New York Independent System Operator, Inc
Open Access Transmission Tariff

1. Definitions

1.1 Definitions - A

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.

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.

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 by an Eligible Customer for Transmission Service pursuant to the provisions of this Tariff.

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 Reserves: For purposes of determining the Real-Time Locational Based Marginal Price in any Real-Time Dispatch interval: the capability of all Suppliers that submit Energy Bids to provide Spinning Reserves, Non-Synchronized 10-Minute Reserves, and 30-Minute Reserves in that interval, and in the relevant location, and the quantity of recallable external ICAP energy sales in that interval.

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. ATC is defined as the Total Transfer Capability, less Transmission Reliability Margin, less the sum of existing transmission commitments, (which includes retail customer service) less the Capacity Benefit Margin. The amount reserved to support existing transmission commitments is defined in the Existing Transmission Agreements and Existing Transmission Capacity for Native Load in Attachment L.

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.

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.

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 purchase and/or sell Energy, Demand Reductions, Transmission Congestion Contracts and/or Ancillary Services at a specified price that is duly submitted to the ISO pursuant to ISO Procedures.

Bid Price: The price at which the Supplier offering the Bid is prepared to provide the product or service, or the buyer offering the Bid is willing to pay to receive such product or service.

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, Energy, and/or Ancillary Services other than those in the ISO Administered Markets.

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.

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.

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.

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.

Curtailment or Curtail: A reduction in Firm or non-Firm 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 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 Bilateral Wheel Through transaction to indicate the Congestion Component cost below which that entity is willing to accept Transmission Service.

Delivering Party: The entity supplying Capacity and Energy to be transmitted at Point(s) of Receipt.

Demand Side Resources: A Resource that results in the control of a Load in a responsive, measurable, and verifiable manner and within time limits established in 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 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 only 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 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 may either be ISO-Committed Flexible or 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 period commencing at the beginning of each day (0000 hour).

Dispute Resolution Administrator ("DRA"): An individual hired by the ISO to administer the Dispute Resolution Process established in the ISO Tariffs and ISO Agreement.

Dispute Resolution Process ("DRP"): The procedures: (1) described in the ISO Tariffs and the ISO Agreement that are used to resolve disputes between Market Participants and the ISO involving services provided under the ISO Tariffs (excluding applications for rate changes or other changes to the ISO Tariffs or rules relating to such services); and (2) described in the ISO/NYSRC Agreement that are used to resolve disputes between the ISO and NYSRC involving the implementation and/or application of the Reliability Rules.

DSASP Component: As defined in the ISO 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.

Eligible Customer: (i) Any electric utility (including the Transmission Owner and any 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 TCCs and Grandfathered Rights that have been allocated at the completion of the last Centralized TCC Auction.

Existing Transmission Agreement ("ETA"): An agreement between two or more Transmission Owners, or between a Transmission Owner and another entity, as defined in this Tariff.

Existing Transmission Capacity for Native Load: 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 generating facilities 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 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.

Exports: A Bilateral Transaction or purchases 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: A series of TCCs, each with a duration of one year, renewable annually for a period of at least five years at a fixed price that is obtained through the conversion of expired or expiring ETAs in accordance with Section 19.2.1 of Attachment M of this OATT.

1.7 Definitions - G

Generator: A facility 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 with transmission wheeling provisions; and (3) Third Party Transmission Wheeling Agreements (“TWA”) 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 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

1.9 Definitions - I

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.

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.

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.

Intermittent Power Resource: Capacity resources that depend upon wind, or solar energy or landfill gas for their fuel and that such dependence precludes accurate prediction of the facility's real-time output. 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.

Interruption: A reduction in non-Firm Transmission service due to economic reasons pursuant to Section 3.2.7.

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.

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator Demand Side Resource follows Base Point Signals and is committed by the ISO.

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/NY**ISO 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: A single LBMP Load Zone or set of adjacent LBMP Load Zones within one Transmission District, and within which a minimum level of Installed Capacity must be maintained.

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 Installed Capacity Requirement: A determination by the ISO of that portion of the statewide Installed Capacity requirement that must be electrically located within a Locality in order to ensure that sufficient Energy and Capacity are available in that Locality and that appropriate reliability criteria are met.

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.

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.

Modified Wheeling Agreements ("MWA"): A Transmission Agreement in existence, as amended, between Transmission Owners, that is associated with existing Generators or power supply contracts, that will be modified effective upon LBMP implementation. The terms and conditions of the MWA will remain the same as the original agreement, except as noted in the ISO OATT.

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.

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 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) The Proxy Generator Bus(es) for the Hydro Quebec Control Area; (b) the Proxy Generator Bus associated with the Dennison Scheduled Line; and (c) any other Proxy Generator Bus(es) for an area outside of the New York Control Area that have been identified by the ISO as characterized by non-competitive Import or Export prices, and that have been approved by the Commission for designation as Non-Competitive Proxy Generator Bus(es).

Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service under the Tariff for which a Transmission Customer is not willing to pay Congestion. Such service is available absent Constraints under Part 3 of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for individual one-hour periods not to exceed twenty-four (24) consecutive hours.

Non-Firm Sale: An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

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.

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 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;

(2) 10-Minute Non-Synchronized Reserve: Operating Reserve provided by Generators, 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 and Demand Side Resources that are not Local Generators; or non-synchronized Operating Reserves provided by Generators 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 nine 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 (<u>See</u> 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 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 <u>et</u> <u>seq.</u>: The Final Rule entitled <u>Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities</u>, 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"), <u>on reh'g</u>, III FERC <u>Stats</u>. & <u>Regs</u>. ¶ 31,048 (1997) ("Order No. 888-A"), on reh'g, 81 FERC ¶ 61,248 (1997) ("Order No. 888-B") (Order <u>on reh'g</u> 82 FERC ¶ 61,046 (1998) ("Order No. 888- C").

Order Nos. 889 <u>et</u> <u>seq.</u>: The Final Rule entitled <u>Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct</u>, issued by the Commission on April 24, 1996, in Docket No. RM95-9-000, as modified on rehearing, or upon appeal. (<u>See</u> FERC <u>Stats.</u> & <u>Regs.</u> [Regs. Preambles 1991-1996] ¶ 31,035 (1996) ("Order No. 889"), <u>on reh'g</u>, III FERC <u>Stats</u>. & <u>Regs</u>. ¶ 31,049 (1997) ("Order No. 889-A"), <u>on reh'g</u>, 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 provide quantitative comparisons of actual values versus expected and forecasted values for Generators and Loads (See Rate Schedule 3 of the ISO Services Tariff). This system will be used by the ISO to measure compliance with criteria associated with the provision of Regulation and Frequency Response Service.

Point(s) of Delivery: Point(s) on the NYS Transmission System where Capacity, Energy, and Ancillary Services transmitted by the ISO will be made available to the Receiving Party under the ISO Tariffs. The Point(s) of Delivery shall be specified in the Bid, Bilateral Transaction schedule, or similar entry. (Same as Point of Withdrawal.)

Point(s) of Injection ("POI"): The point(s) on the NYS Transmission System where Energy, Capacity and Ancillary Services will be made available to the ISO by the Delivering Party under the ISO Tariffs. The Point(s) of Injection shall be specified in the Bid, Bilateral Transaction schedule, or similar entry. (Same as Point of Receipt.)

Point(s) of Receipt: Point(s) of interconnection on the NYS Transmission System where Capacity, Energy, and Ancillary Services will be made available to the ISO by the Delivering Party under the ISO Tariffs. The Point(s) of Receipt shall be specified in the Bid, Bilateral Transaction schedule, or similar entry. (Same as Point of Injection.)

Point(s) of Withdrawal ("POW"): The point(s) on the NYS Transmission System where Energy, Capacity and Ancillary Services will be made available to the Receiving Party under the ISO Tariffs. The Point(s) of Withdrawal shall be specified in the Bid, Bilateral Transaction Schedule, or other similar entry. (Same as Point of Delivery).

Point-to-Point Transmission Service: The reservation and transmission of Capacity and Energy on either a firm or non-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.

Pre-Scheduled Transaction Request: An offer submitted, pursuant to ISO Procedures, for priority scheduling of Transactions between the ISO and neighboring Control Areas to: (i) purchase Energy from the LBMP Market at the LBMP Market Price and deliver it to an External Control Area; (ii) sell Energy delivered from an External Control Area to the LBMP Market at the LBMP Market Price; or (iii) wheel Energy through the New York Control Area from one External Control Area to another External Control Area at the market-determined Transmission Usage Charge. Pre-Scheduled Transaction Requests accepted for scheduling reserve Ramp Capacity and Transfer Capability and receive priority scheduling in the LBMP Market.

Pre-Scheduled Transaction. A Transaction accepted for scheduling in the designated LBMP Market pursuant to a Pre-Scheduled Transaction Request. Pre-Scheduled Transactions may be withdrawn only with the approval of the ISO pursuant to the ISO Procedures.

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 for 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, or an External Control Area operator, 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 Transmission Owner 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 at least seventy-five minutes before the start of a dispatch hour, or at least eighty-five minutes before the start of a dispatch hour if the Bid seeks to schedule an External Transaction at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line.

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 External Transaction schedules. Additional information about RTC's functions is provided in Section 4.4.2 of the ISO Services Tariff.

1.36d.3 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. 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.

Receiving Party: The entity receiving the Capacity and Energy transmitted by the ISO to Point(s) of Delivery.

Reconfiguration Auction: The monthly auction administered by the ISO in which Transmission Customers may purchase and sell one-month TCCs.

Reduction or Reduce: The partial or complete reduction in non-Firm Transmission Service as a result of transmission Congestion (either anticipated or actual).

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.

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 Transmission Owner 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.

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.

Scheduled Energy Injection: Energy injections 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 following transmission facilities are Scheduled Lines: the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Dennison Scheduled Line, the Northport-Norwalk Scheduled Line, and the Linden VFT Scheduled Line.

Scheduling Differential: A monetary amount, to be defined by the ISO pursuant to ISO Procedures that is assigned to, or defines Bid Price limits applicable to, Decremental Bids and Sink Price Cap Bids at Proxy Generator Buses, in order to establish an appropriate scheduling priority for the Transaction or Firm Transmission Service associated with each such Bid. The Scheduling Differential shall be no larger than one dollar ($1.00).

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 Bid Price 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.

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.

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.

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 and Demand Side Resources that satisfy all applicable ISO requirements.

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 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. These agreements are listed in Attachment L, Table 1A and 1B.

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.

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: The agreements listed in Attachment L, Table 2 of the ISO OATT governing the use of specific or designated transmission facilities charges all, or a portion, of the costs to install, own, operate, or maintain said transmission facilities, to the customer under the agreement. These agreements may or may not have provisions to provide Transmission Service utilizing said transmission facilities.

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: The maximum reduction in system costs resulting from an incremental relaxation of a particular Constraint that will be used in calculating LBMP. The Transmission Shortage Cost is set at $4000/MWh.

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 Tables 1A and 1B 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.

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

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 26.8.2 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.

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 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 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 is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (i) Scheduling, System Control and Dispatch, (ii) Voltage Support Service, (iii) Energy Imbalance and (iv) Black Start Service.

The ISO is required to offer to provide the following Ancillary Services only to the Transmission Customers serving Load within the NYCA: (i) Regulation and Frequency Response, and (ii) Operating Reserves. The Transmission Customer serving Load within the NYCA is required to acquire these Ancillary Services, whether from the ISO, a third party, or by Self-Supply pursuant to Schedules 3 and 5. The Transmission Customer may not decline the ISO's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the ISO.

The ISO shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

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 rates and/or methodology are described in Schedule 1.

2.3.2 Voltage Support Service:

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

2.3.3 Regulation and Frequency Response 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 Clearing Account

The ISO will establish an account (the "ISO Clearing Account"), and Transmission Customers shall make payments into or receive payments from 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 ISO Clearing Account established herein shall be opened and operated by the ISO as trustee in trust for ISO creditors and ISO debtors in accordance with this ISO OATT.

The account shall be maintained at a bank or other financial institution in New York State as a trust account. Such account shall not be commingled with any other ISO accounts. The ISO will not take title to the funds held in the ISO Clearing Account. Nor will the ISO take title to any Energy, Capacity, Ancillary Services or TCCs.

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 Eligible Customers Scheduling Export or Wheel-Through Transactions: Eligible 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 Eligible 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. Eligible Customers scheduling non-firm transactions under Part 3 will be subject to the Losses Component of the TUC only except as noted in Section 3.2.7 of this Tariff.

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 Eligible Customers or Transmission Owners Scheduling Direct LBMP Purchases from the LBMP Market: Any Transmission

Customer, or Transmission Owner 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: Eligible 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 Eligible Customers Scheduling Export or Wheel-Through Transactions: Eligible 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 through the NYISO pursuant to Rate Schedule 10.

2.7.2.5.2 Payable by LSEs Serving Load in the NYCA: Each LSE serving Load in the NYCA shall pay an RFC and LIPA RFC to the NYISO in accordance with

Rate Schedule 10.

2.7.3 Billing Procedures and Payments

2.7.3.1 Invoices 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. For each service provided for under this ISO OATT or the ISO Services Tariff, the payments due to the ISO shall be netted against the corresponding amounts due to the Transmission Customer for providing service. Such information shall be electronically transmitted to the Transmission Customer.

Within five (5) business days after the first day of each month, the ISO shall submit an invoice to the Transmission Customer that indicates the net amount owed by or owed to the Transmission Customer for each of the services furnished under this ISO OATT and the ISO Services Tariff during the preceding month. The ISO shall use meter data submitted to the ISO in accordance with Section 3.16 of the ISO OATT; provided, however, that the ISO may use estimates in whole or in part, in accordance with ISO Procedures, to settle an invoice. Any charges based on estimates shall be subject to true-up, including interest calculated from the first due date after the service was rendered in accordance with Section 2.7.4 of this ISO OATT, in invoices subsequently issued by the ISO after the ISO has obtained the requisite actual information, provided that the actual information is supplied to the ISO within the timeframes established in Section 2.7.4.1 of this ISO OATT. The ISO may net any overpayment, including interest calculated from the date the overpayment was made in accordance with Section 2.7.4 of this ISO OATT, 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. The ISO's invoices to Transmission Customers will be submitted only by electronic means via the ISO's Bid/Post System.

2.7.3.2 Payment by the Transmission Customer

A Transmission Customer owing payments on net shall make those payments to the ISO Clearing Account by the first banking day common to all parties after the 15th day of the month that the invoice is rendered by the ISO. All payments shall be made by wire transfer in immediately available funds payable to the ISO as trustee of the ISO Clearing Account.

2.7.3.3 Payments by the ISO

The ISO shall pay all net monies owed to a Transmission Customer from the ISO Clearing Account by the first banking day common to all parties after the 19th day of the month that the invoice is rendered by the ISO. All payments shall be made by wire transfer in immediately available funds payable to the Transmission Customer by the ISO as trustee of the ISO Clearing Account unless other arrangements are made.

2.7.3.4 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 to the ISO Clearing Account have been paid in a timely manner in accordance with ISO Procedures. If a Transmission Customer fails to make a payment within the time period established in Section 2.7.3.2 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. 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 in accordance with ISO Procedures.

2.7.3.5 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.

2.7.3.6 Billing Procedures for Retail Access Programs

The billing procedures for customers participating in retail access programs shall be in accordance with Part IV 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 as trustee of the ISO Clearing Account (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 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 month following the month 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 Between January 1, 2007, and December 31, 2008

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

Settlement information for services furnished between January 1, 2007, and December 31, 2008, 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 seven (7) months from the date of the initial invoice for the month in which the service is rendered 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-one (71) 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.

(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-one (131) 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 fourteen (14) 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.

(v) At one hundred fifty (150) days from the date of the initial invoice, the ISO shall post updated advisory settlement information. Transmission Customers may review, comment on, and challenge this settlement information, except for Generator, tie-line, sub-zone Load, and LSE bus metering data, after which the ISO shall process and correct the data and issue an updated corrected invoice with the regular monthly invoice issued on or about one hundred eighty (180) days from the date of the initial invoice.

(vi) Following the ISO's issuance of an updated corrected invoice, Transmission Customers may continue to review, comment on, and challenge settlement information, excepting Generator, tie line, sub-zone Load, and LSE bus metering data, until the end of the seven-month review period.

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

2.7.4.3.1 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 and as further provided in Section

2.7.4.3.2, 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-one (71)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 2.7.4.3.1.

2.7.4.3.2 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 2.7.4.3.1; *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 2.7.4.3.1. 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 2.7.4.3.2. 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 2.7.4.4 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.

2.7.4.4 Expedited Dispute Resolution Procedures for Unresolved Settlement Challenges

2.7.4.4.1 Applicability of Expedited Dispute Resolution Procedures

This Section 2.7.4.4 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 or 2.7.4.3.1 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 or 2.7.4.3.2 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.

2.7.4.4.2 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 or 2.7.4.3.2 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.

2.7.4.4.3 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 or 2.7.4.3.1 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 2.7.4.4.3, the ISO will accept the Transmission Customer's request to participate in the dispute resolution proceeding.

2.7.4.4.4 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 2.7.4.4.2, 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.

2.7.4.4.5 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 2.7.4.4, 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.

2.7.4.4.6 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 default, the ISO may initiate debt collection procedures on behalf of the ISO Clearing Account. 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 26.4 of Attachment K to the ISO Services Tariff, or (b) as a result of a material adverse change as determined in accordance with Section 26.10 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 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 for up to 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.

2.7.5.1 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.

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 develop 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, 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.

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 when an Emergency State exists.

2.14 Creditworthiness

All Transmission Customers and applicants seeking to become Transmission Customers shall be subject to the creditworthiness requirements contained in Attachment W.

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 this Section 2.16 shall apply to any dispute arising under this Tariff, except as otherwise indicated.

2.16.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and the ISO involving Transmission Service under the Tariff (excluding applications for rate changes or other changes to this Tariff, or to any Service Agreement entered into under this Tariff, which shall be presented directly to the Commission for resolution) or ISO Procedures shall be referred to a designated senior representative of the ISO and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days or such other period as the parties may agree upon by mutual agreement, such dispute may be submitted to the Dispute Resolutions Administrator ("DRA"). The party submitting the matter to the DRA shall include a written statement describing the nature of the dispute and the issues to be resolved. Any subsequent mediation or arbitration process shall be limited to the issues presented for resolution. The DRA may submit disputes to non-binding mediation where the subject matter of the dispute involves the proposed change or modification of a rule, rate or an ISO Tariff provision. The DRA may submit disputes to binding arbitration which involve interpretation of a rule, rate or an ISO Tariff provision. Both the Mediator and the Arbitrator shall have the authorization to dismiss a dispute if: (i) the dispute did not arise under the ISO Tariff; or (ii) the claim is *de minimis.*

2.16.2 External Non-Binding Mediation and Arbitration Procedures:

If the DRA refers the dispute to non-binding mediations, then the following procedure will be followed:

The DRA shall have ten (10) days from the date of such referral to distribute a list of ten (10) qualified mediators to the disputing parties. Absent the express written consent of all disputing parties, as to any particular individual, no person shall be eligible for selection as mediator who is a past or present officer, employee or consultant to any of the disputing parties, or of any entity related to or affiliated with any of the disputing parties or is otherwise interested in the matter to be mediated. Any individual designated as mediator shall make known to the disputing parties any such disqualifying relationship and a new mediator shall be designated.

If the disputing parties cannot agree upon a mediator, the disputing parties shall take turns striking names from a list supplied by the DRA with a disputing party chosen by lot, first striking a name. The last remaining name to be stricken shall be designated as mediator. If that individual is unable or unwilling to serve, the individual last stricken shall be designated and the process repeated until an individual is selected that is able and willing to serve.

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: (i) submit written statements of issue(s) and position(s); (ii) meet for discussions; (iii) provide expert testimony and exhibits; and (iv) comply with the mediation procedures designated by the DRA and/or the mediator.

If the parties have not resolved the dispute within ninety (90) days of the date the mediator was appointed, then the mediator shall promptly provide the disputing parties and the DRA 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 to the dispute. The parties to the dispute 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.

If the parties are still unable to resolve the dispute, then: (i) any dispute not involving the proposed change or modification of a rule, rate, Service Agreement or a Tariff provision may be referred to the arbitration process described below; or (ii) any disputing party may resort to regulatory or judicial proceedings as provided under this Tariff; and (iii) 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.

Each party to the dispute will bear a pro rata portion 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.

2.16.2.1 If the DRA refers the dispute to arbitration, then the following procedure will apply:

The DRA shall have ten (10) days from the date of such decision to distribute a list of qualified arbitrators to the disputing parties. Absent the express written consent of all disputing parties as to any particular individual, no person shall be eligible for selection as an arbitrator that 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. Any individual designated as an arbitrator shall make known to the disputing parties any such disqualifying relationship a new arbitrator shall be designated.

If the disputing parties cannot agree upon an arbitrator, the disputing parties shall take turns striking names from a list of ten (10) qualified individuals supplied by the DRA with a disputing party chosen by lot first striking a name. The last remaining name not stricken shall be designated as the arbitrator. If that individual is unable or unwilling to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected that is able and willing to serve.

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 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 to the dispute shall produce all evidence determined by the arbitrator to be relevant to the issues presented. To the extent such evidence involves propriety or Confidential Information, the arbitrator may issue an appropriate protective order which shall be complied with by all disputing 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 disputing parties in accordance with procedures established by the arbitrator and may request additional information including the opinion of recognized technical bodies or experts. Disputing parties shall be afforded a reasonable opportunity to rebut any such additional information.

2.16.3 Arbitration Decisions:

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) 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 Tariff and any Service Agreement entered into under this Tariff and shall have no power to modify or change any of the above 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 under the following circumstances: (i) all parties agree that the decision will be binding; or (ii) the dispute involves a claim that a party owes another party a sum of money less than $500,000. If the arbitrator concludes that no proposed award is consistent with this Tariff, the FPA and the Commission’s then-applicable standards and policies, nor would address all issues in dispute, the arbitrator shall develop a compromise solution consistent with the terms of this Tariff. A written decision explaining the basis for the award shall be provided by the arbitrator to the parties and the DRA. No award shall be deemed to be precedential in any other arbitration related to a different dispute. Within one (1) year of the arbitral 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: (i) based upon an error of law; (ii) contrary to the statutes, rules or regulation administered by such authority; (iii) violative of Federal Arbitration Act or Administrative Dispute Resolution Act; (iv) based on conduct by an arbitrator that is violative of the Federal Arbitration Act of Administrative Dispute Resolution Act; or (v) involves a dispute in excess of $500,000. The final decision of the arbitrator must be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities. Any arbitration decision that affects matters subject to the jurisdiction of the PSC under the New York State Public Service Law (“PSL”) may be filed with the PSC. The judgment of the arbitrator may be entered on award by any court in New York State having jurisdiction.

2.16.4 Costs:

All costs associated with the time, expense and other charges of the arbitrators shall be borne by the unsuccessful party. Each party shall be responsible for its own costs incurred during the arbitration process including attorney and expert fees.

2.16.5 Rights Under The FPA:

Nothing in this section shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the FPA.

2.17 Incorporation of Certain Business Practice Standards

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

- Business Practices for Open Access Same-Time Information Systems (OASIS), Version 1.4 (WEQ-001, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 001-0.2 through 001-0.8, 001-0.14 through 001-0.20;
- Business Practices for Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.4 (WEQ-002, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 002-1 through 002-5.10, except as provided in Section 2.17.1 below;
- Coordinate Interchange (WEQ-004, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 004-0.1 through 004-17.2, and 004-A through 004-D, except as provided in Section 2.17.1 below;
- Area Control Error (ACE) Equation Special Cases Standards (WEQ-005, Version 001~~0~~, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 005-0.1 through 005-3.1.3, and 005-A;
- Manual Time Error Correction (WEQ-006, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 006-0.1 through 006-12;
- Inadvertent Interchange Payback (WEQ-007, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 007-0.1 through 007-2, and 007-A;
- Transmission Loading Relief - Eastern Interconnection (WEQ-008, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 008-0.1 through 008-3.11.2.8, and 008-A through 008-D;
- Gas/Electric Coordination (WEQ-011, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 011-0.1 through 011-1.6;
- Public Key Infrastructure (PKI) (WEQ-012, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Recommended Standard, Certification, Scope, Commitment to Open Standards, and Standards 012-0.1 through 012-1.26.5; and
- Business Practices for Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.4 (WEQ-013, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Introduction and Standards 013-0.1 through 013-4.2, except as provided in Section 2.17.1 below.

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

- Business Practices for Open Access Same-Time Information Systems (OASIS), Version 1.4 (WEQ-001, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007): Standards 001-2.0 through 001-12.5.2, and Appendices 001-A and 001-B;
- Business Practices for Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.4 (WEQ-002, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007): Standards 002-4.2.10, 002-4.2.11, 002-4.2.12, 002-4.3, *et seq.*, and 002-4.4;
- Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.4 (WEQ-003, Version 001, Oct. 31, 2007January 15, 2005, with minor corrections applied on Nov. 16, 2007): Standard 003-0;
- Coordinate Interchange (WEQ-004, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007): Standards 004-3, 004-3.1, 004-8.2, 004-11.1(a) and Appendices 004-A and 004-C, to the extent they govern physical transmission reservations; and
- Business Practices for Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.4 (WEQ-013, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007): Standard 013-4.1.

3 Point-To-Point Transmission Service

Preamble

The ISO will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff over the transmission facilities of the parties to the ISO/TO Agreement. Point-To-Point Transmission Service is for the receipt of Capacity and Energy at designated Point(s) of Receipt and the transfer of such Capacity and 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. Non-Firm Point-To-Point Transmission Service is service for which the Transmission Customer has not agreed to pay Congestion Rent. 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, or the Linden VFT Scheduled Line shall be subject to the requirements of Attachment N to the ISO 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 one hour 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. All Firm Point-to-Point Transmission Service will have priority over Non-Firm Point-to-Point Transmission Service under the Tariff.

