extent that the party has a good faith basis to assert that the data or information is not included in any of the categories on the list.

30.6.2.3.2 If a party receiving a request for data or information not specified in Section 30.6.2.2 of Attachment O believes that production of the requested data or information would impose a substantial burden or expense, or would require the party to produce information that is not relevant to achieving the purposes or objectives of Attachment O, or would require the production of data or information of extraordinary commercial sensitivity, the party receiving the request shall promptly so notify the ISO, and the ISO shall review the request with the receiving party with a view toward determining whether, without unduly compromising the objectives of Attachment O, the request can be narrowed or otherwise modified to reduce the burden or expense of compliance, or special confidentiality protections are warranted, and if so shall so modify the request or the procedures for handling data or information produced in response to the request.

30.6.2.3.3 If the ISO determines that the requested information has not or will not be provided within a reasonable time, the ISO may invoke the dispute resolution provisions of the ISO Services Tariff to determine the ISO's right to obtain the requested information. The parties may agree to submit any such determination to binding arbitration and may seek expedited resolution, in accordance with the applicable dispute resolution procedures. The ISO may initiate judicial or regulatory proceedings at any time to compel the production of the requested information.

30.6.3 Data Retention

30.6.3.1 Section 30.6.3 of Attachment O sets forth requirements for the retention of market information by the ISO, by the Market Monitoring Unit and by Market Parties. The provisions of this data retention policy are binding on the ISO, on the Market Monitoring Unit and on Market Parties.

30.6.3.2 Except as specified herein, a Market Party shall retain the data and information specified in Section 30.6.2.2 of Attachment O for a period of six years from the date to which the data relates.

30.6.3.3 The ISO or its Market Monitoring Unit (as appropriate) shall retain for a period of six years from the date to which the data or information relates:

30.6.3.3.1 data or information required to be submitted to, or otherwise used by, the ISO in connection with the bidding, scheduling and dispatch of resources or loads in the New York energy, ancillary services, TCC or Installed Capacity (ICAP) markets;

30.6.3.3.2 data or information used or monitored by the ISO on system conditions in the New York Control Area, including but not limited to transmission constraints or planned or forced facility outages, that materially affect transmission congestion costs or market conditions in the New York energy, ancillary services or ICAP markets;

30.6.3.3.3 data or information collected by the ISO or by the Market Monitoring Unit (as appropriate) in the course of their implementation of Attachment O or the Market Mitigation Measures, on conditions in markets external to New York, or on fuel prices or other economic conditions that materially affect market conditions in the New York energy, ancillary services, TCC or ICAP markets;

30.6.3.3.4 data or information relating to the imposition of, or a decision not to impose, mitigation measures; and

30.6.3.3.5 such other data or information as the MMA or Market Monitoring Unit deem it necessary to collect in order to implement Attachment O or the Market Mitigation Measures.

30.6.3.4 The foregoing obligations to retain data or information shall not alter any data retention requirements that may otherwise be applicable to the ISO, to the Market Monitoring Unit, or to a Market Party; nor shall any such other data retention requirement alter the requirements specified above.

30.6.3.5 The ISO, Market Monitoring Unit or a Market Party may, at its option, purge or otherwise destroy any data or information that has been retained for the longest applicable period specified above, provided the retention of such data or information is not mandated by the FERC, the New York Public Service Commission, or other applicable requirement or obligation.

30.6.3.6 Compliance with the requirements specified herein for the retention of data or information shall not suspend or waive any statute of limitations or doctrine of laches, estoppel or waiver that may be applicable to any claim asserted against the ISO, the Market Monitoring Unit, or a Market Party.

30.6.4 Confidentiality

The Market Monitoring Unit and the ISO shall use all reasonable procedures necessary to protect and preserve the confidentiality of Protected Information, provided that such information is not available from public sources, is not otherwise subject to disclosure under any tariff or agreement administered by the ISO, and is properly designated as Protected Information. The ISO and the Market Monitoring Unit's obligation to protect and preserve the confidentiality of

Protected Information shall be of a continuing nature, and shall survive the rescission, termination or expiration of this Plan.