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, or the Linden VFT 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, or the Linden VFT Scheduled Line (as appropriate). If multiple transactions require Curtailment, to the extent practicable and consistent with right to Curtail, in whole or in part, any Firm Transmission Service provided under this Tariff when, in the ISO's sole discretion, an Emergency or other unforeseen condition impairs or degrades 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, other than Transmission Customers taking Firm Point-to-Point Transmission Service associated with a Pre-Scheduled Transaction, may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 3.15.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 3.15.2.

3.1.7.2 The Transmission Customer may purchase Transmission Service to make sales of Capacity and Energy from multiple generating units that are on the NYS Transmission System. For such a purchase of Transmission Service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

3.1.7.3 The ISO shall provide firm deliveries of Capacity and 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 Pre-Scheduled Transaction Requests: Requests for Firm Transmission Service associated with a Pre-Scheduled Transaction Requests for Wheels Through shall be submitted, pursuant to ISO Procedures, no earlier than eighteen (18) months prior to the Dispatch Day, and shall include hourly transaction quantities (in MW) at each affected External Interface for each specified Dispatch Day. Customers may submit requests for Firm Transmission Service associated with Pre-Scheduled Transaction Requests for scheduling in the Day-Ahead Market.

The ISO shall determine, pursuant to ISO Procedures, the amount of Total Transfer Capability at each External Interface to be made available for scheduling Pre-Scheduled Transactions. The ISO shall evaluate Pre-Scheduled Transaction Requests in the order in which they are submitted for evaluation until the Pre-Scheduled Transaction Request expires, pursuant to ISO Procedures, prior to the close of the Day-Ahead Market for the specified Dispatch Day. Modification of a Pre-Scheduled Transaction request shall constitute a withdrawal of the original request and a submission of a new Pre-Scheduled Transaction request. At the request of a Customer, the ISO shall continue to evaluate a Pre-Scheduled

Transaction Request for a Wheel Through that was not accepted for scheduling in the priority order in which the Request was originally submitted until it is either accepted for scheduling, is withdrawn or expires, pursuant to ISO Procedures, prior to the close of the Day-Ahead Market for the specified Dispatch Day. The ISO shall accept Pre-Scheduled Transaction Requests for scheduling, pursuant to ISO Procedures, provided that there is Ramp Capacity, and Transfer Capability available at each affected External Interface, in the NYCA for each hour requested If Ramp Capacity, or Transfer Capability on the designated External Interface, is unavailable in the NYCA for any hour of the Pre-Scheduled Transaction Request, the request shall not be scheduled. The ISO shall confirm the Transaction with affected Control Areas, as necessary, pursuant to ISO Procedures and may condition acceptance for scheduling on such confirmation.

The ISO shall provide the requesting Customer with notice, as soon as is practically possible, as to whether the Pre-Scheduled Transaction Request is accepted for scheduling and, if it is not scheduled, the ISO shall provide the reason.

The ISO shall reserve Ramp Capacity, and Transfer Capability on affected Interfaces, for each Pre-Scheduled Transaction. Pre-Scheduled Transactions shall be automatically submitted for scheduling in the appropriate LBMP Market for the designated Dispatch Day. The ISO shall evaluate requests to withdraw Pre-Scheduled Transactions pursuant to ISO Procedures.

Requests for Firm Transmission Service associated with Pre-Scheduled Transaction Requests for Wheels Through to be scheduled Day-Ahead shall be assigned a Decremental Bid at the Proxy Generator Bus designated as the source of the Transaction that provides the highest scheduling priority available for Firm Transmission Service.

3.1.8.2 **In the Day-Ahead Market:** Schedules for the Transmission Customer's Firm Point-to-Point Transmission Service Day-Ahead, other than schedules from Transmission Customers taking Firm Point-to-Point Transmission Service for a Pre-Scheduled Transaction, must be submitted to the ISO no later than 5:00 a.m. of the day prior to commencement of the Dispatch Day. Decremental Bids submitted at Proxy Generator Buses shall be price no lower than the Bid that provides the highest scheduling priority for sales to the LBMP Market plus the product of (i) the Scheduling Differential and (ii) three. Sink Price Cap Bids submitted at Proxy Generator Buses shall be priced no higher than the Bid that provides the highest scheduling priority for purchases from the LBMP Market minus the product of (i) the Scheduling Differential and (ii) three. 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. will not be accepted in the Day-Ahead schedule. Schedules of any Capacity and Energy that are to be delivered must be stated in increments of 1,000 kWh per hour between each Point of Receipt and corresponding Point of Delivery. Each Transmission Customer within the NYCA with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kWh per hour, may consolidate its service requests at a common Point of Receipt into units of 1,000 kWh per hour for scheduling and billing purposes. The ISO will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party and shall deliver the Capacity and Energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall notify the ISO prior to the close of the Real-Time Market, and the ISO shall have the right to adjust accordingly the schedule for Capacity and Energy to be received and to be delivered.

3.1.8.3 **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 ninety (90) minutes prior to the dispatch hour.

Bids for Exports shall be priced no higher than the Bid that provides the highest scheduling priority for purchases in the LBMP Market, minus the product of (i) the Scheduling Differential and (ii) three. Bids for Imports and Decremental Bids or Wheels Through at the Proxy Generator Bus designated as the source of the Transaction shall be price no lower than the Bid that provides the highest scheduling priority for sales to the LBMP Market plus the product of (i) the Scheduling Differential and (ii) three. Schedules involving the use of LIPA's facilities shall be treated in accordance with Section 2.5.7. Schedules submitted later than ninety (90) minutes prior to the dispatch hour shall not be accepted in the Real-Time schedule. Schedules of any Capacity and 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. The ISO will furnish to the Delivering Party's system operator, if applicable, hour-to-hour schedules equal to those furnished by the Receiving Party and shall deliver the Capacity and Energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall notify the ISO prior to the close of the Real-Time Market, and the ISO shall have the right to adjust accordingly the schedule for Capacity and Energy to be received and to be delivered.

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

3.2.1 Term:

The minimum term of Non-Firm Point-To-Point Transmission Service shall be one (1) hour and the maximum term shall not exceed the maximum permissible term as specified in ISO Procedures.

3.2.2 Reservation Priority:

Non-Firm Point-to-Point Transmission Service shall be available when there is no Congestion between the Point(s) of Receipt and the Point(s) of Delivery for the Transaction. In all instances, Non-Firm Point-to-Point Transmission Service shall have a lower priority than Firm Point-to-Point Transmission Service and Network Service. Non-Firm Point-to-Point Transmission Service shall have an equal priority with Network Service from a secondary resource. A customer requesting non-firm Transmission Service that cannot be accommodated in the Day-Ahead Schedule because of Congestion may upgrade to Firm Point-to-Point Transmission Service up to ninety (90) minutes prior to a given hour by rescheduling the Transaction and agreeing to pay the real-time Congestion Rents associated with the Transaction.

3.2.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Owner:

The Transmission Owners will be subject to the rates, terms and conditions of Part 3 of this Tariff when making Third-Party Sales under (i) agreements executed on or after the date this Tariff is effective 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 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

3.2.4 Service Agreements:

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

3.2.5 Classifications of Non-Firm Point-To-Point Transmission Service:

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part 3 of this Tariff. The ISO undertakes no obligation under this Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of this Tariff. The ISO shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Owner) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of Energy and Capacity on an hourly and daily basis under Schedule 8.

3.2.6 Scheduling of Non-Firm Point-To-Point Transmission Service:

3.2.6.1 In the Day-Ahead Market: Schedules for the Transmission Customer's Non-Firm Point-to-Point Transmission Service in the Day-Ahead must be submitted to the ISO no later than 5:00 a.m. of the day prior to commencement of service. 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. will not be accepted in the Day-Ahead Schedule. Schedules of any Capacity and 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. Each Transmission Customer within the NYCA with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kWh per hour, may consolidate its schedules at a common Point of Receipt into units of 1,000 kWh per hour. The ISO will furnish to the Delivering Party's system operator, hour-to-hour advisory schedules equal to those furnished by the Receiving Party. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall notify the ISO prior to the close or the Real-Time Market, and the ISO shall have the right to adjust accordingly the schedule for Capacity and Energy to be received and to be delivered.

3.2.6.2 **In the Real-Time Market:** Schedules for the Transmission Customer's Non-Firm Point-to-Point Transmission Service in real-time must be submitted to the ISO no later than ninety (90) minutes prior to the hour. Schedules involving the use of LIPA's facilities shall be treated in accordance with Section 2.5.7. Schedules submitted later than ninety (90) minutes prior to the dispatch hour shall not be accepted in the real-time schedule. Schedules of any Capacity and 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. The ISO will furnish to the Delivering Party's system operator, if applicable, hour-to-hour schedules equal to those furnished by the Receiving Party and shall deliver the Capacity and Energy provided by such schedules. Should the Transmission

Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the ISO prior to the close of the Real-Time Market, and the ISO shall have the right to adjust accordingly the schedule for Capacity and Energy to be received and be delivered.

3.2.7 Curtailment or Interruption of Service:

The ISO reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an Emergency or other unforeseen condition threatens to impair or degrade the reliability of the NYS Transmission System. The ISO reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under this Tariff for economic reasons if the NYS Transmission System experiences Congestion. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the Constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Point-to-Point Transmission Service and Network Integration Transmission Service. The ISO will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice. The process of Curtailment of Non-Firm Point-To-Point Transmission Service for Imports, Exports, and Wheels Through may cause these non-firm transactions to incur incidental real-time Congestion Rents due to inter-Control Area Curtailment procedures.

3.3 Service Availability

3.3.1 General Conditions:

The ISO will provide Firm and Non-Firm Point-To-Point Transmission Service over the transmission facilities of the parties to the ISO/TO Agreement, to any Transmission Customer that has met the requirements of Section 3.4.

3.3.2 Determination of 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 or Non-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 Other Transmission Service Schedules:

Eligible Customers receiving Transmission Service under other agreements on file with the Commission may continue to receive Transmission Service under those agreements until such time as those agreements may be modified by the Commission. These agreements are listed in Attachment L.

3.3.7 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; and

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

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

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 the Capacity and Energy to be transmitted by the ISO pursuant to Part 3 of this Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, 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 location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the Capacity and Energy and the location of the Load ultimately served by the Capacity and Energy transmitted. The ISO will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. 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;

(v) A description of the supply characteristics of the Capacity and Energy to be delivered;

(vi) An estimate of the Capacity and Energy expected to be delivered to the Receiving Party;

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

(viii) Any additional information required by the ISO's planning process established in Attachment Y.

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:

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service the ISO shall make a determination as to whether the NY Power System can support the requested service within the Constraint management and redispatch capabilities of the system. If the ISO concludes that such service is not possible, the ISO shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application. The Transmission Customer may request a System Impact Study pursuant to Section 19 at that time.

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 Application. Nothing herein limits the right of an Eligible Customer to file another Application 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

3.6.1 Application:

Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the ISO.

3.6.2 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 Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of Energy to be injected and/or withdrawn at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating Transmission Service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the ISO also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate Load.

The ISO will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this

Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The ISO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations and the ISO Code of Conduct in Attachment F.

3.6.3 Requests for Non-Firm Point-to-Point Transmission:

Requests for daily service and hourly service shall be made by submitting a schedule to the ISO in accordance with Section 3.2.6. Such requests shall be accommodated when no Congestion is present.

3.6.4 Determination of Available Transfer Capability Using Security Constrained Unit Commitment ("SCUC"), Real-Time Commitment ("RTC"), and Real-Time Dispatch ("RTD").

The ISO continuously redispatches the resources subject to its control in order to meet Load and accommodate requests for Firm Transmission Service through the use of SCUC, RTC, and RTD.

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.

The ISO will normally submit System Impact Studies to the Operating Committee before finalizing them. 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 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 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:

(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.

3.9.3 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.

3.9.4 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.

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.

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

3.15.1 Modifications On a Non-Firm Basis:

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the ISO provide Transmission Service on a non-firm basis over Receipt and Delivery Points other than those specified in the Bid, Bilateral Transaction Schedule, or similar entry ("Secondary Receipt and Delivery Points"), in amounts not to exceed the quantities of its Firm Point-to-Point Transmission Service, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions. While there will be no additional charges for requesting service from a new receipt or to a new delivery point, the Transmission Customer shall be responsible for all charges applicable to the new secondary receipt or delivery point in place of the charges applicable to the original receipt or delivery point.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this Section shall not exceed the quantities or its Firm Point-to-Point Transmissions Service requested in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point- To-Point Transmission Service at the Receipt and Delivery Points specified up to the quantities or its Firm Point-to-Point Transmission Service requested in the relevant Service Agreement.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under this Tariff. However, all other requirements of Part 3 of this Tariff (except as to transmission rates) shall apply to Transmission Service on a non-firm basis over Secondary Receipt and Delivery Points.

3.15.2 Modification On a Firm Basis:

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 3.5 hereof. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Bid, Bilateral Transaction schedule, or similar entry.

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 and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). 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 8.

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 Non-Firm Sales delivered pursuant to Part 3 of the Tariff, 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 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 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 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 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.

The ISO will normally submit System Impact Studies to the Operating Committee before finalizing them. 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 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 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 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 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 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 both 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 MWs, are set forth in Attachment Z to this ISO OATT.

4.6 Load Shedding and Curtailments

4.6.1 Procedures:

Prior to the Service Commencement Date, the ISO and the Network Customer shall establish 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 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. The LEER Procedure is intended to prevent the necessity of implementing the curtailment procedures contained in the FERC and NERC tariffs and policies. 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 not unduly 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 - Scheduling, System Control and Dispatch Service

This service is required to schedule the purchase, sale and movement of power through, out of, within, or into the NYCA. This service can be provided only by the ISO. The Transmission Customer must purchase this service from the ISO. The ISO Services Charge for Scheduling, System Control and Dispatch Service and any rebillings associated therewith are set forth below.

6.1.1 Parties to Which Charges Apply

The ISO shall charge, and Transmission Customers taking service under the ISO OATT, only, including Special Case Resources, Emergency Demand Response Program participants, Transmission Customers that have their virtual bids accepted and thereby engage in Virtual Transactions, and Transmission Customers that purchase Transmission Congestion Contracts, excluding Transmission Congestion Contracts that are created prior to [the date that the Commission issues an Order approving these revisions], shall pay an "ISO Services Charge" as calculated in Section 6.1.2.2 of this Rate Schedule on all Transmission Services provided pursuant to Parts 3, 4 and 5 to this Tariff, provided that Transmission Customers who are retail access customers who are being served by an LSE shall not pay this charge to the ISO; the LSE shall pay these charges. Transmission Customers taking service under both the ISO OATT and the ISO Services Tariff shall pay the applicable ISO Services Charge as calculated (i) in Sections 15.1.3.1 through 15.1.3.3 of Rate Schedule 1 of the ISO Services Tariff, and (ii) in Sections 6.1.2.2.3 and 6.1.2.2.4 of this Rate Schedule.

6.1.2 Billing Units and Calculation of Rates

The ISO shall charge each Transmission Customer based on the product of: (i) the ISO Services Charge rate for Scheduling, System Control and Dispatch Service; and (ii) the Transmission Customer's applicable injection billing units and/or withdrawal billing units for the month as described in Section 6.1.2.1.

6.1.2.1 Billing Units

For the ISO Services Charge calculated under Section 6.1.2.2.1 of this Rate Schedule, the Transmission Customer's injection billing units shall be based on 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 wheelthroughs. The Transmission Customer's withdrawal billing units shall be based on its Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA, and hourly Energy schedules for all Wheels Through and Exports. For the ISO Services Charge calculated pursuant to Sections 6.1.2.2.2, 6.1.2.2.3, and 6.1.2.2.4 of this Rate Schedule, the Transmission Customer's billing units shall be based on the Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA, and hourly Energy schedules for all Wheels Through and Exports. To the extent Schedule 1 charges are associated with meeting the reliability needs of a local system, the billing units for such charges will be based on the Actual Energy Withdrawals in the sub-zone(s) where the Resource needed to meet the reliability need is located. To the extent Schedule 1 charges are associated with payments made for supplemental payments and Demand Reduction Incentive payments to Demand Reduction Providers, the billing units of such charges shall be based on Actual Energy Withdrawals to supply Load in the NYCA according to the methodology described in Attachment R. To the extent that the sum of all Bilateral Schedules, excluding schedules of

Bilateral Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to service Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load and the ISO commits Resources in addition to the reserves it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load, charges associated with the costs of Bid Production Cost Guarantees for the additional Resources committed Day-Ahead to meet the ISO's Day-Ahead forecast of Load shall be allocated to Transmission Customers who are not bidding as Suppliers according to the Methodology described in Attachment T.

For Transmission Customers participating in the ISO's Special Case Resource program or in its Emergency Demand Response Program ISO Services Charge calculated under Section 6.1.2.2.1 of this Rate Schedule, shall be the product of: (i) the applicable ISO Services Charge rate; and (ii) the Transmission Customer's applicable billing units for the month. The Transmission Customer's billing units shall be based on the total compensable injection MWh.

For Transmission Customers purchasing Transmission Congestion Contracts or engaged in Virtual Transactions, the ISO Services Charge calculated under Section 6.1.2.2.1 of this Rate schedule shall be the product of: (i) the applicable ISO Services Charge rate; and (ii) the Transmission Customer's applicable billing units for the month.

For Transmission Customers purchasing Transmission Congestion Contracts, the Transmission Customer's billing units shall be based on the settled Transmission Congestion Contract MWh. For Transmission Customers engaging in Virtual Transactions, the Transmission Customer's billing units shall be based on total cleared virtual bid MWh.

6.1.2.2 Computation of Rates

The ISO Services Charge for Scheduling, System Control and Dispatch Service shall consist of six components and shall be recovered on a monthly basis (except for Section 6.1.2.2.5 which shall be billed quarterly) in accordance with the following processes:

6.1.2.2.1 ISO Annual Budget and FERC Regulatory Fees Component

6.1.2.2.1.1 The responsibility for the sum of (a) those costs listed in Section 6.1.3.1 of this Rate Schedule that are included in the ISO's annual budget and (b) the ISO's FERC regulatory fees, shall be allocated 20% to all injection billing units and 80% to all withdrawal billing units. The current 80%/20% cost allocation shall remain unchanged through at least December 31, 2011 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 80%/20% 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 80%/20% cost allocation on a going forward basis:

6.1.2.2.1.1.1 A vote of the Management Committee will be taken in the third calendar quarter of 2010 on whether a new study should be conducted during late-2010 and 2011 to allow modification of the 80%/20% cost allocation, if warranted by the results of the study, to be implemented by January 1, 2012. 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.

6.1.2.2.1.1.2 If the Management Committee vote discussed in (i) above determines that a study should not be conducted, the 80%/20% cost allocation between withdrawal billing units and injection billing units shall be extended through at least December 31, 2012. In the third calendar quarter of 2011, a vote will be taken on whether a new study should be conducted during late-2011 and 2012 to allow modification of the percentage allocation, if warranted by the results of the study, to be implemented by January 1, 2013. 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.

6.1.2.2.1.1.3 If the Management Committee vote in the third calendar quarter of 2011 discussed in (ii) above determines that a study should not be conducted, the current 80%/20% 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 2011 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 gets 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 2011 discussed in (ii) above.

6.1.2.2.1.1.4 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.

6.1.2.2.1.2 The rate to be applied to injection billing units shall be the quotient of 20% of the sum of the ISO's annual budget and FERC regulatory fees divided by the total annual estimated injection billing units as described in Section 6.1.2.1 of this Rate Schedule. The rate to be applied to withdrawal billing units shall be the quotient of 80% of the sum of the ISO's annual budget and FERC regulatory fees divided by the total annual estimated withdrawal billing units as described in Section 6.1.2.1 of this Rate Schedule.

6.1.2.2.1.3 The rates derived in Section 6.1.2.2.1 of this Rate Schedule shall then be multiplied by each Transmission Customer's injection billing units and withdrawal billing units, as appropriate, for the month.

6.1.2.2.1.4 For Transmission Customers that purchase Transmission Congestion Contracts and/or engage in Virtual Transactions their portion of the sum of (a) those costs listed in Section 6.1.3.1 of this Rate Schedule that are included in the ISO's annual budget and (b) the ISO's FERC regulatory fees, attributable to Transmission Congestion Contracts or Virtual Transactions, shall be calculated and billed as follows:

6.1.2.2.1.4.1 For Calendar Year 2010:

(a) $0.020 per MWh for Transmission Congestion Contracts for calendar year 2010, based on a $6.7 million projected 2010 annual revenue requirement.

(b) $0.065 per cleared MWh for Virtual Trading transactions for calendar year 2010 based on a $2.0 million projected 2010 annual revenue requirement.

6.1.2.2.1.4.2 For Subsequent Calendar Years

Each Transmission Customer shall be charged a rate computed annually based on the product of the annual revenue requirement adjusted for the over or under collection of the prior year's annual revenue requirement, divided by the three year rolling average of the billing units, where:

(a) the annual revenue requirement is determined using an escalation factor calculated as the percentage change in the originally-approved ISO budget between the calendar year two years prior to the current calendar year ("Calendar Year Minus 2") and the calendar year one year prior the current calendar year ("Calendar Year Minus 1");

(b) the over/under collection of the prior year's annual revenue requirement is calculated for the period between July of Calendar Year Minus 2 and June of

Calendar Year Minus 1. For the purpose of this calculation the annual revenue requirement will be converted to a monthly requirement and then aggregated across the 12 months;

(c) the three year rolling average of billing units is calculated using an annual average of the 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.

However, the annual rate computed will be subject to a 25% maximum increase or decrease for each year. Revenue collected pursuant to this Section 6.1.2.2.1.4 will be disbursed monthly to all injection billing units as described in Section 6.1.2.1 of this Rate Schedule and to all withdrawal billing units as described in Section 6.1.2.1 of this Rate Schedule on the same basis described in Section 6.1.2.2.1.1 of this Rate Schedule.

6.1.2.2.1.5 For Customers that participate in the ISO's Special Case Resources program or its Emergency Demand Response Program their portion of the sum of (i) the ISO's annual budget including the costs listed in Section 6.1.3.1 of this Rate Schedule; and (ii) the ISO's FERC Regulatory fees, shall be billed at the same rate charged to injection billing units as described in Section 6.1.2.1 of this Rate Schedule. The rate will be reset annually to match the current calendar year's rate for injections. Revenue collected pursuant to this Section 6.1.2.2.1.5 will be disbursed monthly to all injection billing units as described in Section 6.1.2.1 of this Rate Schedule and to all withdrawal billing units as described in

Section 6.1.2.1 of this Rate Schedule on the same basis described in Section 6.1.2.2.1.1 of this Rate Schedule.

6.1.2.2.2 ISO Unbudgeted Cost Component

Except with respect to bad debt loss and working capital contribution costs, the responsibility for those costs listed in Section 6.1.3.1 of this Rate Schedule that are neither (i) included in the ISO's annual budget, nor (ii) FERC-assessed regulatory fees, shall be allocated 100% to all withdrawal billing units. The rate to be applied to withdrawal billing units in each month shall be the quotient of the amount of these costs to be included in the month, as determined by the ISO, divided by the total estimated withdrawal billing units for the month, as described in Section 6.1.2.1 of this Rate Schedule. This rate shall then be multiplied by each Transmission Customer's withdrawal billing units for the month. The responsibility for costs associated with bad debt losses and working capital contributions shall be allocated pursuant to Attachments U and V to this Tariff, respectively.

6.1.2.2.3 Non-ISO Facilities Payments Component

6.1.2.2.3.1 The monthly payments the ISO makes to owners of facilities that are needed for the economic and reliable operation of the NYS Transmission System shall be recovered based on withdrawal billing units. Currently, the ISO makes payments to Consolidated Edison Co. of New York, Inc. for the purchase, installation, operation and maintenance of phase angle regulators at the Branchburg-Ramapo Interconnection between the ISO and PJM Interconnection, LLC and to Rochester Gas & Electric Corporation for the installation of a 135 MVAR Capacitor Bank at Rochester Station 80 on the cross-state 345 kV system. The charges to be applied to withdrawal billing units for Transmission Customers, other than those taking service under Section 5 of the OATT to supply Station Power as third party providers, shall be the product of (A) the sum of the monthly bills for such facilities from: (i) Consolidated Edison Co. of New York (less the one-half of such bill paid by PJM Interconnection, LLC) and (ii) Rochester Gas and Electric Corporation, divided by the total number of hours in the month, and (B) the ratio of (i) the Transmission Customer's withdrawal billing units for that hour as described in Section 6.1.2.1 of this Rate Schedule to (ii) the sum of all ISO Transmission Customers' withdrawal billing units for that hour (other than withdrawal billing units for those taking services under Part 5 of the OATT) as described in Section 6.1.2.1 of this Rate Schedule. Charges to be paid by Transmission Customers for this service shall be aggregated to render a monthly charge.

6.1.2.2.3.2 Transmission Customers 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 sum of the daily bills for such facilities as described in subparagraph (a) above and (B) the ratio of the Transmission Customer's Station Power supplied under Section 5 of the OATT for the day to the sum of all withdrawal billing units for the day.

6.1.2.2.3.3 The ISO shall credit charges paid for this service by Transmission Customers and LSEs taking service under Section 5 of the OATT to supply Station Power as third-party providers for the day on a Load Ratio Share basis to Transmission Customers serving Load in the NYCA for the day.

6.1.2.2.4 Residual Adjustment and Bid Production Guarantees Component

6.1.2.2.4.1 The ISO shall calculate, and Transmission Customers, other than Transmission Customers taking service under Section 5 of the OATT to supply Station Power as third party providers, shall pay an hourly charge equal to the product of (A) the residual adjustment costs listed in Section 6.1.4.1 of this Rate Schedule for each hour and (B) the ratio of (i) the Transmission Customer's withdrawal billing units for that hour as described in Section 6.1.2.1 of this Rate Schedule to (ii) the sum of all ISO Transmission Customers' withdrawal billing units for that hour as described in Section 6.1.2.1 of this Rate Schedule.