Except as may be required by subpoena or other compulsory process, or as authorized in the ISO's Tariffs and governing documents (including this Plan), the Market Monitoring Unit and the ISO shall not disclose Protected Information to any person or entity without the prior written consent of the party that the Protected Information pertains to. Upon receipt of a subpoena or other compulsory process for the disclosure of Protected Information, the ISO and/or the Market Monitoring Unit shall promptly notify the party that the Protected Information pertains to, and shall provide all reasonable assistance requested by the party to prevent or limit disclosure. Upon receipt of a subpoena or other compulsory process for the disclosure of Protected Information that was provided to the ISO or the Market Monitoring Unit pursuant to Section 30.6.6 below, the ISO or the Market Monitoring Unit, as appropriate, shall promptly notify the entity that provided the Protected Information and shall provide all reasonable assistance requested by that party to prevent or limit disclosure. Nothing in this Plan alters any existing statutory jurisdiction or authority to compel disclosure that may apply to the ISO, its Market Monitoring Unit, or to any other ISO, RTO, or market monitoring unit.

The ISO may, in consultation with the Market Monitoring Unit, adopt further or different procedures for the designation of information as Protected Information, or for the reasonable protection of Protected Information, after providing an opportunity for interested parties to review and comment on such procedures; provided, however, that such further or different procedures shall not permit the ISO or Market Monitoring Unit to disclose data or information that would be protected from disclosure under the procedures in place at the time the data or information was provided to the ISO or to the Market Monitoring Unit.

30.6.5 Collection and Availability of Information

30.6.5.1 The ISO and the Market Monitoring Unit shall regularly collect and maintain the information necessary for implementing Attachment O.

The ISO and the Market Monitoring Unit may provide Protected Information to each other as they determine necessary to carry out the purposes of this Plan.

30.6.5.2 The ISO, in consultation with the Market Monitoring Unit, shall make publicly available: (i) a description of the categories of data and information collected and maintained by the MMA and Market Monitoring Unit; (ii) such data or information as may be useful for the competitive or efficient functioning of any of the New York Electric Markets that can be made publicly available consistent with the confidentiality of Protected Information; and (iii) if and to the extent consistent with confidentiality requirements, such summaries, redactions, abstractions or other non-confidential compilations, versions or reports of Protected Information as may be useful for the competitive or efficient functioning of any of the New York Electric Markets. Any such proposed methods for creating non-confidential reports of such information shall only be adopted after provision of a reasonable opportunity for, and consideration of, the comments of Market Parties and other interested parties. All such proposed or adopted methods shall be set forth in the ISO Procedures, shall be made available through the ISO web site or comparable means, and shall be subject to review and approval by the Board.

30.6.5.3 Consistent with the foregoing requirements, the ISO and its Market Monitoring Unit shall make available, through the ISO web site or comparable means, such reports on the New York Electric Markets as they determine will, at reasonable cost, facilitate competition in those markets.

30.6.5.4 Any data or other information collected by the ISO relating to any of the New York Electric Markets shall be provided upon request, and without undue discrimination between requests, to a Market Party, other interested party, or an Interested Government Agency, provided: (i) such data or information is not Protected Information, or the party designating it as Protected Information has consented in writing to its disclosure; (ii) such information can be provided without undue burden or disruption to, or interference with the other duties and responsibilities of the ISO; and (iii) the requesting party, if other than an Interested Government Agency, provides appropriate guarantees of reimbursement of the costs to the ISO of compiling and disclosing the data or information. If the ISO determines that doing so would not be unduly burdensome or expensive, or inconsistent with maintaining the competitiveness or economic efficiency of any market, the ISO shall make data or information provided in accordance with this paragraph available to interested parties through the ISO web site or other appropriate means.

30.6.5.5 The New York Public Service Commission and any Other State Commission may make tailored requests to the Market Monitoring Unit for information related to general market trends and the performance of the New York Electric Markets. If the Market Monitoring Unit determines that such a request is not unduly burdensome, it shall provide the information sought, subject to the restrictions and limitations established in Sections 30.6.5.5.1, 30.6.5.5.2 and 30.6.5.5.4, below.