6.1.2.2.4.2 The ISO shall calculate, and each Transmission Customer taking service under Part 5 of the OATT to supply Station Power as a third party provider shall pay a daily charge equal to the product of (A) the residual adjustment costs listed in Section 6.1.4.1 of this Rate Schedule for each day and (B) the ratio of (i) the withdrawal units of the Transmission Customer taking service under Part 5 of the OATT to supply Station Power as a third party provider for that day to (ii) the sum of all ISO Transmission Customers' withdrawal billing units for that day as described in Section 6.1.2.1 of this Rate Schedule. The ISO shall credit revenue collected by application of this charge, on a Load ratio share basis, to all ISO Transmission Customers' withdrawal billing units as described in Section 6.1.2.1 of this rate Schedule 1 summed for the day.

6.1.2.2.4.3 The ISO shall calculate, and each Transmission Customer shall pay, a daily charge equal to the product of (A) the bid production guarantee costs listed in Section 6.1.4.2 of this Rate Schedule for each day and (B) the ratio of (i) the Transmission Customer's withdrawal billing units for that day as described in

Section 6.1.2.1 of this Rate Schedule to (ii) the sum of all ISO Transmission Customers' withdrawal billing units for that day as described in Section 6.1.2.1 of this Rate Schedule, provided, however, that the costs of supplemental payments and Demand Reduction Incentive Payments made to Demand Reduction Providers shall be allocated to Transmission Customers according to the methodology described in Attachment R. To the extent that the sum of all Bilateral 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 and the ISO commits Resources in addition to the reserves it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load, charges associated with the costs of Bid Production Cost Guarantees for the additional Resources committed Day-Ahead to meet the ISO's Day-Ahead forecast of Load shall be allocated to Transmission Customers who are not bidding as Suppliers according to the Methodology described in Attachment T.

6.1.2.2.5 NERC and Related Dues, Fees and Other Charges Component

Dues, fees, and other charges: (i) of 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) of Northeast Power Coordinating Council: Cross-Border Regional Entity, Inc., 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, all of which dues, fees, and other charges shall be recovered quarterly. Such recovery shall be based on Actual

Energy Withdrawals to supply Load in the NYCA, utilizing the load metering information for the most recent month for which actual load meter data are available for invoices issued through August 31, 2007 and utilizing finalized actual load metering data no longer subject to challenge for invoices issued on or after September 1, 2007. The metering information shall not be subject to correction or adjustment. Notwithstanding any applicable provisions of this Tariff 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.

6.1.2.2.6 Payments Made To Generators Pursuant to Incremental Cost Recovery for Units Responding to Local Reliability Rule I-R3 and I-R5.

Amounts paid to Suppliers, pursuant to the Incremental Cost Recovery for Units Responding to Local Reliability Rules I-R3 and I-R5, shall be recovered from Load in the Transmission District of the Supplier being paid, other than Load scheduled by a Transmission Customer taking service under Part 5 of the OATT to supply Station Power as a third party provider, on the basis of each LSE's contribution to the Load in the day the payment obligation is incurred.

6.1.3 ISO Costs

ISO costs to be recovered through the Rate Schedule 1 charge include:

6.1.3.1 Costs associated with the operation of the NYS Transmission System by the ISO and administration of this Tariff by the ISO, including without limitation, the following:

- 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;
- Billing associated with Transmission Service provided under this Tariff;
- Preparation of settlement statements;
- Rebilling which supports this service;
- 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;
- Dispute resolution;
- Record keeping and auditing;
- Training of ISO personnel;
- Development of new information, communication and control systems;
- Professional services;
- Working capital and carrying costs on ISO assets, capital requirements and debts;
- Tax expenses, if any;
- Administrative and general expenses;
- Insurance expenses, including costs incurred by the Board to procure credit insurance to protect against losses attributable to nonpayment by Customers;
- Any indemnification of or by the ISO pursuant to Section 2.11.2 of this Tariff;
- Costs that the ISO incurs as a result of bad debt, including finance charges;
- Refunds, if any, ordered by the Commission to be paid by the ISO, at the conclusion of Central Hudson Gas & Electric Corp., Docket Nos. ER97-1523-011, OA97-470-010 and ER97-4234-008; and
- Regulatory fees.
- The ISO's share of the expenses of Northeast Power Coordinating Council, Inc. or its successor.

6.1.4 Residual Adjustment and Bid Production Guarantees

6.1.4.1 Residual Adjustment

The ISO's payments from Transmission Customers will not equal the ISO's payments to Suppliers. Part of the difference consists of Day-Ahead Congestion Rent. The remainder comprises the Residual Adjustment, which will be an adjustment to the costs in Section 6.1.3.1. The most significant components of the Residual Adjustment, which is calculated below, include:

- The greater revenue the ISO collects for Marginal Losses from Transmission Customers, in contrast to payments for losses remitted to generation facilities;
- Costs or savings associated with the ISO redispatch of Generators resulting from a change in Transfer Capability between the Day-Ahead schedule and the real-time dispatch;
- The cost resulting from inadvertent interchange (if unscheduled Energy flows out of the NYCA to other Control Areas), or the decrease in cost resulting from inadvertent interchange (if unscheduled Energy flows into the NYCA from other Control Areas) and associated payments in kind;
- Costs or revenues from Emergency Transactions with other Control Area operators;
- Cost or revenues from Special Test Transactions with other Control Area operators;
- Metering errors resulting in payments to or from Transmission Customers to be either higher or lower than they would have been in the absence of metering errors;
- Deviations between actual system Load and the five-minute ahead Load forecast used by SCD, resulting in either more or less Energy than is needed to meet Load;
- Energy provided by generation facilities in excess of the amounts requested by the ISO (through SCD Base Point Signals or AGC Base Point Signals);
- If generation facilities providing Regulation Service have actual output in excess of their AGC Base Point Signals, but the SCD Base Point Signals is higher than either, the real-time payments they receive for Energy produced will be based on the SCD Base Point Signals; and
- Transmission Customers serving Load in the NYCA will be billed based upon an estimated distribution of Loads to buses within each Load Zone. If the actual distribution of Load differs from this assumed distribution, the total amount collected from Transmission Customers could be either higher or lower than the

amount that would have been collected if the actual distribution of Loads had been known.

- Settlements for losses revenue variances, as described in Attachment K of this Tariff, with Transmission Owners that pay marginal losses to the ISO for losses associated with modified TWAs (not converted to TCCs) while receiving losses payments from the participants in those TWAs other than marginal losses.
- Payments made to Generators that are redispatched pursuant to the Interregional Transmission Congestion Management Pilot Program, set forth in Sections 5.1.2-5.1.2.4 of the Services Tariff, to the extent such payments are not recovered by the ISO an Emergency Transaction with another Control Area.

The actual Residual Adjustment for each month shall be the sum of the hourly Residual Adjustments calculated as follows: (A) the ISO's receipts from Transmission Customers and Primary Holders of TCCs for services which equal the sum of: (i) payments for Energy scheduled in the LBMP Market in that hour in the Day-Ahead commitment; (ii) payments for Energy purchased in the Real-Time LBMP Market for that hour that was not scheduled Day-Ahead; (iii) payments for Energy by generating facilities that generated less Energy in the real- time dispatch for that hour than they were scheduled Day-Ahead to generate in that hour for the LBMP Market; (iv) TUC payments made in accordance with Sections 3, 4 and 5 of this Tariff that were scheduled in that hour in the Day-Ahead commitment; and (v) real-time TUC payments in accordance with Parts 3, 4 and 5 of this Tariff that were not scheduled in that hour in the Day-Ahead commitment; (B) less the ISO's payments to generation facilities, Transmission Owners and Primary Holders of TCCs equal to the sum of the following: (i) payments for Energy to generation facilities that were scheduled to operate in the LBMP Market in that hour in the Day-Ahead commitment; (ii) payments to generation facilities for Energy provided to the ISO in the real-time dispatch for that hour that those generation facilities were not scheduled to generate in that hour in the Day-Ahead commitment; (iii) payments for Energy to LSEs that consumed less Energy in the real-time dispatch than those LSEs were scheduled

Day-Ahead to consume in that hour; (iv) payments of the real-time TUC to Transmission Customers that reduced their schedules for that hour after the Day-Ahead commitment; (v) payments of Congestion Rents collected for that hour in the Day-Ahead schedule to Primary Holders of TCCs; (vi) settlements with Transmission Owners for losses revenue variances; and (vii) positive Net Congestion Rents collected in that hour.

6.1.4.2 Bid Production Guarantees

The ISO's costs also include the costs associated with differences between the amounts bid by generating facilities that have been committed and scheduled by the ISO to provide Energy and certain Ancillary Services, and the actual revenues received by these generating facilities for providing such Energy and Ancillary Services. Where the costs are incurred to compensate a Resource for meeting the reliability needs of a local system, the associated charge shall apply only to Transmission Customers serving Load in the Load Zone(s) or sub-zone where the Resource is located. The ISO's costs also include the costs associated with payments made for supplemental payments and Demand Reduction Incentive payments to Demand Reduction Providers.

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, 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 with respect to the Transmission Customer's Transaction 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 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, Exports and Purchases from the LBMP Market where the Energy is delivered to an NYCA Interconnection with another Control Area 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 all Voltage Support Service from the ISO.

6.2.2 Payments

6.2.2.1 Payments made by Transmission Customers and LSEs

Transmission Customers 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

$$Rate_{VSS} = \frac{\sum^{All} NYISO_{VSSPayments} + PYA_{VSS}}{Energy_{NYISO}}$$

Where:

$Rate_{VSS}$ = Voltage Support Service Rate

$Energy_{ISO}$ = The annual forecasted transmission usage for the year as projected by the ISO including Load within the NYCA, Exports and Wheels Through.

$\sum^{All} NYISO_{VSSPayments}$ = The sum of the projected ISO payments to generation facilities 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} = Total of prior year payments to generation facilities 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 and LSEs in the prior year for Voltage Support Service (including all payments for penalties).

Transmission Customers engaging in Wheels Through, Exports and Purchases from the LBMP Market where the Energy is delivered to a NYCA interconnection with another Control Area 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. The ISO shall credit Revenue collected by application of this charge, on a Load ratio share basis, to Transmission Customers engaging in Wheels Through, Exports and Purchases from the LBMP Market where the Energy is delivered to a NYCA interconnection with another Control Area in the day and LSEs serving New York Control Area Load in the day. For LSEs and all Wheels Through, Exports and Purchases from the LBMP Market for Energy delivered to a NYCA interconnection with another Control Area, the ISO shall calculate the payment hourly. The ISO shall bill each Transmission Customer or LSE monthly.

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. Regulation Service is accomplished by committing on-line Generators whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in 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. The Transmission Customer must either purchase this service from the ISO or make alternative comparable arrangements to satisfy its Regulation Service obligation. The charges for Regulation Service are set forth below.

6.3.1 Customer Obligations and Responsibilities

Transmission Customers and LSEs shall either purchase this service from the ISO, Self-Supply or purchase this service from alternate Suppliers.

6.3.2 Charges to Transmission Customers

6.3.2.1 For all Actual Energy Withdrawals for Load located in the NYCA, the LSE is considered the Transmission Customer taking service under Sections 3, 4 and 5 of this Tariff for purposes of this Rate Schedule and shall pay a charge for this service on all Transmission Service in accordance with this Tariff and purchases in the LBMP Markets in accordance with the ISO Services Tariff, when such service serves Load located in the NYCA.

6.3.2.2 The ISO shall charge Transmission Customers and LSEs serving Load in the NYCA for Regulation and Frequency Response for each hour. The ISO shall charge Transmission Customers or LSEs taking service under Section 5 of the ISO OATT to supply Station Power as third-party providers for Regulation and Frequency Response for each day. The charge shall be calculated as the Regulation and Frequency Response Rate, determined as an hourly or a daily rate as appropriate, multiplied by the LSE's or Transmission Customer's Load for the hour or by the Transmission Customers or LSEs withdrawals to provide Station Power as a third party provider for the day. The ISO shall calculate the Regulation and Frequency Response Rate, for an hour or for a day as appropriate, as follows:

$$Rate_{RFR} = \frac{\text{(Supplier Payment - Supplier Charge - Generator Charge)}}{Load_{NYCA}}$$

where: $Rate_{RFR}$ is the hourly or daily rate for Regulation and Frequency Response; 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 Sections 15.3.4, 15.3.5, 15.3.6 and 15.3.7 of 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 15.3.5.5 and, if its provisions are re-instituted, Section 15.3.8 of Rate Schedule 3 of the ISO Services Tariff; (ii) all real-time imbalance charges paid by Suppliers under Section 15.3.5.3(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 Transmission Customers for this service shall be aggregated to render a monthly charge. The ISO shall credit charges paid for Regulation and Frequency Response by Transmission Customers or 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 Transmission Customers and LSEs serving Load in the NYCA for the day.

6.4 Schedule 4 - Energy Imbalance Service

Energy Imbalance Service is provided when (1) a difference occurs between the scheduled and the actual delivery of Energy to a Load located within the NYCA over a single hour, or (2) a difference occurs between the scheduled and actual delivery of Energy from a POI within the NYCA to a neighboring control area in a single hour. 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 must purchase this service from the ISO. The charges for Energy Imbalance Service are set forth below.

6.4.1 Energy Imbalance Service Charges

For each Transmission Customer that has executed a Service Agreement under the ISO Services Tariff, Energy Imbalance Service is considered to be supplied by the Real-Time Market and will be charged at the Real-Time LBMP price determined pursuant to Attachment J.

For each Transmission Customer that is not a Customer under the ISO Services Tariff and is receiving service under Section 3 or 4 of this Tariff, the ISO shall establish a deviation band of +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any Energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate Energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as may be established by the ISO that is generally accepted in the region and consistently adhered to by the ISO. If an Energy imbalance is not corrected within thirty (30) days or such other reasonable period of time as may be established by the ISO that is generally accepted in the region and consistently adhered to by the ISO, the Transmission Customer will compensate the ISO for such service, subject to the charges set forth below. Also, Energy imbalances outside the deviation band will be subject to charges set forth below.

For hours when the Transmission Customer's Actual Energy Withdrawals are greater than that customer's scheduled Energy delivery and applicable tolerance band, the Transmission Customer shall pay to the ISO an amount equal to the greater of 150% of the Real-Time LBMP price at the Point of Delivery or $100 per MWh. In the event that the Transmission Customer's Actual Energy delivery exceeds that customer's Actual Energy Withdrawals, the Transmission Customer shall not receive payment for such Energy.

Transmission Customers with imbalances may also be subject to charges for Regulation and Frequency Response, as described in Rate Schedule 3.

Energy imbalances resulting from inadvertent interchange between Control Areas will continue to be addressed by the procedures that Control Area operators currently use to address such imbalances. Any increase or decrease in costs resulting from pay back of accumulated inadvertent interchange will be included in the ISO Scheduling, System Control and Dispatch Service charge.

6.4.2 Inadvertent Energy Management Requirements

For Energy imbalances resulting from inadvertent interchange between Control Areas, the ISO shall: (i) accurately account for inadvertent Energy interchange, through daily schedule verification and the use of reliable metering equipment; (ii) minimize unintentional inadvertent accumulation in accordance with NERC and NPCC policies; and (iii) minimize accumulated inadvertent Energy balances in accordance with NERC and NPCC policies.

The ISO shall reduce accumulated inadvertent Energy balances with other Control Areas by one or both of the following methods: (i) scheduling interchange payback with another

Control Area as an interchange schedule between Control Areas; and (ii) unilaterally offsetting the tie-line interchange schedule when such action will assist in correcting an existing time error.

Inadvertent interchange accumulated during On-Peak hours shall be paid back during On-Peak hours. Inadvertent interchange accumulated during Off-Peak hours shall be paid back during Off-Peak hours. In either case, payback is made with Energy "in-kind."

6.4.3 Monthly Meter Reading Adjustments

6.4.3.1 Facilities Internal to the NYCA

The ISO shall develop rules and procedures to implement adjustments to meter readings to reflect the differences between the integrated instantaneous metering data utilized by the ISO for SCD and actual data for internal facilities as recorded by billing metering.

6.4.3.2 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 to be established by the ISO in accordance with NERC and other established reliability criteria.

6.4.4 Self-Supply

All Inadvertent Energy Accounting services and Energy Imbalance Services shall be purchased from the ISO.

6.4.5 Verification of Adjustments

The ISO shall provide all necessary meter reading adjustment information required by the Transmission Owners to allow them to verify that meter reading adjustments were performed in accordance with ISO Procedures.

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. The Transmission Customer must either purchase this service from the ISO or make alternative comparable arrangements to satisfy its Operating Reserve obligation. The charges for Operating Reserve Service are set forth below. Operating Reserves requirements are defined by the ISO as is described in Rate Schedule 4 of the ISO Services Tariff, in accordance with the Reliability Rules and other applicable reliability standards. The ISO shall monitor the level of Operating Reserves utilizing the security monitoring program. Transmission Customers, Transmission Owners and Suppliers shall supply all data required for the proper operation of the security monitoring program.

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.

6.5.1 General Requirements

The ISO shall select Operating Reserves Suppliers that are properly located electrically so that all Operating Reserves requirements, as defined in Rate Schedule 4 of the ISO Services Tariff are satisfied and so that transmission Constraints resulting from either the commitment or dispatch of Suppliers do not limit the 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 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).

6.5.2 Operating Reserves Charges

Each Transmission Customer engaging in an Export and each LSE shall pay an hourly charge equal to the product of (A) 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 to (ii) the sum of all Load in the NYCA and all scheduled Exports 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.

Transmission Customers 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 less any revenues from penalties collected during the day and (B) the ratio of (i) the Transmission Customer'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 for the day. The ISO shall credit the daily charges paid for Operating Reserves by Transmission Customers 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.

6.5.3 Self-Supply

Transmission Customers, including LSEs, may provide for Self-Supply of Operating Reserve by placing generation facilities supplying any one of the Operating Reserves under ISO Operational Control. The generation facilities must meet ISO rules for acceptability. The amount that any such customer will be charged for Operating Reserves Services will be reduced by the market value of the services provided by the specified generation facilities 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

Black Start and System Restoration Services are provided by key generation facilities that are capable of starting without an outside electrical supply and/or that are otherwise integral to the restoration of the system after an outage under the ISO's Black Start and System Restoration Services plan (the "ISO Plan") and/or an individual Transmission Owner's Black Start and System Restoration Services plan.

6.6.1 Requirements

The ISO shall develop and periodically review a Black Start and System Restoration Services plan for transmission facilities that are part of the ISO Plan. The ISO may amend this restoration plan to account for changes in system configuration if the ISO determines that additional Black Start and System Restoration Services are needed.

Transmission Customers shall pay a Black Start and System Restoration Services charge on all Transactions to supply Load in the NYCA (including Internal Wheels and Import Transactions) equal to the product of (a) the Transmission Customer's hourly Load Ratio Share and (b) the hourly embedded cost charge for Black Start and System Restoration Services (net of all payments forfeited due to a Generator's failure to pass a required test of its ability to provide Black Start and System Restoration Services).

The full restoration of the NYS Power System will require additional Black Start and System Restoration Services from Generators, which are located in local Transmission Owner areas and which are not presently listed in the ISO Plan. Although the ISO Plan will restore a major portion of the NYS Power System, there are portions of the NYS Power System that will remain under Transmission Owner restoration control. Where the Transmission Owner's restoration plan requires additional local Black Start and System Restoration Services, the ISO will make payments for such local services directly to the Generators that provide them, under the terms of Section 15.5.2 of Rate Schedule 5 to the ISO Services Tariff, except with respect to Black Start and System Restoration Services payments that are subject to Section 15.5.3.1 of that Rate Schedule. The LSEs in those local Transmission Owner areas will be additionally charged for Black Start and System Restoration Services by the ISO using the formula set forth in the following paragraph, except with respect to Black Start and System Restoration Services changes that are subject to Section 15.5.3.2 of Rate Schedule 5 to the ISO Services Tariff. Generating facilities, which are obligated to provide Black Start and System Restoration Services as a result of divestiture contract agreements, will not receive ISO payments for that service if they are already compensated for such service as part of those divestiture contracts.

The charge for LSEs in Local Transmission Owner areas shall be equal to the product of (a) the Transmission Customer's hourly Load Ratio Share of Load requiring local Black Start and System Restoration Services, and (b) the hourly embedded cost charge for providing local Black Start and System Restoration Services capability (net of all payments forfeited due to a local generation facilities failure to pass a Black Start and System Restoration Services capability test), described in ISO Services Tariff, Rate Schedule 5.

6.6.2 Self Supply

Transmission Customers may not Self-Supply this Black Start Capability Service.

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 monthly TUC (in $) shall be the sum of the hourly values for each hour in the month 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 no later than ninety (90) minutes prior to such hour in the Dispatch Day.

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 J.

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 J.

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 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

6.7.1.2.1 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.

6.7.1.2.2 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.

6.7.1.3 Exceptions to the requirement to pay the hourly TUC.

6.7.1.3.1 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.

6.7.1.3.2 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 J.

$DAMLC_{RP}$ 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 J.

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 J.

$RTMLC_{RP}$ 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 J.

6.7.2.2.1 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.

6.7.2.2.2 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.

6.7.3 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

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.

6.7.4 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 month 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 month 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.

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.

6.7.6 Resales

The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section 23.1 of the Tariff.

6.8 Schedule 8 - Non-Firm Point-To-Point Transmission Service

The charges for Non-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.

6.8.1 Marginal Losses

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 J.

$RTMLC_{RP}$ 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 J.

6.8.2 Wholesale Transmission Service Charge ("WTSC")

The Wholesale Transmission Service Charge (in $) is calculated as follows:

6.8.2.1 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 Non-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.

6.8.2.2 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 (l) 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.

6.8.3 Retail Transmission Service Charge ("RTSC")

The rates and charges for retail transmission service are described in Section 5 of this Tariff.

6.8.4 NYPA Transmission Adjustment Charge ("NTAC")

LSEs serving retail access load will be charged an NTAC consistent with each Transmission Owner's retal access program pursuant to Section 2.7 of this Tariff. The

Transmission Customer shall pay to the ISO each month the NTAC. NTAC (in $) is calculated as follows:

6.8.4.1 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 month for Non-Firm Point-To-Point Transmission Service by the Transmission Customer.

6.8.4.2 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 real-time 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 real-time meter; or (3) using a method agreed to by the customer and the applicable Transmission Owner until such time as a revenue-quality real-time meter is available.

6.8.5 Resales

The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by Section 23.1 of the Tariff.

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 monthly TUC (in $) shall be the sum of the hourly values for each hour in the month 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 J.

$DALBMP_{RP}$ 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 J.

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 J.

$DAMLC_{RP}$ 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 J.

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 J.

$RTMLC_{RP}$ 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 J.

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 month 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 month 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 Reliability Facilities Charge ("RFC")

6.10.1 Applicability.

This rate mechanism establishes the Reliability Facilities Charge ("RFC") for the recovery of costs related to each regulated reliability transmission project undertaken pursuant to a determination by the NYISO that a regulated solution is needed to address reliability needs identified by the NYISO in its reliability planning process in accordance with Section 31.2.6.4 of Attachment Y of the NYISO OATT and the NYISO/TO Reliability Agreement. For purposes of this attachment, a regulated reliability transmission project includes a regulated backstop transmission project or a regulated transmission Gap Solution proposed by a Responsible Transmission Owner, or an alternative regulated transmission project proposed by a TO or an Other Developer, provided that such alternative regulated transmission project has been determined by the appropriate state regulatory agency(ies) as the preferred solution to the identified Reliability Need. The rate mechanism shall not apply to projects undertaken by Transmission Owners pursuant to Local Transmission Owner Planning Processes pursuant to Section 31.1.1.2 and Section 31.2.1 of Attachment Y of the NYISO OATT. The RFC shall be comprised of the revenue requirements related to: (i) each regulated reliability transmission project filed with FERC by a Transmission Owner pursuant to the provisions of this Attachment; (ii) any costs incurred by NYPA and filed with FERC by the NYISO pursuant to the provisions of this Attachment; and (iii) any FERC approved costs incurred by an Other Developer under Section 6.10.5 and filed with FERC by the NYISO or Other Developer pursuant to the provisions of this Attachment. Any costs incurred by LIPA and allocable to other Transmission Districts will be collected under a separate LIPA RFC as set forth in Section 6.10.4.3 and filed with FERC by the NYISO pursuant to the provisions of

Section 6.10.4.3. This RFC will provide for full recovery of all reasonably incurred costs related to the preparation of proposals for, and the development, construction, operation and maintenance of any regulated reliability transmission project undertaken pursuant to Attachment Y of this tariff, including all reasonable costs related to such a project that is halted in accordance with the provisions of the NYISO's tariff and the NYISO/TO Reliability Agreement. Subject to regulatory acceptance, the RFC shall include a reasonable return on investment and any applicable incentives. The RFC established under this Attachment shall be separate from the Transmission Service Charge ("TSC") and the NYPA Transmission Adjustment Charge ("NTAC") determined in accordance with Attachment H of the NYISO OATT. With respect to the recovery of costs incurred by LIPA and NYPA, the provisions of Sections 6.10.1, and 6.10.2 through 6.10.3.4 of this Attachment shall not apply to LIPA or NYPA, except as provided for in Sections 6.10.4.3 and 6.10.4.4 of this Attachment. The recovery of costs related to development, construction, operation and maintenance of a regulated reliability transmission project undertaken by LIPA or NYPA shall be pursuant to the provisions of Sections 6.10.4.3 and 6.10.4.4 of this Attachment**.** The recovery of costs related to development, construction, operation and maintenance of an Alternative Regulated Solution proposed by an Other Developer shall be pursuant to the provisions of Section 6.10.5 of this Attachment.

6.10.2 Recovery of Transmission Owner's Costs Related to Regulated Reliability Transmission Solutions.

Each Transmission Owner shall have on file at FERC the rate treatment that will be used to derive and determine the revenue requirement to be included in the RFC, and for the LIPA RFC as applicable, for regulated transmission projects undertaken pursuant to a determination by the NYISO that a regulated solution is needed to address reliability needs identified by the

NYISO in its reliability planning process in accordance with Section 31.2.6.4 of Attachment Y of the NYISO OATT. The filing will provide for the recovery of the full revenue requirement for a regulated reliability transmission project consistent with FERC regulations including but not limited to any incentives for the construction of transmission projects provided for in Section 219 of the Federal Power Act and the FERC regulations implementing that section. Pursuant to a determination by the NYISO that a regulated solution is needed to address reliability needs identified by the NYISO in its reliability planning process in accordance with Section 31.2.6.4 of Attachment Y of the NYISO OATT, the Responsible Transmission Owner(s) proceeding with a Regulated Transmission Backstop Solution or a Transmission Owner proceeding with an Alternative Regulated Transmission Solution that is selected by the appropriate state agency as the preferred solution, will proceed with the approval process for all necessary federal, state and local authorizations for the requested project to which this RFC applies.