30.6.5.5.1 Except as provided in this Section 30.6.5.5.1, the Market Monitoring Unit shall not provide Protected Information to the New York Public Service Commission or to an Other State Commission in response to a request under Section 30.6.5.5 above. The Market Monitoring Unit may, but is not required to, provide Protected Information to the New York Public Service Commission or any Other State Commission when the party to which the requested Protected Information pertains has consented in writing to its disclosure. The Market Monitoring Unit may, but is not required to, provide Protected Information to the New York Public Service Commission or an Other State Commission if the general counsel/chief legal officer of the requesting state commission certifies, in writing, that: (i) the requested Protected Information will be protected from disclosure by law (and provides copies of the relevant laws, rules or regulations under which the requested Protected Information is protected from public disclosure); (ii) the requested Protected Information will be treated as confidential to the fullest extent of the laws of its state; (iii) the state commission will promptly notify the Market Monitoring Unit if it receives a request for disclosure of all or part of the Protected (iv) the state commission agrees to provide all reasonable and permissible assistance to prevent further disclosure of Protected Information provided by the Market Monitoring Unit to the state commission in response to a request governed by Section 30.6.5.5 of this Plan; and (v) the Protected Information will not be used for a state enforcement action.

The Market Monitoring Unit shall not provide Protected Information it received from another ISO or RTO, or from a market monitoring unit for another ISO or RTO, pursuant to the authority to share information granted by Section 30.6.6 of this Plan, in response to a request under Section 30.6.5.5 of this Plan. Instead, the Market Monitoring Unit shall identify to the requesting state commission the ISO, RTO or market monitoring unit that provided the information to the Market Monitoring Unit, so that the New York Public Service Commission or Other State Commission may request the Protected Information directly from its source in accordance with the provisions of the providing entity's tariffs, other governing documents, or an applicable law or rule.

30.6.5.5.2 Prior to disclosing Protected Information pertaining to a particular Market Party in response to a tailored request made under Section 30.6.5.5, the Market Monitoring Unit shall (1) notify the Market Party or Parties to which the Protected Information pertains of the request and describe the information that the Market Monitoring Unit proposes to disclose, and (2) allow the Market Party or Parties a reasonable time to object to the disclosure and to provide context to the Protected Information related to it. Providing the opportunity for Market Parties to object to disclosure, or to provide context to the information being produced shall not be permitted to unduly delay its release.

30.6.5.5.3 Section 30.6.5.5 of Attachment O pertains to requests by the New York Public Service Commission and Other State Commissions to the Market Monitoring Unit to provide information. Section 30.6.4 of Attachment O addresses how the Market Monitoring Unit responds to compulsory processes, such as subpoenas and court orders.

30.6.5.5.4 In responding to a request under Section 30.6.5.5 of Attachment O, the Market Monitoring Unit shall not knowingly provide information to the New York Public Service Commission, or to any Other State Commission, that is designed to aid a state enforcement action.

30.6.5.5.5 The New York Public Service Commission or any Other State Commission may petition FERC to require the ISO to release information that the Market Monitoring Unit is not required to release, or that the Market Monitoring Unit is proscribed from releasing, under this Section 30.6.5.5 of Attachment O.

30.6.5.6 The Market Monitoring Unit shall respond to information and data requests issued to it by the Commission or its staff. If the Commission or its staff, during the course of an investigation or otherwise, requests Protected Information from the Market Monitoring Unit that is otherwise required to be maintained in confidence, the Market Monitoring Unit shall provide the requested information to the Commission or its staff within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit shall, consistent with any FERC rules or regulations that may provide for privileged treatment of that information, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall not be held liable for any losses, consequential or otherwise, resulting from the Market Monitoring Unit divulging such Protected Information pursuant to a request under this Section 30.6.5.6. After the Protected Information has been provided to the Commission or its staff, the Market Monitoring Unit shall immediately notify any affected Market Participant(s) when it becomes aware that a request for disclosure of such Protected Information has been received by the Commission or its staff, or a decision to disclose such Protected Information has been made by the Commission, at which time the Market Monitoring Unit and the affected Market Participant(s) may respond before such information would be made public, pursuant to the Commission's rules and regulations that may provide for privileged treatment of information provided to the Commission or its staff.

30.6.6 Sharing Information with Other ISOs/RTOs and Market Monitoring Units

30.6.6.1 The Market Monitoring Unit or the ISO may disclose Protected Information to another ISO or RTO or to another ISO or RTO's market monitoring unit (each a "Requesting Entity" in Section 30.6.6 of the Plan) if the Requesting Entity submits a written request stating that the requested Protected Information is necessary to an investigation or evaluation that the Requesting Entity is undertaking within the scope of its approved tariffs, other governing documents, or an applicable law or rule to determine (a) if market power is being, or has been, exercised, (b) if market manipulation is occurring or has occurred, or (c) if a market design flaw exists between interconnected markets, and either (i) demonstrates (by providing copies of the relevant documents, provisions, statutes, rules, orders, etc.) that its tariff or other governing document limits further disclosure of the Protected Information in a manner that satisfies all of the requirements set forth in Section 30.6.6.1.1, below, or (ii) executes a non-disclosure agreement with the ISO and/or the Market Monitoring Unit that incorporates all of the requirements set forth in Section 30.6.6.1.1 below, and provides a written certification that the Requesting Entity possesses legal authority to enter into the required non-disclosure agreement and to be bound by its terms.

30.6.6.1.1 The Requesting Entity's governing documents or non-disclosure agreement must:

(1) protect Protected Information that the ISO or the Market Monitoring Unit provides from disclosure, except where disclosure may be required by the FERC or by subpoena or other compulsory process;

(2) establish a legally enforceable obligation to treat Protected Information provided by the ISO or its Market Monitoring Unit as confidential. Such obligation must be of a continuing nature, and must survive the rescission, termination or expiration of the applicable tariff(s), other governing document(s) or non-disclosure agreement;

(3) require state commissions to request Protected Information provided by the ISO or its Market Monitoring Unit directly from the ISO or its Market Monitoring Unit, in a manner consistent with Section 30.6.5.5.1 of this Plan, and promptly inform the ISO or its Market Monitoring Unit of any requests received from a state commission for Protected Information provided by the ISO or its Market Monitoring Unit;

(4) require the Requesting Entity to promptly notify the ISO or its Market Monitoring Unit and seek appropriate relief to prevent or, if it is not possible to prevent, to

limit disclosure in the event that a subpoena or other compulsory process seeks to require disclosure of Protected Information provided by the ISO or its Market Monitoring Unit;

(5) require the Requesting Entity to promptly notify the ISO or its Market Monitoring Unit of any third party requests for additional disclosure of the Protected Information where Protected Information provided by the ISO or its Market Monitoring Unit has been disclosed to a court or regulatory body in response to a subpoena or other compulsory process, and to seek appropriate relief to prevent or limit further disclosure; and

(6) require the destruction of the Protected Information at the earlier of (i) five business days after a request from the ISO or its Market Monitoring Unit for the return of the Protected Information is received, or (ii) the conclusion or resolution of the investigation or evaluation.

30.6.6.2 The ISO or the Market Monitoring Unit may undertake a joint investigation with another ISO/RTO or with another ISO or RTO's market monitoring unit to determine (a) if market power is being, or has been, exercised, (b) if market manipulation is occurring or has occurred, or (c) if a market design flaw exists in or between interconnected markets. In such a case, the ISO and the Market Monitoring Unit may disclose Protected Information to the other ISO/RTO or market monitoring unit as necessary to achieve the objectives of the investigation; provided that the ISO or Market Monitoring Unit first receives a written certification from the other ISO/RTO or market monitoring unit that its tariffs or other governing documents meet the standards set forth in this Section

30.6.6 or executes a non-disclosure agreement.

30.6.6.3 If the ISO discloses Protected Information to a Requesting Entity that is a jurisdictional ISO or RTO, the ISO shall also provide the Protected Information to the Requesting Entity's market monitoring unit as soon as the Requesting Entity's market monitoring unit satisfies the requirements of Section 30.6.6.1.1, above.

30.6.6.4 Protected Information provided by another ISO/RTO or market monitoring unit to the ISO or to the Market Monitoring Unit pursuant to the provisions of this Plan shall either be destroyed or returned to the entity that provided the Protected Information at the earlier of (i) five business days after receipt of a request from that entity for the return of the Protected, or (ii) the conclusion or resolution of the matter being investigated.