6.10.2.1 Upon receipt of all necessary federal, state, and local authorizations, including FERC acceptance of the rate treatment, the Transmission Owner(s) shall commence construction of the project.

6.10.2.2 Upon completion of the project, the Transmission Owner(s) or the NYISO as applicable, will make an informational filing with FERC to provide the final project cost and resulting revenue requirement to be recovered pursuant to this Attachment. The final project cost and resulting revenue requirement will be reduced by any amounts that, pursuant to Section 25.7.12.3.3 of Attachment S to the NYISO OATT, have been previously committed by or collected from Developers for the installation of System Deliverability Upgrades required for the interconnection of generation or merchant transmission projects. The resulting revenue requirement will become effective and recovery of project costs pursuant to this Attachment will commence upon the making of the information filing with FERC, and shall not require and shall not be dependent upon a re-opening or review of the Transmission Owner(s)' revenue requirements for the TSCs and NTAC set forth in Attachment H of the NYISO OATT. This Section 6.10.2.2 also applies to the recovery of all reasonably incurred costs related to either a regulated backstop transmission project or an alternative regulated transmission project that has been selected by the appropriate state agency(ies) as the preferred solution and that is later halted, including but not limited to reasonable and necessary expenses incurred to implement an orderly termination of the project, in accordance with the provisions of the NYISO OATT and the NYISO/TO Reliability Agreement. Following the information filing, the NYISO will bill the RFC or LIPA RFC, as applicable.

6.10.2.3 The Transmission Owners may propose a non-transmission solution subject to state jurisdiction to address a reliability need included in the Comprehensive Reliability Plan, provided that the appropriate state agency(ies) has established procedures to ensure full and prompt recovery of all reasonably incurred costs related to a project, comparable to those set forth in this tariff for cost recovery for regulated reliability transmission projects.

6.10.3 RFC Revenue Requirement Recovery.

The RFC is to be billed by the NYISO and paid by the LSEs located in load zones to which the cost of the transmission facilities have been allocated in accordance with Attachment Y of the NYISO OATT. All LSEs in the load zones to which costs have been allocated, including Transmission Owners, competitive LSEs and municipal systems, will be billed by the NYISO.

6.10.3.1 The revenue requirement filed pursuant to Section 6.10.2.2 will be the basis for the monthly RFC Rate ($/MWh), and shall be applied by the NYISO to each LSE based on its Actual Energy Withdrawals as set forth in Section 6.10.3.4.

6.10.3.2 To the extent that incremental transmission rights owned by the Transmission Owner sponsoring the project are created as a result of a transmission project implemented in accordance with Attachment Y of the NYISO OATT, those incremental transmission rights that can be sold will be auctioned or otherwise sold by the NYISO. The NYISO will disburse the associated revenues to the Transmission Owner(s). The associated revenues will be used in the calculation of the RFC as set forth in Section 6.10.3.4. The incremental transmission rights will continue to be sold for the depreciable life of the project, and the revenues offset discussed above will commence upon the first payment of revenues related to a sale of incremental transmission rights on or after the RFC is implemented for a specific project. These incremental revenues shall not require and shall not be dependent upon any reopening or any review of the Transmission Owner(s) TSCs or NTAC under Attachment H of the NYISO OATT.

6.10.3.3 The NYISO will collect the appropriate RFC revenues on a monthly basis and remit those revenues to the appropriate Transmission Owner(s) in accordance with the NYISO's billing and settlement procedures pursuant to Section 2.7.2.5 of the NYISO OATT.

6.10.3.4 The Billing Units for the monthly RFC Rate shall be based on the Actual Energy Withdrawals available for the prior month for those zones determined to be allocated the costs of the project in accordance with Attachment Y of the NYISO OATT.

Step 1: Calculate the $ assigned to each Zone

$$\boxed{\begin{aligned}RFC_{z.m} = \sum_{p \in P} \{ [(Annual\,RR_p - Incremental\,Transmission \\ Rights\,Revenue_p\,)/12]*(Zonal\,Cost\,Allocation\%_p) \}\end{aligned}}$$

Step 2: Calculate a per-MWh Rate for each Zone

$$\boxed{RFC\ Rate_{z.m} = RFC_{z.m} \,/\, MWh_{z,\,m}}$$

Step 3: Calculate monthly charge for each LSE in each Zone

$$\boxed{Charge_{\,m,l,z} = RFC\ Rate_{z,m} * MWh_{l,z,m}}$$

Step 4: Calculate monthly charge for each LSE across all Zones

$$\boxed{Charge_{m,l} = \sum_{z \in Z} (Charge_{m,l,z})}$$

Where,

P = set of Projects
Z = set of NYISO Zones
$MWh_{z,\,m}$ = Actual Energy Withdrawals in zone z aggregated across all hours in month m
$MWh_{\,l,\,z,\,m}$= Actual Energy Withdrawals for LSE l in zone z aggregated across all hours in month m
R_P = the annual Revenue Requirement for each Project as discussed in Section 6.10.2.2 above.

6.10.4 Recovery of Costs by an Unregulated Transmitting Utility.

An Unregulated Transmitting Utility is a Transmission Owner that, pursuant to Section 201(f) of the FPA is not subject to the Commission's jurisdiction under Sections 205 and 206 of the FPA. The recovery of costs related to the preparation of proposals for, and the development, construction, operation and maintenance of, a regulated reliability transmission project undertaken pursuant to Attachment Y of the NYISO OATT by LIPA, as an Unregulated Transmitting Utility, shall be conducted as follows:

6.10.4.1 Upon the request of the NYISO, an Unregulated Transmitting Utility will proceed with the process of receiving any necessary authorization for the requested project.

6.10.4.2 Upon receipt of all necessary federal, state and local authorizations, the Unregulated Transmitting Utility shall commence with construction of the project.

6.10.4.3 Cost Recovery for LIPA

Transmission Owners other than LIPA that propose an alternative regulated transmission project on Long Island would recovery any costs per Sections 6.10.2 through 6.10.3.4 of this Attachment. Other Developers that propose an alternative regulated transmission project on Long Island would recover any costs per Section 6.10.5 of this Attachment.

6.10.4.3.1 Any costs incurred for a regulated backstop reliability transmission project or an alternative regulated transmission project undertaken by LIPA, as an Unregulated Transmitting Utility, shall be recovered as follows:

6.10.4.3.1.1 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 NYISO, for purposes of inclusion within the NYISO OATT and filing with FERC on an informational basis only, a description of the rate recovery mechanism and the rate that LIPA will charge and collect from responsible entities within the Long Island Transmission District in accordance with the NYISO cost allocation methodology pursuant to Section 31.4.2.2 of Attachment Y of the NYISO OATT.

6.10.4.3.1.2 For Costs to Other Transmission Districts: Where the NYISO determines that there are responsible entities outside of the Long Island Transmission District that should be allocated a portion of the costs of the regulated backstop reliability transmission solution or an alternative regulated transmission solution undertaken by LIPA, LIPA shall inform the NYISO 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 6.10.4.3.1.1 in accordance with the formula set forth in Section 6.10.3.4. The costs of a LIPA regulated backstop reliability transmission project or an alternative regulated transmission solution, allocable to responsible entities outside of the Long Island Transmission District shall constitute the “revenue requirement” that the NYISO shall include and, and recover through, a separate “LIPA RFC”. The NYISO shall file the LIPA RFC with the Commission as an informational filing. The NYISO will file such RFC for Commission review under the same “comparability” standard as is applied to review of changes in LIPA’s TSC under Attachment H of this tariff. LIPA shall intervene in support of such filing at the Commission and shall take the responsibility to resolve all concerns about the contents of the filing that might be raised in such proceeding. The NYISO shall bill for LIPA the LIPA RFC to responsible entities in Transmission Districts other than the Long Island Transmission District consistent with Sections 6.10.3.1 through 6.10.3.4 and shall remit the revenues collected to LIPA on a monthly basis.

6.10.4.4 Savings Clause. The inclusion in the NYISO OATT or in a FERC filing on an informational basis of the charges for recovery of costs incurred by LIPA or NYPA related to a regulated project undertaken pursuant to Attachment Y into the NYISO OATT, as provided for in Sections 6.10.4.3 and 6.10.4.4, or the inclusion of such charges in the NYISO RFC pursuant to Section 6.10.4.3.1.2, shall not be deemed to modify the treatment of such rates as non-jurisdictional pursuant to Section 201(f) of the FPA.

6.10.5 Recovery of Costs Incurred by an Other Developer Related to an Alternative Regulated Solution.

6.10.5.1 The RFC shall be used as the cost recovery mechanism for the recovery of the costs of an alternative regulated reliability transmission project pursuant to a determination by the NYISO that a regulated solution is needed to address reliability needs identified by the NYISO in its reliability planning process in accordance with Section 31.2.6.4 of Attachment Y of the NYISO OATT, that is proposed, developed or constructed by an Other Developer who is otherwise authorized to propose, develop or construct a regulated transmission project under applicable state and federal law, and that has been determined by the appropriate state regulatory agency(ies) as the preferred solution to the identified Reliability Need , and who is authorized by FERC to recover costs under this rate mechanism. Provided however, nothing in this cost recovery mechanism shall be deemed to create any additional rights for an Other Developer to proceed with a regulated transmission project that such Other Developer does not otherwise have at law. The provisions of Sections 6.10.3 through 6.10.3.4 of this Attachment shall be applicable to the recovery of the costs incurred by an Other Developer for proposing, developing and constructing an alternative regulated transmission project that has been determined by the appropriate state regulatory agency(ies) as the preferred solution to the identified Reliability Need.

6.10.5.2 Upon receipt of all necessary federal, state, and local authorizations, including FERC acceptance of a Section 205 filing authorizing cost recovery under the NYISO tariff, the Other Developer shall commence construction of the project. Upon completion of the project, the Other Developer and/or the NYISO, as applicable, will make a filing with FERC to provide the final project cost and resulting revenue requirement to be recovered pursuant to this Attachment. The resulting revenue requirement will become effective and recovery of project costs pursuant to this Attachment will commence upon the acceptance of the filing by FERC. This Section 6.10.5.2 also applies to the recovery of all reasonably incurred costs related to a project that has been selected as the preferred solution by the appropriate state regulatory agency(ies) and is later halted, including but not limited to reasonable and necessary expenses incurred to implement an orderly termination of the project, in accordance with the provisions of the NYISO OATT.

6.10.5.3 Other Developers may also propose a non-transmission solution subject to state jurisdiction to address a Reliability Need included in the Comprehensive Reliability Plan.

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' next monthly invoice. 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. The rate to be applied to injection and withdrawal billing units in each month shall be the quotient of the amount of these costs to be included in the month divided by the sum of the total injection and withdrawal billing units for the month. This rate shall then be multiplied by each Transmission Customer's aggregate injection and withdrawal billing units for the month.

6.11.3.4.2 Billing Units. For all charges calculated under Section 6.11.3.0 of this Rate Schedule, the Transmission Customer's injection billing units shall be based on 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 wheelthroughs. The Transmission Customer's withdrawal billing units shall be based on its Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA, and hourly Energy schedules for all Wheels Through and Exports.

6.11.3.4.3 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 next monthly invoice utilizing the billing units described in Section 6.11.3.4.2 of this Schedule 11 for the month of infraction. For purposes of this calculation, the "month of infraction" shall be the service month in which the violation occurred. Should the penalty be assessed for a violation occurring over multiple service months, the penalty to be recovered for each service month shall be the total penalty to be recovered through Section 6.11.3 of this Schedule divided by the number of months over which the violation occurred. Whenever practicable, the ISO shall recover this Rate Schedule 11 charge in the invoice issued in the month following the month in which the NYISO incurs the penalty charge. The ISO may recover penalty charges over several months 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.

This rate mechanism 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 NYISO OATT that are allocated to Load Serving Entities ("LSEs"). The rate mechanism shall not apply to: (i) the extent that a Highway SDU is undertaken and funded pursuant to Attachment Y of the NYISO 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; or (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 NYISO OATT. The HFC shall be comprised of the revenue requirements related to each Highway SDU filed with FERC by a Transmission Owner pursuant to the provisions of this Schedule. The HFC will provide for full recovery of all reasonably incurred costs 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. Subject to regulatory acceptance, the HFC shall include a reasonable return on investment. The HFC established under this Schedule shall be separate from the Transmission Service Charge ("TSC") and the NYPA Transmission Adjustment Charge ("NTAC") determined in accordance with Attachment H of the NYISO OATT and the Reliability Facilities Charge ("RFC") established in accordance with Attachment Y and Rate Schedule 10 of the NYISO OATT.

6.12.2 Recovery of Transmission Owner's Costs Related to Highway SDUs.

Each Transmission Owner shall file with FERC 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 NYISO 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 NYISO 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 NYISO OATT, 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 FERC 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 Upon completion of the project, the Transmission Owner(s) will make an informational filing with FERC to provide the final project cost and resulting revenue requirement to be recovered pursuant to this Schedule. The recovery of project costs pursuant to this Schedule will commence on the effective date proposed in the informational filing and accepted by FERC, and shall not require and shall not be dependent upon a re-opening or review of the Transmission Owner's revenue requirements for the TSCs and NTAC set forth in

Attachment H of the NYISO OATT. Following the informational filing, the NYISO will bill the HFC, as applicable.

6.12.3 HFC Revenue Requirement Recovery.

The HFC is to be invoiced by the NYISO and paid by the LSEs allocated in accordance with Section 25.7.12.3.2 of Attachment S of the NYISO OATT. All LSEs to which costs have been allocated, including Transmission Owners, non-Transmission Owner LSEs and municipal systems, will be invoiced by the NYISO.

6.12.3.1 The revenue requirement filed pursuant to Section 6.12.2.3 will be the basis for the monthly HFC, and shall be allocated by the NYISO to each LSE based on its proportionate share of the ICAP requirement in the statewide capacity market, adjusted to subtract locational capacity requirements as set forth in Attachment S.

6.12.3.2 The monthly HFC 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.

6.12.3.4 To the extent that Incremental TCCs are created as a result of a Highway SDU implemented in accordance with Attachment S of the NYISO OATT, that portion of those Incremental TCCs attributed to LSEs pursuant to Attachment S that can be sold will be auctioned or otherwise sold by the NYISO. The NYISO will disburse or credit the associated revenues to the LSEs. These Incremental TCCs will continue to be sold for so long as LSEs are responsible for funding the Highway SDU through an HFC, and the disbursements or credits discussed above will commence upon the first payment of revenues related to a sale of Incremental TCCs on or after the HFC is first invoiced for a specific Highway SDU. These incremental revenues shall not require and shall not be dependent upon any reopening or any review of the Transmission Owner(s) TSCs or NTAC under Attachment H of the NYISO OATT.

6.12.3.5 The NYISO will collect the appropriate HFC revenues on a monthly basis and remit those revenues to the appropriate Transmission Owner(s) in accordance with the NYISO's billing and settlement procedures pursuant to the NYISO OATT.

6.12.3.6 The monthly HFC 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 NYISO OATT.

6.12.3.6.1 For Year 1, the LSEs' ICAP requirements for the most recent NYISO Capability Year prior to the in-service date of the Highway SDU shall be used for cost allocation.

6.12.3.6.2 For subsequent years, the billing cycle shall be adjusted, if necessary, to start following the establishment of the LSEs' ICAP requirements for the current Capability Year.

6.12.3.6.3 Each LSE's share of the monthly HFC shall be allocated as follows: LSE HFC Allocation = Monthly HFC x (LSE ICAP Requirement - Locational ICAP Requirement (if applicable))/(Statewide ICAP Requirement – Sum of Locational ICAP Requirements)

6.12.3.6.4 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.

6.12.3.6.5 Revenue shortfalls, if any, will be allocated to the remaining LSEs in proportion to their ICAP requirements for the Capability Year. Billing adjustments for revenue shortfalls will occur on a monthly basis.

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.

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.

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 to account for the payment received from the subsequent Developer or Interconnection Customer to lower the HFC charged to LSEs going forward.

6.12.4.2 The NYISO will credit the subsequent Developer or Interconnection Customer with any revenues derived from the monetization of Incremental TCCs created by the Highway SDU in proportion to the use of Headroom by the Developer's or Interconnection Customer's project. Credits to the LSEs from sales of Incremental TCCs will be reduced proportionately.

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.

ISO:

____

____

____

Transmission Customer:

____

____

____

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

Specifications For Firm Point-To-Point
Transmission Service

l.0 Term of Transaction: ____

Start Date: ____

Termination Date: ____

2.0 Description of Capacity and Energy to be transmitted by ISO including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____

Delivering Party: ____

4.0 Point(s) of Delivery: ____

Receiving Party: ____

5.0 Maximum amount of Capacity and Energy to be transmitted: ______________

6.0 Designation of party(ies) subject to reciprocal service obligation:

____

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service:

____

____

8.0 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 the Tariff.)

8.1 Transmission Service Charge:____

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:___________________________________

____

8.4 Ancillary Services Charges:____

____

____

____

____

8.5 Other Charges: ____

____

____

____

____

8 Attachment B - Form of Service Agreement for Non-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 be a Transmission Customer under Section 3 of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 3 of this Tariff.

3.0 Service under this Agreement shall be provided by the ISO upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the ISO deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The ISO agrees to provide and the Transmission Customer agrees to pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Section 3 of the 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:

____

____

____

Transmission Customer:

____

____

____

7.0 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

9 Attachment C - Methodology to Assess Available Transfer Capability

The ISO shall calculate Firm and Non-Firm Available Transfer Capability ("ATC") according to the procedures set forth in this Attachment C.

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.

ATC shall be calculated and posted after the close of the ISO's Day-Ahead Market and Real-Time Market for all Internal and External Interfaces and for Scheduled Lines. ATC is also posted two days to eighteen months in advance of the Dispatch Day to accommodate Pre-Scheduled Transaction Requests at External Interfaces.

The ISO shall calculate ATC values using a methodology that reflects its provision of transmission service under an LBMP system and the schedules produced by its Day-Ahead Market and Real-Time Market software (except with respect to Pre-Scheduled Transactions). The ISO shall not limit Transmission Customers' ability to schedule Firm Transmission Service across Internal Interfaces based on ATC values. 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 Internal Interfaces for Transmission

Customers that are willing to pay congestion charges by redispatching New York State Power System.

9.2 Methodology for Computing Firm and Non-Firm ATC

The ISO shall calculate and post Firm ATC and Non-Firm ATC from two days to eighteen months in advance of the Dispatch Day based on accepted Pre-scheduled Transaction Requests across External Interfaces.

The ISO also calculates Firm ATC based on the market schedules determined using its Security Constrained Unit Commitment ("SCUC") process for the Day-Ahead Market and its Real-Time Commitment ("RTC") and Real-Time Dispatch ("RTD") (together, "Real-Time Scheduling" ("RTS")) process for the Real-Time Market. These Firm ATC values shall be posted after the close of the Day-Ahead Market and Real-Time Market for all Interfaces and Scheduled Lines.

For all purposes and for all time periods, the ISO calculates and posts Firm ATC by first determining Total Transfer Capability ("TTC") and then subtracting Firm Transmission Flow Utilization and Transmission Reserve Margin ("TRM"). Thus:

$$ATC_{Firm} = TTC - Transmission\ Flow\ Utilization_{Firm} - (TRM)$$

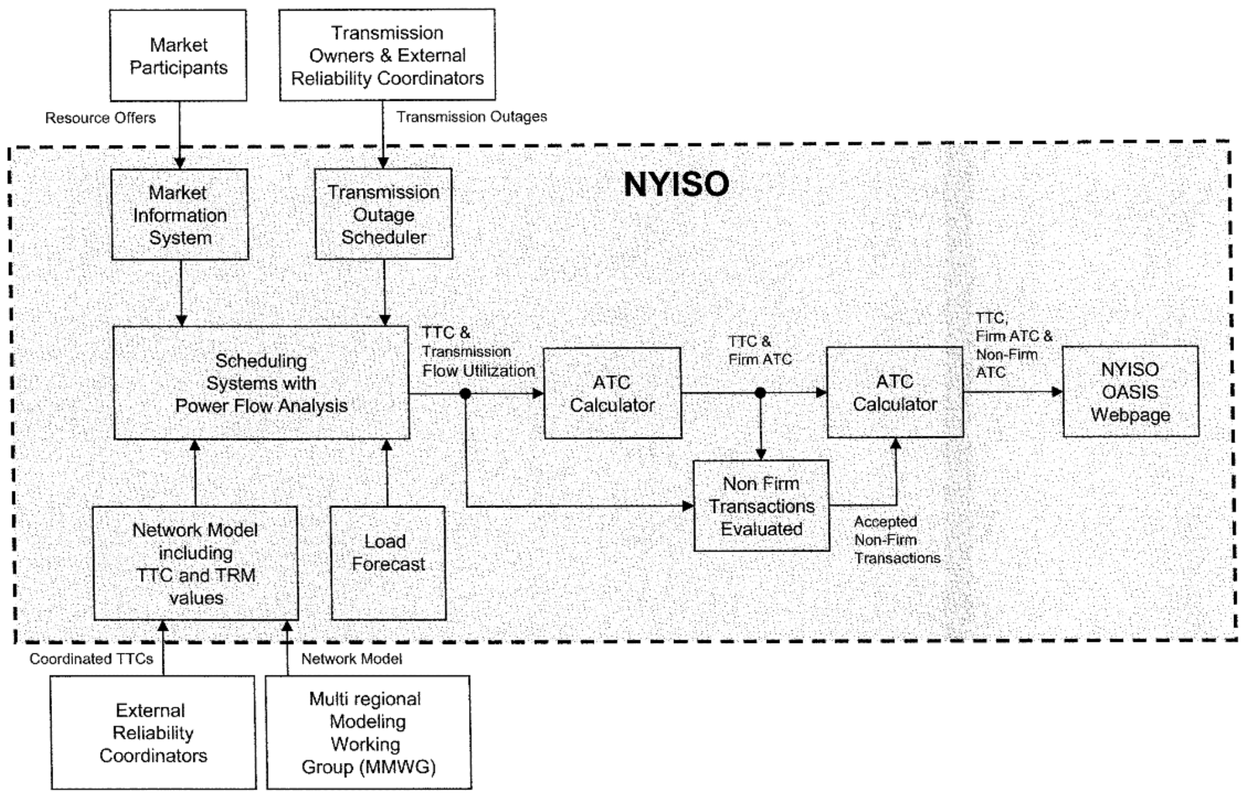
For all purposes and for all time periods, the ISO calculates and posts Non-Firm ATC by first calculating the amount of Firm ATC and then subtracting Non-Firm Transmission Flow Utilization:

$$ATC_{Non\text{-}Firm} = ATC_{Firm} - Transmission\ Flow\ Utilization_{Non\text{-}Firm}$$

The ISO's ATC calculation algorithms are posted at the "ATC Detailed Algorithms" link at: http://www.nyiso.com/public/market_data/power_grid_data/dam_outages.jsp.

9.3 Process Flow Diagram

The following diagram illustrates the process that the ISO follows when computing and posting ATC.



9.4 Total Transfer Capability ("TTC")

The ISO shall develop TTC values for each Interface and Scheduled Line. 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 TCC 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.

Databases used in the determination of the TTC values include MultiRegional Modeling Working Group 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 NYISO receives timely notification of such conditions, or to account for operating conditions affecting the New York State Transmission System.

9.5 Transmission Flow Utilization

With respect to the ATC calculations relating to Pre-Scheduled Transactions that are conducted for External Interfaces from eighteen months until two days before the Dispatch Day:

Transmission Flow Utilization$_{Firm}$ associated with Pre-Scheduled Transactions Requests shall be the algebraic sum of all Pre-Scheduled Transactions scheduled.

Transmission Flow Utilization$_{Non\text{-}Firm}$ associated with Pre-Scheduled Transactions Requests is not permitted and its value is assumed to be zero.

With respect to the ATC calculation that the ISO performs after the closing of the Day-Ahead Market and the Real-Time Market, the ISO shall use the SCUC and RTS market software to determine market schedules. 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 RTS, 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 RTS, as applicable.

Transmission Flow Utilization$_{Non\text{-}Firm}$ for Scheduled Lines is the sum of Non-Firm Transactions scheduled.

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.

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.

The TRM used to calculate ATC at External Interfaces in connection with Pre-Scheduled Transactions up to eighteen months before the Dispatch Day will normally be significantly greater than the TRM used to calculate ATC for External Interfaces for the Day-Ahead Market and the Real-Time Market due to the greater uncertainty regarding long range External Interface transmission facility availability.

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) unscheduled loop or parallel flows ranging in value from zero (0) MW to five hundred (500) MW based on the average of the last three months of historical parallel flows observed 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) unscheduled loop or parallel flows ranging in value from zero (0) to five hundred (500) MW based on the average of the last three months of historical parallel flows observed 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 (o) 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, and thus is not available when requesting Non-Firm transmission service. 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 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.

9.7 Existing Transmission Commitments ("ETC")

The ISO shall not set aside transmission capacity as ETC when calculating ATC or otherwise in developing SCUC and RTS market schedules.

9.8 Capacity Benefit Margin

The ISO shall not set aside transmission capacity as CBM when calculating ATC or otherwise in developing SCUC and RTS market schedules.

9.9 Coordinated ATC Postings

The ISO's practice is to make joint TTC/ATC postings along with neighboring system operators on the website of the Northeast Power Coordinating Council. The ISO does not coordinate its ATC calculations with neighboring system operators because they do not incorporate the Transmission Flow Utilization information produced by the ISO's market software into their ATC calculations.

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 12.12 below.

The ISO Employees shall take all reasonable actions within their authority under the ISO Tariffs and Agreements[1] 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,[2] 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;

---

[1] 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.

[2] 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[3] in accordance with Section 12.6, below;

(6) protect the ISO's assets including property, facilities, equipment and supplies in accordance with Section 12.11, below; and

(7) avoid contact with Market Participants[4] which could cause or appear to cause a conflict of interest under Section 12.7, below.

---

[3] 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.

[4] 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 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 12.10) 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 does 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 information from a Market Participant to the ISO;

(3) 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;

(4) 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; and

(5) information that is not listed in NYPP OP-18 and has not been designated by the supplier or owner as Confidential Information.

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, 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.

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.

If the FERC or its staff, during the course of an investigation or otherwise, requests information 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 its Staff within the time provided for in the request for information. In providing the information to the FERC or its staff, the ISO 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 ISO shall not be held liable for any losses, consequential or otherwise, resulting from the ISO divulging such Confidential Information pursuant to a request under this paragraph. After the Confidential Information has been provided to the FERC or its 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 its staff, or a decision to disclose such confidential information has been made by the FERC, 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 rules and regulations that may provide for privileged treatment of information provided to the FERC or its staff.

The ISO shall establish procedures for handling Confidential Information that minimize the possibility of intentional or accidental improper disclosure.

12.4.1 Insider Trading

This section defines insider trading, explain the duties of ISO Employees and describes behavior that is prohibited under securities laws.

12.4.1.1 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 12.7), 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.

12.4.1.2 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 12.10) 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.

12.5 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.

12.6 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.

12.7 Conflicts of Interest

Certain contacts between the ISO Employees 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.

12.7.1 Financial Interests:

Financial interests refer to the ownership of the Securities[5] of Market Participants or their Affiliates whose primary business purpose is to buy, sell or schedule Energy, Capacity, Ancillary Services or Transmission Services, whether ownership is direct or through participation in mutual funds concentrating in investments in Market Participants or their Affiliates. The ISO shall compile a list of the current Market Participants and their Affiliates whose Securities trade publicly and will 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 Securities of any Market Participant or any of their Affiliates:

- No ISO Employee or their spouse or minor children shall own, control, or hold with power to vote, Securities of a Market Participant or any of their Affiliates; provided, however, 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

[5] The term "Securities" refers to stocks, stock options, bonds and any other instruments of debt or equity.

transfer, spin off and merger of assets and liabilities of such plans to new plans maintained by the ISO; provided, further that this provision shall not apply to any purchase of Securities of a Market Participant or any Affiliate of such Market Participant by a spouse of an 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.

- 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. The ISO Board will establish reasonable guidelines with respect to the financial interests of covered consultants or contracts, in accordance with Section 12.12.

12.7.2 ISO Policy on Divestiture of Financial Interests:

If an ISO Employee or his/her immediate family[6] owns, controls or has the power to vote such Securities of Market Participants or their Affiliates, the ISO shall require the divestiture of those Securities within a reasonable time in accordance with the ISO's divestiture procedure set forth below unless material hardship would result. The ISO shall develop a procedure establishing the conditions under which a divestiture would result in material hardship.

If an ISO Employee or member of the ISO Employee's immediate family owns, controls or holds with the power to vote any prohibited Securities, divestiture must occur as follows: (1) as of the effective date of ISO OATT, divestiture of prohibited Securities must occur within six months; (2) new ISO Employees must divest prohibited Securities within six months of commencement of employment; (3) if ownership, control or the power to vote such Securities results from an entity becoming a Market Participant, divestiture must occur within six months of receipt of the ISO's list of prohibited Securities referencing such Securities; and (4) if ownership, control or the power to vote such Securities is as a result of a gift, inheritance,

[6] Immediate family refers to spouse and minor children.

distribution of marital property or other involuntary acquisition, divestiture must occur within six months of the acquisition.

Ownership of mutual funds by ISO Employees which contain investments in Market Participants or their Affiliates is permitted so long as: (1) the fund is publicly traded; (2) the fund's prospectus does not indicate the objective or practice of concentrating its investment in Market Participants or their Affiliates; and (3) the ISO Employee does not exercise or have the ability to exercise control over the financial interests held by the fund.

12.7.3 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.

12.7.4 Secondary Employment:[7]

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, that ISO Employee may not transact business with the ISO on behalf of the Secondary Employer.

An ISO Director or an individual representative of a member of an ISO committee shall not serve as a representative of a member of the Executive Committee of the NYSRC.

12.7.5 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,

[7] 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.

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.

12.8 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.

12.9 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.

12.10 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.

12.11 ISO Property and Other Assets

ISO property and other assets shall be used only for ISO-related business.

12.12 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. 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 12.12 of the ISO OATT.

12.13 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.

12.14 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 of in accordance with the ISO's divestiture policy (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 14.1.2.2 of this Attachment for the first two months of LBMP implementation and in accordance with Section 14.1.2.1 of this Attachment thereafter. 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");[8]

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");[8] 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;

[8] The TSC shall not apply to Wheels Through or 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.

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

Beginning with the second month of the Capability Period corresponding to the initial auction for Long Term TCCs through the end of the LBMP Transition Period, 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:

WHOLESALE TSC = {(RR÷12) + (CCC÷12) + (LTPP÷12) - SR - ECR - CRR - WR - Reserved}/(BU÷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.

LTPP = The Transmission Owner's annual Net LBMP Transition Period Payment ("LTPP") (expressed as a positive value) or receipt (expressed as a negative value) as described in Attachment K, Section 17.6 (Note - The LTPP will be established once for the entire LBMP Transition Period after the Initial Auction, as defined in Attachment M, for Long Term TCCs). Prior to a 205 Filing under the FPA by the Transmission Owners, the LTPP will be set at zero.

$SR = SR_1 + SR_2$.

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 Owner of said TCCs.

SR_2 will equal the Transmission Owner's revenues from the Centralized TCC Auction allocated pursuant to Attachments N. SR_2 includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; (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 Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N).

SR_1 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 TSC effective in March). SR_1 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 the Direct Sale divided by the duration of the TCC (in months). SR_2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR_2 shall be adjusted after each Centralized TCC Auction and the revised SR_2 shall be effective at the start of each Capability Period;

ECR = The Transmission Owner's share of Net Congestion Rents in a month, calculated pursuant to Attachment N;

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)

14.1.2.1.1 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 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.

Reserved = $\quad$ $Reserved_1 + Reserved_2 + Reserved_3 + Reserved_4$

$Reserved_1$ 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 months remaining until the expiration of that ETCNL TCC. $Reserved_4$ 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 months remaining until the expiration of that ETCNL TCC.

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.

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; and (3) the BU component of its TSC charge.

The LTPP component of each Member System's TSC charge is initially set at zero. Any changes must be made by unanimous consent of the Transmission Owners (See ISO OATT Original Sheet No. 267). The Member Systems will make a Section 205 filing to propose any change to the LTPP.

The NYISO is responsible for calculating (1) 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 will be divided equally among the months for which the TCC is sold. The revenue from these TCCs will enter the TSC formula month-by-month through the SR term, beginning with the first month of the period covered by the Centralized Auction. The ISO is responsible for calculating the SR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation. 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 shall calculate a Transmission Owner's Reserved.

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.

14.1.2.2 Implementation of TSC

At the start of LBMP implementation, certain variables of the TSC equation will not be available. For the first and second month of LBMP implementation, the only terms in the TSC equation that will be known by each Transmission Owner are its Annual Transmission Revenue Requirement (RR), Scheduling, System Control and Dispatch Costs (CCC), Revenues from the Sale of TCCs in the Transitional Auction (SR_2), Wheeling Revenues Associated with continuing OATT reservations (WR) and Billing Units (BU), which have been approved by or filed with FERC or, in the case of LIPA, approved by the Long Island Power Authority's Board of Trustees. (Billing Units for “metered” retail customers are based on manual meter readings). For these two months each Transmission Owner shall calculate its TSC using the following equation:

$$\textbf{WHOLESALE TSC} = [(RR\div12) + (CCC\div12) - SR - WR]/BU\div12)$$

LTPP will not be available until after the Initial Auction as defined in Attachment M for Long Term TCCs. For the third month of LBMP implementation until the second month of the Capability Period corresponding to the initial auction for Long Term TCCs, each Transmission Owner shall calculate its TSC using the following equation:

$$\textbf{WHOLESALE TSC} = \{(RR\div12) + (CCC\div12) - SR - ECR - CRR - WR\}/(BU\div12)$$

From the second month of the Capability Period corresponding to the initial auction for Long Term TCCs , until the conclusion of the LBMP Transition Period, the TSC shall be calculated using the equation in Section 14.1.2.1.

After the conclusion of the LBMP Transition Period, the LTPP component will no longer be applicable and each Transmission Owner shall calculate its Wholesale TSC using the following equation:

WHOLESALE TSC = {(RR÷12) + (CCC÷12) - SR - ECR - CRR - WR - Reserved}/(BU÷12)

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. Beginning with the implementation of LBMP, 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 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[9] and the Ontario-Hydro intertie shall be the same as (b). 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

[9] 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.

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 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 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	1.33
352	Structures and Improvements	1.92
353	Station Equipment	1.90
353.55	Station Equipment – EMS	5.00
354	Towers and Fixtures	1.47
355	Poles and Fixtures	1.91
356	Overhead Conductors and Devices	
	Steel Tower Lines	1.40
	Wood Pole Lines	1.58
357	Underground Conduit	2.02
358	Underground Conductors and Devices	1.40
359	Roads and Trails	1.33
370	Meters	
	Meters	2.78
	Installation	2.78

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 NMPC's internal Account 930.200.

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 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 NMPC internal Account No. 930.210.

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 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 NMPC's internal Account Nos. 408.100, 408.110 and 408.130.

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 NMPC's internal Account No. 408.140 and 408.180.

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, 562-574.

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 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.

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 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

14.2.1 Schedules

Table of Contents

Historical Transmission Revenue Requirement	Schedule 1
Forecasted Transmission Revenue Requirement	Schedule 2
Annual True-up with Interest Calculation	Schedule 3
Year to Year Comparison	Schedule 4
Allocators	Schedule 5
Transmission Investment Base (Part 1 of 2)	Schedule 6 Page 1 of 2
Transmission Investment Base (Part 1 of 2)	Schedule 6 Page 2 of 2
Transmission Investment Base (Part 2 of 2)	Schedule 7
Capital Structure	Schedule 8
Expenses	Schedule 9
Other	Schedule 10
System Dispatch Expense - Component CCC	Schedule 11
Billing Units - Component BU	Schedule 12

Niagara Mohawk Power Corporation | Year | **Attachment 1**
Calculation of RR Pursuant to Attachment H, Section 14.1.9.2 | | **Schedule 1**

Calculation of RR

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	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
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 37, column 5
16		Transmission Related Payroll Tax Expense	(G)	$0	Schedule 9, Line 43, column 5
17		Sub-Total (sum of Lines 10 - Line 16)		#DIV/0!	
18					
19		Plus: Billing Adjustments	(H)	$0	Schedule 10, Line 1
20		Plus : Bad Debt Expenses	(I)	$0	Schedule 10, Line 4
21		Less: Revenue Credits	(J)	$0	Schedule 10, Line 7
22		Less: 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 9.2

0

Shading denotes an input

Line No.			Period	Reference		Source
1	9.2 (b)	**FORECASTED TRANSMISSION REVENUE REQUIREMENTS**				
2		Forecasted TRR shall equal (1) the Forecasted Transmission Plant Additions (FTPA) multiplied by the Annual FTRRF, plus (2) the Mid-Year Trend				
3		Adjustment (MYTA), plus (3) the Tax Rate Adjustment (TRA), as shown in the following formula:				
4						
5		Forecasted TRR = (FTPA * FTRRF) + MYTA + TRA				
6						
7			Period	Reference		Source
8						
9						
10	(1)	Forecasted Transmission Plant Additions (FTPA)			$0	Workpaper 8, Section I, Line 16
11		Annual Transmission Revenue Requirement Factor (FTRRF)			#DIV/0!	Line 35
12		Sub-Total (Lines 10*11)			#DIV/0!	
13		Plus Mid-Year Trend Adjustment (2) (MYTA)			$0	Workpaper 9, line 31, variance column
14		Forecasted Transmission Revenue Requirement (Line 12 + Line 13)			**#DIV/0!**	
15						
16	(2)	**MID YEAR TREND ADJUSTMENT (MYTA)**				
17		The Mid-Year Trend Adjustment shall be the difference, whether positive or negative, between				
18		(i) the Historical TRR Component (E) based on actual data for the first three months of the Forecast Period,				
19		and (ii) the Historical TRR Component (E) based on data for the first three months of the year prior to the Forecast Period.				Workpaper 9
20						
21	(3)	**The Tax Rate Adjustment (TRA)**				
22		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				
23		and/or the State Income Tax Rate that takes effect during the first five months of the Forecast Period.				
24						
25	9.2 (c)	**ANNUAL FORECAST TRANSMISSION REVENUE REQUIREMENT FACTOR**				
26		The Annual Forecast Transmission Revenue Requirement Factor (Annual FTRRF) shall equal the sum of Historical TRR components (A) through (C),				
27		divided by the year-end balance of Transmission Plant in Service determined in accordance with Section 9.2 (a), component (A)1(a).				
28						
29						
30		Investment Return and Income Taxes		(A)	#DIV/0!	Schedule 1, Line 10
31		Depreciation Expense		(B)	#DIV/0!	Schedule 1, Line 11
32		Property Tax Expense		(C)	#DIV/0!	Schedule 1, Line 12
33		Total Expenses (Lines 30 thru 32)			#DIV/0!	
34		Transmission Plant		(a)	#DIV/0!	Schedule 6, Page 1, Line 12
35		Annual Forecast Transmission Revenue Requirement Factor (Lines 33/ Line 34)			#DIV/0!	

Niagara Mohawk Power Corporation **Attachment 1**
Annual True-up (ATU) **Schedule 3**
Attachment H Section 9.2 (c)

Line No.			**0** Year	**Source:**
1				
2	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
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	Days	Multiplier	Of Period	Of Period
35									
36	3rd QTR '07		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 '07		#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!

	'08								
47	January	0.00%		#DIV/0!	31	91	1.0000	#DIV/0!	#DIV/0!
48	February	0.00%		#DIV/0!	29	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 '08		#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

Attachment 1
Schedule 4

Niagara Mohawk Power Corporation Wholesale TSC Calculation Information
2008 Forecast using 2007 Historical Data and 2008 Forecast

		(a)	(b)	See Note (**) below. (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, 2008	#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 14
(c) Schedule 3, Line 28
(d) Attachment H, Section 9.2 The RR Component shall equal Col (a) Historical Transmission Revenue Requirement plus Col (b) the Forecasted Transmission Revenue Requirement plus Col (c) the Annual True-Up
(e) Schedule 11 - 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 Operating (NYISO) system control and load dispatch expenses already recovered under Schedule 1 of the NYISO Tariff.
(f) Schedule 12 - 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.
(**) There was no true-up for this period. This is illustrative only.

Niagara Mohawk Power Corporation
Allocation Factors - As calculated pursuant to Section 9.1

Attachment 1
Schedule 5

0

Shading denotes an input

Line No.

Source

Definition

Line					
1	9.1 1.	**Electric Wages and Salaries Factor**	**83.5000%**		Fixed per settlement
2					
3	9.1 3.	**Transmission Wages and Salaries Allocation Factor**	**13.0000%**		Fixed per settlement
4					
5					
6					
7					
8	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 207.104	
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	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	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H, section 9.2

Line No.

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.		Reference	2007	Reference
10		Reference	**2007**	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 9.2

Attachment 1
Schedule 6
Page 2 of 2

(a) A. 1.

0

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	9.2(a)A.1.(a)	Transmission Plant in Service shall equal the balance of total investment in Transmission Plant
2	Wholesale Meter Plant							#DIV/0!	Workpaper 1, Line 45		
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	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	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	9.2(a)A.1.(d)	Transmission Related Intangible Plant shall equal Intangible
16											Electric Plant multiplied by the Transmission Wages and
17											Salaries Allocation Factor.
18											
19	Transmission Plant Held for Future Use	$0						$0	Workpaper 10, Line 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	9.2(a)A.1.(f)	Transmission Related Depreciation Reserve shall equal the

Line		(1) Total	(2) Allocation Factor		(3) = (1)*(2) Electric Allocated	(4) Allocation Factor		(5) = (3)*(4) Transmission Allocated	Reference for col (1)	Definition
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, Line 46	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 **Attachment 1**
Annual Revenue Requirements of Transmission Facilities **Schedule 7**
Transmission Investment Base (Part 2 of 2)

Attachment H Section 9.2 (a) A. 1.
Shading denotes an input

0

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	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 (link)		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		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 267.8h		stranded costs), multiplied by the Gross Transmission Plant

	(255)									
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 2,4,9,17	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 278.1 lines 4&21(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	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 & 9 (h)		Prepayments excluding Federal and State taxes multiplied by
15	Total Prepayments	$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								9.2(a)A.1.(j)	Transmission Related Materials and Supplies shall equal: (i)
19	Trans. Specific O&M Materials and Supplies						$0	FF1 227.8		the balance of Materials and Supplies assigned to
20	Construction Materials and Supplies		#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!	FF1 227.5		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								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 **0**

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 11.5% 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			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!	11.50%		#DIV/0!	#DIV/0!
20									
21		Total Investment Return	$0		#DIV/0!			#DIV/0!	#DIV/0!

22

23

24

25

26 9.2.2.(b) Federal Income Tax shall equal

$$= \frac{(\;A.\; + \;[\;B\;/\;C]\;\;X\;\;\text{Federal Income Tax Rate}\;)}{(\;1\;-\;\text{Federal Income Tax Rate}\;)}$$

27

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 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 Tax = Federal Income State Income

9.2.2.(c) shall equal (A. + [B / C] + Tax Rate) X Tax 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

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 9.2 | **0** |

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	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, Line 47		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	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	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	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							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 Research and
28	less Pensions and Benefits (#926)						FF1 323.187b		Development Expense and Electric Environmental Remediation Expense,
29	less: Research and Development Expenses (#930)	$0					Workpaper 12, Line 3		and 50% of the NYPSC Regulatory Expense
30	Less: 50% of NY PSC Regulatory Expense						FF1 351.4h		multiplied by the Transmission Wages and Salaries Allocation Factor,

31	less: Environmental Remediation Expense	$0					Workpaper 11, Line 3		plus the sum of Electric Property Insurance multiplied by the Gross
32	Subtotal (Line 26-27-28-29-30-31)	$0	100.0000 %	$0	13.0000% (c)	$0			Transmission Plant Allocation Factor, plus transmission-specific Electric
33	PLUS Property Insurance alloc. using Plant Allocation	$0	100.0000 %	$0	#DIV/0! (d)	#DIV/0!	Line 27		Research and Development Expense, and transmission-specific
34	PLUS Pensions and Benefits	$88,644,000	100.0000 %	$88,644,000	13.0000% (c)	$11,523,720	Workpaper 3		Electric Environmental Remediation Expense. In addition, Administrative
35	PLUS Transmission-related research and development	$0				$0	Workpaper 12		and General Expenses shall exclude the actual Post-Employment
36	PLUS Transmission-related Environmental Expense	$0				$0	Workpaper 11		Benefits Other than Pensions ("PBOP") included in FERC Account 926,
37	Total A&G (Line 32+33+34+35+36)	$88,644,000		$88,644,000		#DIV/0!			and shall add back in the amounts shown on Workpaper 3, page 1,
38									or other amount subsequently approved by FERC under Section 205 or 206.
39	Payroll Tax Expense							9.2.G.	Transmission Related Payroll Tax Expense shall equal the product of
40	Federal Unemployment						FF1 263.4i		electric Payroll Taxes multiplied by the Transmission Wages and Salaries Allocation Factor.
41	FICA						FF1 263.3i		
42	State Unemployment						FF1 263.17i		
43	Total (Line 40+41+42)	$0	100.0000 %	$0	13.0000% (b)	$0			

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 **Attachment 1**
Annual Revenue Requirements of Transmission Facilities **Schedule 10**
Billing Adjustments, Revenue Credits, Rental Income

0

Attachment H Section
14.1.9.2 (a)

Shading denotes an input

Line No.		(1) Total	Source		Definition
1	Billing Adjustments			9.2.H.	Billing Adjustments shall be any adjustments made in accordance with Section 14.1.9.4.4 below.
2					
3					
4	Bad Debt Expense	$0	Workpaper 4, Line 4	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, Line 11	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	9.2.K.	Transmission Rents shall equal all Transmission-related rental income recorded in FERC
15					account 454.615
16					
17				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
31					Formula Rate during the five (5) years prior to the Update Year in which the error
32					was first discovered shall be corrected by incorporating the impact of the error on
33					the charges produced by the Formula Rate during the five-year period into the
34					charges produced by the Formula Rate (with interest determined in accordance
35					with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
36					Year. Charges collected before the five-year period shall not be subject to correction.

(b)	List of Items excluded from the Revenue Requirement	Reason

Niagara Mohawk Power Corporation
System, Control, and Load Dispatch Expenses (CCC)
Attachment H, Section
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.

1	**Scheduling and Dispatch Expenses**			**0**	**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 lines 3 - 11
14					
15	Less Account 561 directly recovered under Schedule 1 of the NY ISO 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

Niagara Mohawk Power Corporation

Billing Units - MWH
Attachment H, Section 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.		Dec 06- Nov 07	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 lines 1-6
8	LESS: All non-retail transactions		
9	Watertown		FF1 page 329.11.j
10	High Load Factor Fitzpatrick		NIMO TOL (transmission owner load)
11	Disputed Station Service		NIMO TOL (transmission owner load)
12	Other non-retail transactions		All other non-retail transactions (Sum of 300,000 series PTID's from TOL)
13	Total Deductions	**0.000**	sum lines 9 - 12
14	PLUS: TSC Load		
15	NYMPA Muni's, Misc. Villages, Jamestown (X1)**		FF1 page 329.19.j ****
16	NYPA Niagara Muni's (X2)		FF1 page 329.1.j ****
17	Total additions	**0.000**	sum lines 15 -17
18	Total Billing Units	**0.000**	line 7 - line 13 + line 18

**** In 2007, the volumes were not detailed in FERC Form 1 as shown. Detail for 2007 will be provided as requested.
On 8/31/07, the contracts for Jamestown and the NYPA Niagara Municipal expired. The previous contract was billed at demand.
The 2007 energy values for the NYPA Niagara Municipals and Jamestown are proxy numbers representing a full year of metered load for December 2006 - November 2007 as billed in January - December. These entities transitioned to the TSC rate on September 1, 2007 for billing effective October 2007. However, the full year billing load was included above.

** One of the Misc Villages at Line 15 is reported on the TOL file with one of the NYPA Niagara Muni's labeled X2.

14.2.2 NYPA Transmission Adjustment Charge ("NTAC")

14.2.2.1 Applicability of the NYPA Transmission Adjustment Charge

Each month, the ISO shall charge, and each Transmission Customer shall pay, the applicable NYPA Transmission Adjustment Charge ("NTAC") calculated in accordance with Section 14.1.2.2 of this Attachment for the first two (2) months of LBMP and in accordance with Section 14.1.2.1 of this Attachment thereafter. 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");[10] 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");[10] 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

Beginning with January 2001, NYPA shall calculate the NTAC applicable to Transmission Service to serve New York State Load, Wheels Through and Exports as follows:

$$\textbf{NTAC} = \{(RR\div 12) - (EA) - (IR\div 12) - SR - CRN - WR - ECR - NR - NT\}/(BU\div 12)$$

[10] The NTAC shall not apply to Wheels Through or 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.

Where:

RR = NYPA's Annual Transmission Revenue Requirement, which includes the Scheduling, System Control and Dispatch Costs of NYPA's control center, as approved by FERC;

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_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 Revenue Requirement where NYPA is the Primary Owner of said TCCs.

SR_2 will equal NYPA's revenues from the Centralized TCC Auction allocated pursuant to Attachment M; this includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; and (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for these ETAs are included in NYPA's Revenue Requirement.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Providers sell through the Centralized TCC Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N).

SR_1 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). SR_1 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 the TCC (in months).

SR_2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR_2 shall be adjusted after each Centralized TCC Auction, and the revised SR_2 shall be effective at the start of each Capability Period;

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 RR 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 RR for NYPA transmission initially accepted by FERC ("Base Period RR") for the purposes of computing the Initial Cost. Whenever an amendment to the RR is accepted by FERC ("Amended RR"), the system rate for the purpose of computing the Initial Cost will be increased (or decreased) by the ratio of the Amended RR to the Base Period RR 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 Reserved_1 + NYPA Reserved_2

NYPA Reserved_1 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

$Reserved_2$ 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 months remaining until the expiration of that RCRR TCC.

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 RR 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, 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.

14.2.2.2.2 Implementation of NTAC

At the start of LBMP implementation certain variables of the NTAC equation will not be available. For the first and second months of LBMP implementation, the only terms in the NTAC equation that will be known by NYPA are its historical Annual Transmission Revenue Requirement (RR) and the historical Billing Units (BU), which have been approved by or filed with FERC. For these two months NYPA shall calculate the NTAC using the following equation:

$$\mathbf{NTAC = \{(RR \div 12) - (EA) - (IR \div 12)\}/(BU \div 12)}$$

SR_2 shall not be available until after the first Centralized TCC Auction. For the third month of LBMP implementation until the second month of the Capability Period corresponding to the first Centralized TCC Auction, NYPA shall recalculate the NTAC using the following equation:

$$\mathbf{NTAC = \{(RR \div 12) - (EA) - (IR \div 12) - WR - CRN - SR_1 - ECR\}/(BU \div 12)}$$

Prior to and during implementation of LBMP those current NYPA transmission customers wishing to terminate their Third Party TWAs shall notify the ISO. The ISO shall duly inform NYPA of such conversion so that NYPA can calculate revenues (EA) to be derived from Existing Transmission Wheeling Agreements.

14.2.2.2.2.1 NYPA's recovery pursuant to NTAC initially is limited to expenses and return associated with its transmission system as that system exists at the time of FERC approval of the NTAC ("base period revenue requirement"). Additions to its system may be included in the computation of NTAC only if: a) upgrades or expansions do not exceed $5 million on an annual basis; or b) such upgrades or expansions have been unanimously approved by the Transmission Owners. Notwithstanding the above, NYPA may invest in transmission facilities in excess of $5 million annually without unanimous Transmission Owners' authorization 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.