30.7 Performance Indices and screens

30.7.1 Development of Indices and Screens

The MMA or the Market Monitoring Unit, with due consideration of the proposals and comments of Market Parties and other interested parties submitted as specified below, with the approval of the CEO or the CEO's designee, the COO, and the Market Monitoring Unit (for indices and screens developed by the MMA), or subject to review and comment by the ISO and review and approval by the Board (for indices and screens developed by the Market Monitoring Unit), shall develop, adopt and refine on the basis of experience with their application, such indices or other screens for reviewing the data or other information collected in connection with the implementation of Attachment O, or the ISO's Market Mitigation Measures, as the MMA or Market Monitoring Unit deem appropriate. All proposed or adopted indices and screens shall be described in the ISO Procedures and shall be made available through the ISO web site or comparable means, provided and to the extent that any such description does not provide details of the standards, criteria or thresholds for evaluating such data or information that would facilitate conduct inconsistent with the competitiveness or economic efficiency of any of the New York Electric Markets.

30.7.2 Consultation with Market Parties

In connection with the development of indices and screens as specified above, Market Parties or other interested parties may submit proposed indices or screens for review of the data or other information collected in connection with the implementation of Attachment O, along with any justification for the adoption thereof, to the ISO or Market Monitoring Unit for consideration and adoption if and to the extent appropriate.

30.7.3 Use of Indices and Screens

As much as practicable, the MMA and the Market Monitoring Unit shall review data or other information collected in connection with implementation of Attachment O and the Market Mitigation Measures in accordance with the indices or screens adopted as specified above; provided, however, that nothing herein shall be deemed to prevent the ISO or the Market Monitoring Unit from conducting such further or different review or evaluation of such data or information as appropriate for the effective implementation of Attachment O.

30.8 Market Power Mitigation Measures

30.8.1 Review and Regulatory Approval

A mitigation measure developed as specified below and recommended by the Market Monitoring Unit and the CEO or the CEO's designee, the COO, shall, with the review and approval of the Board, and in accordance with the ISO procedures applicable to tariff filings, be submitted by the ISO to the FERC for approval as an addendum to Attachment O or to the Market Mitigation Measures, and shall be provided as an informational submission to the other Interested Government Agencies. A market power mitigation measure shall become effective and available for use by the ISO as soon as practicable upon FERC approval.

30.8.2 Development of Mitigation Measures

The Market Monitoring Unit, with the assistance of the MMA and the approval of the Reliability and Markets Committee of the Board (or any successor committee thereto), shall propose, and refine or revise as may be appropriate in consideration of the comments of Market Parties and other interested parties and market experience, measures for the mitigation of market power in any of the New York Energy Markets administered by the ISO, and standards for determining the actual or potential existence of market power requiring the application of such measures. A description of all effective and proposed mitigation measures and of the standards for the application of each such measure shall be made available through the ISO web site or comparable means. Except for mitigation measures that the ISO is required to file in accordance with Section 23.3.2.3 of the Market Mitigation Measures, prior to the submission of any market power mitigation measure to the FERC for approval as specified above, the ISO shall notify the Market Parties and other interested parties and provide an opportunity for comment on the proposed measure, and shall submit such measure for review and vote by the Management

Committee in accordance with the procedures applicable to tariff filings.

30.8.3 Implementation of Mitigation Measures

The ISO, as directed and authorized by the CEO or the CEO's designee, the COO, shall implement the mitigation measures developed as specified above and such other mitigation measures as may be authorized or required by the FERC as a result of filings or other submissions by Market Parties or other interested parties or otherwise. The Market Monitoring Unit may participate in the implementation of mitigation measures to the extent permitted in Section 30.4.4 of Attachment O.

30.9 Complaints and Requests for Investigations

Any Market Party or other interested person or entity may at any time submit information to the Market Monitoring Unit concerning any matter relevant to the responsibilities of the Market Monitoring Unit under Attachment O, or may submit a request to the Market Monitoring Unit for the Market Monitoring Unit to conduct an investigation, or take any other action contemplated by Attachment O. Such submissions or requests may be made on a confidential basis. The Market Monitoring Unit's authority to conduct an investigation may be limited by Section 30.4.5.3 of Attachment O. The Market Monitoring Unit shall provide a copy of any such submission or request to the ISO, unless a confidential investigation request addresses the ISO's actions or inaction, and the Market Monitoring Unit determines that it would not be appropriate to reveal the submission or request to the ISO, or that it would not be appropriate to reveal the submission or request to certain ISO personnel or departments. At the time it provides a copy of a confidential submission or request to the ISO, the Market Monitoring Unit may include written instructions to the ISO staff to whom the copy of the submission or request is sent, requiring them to limit their distribution of such submission or request. ISO staff shall abide by any limitation on distribution imposed by the Market Monitoring Unit until the information is made public, or the Market Monitoring Unit, FERC, or FERC staff provide written instructions to the contrary. The MMA shall be available to assist the Market Monitoring Unit's efforts to process or investigate the submissions and requests it receives. The Market Monitoring Unit may request further relevant information available from the submitting Market Party, or from any other person or entity, as a condition of undertaking any further investigation. Following a preliminary review, acting in a timely manner, the Market Monitoring Unit shall decline to take further action, or shall carry out such investigation as it deems appropriate, or as may be required by the