14.2.2.2.3 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 RR, initially approved by FERC, and such updates shall be submitted to FERC. An integral part of the agreement between the other Transmission Owners and NYPA is NYPA's consent to the submission of its RR 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 to become effective on the first day of the next calendar month.

14.2.2.3 NTAC Calculation Information

NYPA's Annual Transmission Revenue Requirement (RR), for facilities owned as of January 31, 1997, and Annual Billing Units (BU) of the NTAC are:

RR = $165,449,297

BU = 133,386,541MWh

NYPA's Annual Transmission Revenue Requirement is subject to Commission approval in accordance with Section 14.2.3 of this Attachment.

14.2.2.4 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 month. The billing units will be based on the monthly metered energy for all Transactions to supply Load in the NYCA, and hourly Energy schedules for all Wheels Through and Exports.

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)
75	102	NYPA – EDP	294
74	78	NYPA - MDA	115
76	60	NYPA - Brookhaven	609
77	66	NYPA - Grumman	108
12	117	LIPA - Fitzpatrick	1,665
16	117	LIPA - Nine Mile	2,643
17	94	LIPA - Gilboa	1,465
20	112	NYSEG Wood	896
N/A	105	O&R - PP&L	474

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 LBMP Calculation Method

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 either the Real-Time Dispatch program, or during intervals when it is activated, the RTD-CAM program (together "RTD"), or, with respect to External Transactions, 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 incremental of Load at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Availability 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 and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively of the 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 4.4.3.3 of the 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.

16.1.1 Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Sections 16.1.1.1.1-16.1.1.1.5 to calculate Real-Time LBMPs, the Marginal Losses Component, and the Congestion Component at each Load Zone and Generator bus in the table below, the ISO shall employ the special scarcity pricing rules described in Sections 16.1.1.2 and 16.1.1.3 Procedures governing the calculation of LBMPs at External locations are set forth below in Section 16.1.5.

SCR/EDRP NYCA Called and Needed	SCR/EDRP East Called and Needed	Scarcity Pricing Rule to be Used in the West	Scarcity Pricing Rule to be Used in the East
NO	**NO**	**NONE**	**NONE**
	YES	**NONE**	**B**
YES	**NO**	**a**	**A**
		A	**A**

Where

SCR/EDRP NYCA, Called and Needed	Is “YES” if the ISO has called SCR/EDRP resources and determined that, but for the Expected Load Reduction, the Available Reserves would have been less than the NYCA requirement for total 30-Minute Reserves; or is “NO” otherwise.
SCR/EDRP East, Called and Needed	Is “YES” if the ISO has called SCR/EDRP from resources located East of Central-East and determined that, but for the Expected Load Reduction, the Available Reserves located East of Central-East would have been less than the requirement for 10-Minute Reserves located East of Central-East; or is “NO” otherwise.
Scarcity Pricing Rule to be Used in the West	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Zones located West of Central-East, including the Reference Bus.
Scarcity Pricing Rule to be Used in the East	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Zones located East of Central-East.

16.1.1.1 General Procedures

16.1.1.1.1 Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes or each Real-Time Dispatch run, except as noted below in Section 16.1.1.1.3. A new Real-Time Dispatch run will begin every five minutes and each run will produce prices and schedules for five points in time. Only the prices and schedules determined for the first point in time of a Real-Time Dispatch run will be binding. Prices and schedules for the other four points in time shall be advisory only.

Each Real-Time Dispatch 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 point in time that it addresses. The first and second points of time in each Real-Time Dispatch run will be five minutes apart. The remaining points in time in each run 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 run 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.

16.1.1.1.2 Description of the Real-Time Dispatch Process

16.1.1.1.2.1 The First Pass

The first Real-Time Dispatch 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 run. 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 Real-Time Dispatch run at its specified response rate.

16.1.1.1.2.1.1 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 Resource's lower and upper dispatch limits. A 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 Real-Time Dispatch 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 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 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, or, to the extent that the ISO's software can support demand side participation, Demand Reduction level; 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 the extent that the ISO's software can support demand side participation, 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.

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 or, for Intermittent Power Resources (as defined in the ISO Services Tariff) depending on wind as their fuel, the output level specified by the Wind Energy Forecast, 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.

16.1.1.1.2.1.2 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 depending 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.

16.1.1.1.2.1.3 Setting Physical Basepoints for Fixed Generators

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.

16.1.1.1.2.2 The Second Pass

The second Real-Time Dispatch 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 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. This pass shall establish "hybrid base points" (*i.e.*, real-time

Energy schedules) that are used in the third pass to determine whether minimum run-time constrained Fixed Block Units should be blocked on at their UOLN or UOLE, whichever is applicable, or dispatched flexibly. 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.

16.1.1.1.2.2.1 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 Real-Time Dispatch immediately prior to the previous Real-Time Dispatch minus the Resource’s metered output level at the time that the current Real-Time Dispatch 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 Real-Time Dispatch run was initialized minus the physical base point established during the first pass of the Real-Time Dispatch immediately prior to the previous Real-Time Dispatch; 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.

16.1.1.1.2.2.2 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.

16.1.1.1.2.3 The Third Pass

The third Real-Time Dispatch pass is the same as the second pass with three variations. First, the third pass treats Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO that received a non-zero physical base point in the first pass, and that received a hybrid base point of zero in the second pass, as blocked on at their UOL_N or UOL_E, whichever is applicable. Second, the third pass produces "pricing base points" instead of hybrid base points. Third, and finally, the third 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 the ISO Services Tariff respectively. The ISO shall not use schedules for Energy, Regulation Service and Operating Reserves that are established in the third pass to dispatch Resources.

16.1.1.1.3 Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 16.1.1.1.1 and 16.1.1.1.2 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 Regulation Service markets will be temporarily suspended as described in Rate Schedule 3 of the ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments before executing the three Real-Time Dispatch 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 Regulation Service markets will be temporarily suspended as described in Rate Schedule 3 of the ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments in the affected area before executing the three Real-Time Dispatch 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 Real-Time Dispatch 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.

16.1.1.1.4 Calculating the Marginal Losses and Congestion Components

The Marginal Losses Component of the price at each location shall be calculated as the product of the price at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one (1).

The Congestion Component of the price at each location shall be calculated as the price at that location, minus the Marginal Losses Component of the price at that location, minus the price at the Reference Bus.

16.1.1.1.5 The Real-Time Commitment ("RTC") Process and Automated Mitigation

Attachment H of that ISO 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 Attachment H of that ISO Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures 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 Section 4 of the ISO Services Tariff, and this

Attachment J (as well as the corresponding provisions of Attachment B to the 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).

16.1.1.2 Scarcity Pricing Rule "A"

The ISO shall implement the following price calculation procedures for intervals when scarcity pricing rule "A" is applicable.

16.1.1.2.1 Except as noted in Pricing Rule 16.1.1.2.2 below:

- The LBMP at the Reference Bus shall be determined by dividing the lowest offer price at which the quantity of Special Case Resources offered is equal to

$RREQ_{NYCA}$ – ($RACT_{NYCA}$ – ELR_{NYCA}), or \$500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{NYCA}$ – ($RACT_{NYCA}$ – ELR_{NYCA}), by the weighted average of the delivery factors produced by RTD that the ISO uses in its calculation of prices for Load Zone J in that RTD interval,

where:

- $RACT_{NYCA}$ equals the quantity of Available Reserves in the RTD interval;

- $RREQ_{NYCA}$ equals the 30-Minute Reserve requirement set by the ISO for the NYCA; and
- ELR_{NYCA} equals the Expected Load Reduction in the NYCA from the Emergency Demand Response Program and Special Case Resources in that RTD interval.
- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one.
- The LBMP at each location shall be the sum of the Marginal Losses Component of the LBMP at that location, plus the LBMP at the Reference Bus.
- The Congestion Component of the LBMP at each location shall be set to zero.

16.1.1.2.2 However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section 16.1.1.1 above. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location pursuant to Section 16.1.1.1; or the LBMP calculated for that location using the scarcity pricing rule "A" procedures.
- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one.
- The Congestion Component of the LBMP at each location shall be calculated as the LBMP at that location, minus the LBMP at the Reference Bus, minus the Marginal Losses Component of the LBMP at that location.

16.1.1.3 Scarcity Pricing Rule "B"

The ISO shall implement the following price calculation procedures in intervals when scarcity pricing rule "B" is applicable.

16.1.1.3.1 Except as noted in 16.1.1.3.2 below:

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section 16.1.1.1) and a quantity equal to the delivery factor produced by RTD for that location minus one.
- The Congestion Component of the LBMP at each location shall be equal to the lowest offer price at which the quantity of Special Case Resources offered is equal to $RREQ_{East}$ – ($RACT_{East}$ – ELR_{East}), or $500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{East}$ – ($RACT_{East}$– ELR_{East}), minus the LBMP calculated for the Reference Bus (according to Section 16.1.1.1), minus the Marginal Losses Component of the LBMP for Load Zone J,

where:

- $RACT_{East}$ equals the quantity of Available Reserves located East of Central-East in that RTD interval;
- $RREQ_{East}$ equals the 10-Minute Reserve requirement set by the ISO for the portion of the NYCA located East of Central-East; and
- ELR_{East} equals the Expected Load Reduction East of Central-East from the Emergency Demand Response Program and Special Case Resources in that RTD interval.

- The LBMP at each location shall be the sum of the LBMP calculated for the Reference Bus (according to Section 16.1.1.1) and the Marginal Loss Component and the Congestion Component for that location.

16.1.1.3.2 However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section 16.1.1.1. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each such location shall be set to the LBMP calculated for that location pursuant to Section 16.1.1.1.
- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section 16.1.1.1) and a quantity equal to the delivery factor produced by RTD for that location minus one.
- The Congestion Component of the LBMP at each such location shall be calculated as the LBMP at that location, minus the LBMP calculated for the Reference Bus (according to Section 16.1.1.1), minus the Marginal Losses Component of the LBMP at that location.

16.1.2 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 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 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 Security Constrained Unit Commitment 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 1B to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices 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 Security Constrained Unit Commitment 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 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, 1C, or 1D depending on activation of 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 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.

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 the 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.

16.1.3 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 within the NYCA 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 = system losses; and

P_i = injection at bus I

The Congestion Component of the LBMP at bus i is calculated using the equation:

Where:

$$\gamma_i^C = -\left(\sum_{k \in K}^{n} GF_{ik}\,\mu_k\right)$$

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:

$$\gamma_i = \lambda^R + (DF_i - 1)\lambda^R - \sum_{k \in K} GF_{ik}\,\mu_k$$

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.

16.1.4 Determination of Transmission Shortage Cost

The Transmission Shortage Cost represents the limit on system costs associated with efficient dispatch to meet a particular Constraint. It is the maximum Shadow Price that will be used in calculating LBMPs. The Transmission Shortage Cost is set at $4000/MWh.

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 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 consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Attachment J to the ISO OATT are also addressed in Section 30.4.6.8.1 of the Market Monitoring Plan (*i.e.*, MST Attachment O).

16.1.5 Zonal LBMP Calculation Method

The computation described above 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 zone. The Load weights which will sum to unity will be predetermined by the ISO. 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:

$\gamma^Z_j =$ 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;

$\gamma_j^{C,Z} = \sum W_i \gamma_i^C$ 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 zonal LBMPs will be a weighted average of the Load bus LBMPs in the zone. The weightings will be predetermined by the ISO.

16.1.6 Real Time LBMP Calculation Method for Proxy Generator Buses, Non-Competitive Proxy Generator Buses and Proxy Generator Buses Associated with Designated Scheduled Lines

16.1.6.1 General Rules

External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. External Generators may arrange Bilateral Transactions with Internal or External Loads and External Loads may arrange 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 buses External to the NYCA. LBMPs will be calculated for each bus within this limited set. The three components of LBMP will be calculated from the results of RTD, or, except as set forth in Sections 16.1.6.2 and 16.1.6.3 below, in the case of a Proxy Generator Bus, from the results of RTC_{15} during periods in which (1) proposed economic transactions over the Interface between the NYCA and the Control Area with which that Proxy Generator Bus is associated would exceed the Available Transfer Capability for the Proxy Generator Bus or for that Interface, (2) 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, or (3) proposed interchange schedule changes pertaining to the Interface between the NYCA and the Control Area in which that Proxy Generator Bus is associated would exceed any Ramp Capacity limit imposed by the ISO for the Proxy Generator Bus or for that Interface.

16.1.6.2 Rules for Non-Competitive Proxy Generator Buses

Real-Time LBMPs for a Non-Competitive Proxy Generator Bus shall be determined as follows.

When (i) proposed Real-Time Market economic net Import transactions into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control

Area in which the Non-Competitive Proxy Generator Bus is located or would exceed the Available Transfer Capability of the Non-Competitive Proxy Generator Bus, or (ii) proposed interchange schedule changes pertaining to increases in Real-Time Market net imports into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the ISO for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located or would exceed the Ramp Capacity limit imposed by the ISO for the Non-Competitive Proxy Generator Bus, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the higher of (i) the RTC-determined price at that Non-Competitive Proxy Generator Bus or (ii) the lower of the LBMP determined by RTD for that Non-Competitive Proxy Generator Bus or zero.

When (i) proposed Real-Time Market economic net Export Transactions from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located or would exceed the Available Transfer Capability of the Non-Competitive Proxy Generator Bus, or (ii) proposed interchange schedule changes pertaining to increases in Real-Time Market net Exports from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the ISO for the Interface between the NYCA and the Control Area in which that Non-Competitive Proxy Generator Bus is located or would exceed the Ramp Capacity limit imposed by the ISO for the Non-Competitive Proxy Generator Bus, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the lower of (i) the RTC-determined price at the Non-Competitive Proxy Generator Bus or (ii) the higher of the LBMP determined by RTD for the Non-Competitive Proxy Generator Bus or the Day-Ahead LBMP determined by

SCUC for the Non-Competitive Proxy Generator Bus. At all other times, the Real-Time LBMP shall be calculated as specified in Section 16.1.6.1, above.

16.1.6.3 Special Pricing Rules for Scheduled Lines

Real-Time LBMPs for the Proxy Generator Buses associated with designated Scheduled Lines shall be determined as follows:

When proposed Real-Time Market economic net Import Transactions into the NYCA associated with a designated Scheduled Line would exceed the Available Transfer Capability of the designated Scheduled Line, the Real-Time LBMP at the Proxy Generator Bus associated with the designated Scheduled Line will be the higher of (i) the RTC-determined price at that Proxy Generator Bus or (ii) the lower of the LBMP determined by RTD for that Proxy Generator Bus or zero.

When proposed Real-Time Market economic net Export Transactions from the NYCA associated with a designated Scheduled Line would exceed the Available Transfer Capability of the designated Scheduled Line, the Real-Time LBMP at the Proxy Generator Bus associated with the designated Scheduled Line will be the lower of (i) the RTC-determined price at the Proxy Generator Bus or (ii) the higher of the LBMP determined by RTD for the Proxy Generator Bus or the Day-Ahead LBMP determined by SCUC for the Proxy Generator Bus. At all other times, the Real-Time LBMP shall be calculated as specified in Section 16.1.6.1 above.

The Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line are designated Scheduled Lines.

16.1.6.4 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 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 subsections 16.1.6.2 and 16.1.6.3, 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-Time LBMP = $Losses_{RTC\ PROXY\ GENERATOR\ BUS}$; and

Congestion Component of the Real-Time LBMP = - ($Energy_{RTC\ REF\ BUS}$+ $Losses_{RTC\ PROXY\ GENERATOR\ BUS}$).

When the Real-Time LBMP is set to the Day-Ahead LBMP:

Marginal Losses Component of the Real-Time LBMP = $Losses_{RTC\ PROXY\ GENERATOR\ BUS}$; and

Congestion Component of the Real-Time LBMP = Day-Ahead $LBMP_{PROXY\ GENERATOR\ BUS}$ - ($Energy_{RTC\ REF\ BUS}$ + $Losses_{RTC\ PROXY\ GENERATOR\ BUS}$).

where:

$Energy_{RTC\ REF\ BUS}$	=	marginal Bid cost of providing Energy at the reference Bus, as calculated by RTC_{15} for the hour;
$Losses_{RTC\ PROXY\ GENERATOR\ BUS}$	=	Marginal Losses Component of the LBMP as calculated by RTC_{15} at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line for the hour; and
Day-Ahead $LBMP_{PROXY\ GENERATOR\ BUS}$	=	Day-Ahead LBMP as calculated by SCUC for the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line for the hour.

16.1.6.5 The Marginal Losses Component of LBMP at Proxy Generator Buses

The components of LBMP will be posted in the Day-Ahead and Real-Time Markets as described above, except that the Marginal Losses Component of LBMP will be calculated differently for Internal locations. The Marginal Losses Component of the LBMP at each bus, as described above, includes the difference between the marginal cost of losses at that bus and the Reference Bus. If this formulation were employed for an External bus, then the Marginal Losses Component would include the difference in the cost of Marginal Losses for a section of the transmission system External to the NYCA. Since the ISO will not charge for losses incurred Externally, the formulation will exclude these loss effects. To exclude these External loss effects, the Marginal Losses Component will be calculated from points on the boundary of the NYCA to the Reference Bus.

The Marginal Losses Component of the LBMP at the External bus will be a weighted average of the Marginal Losses Components of the LBMPs at the Interconnection Points. To derive the Marginal Losses Component of the LBMP at an External location, a Transaction will be assumed to be scheduled from the External bus to the Reference Bus. The Shift Factors for this Transaction on the tie lines into these Interconnection buses, which measure the per-unit effect of flows over each of those tie lines that results from the hypothetical transaction, will provide the weights for this calculation. Since all the power from this assumed Transaction crosses the NYCA boundary, the sum of these weights is unity.

The sum of the products of these Shift Factors and the Marginal Losses Component of the LBMP at each of these Interconnection buses yields the Marginal Losses Component of the LBMP that will be used for the External bus. Therefore, the Marginal Losses Component of the LBMP at an External bus E is calculated using the equation:

$$\gamma_E^L = \sum_{b \in I} F_{Eb} \left(DF_b - 1 \right) \lambda^R$$

where:

γ_E^L = Marginal Losses Component of the LBMP at an External bus E;

F_{Eb} = Shift Factor for the tie line going through bus b, computed for a hypothetical Bilateral Transaction from bus E to the Reference Bus;

Marginal Losses Component of the LBMP at bus b; and

$(DF_b - 1)\lambda^R$ = The set of Interconnection buses between the NYCA and adjacent

I = Control Areas.

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; (ii) by RTC_{15}, for External Transactions; or (iii) during intervals when the conditions specified in Part 16.1 of this Attachment J 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 LSEs that purchase Energy from the Real-Time 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 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 ISO's General Responsibilities

The ISO shall evaluate requests for 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 RTC_{15} to establish schedules for each hour of dispatch in that day.

The ISO shall use the information provided by RTC when making Curtailment decisions pursuant to the Curtailment rules described in Section 16.3.4 of this Attachment J.

16.3.2 Use of Decremental Bids to Dispatch Internal Generators

When dispatching Generators taking service under this Tariff to match changing conditions, the ISO shall treat Decremental Bids and Incremental Energy Bids simultaneously and identically as follows: (i) a generating facility selling energy in the LBMP Market may be dispatched downward if the LBMP at the Point of Receipt falls below the generating facility's Incremental Energy Bid; (ii) a Generator serving a transaction scheduled under this Tariff may be dispatched downward if the LBMP at the Generators's Point of Receipt falls below Decremental Bid for the Generator; (iii) a Supplier's Generator may be dispatched upward if the LBMP at the Generator's Point of Receipt rises above the Decremental or Incremental Energy Bid for the Generator regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a transaction scheduled under this Tariff.

16.3.2.1 Use of Decremental Bids to Dispatch External Generators

When determining the amount of Energy that External Generators taking service under this Tariff are scheduled an hour ahead to produce, the ISO shall treat Decremental Bids and Incremental Energy Bids simultaneously and identically as follows: (i) a generating facility selling Energy in the LBMP Market will have its hour-ahead schedule reduced if the LBMP forecasted for the next hour by BME at the Point of Receipt falls below the generating facility's Incremental Energy Bid; (ii) a Generator serving a Transaction scheduled under this Tariff will have its schedule reduced if the LBMP forecasted for the next hour by RTC_{15} at the Generator's Point of Receipt falls below the Decremental Bid for the Generator; (iii) a Supplier's Generator will have its schedule increased if the LBMP forecasted for the next hour by RTC_{15} at the Generator's Point of Receipt rises above the Decremental or Incremental Energy Bid for the Generator, regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a Transaction scheduled under this Tariff.

16.3.3 Day-Ahead Schedules

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 and Network Integration Transmission Service schedules, Load forecasts, and submitted Incremental Energy Bids, Decremental Bids and Sink Price Cap Bids.

In the Day-Ahead schedule, the ISO shall use the SCUC to determine Generator schedules, Transmission Service schedules and DNIs with adjacent Control Areas. The ISO shall not use Decremental Bids submitted by Transmission Customers for Generators associated with Non-Firm Point-to-Point Transmission Service in the determination of the Day-Ahead schedule.

16.3.4 Reduction and Curtailment

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, the ISO shall not reduce the Transmission Service.

If the Transaction was scheduled in the Day-Ahead Market, and the Day-Ahead Schedule for the Generator designated as the Supplier of Energy for that Bilateral Transaction called for that Generator to produce less Energy than was scheduled Day-Ahead to be consumed in association with that Transaction, the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Day-Ahead LBMP Market. The Transmission Customer shall continue to pay the Day-Ahead TUC and in addition, the Supplier of Energy for the Bilateral Transaction, if it takes service under the ISO Services Tariff, shall pay the Day-Ahead LBMP price, at the Point of Receipt for the Transaction, for the replacement amount of Energy in (MWh) purchased in the LBMP Market. If the Supplier of Energy for the Bilateral Transaction does not take service under the ISO Services Tariff, it shall pay the greater of 150 percent of the Day-Ahead LBMP at the Point of Receipt for the Transaction or $100/MWh, for the replacement amount of Energy, as specified in this Tariff. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with the Transaction was located inside or outside the NYCA.

If the Transaction was scheduled following the Day-Ahead Market, or the schedule for the Transaction was revised following the Day-Ahead Market, then the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Real-Time LBMP Market, at the Real-Time LBMP, if necessary. If (1) the Generator designated to supply the Transaction is an Internal Generator, and it has been dispatched to produce less than the amount of Energy that is scheduled hour-ahead to be consumed in association with that Transaction; or (2) the Generator designated to supply the Transaction is an External Generator, and the amount of Energy it has been scheduled an hour ahead to produce (modified for any within-hour changes in DNI, if any) is less than the amount of Energy scheduled hour-ahead to be consumed in association with that Transaction; then the Transmission Customer shall pay the Real-Time TUC for the amount of Energy withdrawn in real-time in association with that Transaction minus the amount of Energy scheduled Day-Ahead to be withdrawn in association with that Transaction. In addition, to the extent that it has not purchased sufficient replacement Energy in the Day-Ahead Market, the Supplier of Energy for the Bilateral Transaction, if it takes service under the ISO Services Tariff, shall pay the Real-Time LBMP price, at the Point of Injection for the Transaction, for any additional replacement Energy (in MWh) necessary to serve the Load. If the Supplier of Energy for the Bilateral Transaction does not take service under the ISO Services Tariff, it shall pay the greater of 150 percent of the Real-Time LBMP at the Point of Injection for the Transaction or $100/MWh for the replacement amount of Energy, as specified in this Tariff. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with that Transaction was located inside or outside the NYCA. Notwithstanding the foregoing, the amount of Transmission Service scheduled hour-ahead in the RTC for Transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each RTD interval:

16.3.4.1 Generators

16.3.4.1.1 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;

16.3.4.1.2 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 499 MW of such units; and

16.3.4.1.3 Existing intermittent (i.e., non-schedulable) renewable resource Generators in operation on or before November 18, 1999 within the NYCA, plus up to an additional 1000 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.

If the Energy injections scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier of Transmission Customer whose transaction is Curtailed, in addition to paying the charge for replacement Energy necessary to serve the Load, shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of the Real-Time Bid price and zero; and (b) the scheduled Energy injection minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour.

If the Transmission Customer was receiving Non-Firm Point-to-Point Transmission Service, and its Transmission Service was Reduced or Curtailed, the replacement Energy may be purchased in the Real-Time LBMP Market, at the Real-Time LBMP, by the Internal Load. An Internal Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed may sell its excess Energy in the Real-Time LBMP Market.

The ISO shall not automatically reinstate Non-Firm Point-to-Point Transmission Service that was Reduced or Curtailed. Transmission Customers may submit new schedules to restore the Non-Firm Point-to-Point Transmission Service in the next RTC_{15} execution.

If a security violation occurs or is anticipated to occur, the ISO shall attempt to relieve the violation using the following procedures:

16.3.4.2 Procedures

16.3.4.2.1 Reduce Non-Firm Point-to-Point Transmission Service: Partially or fully physically Curtail External Non-Firm Transmission Service (Imports, Exports and Wheels Through) by changing DNI schedules to (1) Curtail those in the lowest NERC priority categories first; (2) Curtail within each NERC priority category, based on Decremental Bids; and Incremental Energy Bids for Imports and Wheel Throughs; and based on Sink Price Cap Bids for Exports and (3) prorate Curtailment of equal cost transactions within a priority category ;

16.3.4.2.2 Curtail non-Firm Point-to-Point Transmission Service: Curtail (through changing DNI) unscheduled non-Firm Transactions which contribute to the violation, starting with the lowest NERC priority category;

16.3.4.2.3 Dispatch Internal Generators, based on Incremental Energy Bids and Decremental Bids, including committing additional resources, if necessary;

16.3.4.2.4 Adjust the DNI associated with Transactions supplied by External Resources: Curtail External Firm Transactions until the Constraint is relieved by (1) Curtailing based on Incremental Energy Bids, Decremental Bids and Sink Price Cap Bids; and (2) except for External Transactions with minimum run times, prorating Curtailment of equal cost transactions;

16.3.4.2.5 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;

16.3.4.2.6 In over generation conditions, decommit Internal Generators based on Minimum Generation Bid rate in descending order; and

16.3.4.2.7 Invoke other emergency procedures including involuntary load Curtailment, if necessary.

16.3.5 Scheduling Transmission Service for External Transactions

The amount of Firm Transmission Service scheduled Day-Ahead for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions Day-Ahead. The amount of Firm Transmission Service scheduled in the RTC_{15} for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions in the RTC_{15}. 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. Additionally, any Curtailment or Reductions of schedules for Export Transactions will cause the scheduled amount of Transmission Service to change.