Board acting on its own initiative or at the request of a Market Party or other interested party. The Market Monitoring Unit shall include a summary of its actions or decisions not to act under this Section 30.9 in its annual report to the Board. The summary included in the annual report to the Board need not contain any Protected Information.

30.10 Reports

30.10.1 Annual Reports

The Market Monitoring Unit shall prepare and submit to the Board an annual report on the competitive structure of, market trends in, and performance of, other competitive conditions in or affecting, and the economic efficiency of, the New York Electric Markets. Such report shall include recommendations for the improvement of the New York Electric Markets or of the monitoring, reporting and other functions undertaken pursuant to Attachment O and the Market Mitigation Measures. A copy of the report shall be forwarded by the Board to each of the Interested Government Agencies, with such comments or other remarks as the Board shall deem appropriate. Copies of the report shall be made publicly available by the Board by posting them on the ISO's web site, subject to redaction or other measures necessary for the protection of Protected Information.

30.10.2 Quarterly Reports

In addition to the annual report, the Market Monitoring Unit shall issue three quarterly reports that are less extensive than the annual report. Each quarterly report shall provide timely updates to the annual report, emphasizing issues of concern to the Market Monitoring Unit. Quarterly reports shall be distributed in the same manner as the annual report.

30.10.3 Report on Virtual Bid and Offer Market Design and Rules

The Market Monitoring Unit shall monitor and assess the impact of virtual bids and offers on the competitive structure and performance of, and the economic efficiency of, the ISO Administered Markets. Such monitoring and assessment shall include the effects, if any, of virtual bids and offers on any automated mitigation procedures, or any mitigation measures specified in Section 23.5 of the Market Mitigation Measures. An assessment of the market impacts of virtual bids and offers shall be included in the annual report required by Section 30.10.1, above, and in a quarterly report when the Market Monitoring Unit deems appropriate.

30.10.4 Reports on Offer Floor or Exemption Determinations

The Market Monitoring Unit shall prepare a written report as described in Section 30.4.6.2.12 confirming whether the ISO's determinations and calculations conducted pursuant to Section 23.4.5.7 were conducted in accordance with the terms of the Services Tariff, and if not, identifying the flaws inherent in the ISO's approach. The Market Monitoring Unit's report shall be presented concurrently with the ISO's posting of the exempt/non-exempt determinations.

30.10.5 Conference Calls

The Market Monitoring Unit shall participate in regular conference calls for the presentation of market data and analyses of the type regularly gathered and prepared by the Market Monitoring Unit under Attachment O, subject to limitations on dissemination of Protected Information. Market Participants, staff of the Commission and the New York Public Service Commission, and representatives of the ISO may attend such conference calls.

30.10.6 Other Reports or Filings

The Market Monitoring Unit, with the assistance of the MMA, where appropriate, shall prepare such other periodic or other reports on any matters within their purview as the Market Monitoring Unit determines are necessary, or as may be requested by the Board, the CEO or the CEO's designee, the COO, or any of the Interested Government Agencies. Unless the Board or the Interested Government Agency requesting such report specifies to the contrary, copies of such reports shall be made publicly available by the Board, subject to redaction or other measures necessary for the protection of Protected Information. All reasonable fees and expenses for the preparation of reports or other filings relating to the New York Electric Markets that are requested by an Interested Government Agency from the Market Monitoring Unit, or that are requested by an Interested Government Agency from a former Market Monitoring Unit with respect to conditions or conduct occurring in or relating to the period during which the person, persons or entity receiving the request served as the Market Monitoring Unit, shall be borne by the ISO.

30.11 Liability

The liability of the ISO and its directors, officers, employees and agents, and of the Market Monitoring Unit and its directors, officers, employees and agents, for any matter arising under or relating to Attachment O shall be governed by this section. The ISO and its directors, officers, employees and agents, and the Market Monitoring Unit and its directors, officers, employees and agents, shall not be liable to any person or entity for any matter, act or omission described in or contemplated by Attachment O, as the same may be amended or supplemented from time to time, including but not limited to liability for any financial loss, loss of economic advantage, opportunity cost, or actual, direct, indirect or consequential damages of any kind resulting from or attributable to any act or omission of the ISO or the Market Monitoring Unit under Attachment O. The ISO shall indemnify and hold harmless its directors, officers, employees and agents and the Market Monitoring Unit and its directors, officers, employees and agents of and from any and all actions, claims, demands, costs (including any form of damages or other economic loss and all court costs and reasonable attorneys' fees) and liabilities to third parties, arising from or in any way connected with, the implementation or a failure to implement Attachment O, except to the extent that such action, claim, demand, cost or liability results from the willful misconduct of any of the foregoing persons or entities.

30.12 Rights and Remedies

30.12.1

With the exception of the limitation of liability specified in Attachment O, nothing herein shall prevent the ISO or any other person or entity from asserting any rights it may have under the Federal Power Act or any other applicable law, statute, or regulation, including the filing of a petition with or otherwise initiating a proceeding before the FERC regarding any matter which is the subject of Attachment O.

30.12.2

Except as and to the extent otherwise specified in Attachment O, parties with disputes as to the implementation of or compliance with Attachment O may utilize the dispute resolution procedures of the ISO Services Tariff.

30.13 Effective Date

Attachment O shall be effective as of the date it is accepted for filing by the FERC.

31 Attachment P – Coordinated Transaction Scheduling with ISO New England; Actions, Thresholds and Triggers

31.1 Background and Overview

This Attachment P describes the process for pursuing amendments to the ISO tariff in the event that the production cost savings of the ISO's interchange on the NYISO – ISO-NE AC Interface and the Northport/Norwalk Line (both together - "NYISO / ISO-NE Interface"), following the implementation of an Inter-Regional Interchange Scheduling process known as Coordinated Transaction Scheduling ("CTS") on the NYISO/ISO-NE Interface, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Attachment P. The actions, thresholds and triggers described in this Attachment P shall only be measured based upon interchange schedules and estimated schedules at the CTS Enabled Proxy Generator buses on the NYISO / ISO-NE Interface.

If pursuant to the actions, thresholds and triggers described in this Attachment P, the production cost savings of CTS are not satisfactory, and a superior alternative has not become known, the ISO will develop tariff amendments, for filing with the Commission pursuant to Section 31.5, to implement the Inter-Regional Interchange Scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Attachment P become null and void and the ISO continues to implement CTS unless and until future Section 205 filings are pursued to amend CTS.

31.2 The Two-Year Analysis

Within 120 days of the close of the first and second years following the date that CTS as an interface scheduling tool is activated in the ISO and ISO-NE markets, the Market Monitoring Unit (MMU) of the ISO will develop, for presentation to and comment by ISO stakeholders, an analysis, of: (i) the actual bid production cost savings of incremental interchange that would have occurred had the ISOs had an infinite number of zero bids in the CTS process, which utilizes the supply curves and forecasted prices for each market ("Tie Optimization interchange"); and (ii) the actual bid production cost savings of incremental interchange that would have occurred had the ISOs had an infinite number of zero bids in the CTS process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the CTS process ("optimal interchange").

The bid production cost savings associated with Tie Optimization interchange as developed in 31.2(i) for the second year following the date that CTS is activated in the ISO and ISO-NE markets, will reveal the "foregone" production cost savings from implementing CTS rather than Tie Optimization, represented in the Section 31.2.1 formula as the term "b." The difference in bid production cost savings between 31.2 (i) and 31.2 (ii) for the second year following the date that CTS is activated in the ISO and ISO-NE markets will reveal the "foregone" bid production cost savings of the Tie Optimization interchange rather than an optimal interchange, represented in the Section 31.2.1 formula as the term "a."