To the extent possible, Curtailments of External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line shall be based on the transmission priority of the associated Advance Reservation for use of the Cross-Sound Scheduled Line, Neptune Scheduled Line, or the Linden VFT Scheduled Line (as appropriate).

The ISO shall use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy those Generators are scheduled Day-Ahead to produce in each hour. This in turn will determine the Firm Transmission Service scheduled Day-Ahead to support those Transactions. The ISO shall also use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy these Generators are scheduled to produce in the RTC_{15}, which, in turn, will determine the Transmission Service scheduled in the RTC to support those Transactions.

The ISO will not schedule a Bilateral Transaction which crosses an Interface between the NYCA and a neighboring Control Area if doing so would cause the DNI to exceed the Transfer Capability of that Interface.

The ISO shall not permit Market Participants to schedule External Transactions over the following eight scheduling paths:

16.3.5.1 External Transactions that are scheduled to exit the NYCA at the Proxy Generator Bus that represents the NYCA's 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");

16.3.5.2 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;

16.3.5.3 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;

16.3.5.4 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;

16.3.5.5 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");

16.3.5.6 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;

16.3.5.7 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

16.3.5.8 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.

External Transactions at the Proxy Generator Buses that are associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line shall also be governed by Attachment N to the ISO Services Tariff.

17 Attachment K – Reservation of Certain Transmission Capacity and LBMP Transition Period

17.1 General Description of Existing Transmission Capacity Reservations

This Attachment describes the treatment of Existing Transmission Agreements ("ETA"), including Transmission Wheeling Agreements ("TWA") and Transmission Facilities Agreements ("TFA"), Existing Transmission Capacity for Native Load and the LBMP Transition Period during which certain rights and obligations apply. The applicability of this Attachment with the exception of Section 17.6 of this Attachment, is subject to the effective date of any necessary Section 205 filing pursuant to the FPA or, for agreements not subject to FERC jurisdictions, the execution of an amendment adopting the provisions of this Attachment.

17.2 Transmission Wheeling Agreement ("TWA") Treatment

17.2.1 TWAs between Transmission Owners associated with Generators or Power Supply Contracts (Modified Wheeling Agreements or "MWAs")

Each TWA between Transmission Owners associated with a Generator or a power supply contract shall be converted into a Modified Wheeling Agreement ("MWA") to be effective upon LBMP implementation. The TWAs being converted to MWAs are listed in Attachment L, Table 1, 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 will have the option of retaining the transmission rights received under the existing TWA ("Grandfathered Rights") or converting those transmission rights to TCCs ("Grandfathered TCCs"); (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 Sections 17.3.2 and/or 17.4.1, below except that it shall have to pay for losses under this Tariff and the Transmission Owner shall not charge the MWA Customer or the assignee for losses to the extent they are provided under this Tariff; (iv) the payments under MWAs for Grandfathered Rights and Grandfathered TCCs do not include the costs of Ancillary Services and customers under these agreements will be responsible for Ancillary Services consistent with the other provisions of this Tariff; (v) any additional modifications to each TWA necessary to convert it into a MWA shall be the subject of a separate amendment to the TWA; and (vi) the corresponding MWA will be terminated to the extent the TWA is to transmit Energy from such 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 TWA, except as follows:

17.2.1.1 Subject to Section 17.2.1.2, for each TWA associated with a power supply contract, that is terminated pursuant to its terms prior to the end of the LBMP Transition Period, the MWA shall remain in effect until the end of the LBMP Transition Period. At the end of the LBMP Transition Period, such MWAs will be automatically terminated.

17.2.1.2 For each TWA associated with (a) the Blenheim-Gilboa power supply contract (as noted in Attachment L, Table 1, Line Items 2, 8, 17, 31, 48 and 59) or, if the power supply contract is terminated pursuant to its terms prior to the end of the LBMP Transition Period, the MWA shall also be terminated.

As long as each MWA Customer retains Grandfathered Rights or Grandfathered TCCs, it must maintain all MWAs from each associated Point of Receipt of the Generator or the NYCA Interconnection with another Control Area to the corresponding Point of Delivery of the Load served by the MWA or at the NYCA Interconnection with another Control Area.

Any other differences between the terms and conditions of the MWAs and those of the associated TWAs for which a customer elects Grandfathered Rights or Grandfathered TCCs are discussed in Sections 17.3 and 17.4 of this Attachment, respectively.

17.2.2 Third Party TWAs

Each existing TWA with a Third Party (“Third Party TWA”), all of which are listed in Attachment L, Table 1, where the “Treatment” column is denoted as “Third Party TWA” or “OATT,” will remain in effect in accordance with its terms and conditions, including provisions governing modification or termination, except that the Third Party TWA customer may:

17.2.2.1 retain the existing transmission rights ("Grandfathered Rights") subject to the provisions below;

17.2.2.2 convert the transmission rights to Grandfathered TCCs, and (a) purchase or sell power in the LBMP Market pursuant to this Tariff or (b) execute Bilateral Transactions for Capacity, Energy, and/or Ancillary Services, and obtain Transmission Service subject to the rates, terms, and conditions of this Tariff except as explicitly noted below in this Attachment; or

17.2.2.3 terminate the existing agreement (if the terms and conditions allow termination), and (a) purchase or sell power in the LBMP Market pursuant to this Tariff or (b) execute Bilateral Transactions for Capacity, Energy, and/or Ancillary Services, and obtain Transmission Service subject to the rates, terms, and conditions of this Tariff.

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 Receipt of the Generator or the NYCA Interconnection with another Control Area to the corresponding Point of Delivery of the Load served by the TWA or at the NYCA Interconnection with another Control Area.

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. Customers electing Grandfathered Rights will be exempt from having to pay the Congestion Component of the TUC.

For the Third Party TWAs listed in Attachment L, Table 1, Line Items 55-62, 65-69, 73-82, 84-92, 98-114, 150-190, each specific individual municipal or cooperative electrical system listed in each such Agreement shall be deemed to be the Third Party TWA Customer for purposes of electing one (1) of the options set forth above. The municipal or cooperative may elect Grandfathered Rights or Grandfathered TCCs in specified amounts between specified Points of Receipt and Points of Delivery. Those Grandfathered Rights or TCCs become the rights or TCCs of the municipal or cooperative. Whichever option is selected 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 TWA rights elections. If any specific municipal or cooperative fails to make this election, NYPA shall have the right to make the election for that municipal or cooperative.

17.2.3 Other TWAs Between Transmission Owners

Commencing with LBMP implementation, certain TWAs between the Transmission Owners will be terminated. These TWAs are listed in Attachment L, Table 1, where the "Treatment" column is denoted as "Terminated."

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 that contain provisions for transmission service are listed in Attachment L, Table 1, 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, except that customers under these agreements may elect Grandfathered Rights or may convert their rights to Grandfathered TCCs.

17.2.5 Existing Transmission Capacity for Native Load ("ETCNL")

Certain transmission capacity associated with the use of a Transmission Owner's own system to serve its own load will be designated as Existing Transmission Capacity for Native Load and shown on Table 3 of Attachment L. The transmission Capacity shown on Table 3 of Attachment L will be available in each Auction; *provided, however*, that the amount of transmission Capacity available from each set of ETCNL may be reduced (i) if the ETCNL was previously sold as TCCs that are valid for any part of the duration of any TCCs to be sold in the Centralized TCC Auction, (ii) if the ETCNL is reduced pursuant to Section 19.8.2 of Attachment M of this Tariff, or (iii) if the ETCNL is converted to ETCNL TCCs pursuant to Section 19.4 of Attachment M of this Tariff.

The Transmission Owners shall release all ETCNL that is not converted into ETCNL TCCs into each Centralized TCC Auction in accordance with Attachment M.

Such Existing Transmission Capacity for Native Load shall not be increased above the megawatt (MW) amounts noted in Attachment L, Table 3, of the ISO Tariff.

17.3 Terms Applicable to Grandfathered Rights Under MWAs, TFAs, and Third Party TWAs.

17.3.1 Congestion Charges

Each ETA Customer that maintains Grandfathered Rights under an option listed in Section 17.2 above, retains the right to inject power at one specified bus and take power at another specified bus up to amounts reflected in Attachment L, Table 1, without having to pay the Congestion Component of the TUC, but only to the extent it schedules the injection and withdrawal Day-Ahead and is on schedule. If it 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 customer under the MWA, TFA or Third Party TWA transmits Energy without scheduling it Day-Ahead or exceeds the amounts specified in Attachment L, Table 1, 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. If the ETA Customer 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. The ETA Customer will not be permitted to resell or transfer these Grandfathered Rights unless permitted in the existing agreements, except as noted above.

17.3.2 MWAs and TFAs

Subject to the losses provision below, each MWA or TFA Customer shall pay the contract rates for the Grandfathered Rights which shall be frozen at the contract rates that were in effect on the date the ISO Tariff was originally filed at FERC (January 31, 1997), through the LBMP Transition Period or the termination date of the TFA, if earlier. After the LBMP

Transition Period, rates under each MWA or TFA will be based on embedded cost, and these contract rates may be updated, if allowed for in the terms and conditions of each MWA or TFA. Each MWA or TFA Customer or its assignee shall pay the Transmission Owner under the MWA or TFA directly for the Grandfathered Rights.

Each MWA or TFA customer that chooses Grandfathered Rights shall pay the ISO for losses, under this Tariff. The Transmission Owner shall not charge for losses under the ETA, MWA or TFA to the extent the losses are provided under this Tariff. To the extent losses on the Transmission Owner's system are not provided under this Tariff, the Transmission Owner may charge for losses unless prohibited from doing so under the MWA or TFA. The customer will pay or receive payment for losses between the Point of Receipt and the Point of Delivery under the MWA or TFA listed in Attachment L, Table 1, as calculated in accordance with this Tariff.

17.3.3 Third Party TWAs

Subject to Section 17.5 below, each Third Party TWA Customer will compensate the Transmission Owner under a Third Party TWA for transmission charges in accordance with the terms and conditions of the TWA, including any provisions governing modification or termination.

Third Party TWA Customers that choose Grandfathered Rights shall pay the ISO for losses under the ISO Tariff. The Transmission Owner shall not charge for losses under the Third Party TWA to the extent the losses are provided under this Tariff. To the extent losses on the Transmission Owner's system are not provided, the Transmission Owner may charge for losses, unless prohibited from doing so under the Third Party TWA. The Transmission Customer will pay or receive payment for losses between the Points of Receipt and Points of Delivery under the Third Party TWA listed in Attachment L, Table 1, as calculated in accordance with this Tariff.

17.4 Terms Applicable to Conversion to Grandfathered TCCs

Each ETA Customer, that has the right to convert transmission rights to TCCs in accordance with Section 17.2 above, must notify the ISO of its election to convert to TCCs the earlier of two weeks prior to the first TCC Auction or six weeks prior to the start-up of the ISO in accordance with procedures that the ISO will post. Where the applicable ETA provides for more than one Point of Receipt and/or more than one Point of Delivery, these ETA Customers may designate Grandfathered Rights or Grandfathered TCCs, but not both, from each Point of Receipt to each Point of Delivery. The ISO will assign point-to-point TCCs to the ETA Customer, equivalent to the amount of transmission capacity (in MWs) associated with the transmission service received under each ETA, as measured between the Generator bus or NYCA Interconnection with another Control Area where the power is injected and the Point of Delivery of the Load served by the ETA or at the NYCA Interconnection with another Control Area. If the ETA Customer fails to duly notify the ISO of its conversion to Grandfathered TCCs, the ISO and Transmission Owner will deem the ETA Customer to have elected Grandfathered Rights.

17.4.1 MWAs and TFAs

Each MWA or TFA Customer shall continue to pay the Transmission Owner rates which shall be frozen at the contract rates that were in effect on the date this Tariff was originally filed at FERC (January 31, 1997), through the LBMP Transition Period or the termination date of the MWA or TFA, if earlier. After the LBMP Transition Period, 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 or TFA Customer or its assignee shall pay the Transmission Owner directly for the Grandfathered TCCs.

Each MWA or TFA Customer that chooses Grandfathered TCCs, shall receive (or pay, when negative congestion occurs) the Day-Ahead Congestion Rent associated with its Grandfathered TCCs, and 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.

17.4.2 Third Party TWAs

Subject to Section 17.5, below, 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. Third Party TWA Customers that convert the existing transmission rights to TCCs shall receive (or pay, when negative congestion occurs) the Day-Ahead Congestion Rent associated with its TCCs, and will be subject to the service provisions of this Tariff, including the duty to pay for:
(i) Congestion Rent; and (ii) Marginal Losses for use of the transmission system.

17.5 Responsibility for Ancillary Services

Irrespective of whether an ETA is a MWA, Third Party TWA or a TFA, or whether a customer thereunder elects Grandfathered Rights or Grandfathered TCCs, the customer shall be responsible for payment for any applicable Ancillary Services that shall be provided pursuant to this Tariff.

17.6 LBMP Transition Period and Payment

In the absence of an effective Section 205 Filing under the FPA, the ISO shall follow the methodology prescribed in the Transmission Agreement governing the specific transaction in question. The ISO shall not hold a Transmission Owner responsible for any shortfall in loss revenue resulting from discrepancies between losses calculations used by the ISO and losses calculations prescribed by any Transmission Agreement. In the event Third Party TWAs do not convert the existing rights to TCCs, and in which the participants pay losses other than marginal losses, and in the event the applicable Transmission Owner experiences losses revenue deficiencies due to the event that the Transmission Owner is charged on a marginal losses basis by the ISO for the losses associated with these unmodified TWAs the following procedures shall be implemented. To the extent any Transmission Owner incurs payments to the ISO for its unmodified TWAs resulting from any marginal losses provisions of this Tariff over and above the compensation the Transmission Owner receives under its TWA, and the following is a good faith effort by the Transmission Owner to modify the TWA via a FERC Section 205 filing pursuant to the Federal Power Act to pay charges consistent with this Tariff, the ISO will reimburse each affected Transmission Owner for its losses revenue deficiencies as follows: (a) for each specific bilateral transaction associated with an unmodified TWA, the ISO will calculate the marginal loss component “L” of the TUC; (b) the Transmission Owner will be responsible to the ISO for each marginal losses charge “L”; (c) the Transmission Owner will submit arrangements specified in each of its unmodified TWAs to the ISO including the amount of reimbursement “R” from the participant for the losses associated with each bilateral transaction; (d) the Transmission Owner will compute its losses revenue variances for each applicable unmodified TWA as its marginal losses charge “L” minus the amount of reimbursement “R” for the losses associated with the bilateral transaction; (e) the ISO will settle with each Transmission Owner for the sum total of its losses revenue variances; and (f) total losses revenue variances will reduce or increase the amount of the Residual Adjustment in Schedule 1 of this Tariff.

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;[11]

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

[11] 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.

18 Attachment L - Existing Transmission Agreements & Existing Transmission Capacity for Native Load Tables

18.1 Existing Transmission Wheeling Agreements

18.1.1 Table 1A - Existing Long Term Transmission Wheeling Agreements

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						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	CH0G&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	Wood St-Bowl	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	4/30/2015	MWA-Gilboa Contract	125	125						125				
9	N/A	Con Edison	LIPA	Y50 Cable (1)	228	Con Ed - Cent.	Con Edison	4/4/75	Life of the facility	Facility Agmt - MWA	228	228									228	
12	142	LIPA	NMPC	Fitzpatrick Delivery - Firm	160/124	Fitzpatrick	Con Ed - Mid Hud	2/14/75	1 year notice	MWA-Fitzpatrick Contract	160	124			160		160	160				
	117	LIPA	Con Edison	Fitzpatrick Delivery - Firm	103/100	Con Ed - Mid Hud	LIPA	7/15/75	1 year notice	MWA-Fitzpatrick Contract	103	100							103	103	103	103
14	N/A	LIPA	NYPA	Y49 Cable (2)	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
	N/A	LIPA	NYPA	Remainder of Interface	229	Con Ed - Cent.	LIPA		Later of Ret. Of Bonds or upon mutual agreement	Facility Agmt - MWA	229	229									229	229
16	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				
	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	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			

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
	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	NMPC	Remote Load Agmt	298(17)	Kintigh	NYSEG - Cent.		Ret. of Kintigh		298	298	298	298								
20	165	NYSEG	NMPC	Remote Load Agmt	277	Kintigh	NYSEG - Cent.	12/1/52	Ret. of Kintigh (9)	MWA-Kintigh	277	277	277	277								
	165	NYSEG	NMPC	Remote Load Agmt	277	NYSEG - Cent.	NYSEG - Mech.	12/1/52	Ret. of Kintigh (9)	MWA-Kintigh	277	277			277		277					
	165	NYSEG	NMPC	Remote Load Agmt	205	NYSEG - Mech.	NYSEG - Hudson	12/1/52	Ret. of Kintigh (9)	MWA-NMP2/Kintigh	205	205						205				
	112	NYSEG	Con Edison	Wood Street	205	NYSEG - Hudson	NYSEG-Brewster	3/1/88	Ret. of Kintigh	MWA-NMP2/Kintigh	205	205							205			
	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					
	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				
	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			
	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	Moses 17-18	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	8/31/2007	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	Moses 17-18	NMPC-Cent Ea	2/10/61	8/31/2007	MWA-Hydro Contract	104	104				104						

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
31	N/A	O&R	NYPA	Gilboa	25	Gilboa #1	CHG&E	4/1/89	4/30/2015	MWA-Gilboa Contract	25	25						25				
	51	O&R	CHG&E	Gilboa	25	CHG&E	O&R	4/1/89	4/30/2015	MWA-Gilboa Contract	25	25										
41	32	O&R	CHG&E	Grahmsville	18	Grahmsville	O&R	12/31/62	12/31/2001	MWA-Grahmsville	18	18										
45	N/A	RG&E	NYPA	St. Lawrence	55	Moses 17-18	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	54	RG&E	NYSEG	Gilboa	30	RG&E/Ginna	NYSEG - East	5/10/73	6/30/2002	MWA-Gilboa Contract	30	30		30	30							
	54	RG&E	NYPA	Gilboa	30	NYSEG - East	NMPC - East	5/10/73	6/30/2002	MWA-Gilboa Contract	30	30					30					
49	176	RG&E	NMPC	Exit Agreement (3)	77 to 0	RG&E/Ginna	NMPC - East	4/12/73	6/30/2043	Exit Agmt	77	77		77	77		77					
	N/A	NRG Energy, Inc.	NMPC	Assets Purchase Agreement	43 to 0	RG&E/Ginna	NMPC - East	8/31/99	6/30/2035	Assets Purchase Agreement	43	43		43	43		43					
55	65	SENY	CHG&E	Ashokan/Kensico	6	Ashokan	Con Ed - North	11/23/82	Beyond 12/31/2004	Third Party TWA	6	6										
	N/A	SENY	Con Edison	Ashokan/Kensico	6	Con Ed - North	Con Edison	3/10/89	Beyond 12/31/2004	Third Party TWA	6	6							6	6	6	
56	180	SENY	NMPC	Jarvis	4	Jarvis	Con Ed - Mid Hud	10/29/92	Beyond 12/31/2004	Third Party TWA	4	4					4	4				
	N/A	SENY	Con Edison	Jarvis	4	Con Ed - Mid Hud	Con Edison	3/10/89	Beyond 12/31/2004	Third Party TWA	4	4							4	4	4	
57	180	SENY	NMPC	Crescent-Vischers	20	Vischers	Con Ed - Mid Hud	10/29/92	Beyond 12/31/2004	Third Party TWA	20	20						20				
	N/A	SENY	Con Edison	Cresent-Vischers	20	Con Ed - Mid Hud	Con Edison	3/10/89	Beyond 12/31/2004	Third Party TWA	20	20							20	20	20	
58	96	SENY	Con Edison	NYPA Load-NYC- IP3 (11)	800	Indian Pt 3	Con Edison	3/10/89	Beyond 12/31/2004	Third Party TWA	800	800								800	800	
59	N/A	SENY	NYPA	Gilboa	250	Gilboa #1	Con Ed - North	11/24/86	Beyond 12/31/2004	Third Party TWA	250	250						250	250			

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
	N/A	SENY	Con Edison	Gilboa	250	Con Ed - North	Con Edison	3/10/89	Beyond 12/31/2004	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	N/A	SENY	NYPA	MTA/SENY	10	Moses 17-18	Con Ed - North	5/7/81	7/31/2000	Third Party TWA	10	10				10	10	10	10			
	N/A	SENY	Con Edison	MTA/SENY	10	Con Ed - North	Con Edison	5/7/81	7/31/2000	Third Party TWA	10	10								10	10	
62	N/A	SENY	NYPA	MDA/EDP to CE	139	Fitzpatrick	Con Ed - North	12/31/91	12/31/2013	Third Party TWA	139	139			139		139	139	139			
	97, 98	SENY	Con Edison	MDA/EDP to CE	114	Con Ed - North	Con Edison	12/31/91	12/31/2013	Third Party TWA	114	114								114	114	
65	32	Greenport	NYPA	Munis 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			
	32	Freeport	NYPA	Munis 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			
	32	Rockville Centre	NYPA	Munis 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			
	51	Greenport	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
	51	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
	51	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
	N/A	NYPA for Greenport	LIPA	Munis on LI	5	LIPA	LIPA	4/10/81	2 year notice	Third Party TWA	5	5										
	N/A	Freeport	LIPA	Munis on LI	38	LIPA	LIPA	4/10/81	2 year notice	Third Party TWA	38	38										
	N/A	Rockville Centre	LIPA	Munis on LI (12)	29	LIPA	LIPA	4/10/81	2 year notice	Third Party TWA	29	29										
66	134	Festival of Lights	NMPC	Festival of Lights	0.1	Niagara	NMPC - West			Third Party TWA	0	0										
73	68	EDP in O&R	CHG&E	EDP in O&R	0.3	CHG&E	O&R	12/31/91		Third Party TWA	0	0										
74	N/A	MDA to LI	NYPA	MDA to LI	10	Fitzpatrick	Con Ed - North	12/31/91	10/31/2011	Third Party TWA	10	10			10		10	10	10			
	78	MDA on LI	Con Edison	MDA's on LI	10	Con Ed - North	Con Ed - Cent	12/31/91	10/31/2011	Third Party TWA	10	10								10		

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
	N/A	MDA to LI	NYPA	MDA's on LI	10	Con Ed - Cent	LIPA	12/31/91	10/31/2011	Third Party TWA	10	10									10	10
	N/A	Nassau County	LIPA	MDA's on LI	5	LIPA	LIPA	11/14/85	10/31/2011	Third Party TWA	5	5										
	N/A	Suffolk County	LIPA	MDA’s on LI	5	LIPA	LIPA	7/21/99 (13)	6/30/2011 (14)	OATT	5	5										
75	N/A	EDP to LI	NYPA	EDP to LI	26	Fitzpatrick	Con Ed - North	12/31/91	12/31/2005	Third Party TWA	26	26			26		26	26	26			
	102	EDP on LI	Con Edison	EDP on LI	26	Con Ed - North	Con Ed - Cent	12/31/91	12/31/2005	Third Party TWA	26	26								26		
	N/A	EDP to LI	NYPA	EDP on LI	26	Con Ed - Cent	LIPA	12/31/91	12/31/2005	Third Party TWA	26	26									26	26
	N/A	EDP on LI	LIPA	EDP on LI	19/18	LIPA	LIPA	6/1/91	upon notice	Third Party TWA	19	18										
76	N/A	Brookhaven	NYPA	Brookhaven	60/68	Fitzpatrick	Con Ed - North	12/31/91	6/30/2000	Third Party TWA	60	68			60		60	60	60			
	60	Brookhaven	Con Edison	Brookhaven	60/68	Con Ed - North	Con Ed - Cent	10/26/82	6/30/2000	Third Party TWA	60	68								60		
	N/A	Brookhaven	NYPA	Brookhaven	60/68	Con Ed - Cent	LIPA	12/31/91	10/31/2005	Third Party TWA	60	68									60	60
	N/A	Brookhaven	LIPA	Brookhaven	60/68	LIPA	LIPA	10/1/81	2 year notice	Third Party TWA	60	68										
77	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			
	66	Grumman	Con Edison	Grumman	0	Con Ed - North	Con Ed - Cent	2/20/85	12/31/2001	Third Party TWA	0	0								0		
	N/A	Grumman	NYPA	Grumman	0	Con Ed - Cent	LIPA	12/31/91	12/31/2001	Third Party TWA	0	0									0	0
	N/A	Grumman	LIPA	Grumman	0	LIPA	LIPA	10/1/81	2 year notice	Third Party TWA	0	0										
78	N/A	MDA/EDP to O&R	NYPA	MDA/EDP to O&R	1	Fitzpatrick	O&R	12/31/91	10/31/2003	Third Party TWA	1	1			1		1	1				
79	N/A	MDA/EDP to NYSEG	NYPA	MDA/EDP to NYSEG	38	Fitzpatrick	NYSEG - Cent.	12/31/91	12/31/2009	Third Party TWA	38	38										
	179	MDA/EDP to NYSEG	NYSEG	MDA/EDP to NYSEG (16)	38	NYSEG - Cent.	NYSEG - Cent.		12/31/2009	Third Party TWA	38	38										
80	N/A	MDA/EDP to NMPC	NYPA	MDA/EDP to NMPC	46	Fitzpatrick	NMPC-Cent. Ea.	12/31/91	12/31/2011	Third Party TWA	46	46			46							
81	N/A	Industrials to NMPC	NYPA	Industrials to NMPC	68	Fitzpatrick	NYPA - C	12/31/91	Ret. of Fitzpatrick	Third Party TWA	68	68										
82	N/A	Munis in NMPC	NYPA	Munis in NMPC	99	Niagara	NMPC-Cent. Ea.	12/31/61	10/31/2013	Third Party TWA	99	99	99	99	99							