This analysis will be consistent with the presentation Benefits of Coordinating the Interchange Between New York and New England made by Dr. David Patton of the MMU to the ISO's stakeholders on January 21, 2011. The bid production cost savings will be calculated in accordance with, and the operation of the threshold and trigger will be consistent with, the presentation Potential Trigger to Switch from CTS to TO made by Dr. David Patton of the MMU to the ISO's stakeholders on August 9, 2011.

31.2.1 Using these calculations, the MMU will compute the following ratio:

b/a

If, the ratio b/a is greater than 60% and b is greater than $3 Million, the MMU will advise whether in its opinion the threshold has triggered.

31.3 Improving CTS

31.3.1 If the ratio b/a, developed pursuant to Section 31.2.1 of this Attachment P, is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the MMU and stakeholders.

31.3.2 If the ISO declares the threshold has not triggered the process further described in this Attachment P becomes null and void.

31.3.3 If the ISO declares that the threshold has triggered, the MMU will provide recommendations of adjustments to the design or operation of CTS to improve the production cost savings available from its implementation.

31.3.4 The ISO, considering the input of its stakeholders and the recommendation of the MMU, will develop and implement adjustments to CTS. To the extent tariff revisions are necessary to implement the adjustments to CTS, the ISO will file such revisions with the Commission as a compliance filing in the CTS docket, pursuant to the process described in Section 31.5. If no adjustments to CTS have been identified, the ISO will proceed to develop and file the revisions necessary to amend the ISO Tariffs to implement the Inter-Regional Interchange Scheduling Practice known as Tie Optimization as a compliance filing, pursuant to the process described in Section 31.5.

31.4 The Second Analysis

31.4.1 Within 120 days of the close of the twelve months following the date that the adjustments to CTS, developed under Section 31.3.4, are activated in the ISO and ISO-NE markets, the MMU of the ISO will develop a second analysis, for presentation to and comment by ISO stakeholders. The analysis will be consistent with the analysis described in Section 31.2 of this Attachment P but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section 31.3.4 are in place.

31.4.2 The bid production cost savings associated with Tie Optimization interchange as developed in Section 31.4.1 will reveal the “foregone” bid production cost savings from implementing CTS rather than Tie Optimization, represented in the Section 31.4.3 formula as the term “b.” The difference in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section 31.4.1, will reveal the “foregone” bid production cost savings of the Tie Optimization interchange rather than optimal interchange, represented in the Section 31.4.3 formula as the term “a.”

31.4.3 Using these calculations, the MMU will compute the following ratio:

b/a

If the ratio b/a is greater than 60% and b is greater than $3 Million, the MMU will advise whether in its opinion the threshold has triggered.

31.4.4 If the ratio b/a is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the MMU and their respective stakeholders.

31.4.5 If the ISO declares the threshold has not triggered the process further described in this Attachment P becomes null and void.

31.4.6 If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the MMU, the ISO will determine whether a superior alternative has been proposed, considering the input of the stakeholders and the recommendation of the MMU. If the ISO determines a superior alternative has been proposed, the ISO will prepare tariff amendments for a filing with the Commission to implement the superior alternative utilizing the process for amending the NYISO Tariffs set forth in Article 19 of the ISO Agreement and will not pursue the balance of the actions required by this Attachment P.

31.4.7 If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the ISO Tariffs to implement the Inter-Regional Interchange Scheduling Practice known as Tie Optimization as a compliance filing, pursuant to the process described in Section 31.5. Tie Optimization was described for Stakeholders in the Design Basis Document for NE/NY Inter-Regional Interchange Scheduling presented at a Business Issues Committee meeting June 1, 2011.

31.5 The Compliance Filing

31.5.1 The filing of Tariff revisions with the Commission pursuant to Sections 31.3.4 and/or Section 31.4.7 shall be pursuant to this section.

The ISO will present to its Board tariff language to implement changes to CTS, developed pursuant to Section 31.3.4, for filing through a compliance filing under Section 205 of the Federal Power Act, following stakeholder review and comment, which comments shall be shared with the ISO Board for use as it deliberates the tariff amendments proposed to be filed with the Commission.

The ISO will present to its Board tariff language to implement Inter-Regional Interchange Scheduling Practice known as Tie Optimization, pursuant to Section 31.4.7, through a compliance filing under Section 205 of the Federal Power Act, following stakeholder review and comment, which comments shall be shared with the ISO Board for its use as it deliberates the tariff amendments proposed to be filed with the Commission.