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
	OATT	Booneville	NMPC	Munis in NYS	13	NMPC-Cent. Ea.	NMPC-Cent. Ea.	2/10/61	10/31/2013	Third Party TWA	13	13										
	OATT	Frankfort	NMPC	Munis in NYS	4	NMPC-Cent. Ea.	NMPC-Cent. Ea.	2/10/61	10/31/2013	Third Party TWA	4	4										
	OATT	Ilion	NMPC	Munis in NYS	13	NMPC-Cent. Ea.	NMPC-Cent. Ea.	2/10/61	10/31/2013	Third Party TWA	13	13										
	204	Lake Placid	NMPC	Munis in NYS	29	NMPC-Cent. Ea.	NMPC-Cent. Ea.	2/10/61	8/31/2007	Third Party TWA	29	29										
	OATT	Mohawk	NMPC	Munis in NYS	4	NMPC-Cent. Ea.	NMPC-Cent. Ea.	2/10/61	10/31/2013	Third Party TWA	4	4										
	204	Oneida-Madison	NMPC	Munis in NYS	1	NMPC - Cent. Ea.	NMPC - Cent. Ea.	2/10/61	8/31/2007	Third Party TWA	1	1										
	OATT	Philadelphia	NMPC	Munis in NYS	2	NMPC-Cent. Ea.	NMPC-Cent. Ea.	2/10/61	10/31/2013	Third Party TWA	2	2										
	204	Sherrill	NMPC	Munis in NYS	12	NMPC-Cent. Ea.	NMPC-Cent. Ea.	2/10/61	8/31/2007	Third Party TWA	12	12										
	OATT	Theresa	NMPC	Munis in NYS	2	NMPC-Cent. Ea.	NMPC-Cent. Ea.	2/10/61	10/31/2013	Third Party TWA	2	2										
	204	Tupper Lake	NMPC	Munis in NYS	19	NMPC-Cent. Ea.	NMPC-Cent. Ea.	2/10/61	8/31/2007	Third Party TWA	19	19										
	N/A	Munis in NMPC	NYPA	Munis in NMPC	18	Niagara	NMPC-Genessee	12/31/61	10/31/2013	Third Party TWA	18	18	18									
	OATT	Akron	NMPC	Munis in NYS	8	NMPC-Genessee	NMPC-Genessee	2/10/61	10/31/2013	Third Party TWA	8	8										
84	204	Bergen	NMPC	Munis in NYS	2	NMPC-Genessee	NMPC-Genessee	2/10/61	8/31/2007	Third Party TWA	2	2										
	OATT	Churchville	NMPC	Munis in NYS	4	NMPC-Genessee	NMPC-Genessee	2/10/61	10/31/2013	Third Party TWA	4	4										
	OATT	Holley	NMPC	Munis in NYS	4	NMPC-Genessee	NMPC-Genessee	2/10/61	10/31/2013	Third Party TWA	4	4										
	N/A	Munis in NMPC	NYPA	Munis in NMPC	6	Niagara	NMPC - Cent.	12/31/61	10/31/2013	Third Party TWA	6	6	6	6	6							
85	OATT	Green Island	NMPC	Munis in NMPC	3	NMPC - Cent.	NMPC - East	12/31/61	10/31/2013	Third Party TWA	3	3					3					
	OATT	Richmondville	NMPC	Munis in NMPC	3	NMPC - Cent.	NMPC - East	12/31/61	10/31/2013	Third Party TWA	3	3					3					

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
86	N/A	Munis in NMPC	NYPA	Munis in NMPC	135	Niagara	NMPC - Cent.	12/31/61	10/31/2013	Third Party TWA	135	135	135	135								
	204	Fairport	NMPC	Munis in NMPC	77	NMPC - Cent.	NMPC - Cent.	2/10/61	8/31/2007	Third Party TWA	77	77										
	OATT	Skaneateles	NMPC	Munis in NYS	5	NMPC - Cent.	NMPC - Cent.	2/10/61	10/31/2013	Third Party TWA	5	5										
	204	Solvay	NMPC	Munis in NYS	53	NMPC - Cent.	NMPC - Cent.	2/10/61	8/31/2007	Third Party TWA	53	53										
87	N/A	Munis in NYSEG	NYPA	Munis in NYSEG	72	Niagara	NYSEG - Cent.	12/31/61	10/31/2013	Third Party TWA	72	72	72	72								
	OATT	Bath	NYSEG	In-State Munis/Coops	13	NYSEG - Cent.	NYSEG - Cent.	2/3/82	6/30/2013	Third Party TWA	13	13										
	OATT	Endicott	NYSEG	In-State Munis/Coops	9	NYSEG - Cent.	NYSEG - Cent.	2/3/82	6/30/2013	Third Party TWA	9	9										
	OATT	Greene	NYSEG	In-State Munis/Coops	7	NYSEG - Cent.	NYSEG - Cent.	2/3/82	6/30/2013	Third Party TWA	7	7										
	OATT	Groton	NYSEG	In-State Munis/Coops	4	NYSEG - Cent.	NYSEG - Cent.	2/3/82	6/30/2013	Third Party TWA	4	4										
	67, 70, 80	Marathon	NYSEG	In-State Munis/Coops	4	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/21/2007	Third Party TWA	4	4										
	67, 70, 80	Penn Yan	NYSEG	In-State Munis/Coops	13	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/21/2007	Third Party TWA	13	13										
	OATT	Silver Springs	NYSEG	In-State Munis/Coops	1	NYSEG - Cent.	NYSEG - Cent.	2/3/82	6/30/2013	Third Party TWA	1	1										
	67, 70, 80	Steuben	NYSEG	In-State Munis/Coops	13	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/21/2007	Third Party TWA	13	13										
	67, 70, 80	Watkins Glen	NYSEG	In-State Munis/Coops	6	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/21/2007	Third Party TWA	6	6										
	OATT	Castile	NYSEG	In-State Munis/Coops	2	NYSEG - Cent.	NYSEG - Cent.	2/3/82	6/30/2013	Third Party TWA	2	2										
88	N/A	Munis in NYSEG	NYPA	Munis in NYSEG	46	Niagara	NYSEG - East	12/31/61	10/31/2013	Third Party TWA	46	46	46	46	46							
	67, 70, 80	Delaware	NYSEG	In-State Munis/Coops	10	NYSEG - East	NYSEG - East	2/3/82	8/21/2007	Third Party TWA	10	10										
	OATT	Hamilton	NYSEG	In-State Munis/Coops	11	NYSEG - East	NYSEG - East	2/3/82	6/30/2013	Third Party TWA	11	11										
	67, 70, 80	Oneida-Madison	NYSEG	In-State Munis/Coops	4	NYSEG - East	NYSEG - East	2/3/82	8/21/2007	Third Party TWA	4	4										

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
	67, 70, 80	Otsego	NYSEG	In-State Munis/Coops	8	NYSEG - East	NYSEG - East	2/3/82	8/21/2007	Third Party TWA	8	8										
	OATT	Sherbourne	NYSEG	In-State Munis/Coops	13	NYSEG - East	NYSEG - East	2/3/82	6/30/2013	Third Party TWA	13	13										
	N/A	Rouses Point	NYPA	In-State Munis/Coops	14	Niagara	NYSEG - North	12/31/61	10/31/2013	Third Party TWA	14	14	14	14	14	-14						
	OATT	Rouses Point	NYSEG	In-State Munis/Coops	14	NYSEG -North	NYSEG - North	2/3/82	6/30/2013	Third Party TWA	14	14										
89	N/A	Plattsburgh	NYPA	Niagara Hydro	103	Niagara	NYPA - North	12/31/61	10/31/2013	Third Party TWA	103	103	103	103	103	-103						
90	N/A	Massena	NYPA	Niagara Hydro	23	Niagara	NYPA - North	12/31/61	10/31/2013	Third Party TWA	23	23	23	23	23	-23						
91	N/A	Massena	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	Fitzpatrick	17	Fitzpatrick	NYPA-E	7/28/75	Indefinite	Third Party TWA	17	17			17	-17						
98	136	NFTA	NMPC	NFTA	1	Moses 17-18	NYPA - West	7/30/85	Ret. of St. Lawrence	Third Party TWA	1	1	-1	-1	-1	1						
99	159	Expansion Industrials	NMPC	Expansion Industrials	210	Niagara	NMPC - West	2/10/61	6/30/2013	Third Party TWA	210	210										
100	19	Replacement Industrials	NMPC	Replacement Industrials	445	Niagara	NMPC - West	2/10/61	1/1/2013	Third Party TWA	445	445										
101	N/A	Munis in RG&E	NYPA	Munis in RG&E	14	Niagara	RG&E	12/31/61	10/31/2013	Third Party TWA	14	14	14									
	OATT	Angelica	RG&E	Munis's & Coops	2	RG&E	RG&E	12/31/61	10/31/2013	Third Party TWA	2	2										
	OATT	Spencerport	RG&E	Munis's & Coops	12	RG&E	RG&E	12/31/61	10/31/2013	Third Party TWA	12	12										
102	178	Sithe	NMPC	Sithe Delivery	853	Sithe	Pleasnt Vlly 345kV	11/5/91	8/19/2014	Third Party TWA	853	853			853		853	853				
103	175	Indeck-Corinth	NMPC	Corinth Delivery	134	Indeck-Corinth	Pleasnt Vlly 345kV	6/26/91	7/1/2015	Third Party TWA	134	134						134				
104	171	Selkirk	NMPC	Selkirk Delivery	265	Selkirk-JMC	Pleasnt Vlly 345kV	12/13/90	3/3/2012	Third Party TWA	265	265						265				
105	172	Lockport Energy (LEA)	NMPC	LEA Delivery	100	Harrison Rad	Grdnvlle 115 kV	4/11/91	7/31/2012	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	2/4/86	12/31/2009	Third Party TWA	7	7					7					

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
108	N/A	Out-of-State Munis - NJ	NYPA	Niagara Deliveries	14	Niagara	CHG&E	2/10/61	10/31/2003	Third Party TWA	14	14	14	14	14		14	14				
	68	Out-of-State Munis - NJ	CHG&E	Out-of-State Munis	14	CHG&E	O&R	2/28/90	10/31/2003	Third Party TWA	14	14										
	50	Out-of-State Munis - NJ	O&R	Out-of-State Munis	14	O&R	PJM Proxy	6/28/85	10/31/2003	Third Party TWA	14	14										
109	N/A	Out-of-State Munis - NE	NYPA	Niagara Deliveries	89	Niagara	NMPC-Cent. Ea.	2/10/61	10/31/2003	Third Party TWA	89	89	89	89	89							
	138	Out-of-State Munis - NE	NMPC	Niagara Deliveries	89	NMPC-Cent. Ea.	NE Proxy	2/10/61	10/31/2003	Third Party TWA	89	89					89					
110	138	Allegheny Electric Coop.	NMPC	Out-of-State Munis - PA	28	Niagara	PJM Proxy	7/1/85	10/31/2003	Third Party TWA	28	28										
	OATT	Allegheny Electric Coop.	NMPC	Out-of-State Munis - PA	20	Niagara	PJM Proxy	6/30/98	6/30/2001	Third Party TWA	20	20										
	138	Am. Mun. Power- Ohio	NMPC	Out of State Munis - Ohio	36	Niagara	PJM Proxy	2/10/61	10/31/2003	Third Party TWA	36	36										
	OATT	Am. Mun. Power- Ohio	NMPC	Out of State Munis - Ohio	28	Niagara	PJM Proxy	12/1/98	12/31/1999	Third Party TWA	28	28										
111	N/A	Out-of-State Munis - VT	NYPA	Niagara Deliveries	14	Niagara	NYPA - E	2/10/61	10/31/2003	Third Party TWA	14	14	14	14	14							
	N/A	Out-of-State Munis - VT	NYPA	Niagara Deliveries	14	NYPA E	NE Proxy	2/10/61	10/31/2003	Third Party TWA	14	14					14					
112	N/A	Out-of-State Munis - NE	NYPA	St. Lawrence Deliveries	17	Moses 17-18	NMPC-Cent. Ea.	2/10/61	10/31/2003	Third Party TWA	17	17				17						
	138	Out-of-State Munis - NE	NMPC	St. Lawrence Deliveries	17	NMPC-Cent. Ea.	NE Proxy	2/10/61	10/31/2003	Third Party TWA	17	17					17					
113	N/A	Allegheny Electric Coop.	NYPA	St. Law. Deliveries - PA	20	Moses 17-18	NMPC - West	2/10/61	10/31/2003	Third Party TWA	20	20	-20	-20	-20	20						
	OATT	Allegheny Electric Coop.	NMPC	St. Law. Deliveries - PA	9	NMPC - West	PJM Proxy	6/30/98	6/30/2001	Third Party TWA	9	9										
	138	Allegheny Electric Coop.	NMPC	St. Law. Deliveries - PA	11	NMPC - West	PJM Proxy	2/10/61	10/31/2003	Third Party TWA	11	11										
	N/A	Am. Mun. Power- Ohio	NYPA	St. Law. Deliveries - Ohio	18	Moses 17-18	NMPC - West	2/10/61	10/31/2003	Third Party TWA	18	18	-18	-18	-18	18						
	OATT	Am. Mun. Power- Ohio	NMPC	St. Law. Deliveries - Ohio	8	NMPC - West	PJM Proxy	12/1/98	12/31/1999	Third Party TWA	8	8										

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
	138	Am. Mun. Power- Ohio	NMPC	St. Law. Deliveries - Ohio	10	NMPC - West	PJM Proxy	2/10/61	10/31/2003	Third Party TWA	10	10										
114	N/A	Out-of-State Munis - VT	NYPA	St. Lawrence Deliveries	1	Moses 17-18	NE Proxy	2/10/61	10/31/2003	Third Party TWA	1	1				1	1					
150	N/A	Out-of-State Munis - NJ	NYPA	St. Lawrence Deliveries	12	Moses 17-18	CHG&E	2/10/61	10/31/2003	Third Party TWA	12	12				12	12	12				
	68	Out-of-State Munis - NJ	CHG&E	Out-of-State Munis	12	CHG&E	O&R	2/28/90	10/31/2003	Third Party TWA	12	12										
	50	Out-of-State Munis - NJ	O&R	Out-of-State Munis	12	O&R	PJM Proxy	6/28/85	10/31/2003	Third Party TWA	12	12										
151	N/A	Munis in NMPC	NYPA	Munis in NMPC	83	Niagara	NMPC - West	12/31/61	10/31/2013	Third Party TWA	83	83										
	OATT	Andover	NMPC	Munis in NMPC	1	NMPC - West	NMPC - West	2/10/61	10/31/2013	Third Party TWA	1	1										
	OATT	Arcade	NMPC	Munis in NMPC	25	NMPC - West	NMPC - West	2/10/61	10/31/2013	Third Party TWA	25	25										
	OATT	Brocton	NMPC	Munis in NMPC	3	NMPC - West	NMPC - West	2/10/61	10/31/2013	Third Party TWA	3	3										
	OATT	Little Valley	NMPC	Munis in NMPC	4	NMPC - West	NMPC - West	2/10/61	10/31/2013	Third Party TWA	4	4										
	204	Mayville	NMPC	Munis in NMPC	4	NMPC - West	NMPC - West	2/10/61	8/31/2007	Third Party TWA	4	4										
	OATT	Salamanca	NMPC	Munis in NMPC	14	NMPC - West	NMPC - West	2/10/61	10/31/2013	Third Party TWA	14	14										
	OATT	Springville	NMPC	Munis in NMPC	9	NMPC - West	NMPC - West	2/10/61	10/31/2013	Third Party TWA	9	9										
	OATT	Wellsville	NMPC	Munis in NMPC	10	NMPC - West	NMPC - West	2/10/61	10/31/2013	Third Party TWA	10	10										
	204	Westfield	NMPC	Munis in NMPC	13	NMPC - West	NMPC - West	2/10/61	8/31/2007	Third Party TWA	13	13										
152	N/A	Jamestown	NYPA	Jamestown	75	Niagara	NMPC - West		10/31/2013	Third Party TWA	75	75										
	204	Jamestown	NMPC	Jamestown	100	NMPC - West	NMPC - West		8/31/2007	Third Party TWA	100	100										
153	N/A	In-State Munis	NYPA	Fitzpatrick Firm Incremental	2/3	Fitzpatrick	NYSEG - Cent.	2/3/82	10/31/2013	Third Party TWA	2	3										
	67, 70, 80	Penn Yan	NYSEG	Fitzpatrick Firm Incremental	1/1	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/21/2007	Third Party TWA	1	1										
	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										
	67, 70, 80	Watkins Glen	NYSEG	Fitzpatrick Firm Incremental	1/2	NYSEG - Cent.	NYSEG - Cent.	2/3/82	8/21/2007	Third Party TWA	1	2										

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
	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	In-State Munis	NYPA	Fitzpatrick Firm Incremental	1/6	Fitzpatrick	NYSEG - East	2/3/82	10/31/2013	Third Party TWA	1	6			1							
	67, 70, 80	Delaware	NYSEG	Fitzpatrick Firm Incremental	0/1	NYSEG - East	NYSEG - East	2/3/82	8/21/2007	Third Party TWA	0	1										
	67, 70, 80	Oneida-Madison	NYSEG	Fitzpatrick Firm Incremental	0/1	NYSEG - East	NYSEG - East	2/3/82	8/21/2007	Third Party TWA	0	1										
	OATT	Sherburne	NYSEG	Incremental EDP	1	NYSEG - East	NYSEG - East	2/3/82	8/21/2007	Third Party TWA	1	1										
	67, 70, 80	Otsego	NYSEG	Fitzpatrick Firm Incremental	0/3	NYSEG - East	NYSEG - East	2/3/82	8/21/2007	Third Party TWA	0	3										
155	N/A	In-State Munis	NYPA	Fitzpatrick Firm Incremental	2/4	Fitzpatrick	NMPC - West		10/31/2013	Third Party TWA	2	4	-2	-2								
	204	Mayville	NMPC	Fitzpatrick Firm Incremental	0/1	NMPC - West	NMPC - West		10/31/2013	Third Party TWA	0	1										
	204	Westfield	NMPC	Fitzpatrick Firm Incremental	0/1	NMPC - West	NMPC - West		10/31/2013	Third Party TWA	0	1										
	OATT	Arcade	NMPC	Firm Incremental	1	NMPC - West	NMPC - West		10/31/2013	Third Party TWA	1	1										
	OATT	Salamanca	NMPC	Firm Incremental	1	NMPC - West	NMPC - West		10/31/2013	Third Party TWA	1	1										
156	N/A	In-State Munis	NYPA	Fitzpatrick Firm Incremental	0/20	Fitzpatrick	NMPC Central		10/31/2013	Third Party TWA	0	20										
	204	Fairport	NMPC	Fitzpatrick Firm Incremental	0/20	NMPC Central	NMPC Central		10/31/2013	Third Party TWA	0	20										
157	N/A	In-State Munis	NYPA	Fitzpatrick Firm Incremental	2/19	Fitzpatrick	NMPC-Cent. Ea.		10/31/2013	Third Party TWA	2	19			2							
	204	Lake Placid	NMPC	Fitzpatrick Firm Incremental	0/11	NMPC-Cent. Ea.	NMPC-Cent. Ea.		10/31/2013	Third Party TWA	0	11										
	204	Sherrill	NMPC	Fitzpatrick Firm Incremental	2/3	NMPC-Cent. Ea.	NMPC-Cent. Ea.		10/31/2013	Third Party TWA	2	3										
	204	Tupper Lake	NMPC	Fitzpatrick Firm Incremental	0/5	NMPC-Cent. Ea.	NMPC-Cent. Ea.		10/31/2013	Third Party TWA	0	5										
158	N/A	In-State Munis	NYPA	Fitzpatrick Firm Incremental	0/0	Fitzpatrick	NMPC - Cent.		10/31/2013	Third Party TWA	0	0										
	204	Solvay	NMPC	Fitzpatrick Firm Incremental	0/0	NMPC - Cent.	NMPC - Cent.		10/31/2013	Third Party TWA	0	0										

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
160	N/A	In-State Munis	NYPA	Fitzpatrick Firm Incremental	1/1	Fitzpatrick	NYPA - H		10/31/2013	Third Party TWA	1	1			1		1	1	1			
	N/A	Greenport	LIPA	NYPA Firm Incremental	0/1	LIPA	LIPA		10/31/2013	Third Party TWA	0	1										
161		Munis in NMPC																				
	OATT	Booneville	NMPC	Supplemental	1/6	OH Proxy Bus	NMPC-Cent. Ea.	6/1/1998	10/31/2013	Third Party TWA	1	6	1	1	1							
	OATT	Frankfort	NMPC	Supplemental	1/2	OH Proxy Bus	NMPC-Cent. Ea.	6/1/1998	10/31/2013	Third Party TWA	1	2	1	1	1							
	OATT	Ilion	NMPC	Supplemental	0/2	OH Proxy Bus	NMPC-Cent. Ea.	6/1/1998	10/31/2013	Third Party TWA	0	2	0	0	0							
	OATT	Mohawk	NMPC	Supplemental	0/1	OH Proxy Bus	NMPC-Cent. Ea.	6/1/1998	10/31/2013	Third Party TWA	0	1	0	0	0							
	OATT	Philadelphia	NMPC	Supplemental	0/1	OH Proxy Bus	NMPC-Cent. Ea.	6/1/1998	10/31/2013	Third Party TWA	0	1	0	0	0							
	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																				
	OATT	Akron	NMPC	Supplemental	1/4	OH Proxy Bus	NMPC-Genessee	6/1/1998	10/31/2013	Third Party TWA	1	4	1									
	OATT	Churchville	NMPC	Supplemental	0/1	OH Proxy Bus	NMPC-Genessee	6/1/1998	10/31/2013	Third Party TWA	0	1	0									
	OATT	Holley	NMPC	Supplemental	0/2	OH Proxy Bus	NMPC-Genessee	6/1/1998	10/31/2013	Third Party TWA	0	2	0									
163		Munis in NMPC																				
	OATT	Richmondville	NMPC	Supplemental	0/1	OH Proxy Bus	NMPC - East	6/1/1998	10/31/2013	Third Party TWA	0	1	0	0	0		0					
164		Munis in NMPC																				
	OATT	Skaneateles	NMPC	Supplemental	0/2	OH Proxy Bus	NMPC - Cent.	6/1/1998	10/31/2013	Third Party TWA	0	2	0	0								
165		Munis in NYSEG																				

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
	OATT	Bath	NYSEG	Supplemental	0/7	PJM Proxy Bus	NYSEG - Cent.	6/1/1998	6/30/2013	Third Party TWA	0	7	0	0								
	OATT	Endicott	NYSEG	Supplemental	0/4	PJM Proxy Bus	NYSEG - Cent.	6/1/1998	6/30/2013	Third Party TWA	0	4	0	0								
	OATT	Greene	NYSEG	Supplemental	0/3	PJM Proxy Bus	NYSEG - Cent.	6/1/1998	6/30/2013	Third Party TWA	0	3	0	0								
	OATT	Groton	NYSEG	Supplemental	0/3	PJM Proxy Bus	NYSEG - Cent.	6/1/1998	6/30/2013	Third Party TWA	0	3	0	0								
	OATT	Castile	NYSEG	Supplemental	0/0	PJM Proxy Bus	NYSEG - Cent.	6/1/1998	6/30/2013	Third Party TWA	0	0	0	0								
166		Munis in NYSEG																				
	OATT	Hamilton	NYSEG	Supplemental	0/3	PJM Proxy Bus	NYSEG - East	6/1/1998	6/30/2013	Third Party TWA	0	3	0	0	0							
	OATT	Sherbourne	NYSEG	Supplemental	1/4	PJM Proxy Bus	NYSEG - East	6/1/1998	6/30/2013	Third Party TWA	1	4	1	1	1							
	OATT	Rouses Point (8)	NYSEG	Supplemental	1/5	NYSEG - North	NYSEG - North	6/1/1998	6/30/2013	Third Party TWA	1	5										
167		Munis in RG&E																				
	OATT	Spencerport	RG&E	Supplemental	0/2	RG&E	RG&E	6/1/1998	10/31/2013	Third Party TWA	0	2										
168		Munis in NMPC																				
	OATT	Arcade	NMPC	Supplemental	1/13	OH Proxy Bus	NMPC - West	6/1/1998	10/31/2013	Third Party TWA	1	13										
	OATT	Brocton	NMPC	Supplemental	1	OH Proxy Bus	NMPC - West	6/1/1998	10/31/2013	Third Party TWA	1	1										
	OATT	Salamanca	NMPC	Supplemental	1/5	OH Proxy Bus	NMPC - West	6/1/1998	10/31/2013	Third Party TWA	1	5										
	OATT	Springville	NMPC	Supplemental	1/4	OH Proxy Bus	NMPC - West	6/1/1998	10/31/2013	Third Party TWA	1	4										
	OATT	Wellsville	NMPC	Supplemental	0/3	OH Proxy Bus	NMPC - West	6/1/1998	10/31/2013	Third Party TWA	0	3										
169	N/A	PG&E Energy Trading	NMPC	PG&E Energy Trading	40	NE Proxy	PJM Proxy	6/1/99	5/31/20/00	OATT	40	40	-40	-40	-40		-40					
172	N/A	Niagara Mohawk Energy	NMPC	Niagara Mohawk Energy	52	Indeck - Illion	PJM Proxy	3/1/99	2/29/2000	OATT	52	52	-52	-52	-52							
173	N/A	Niagara Mohawk Energy	NMPC	Niagara Mohawk Energy	52	Indeck - Olean	PJM Proxy	3/1/99	2/29/2000	OATT	52	52										

Table 1A - Existing Long Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
174	N/A	NYPA	NMPC	BOC Gases	2.55	Fitzpatrick	NMPC - West	5/23/97	1/1/2010	OATT	3	3	-3	-3								
175	N/A	NYPA	NMPC	BOC Gases	14	Fitzpatrick	NMPC - East	5/23/97	1/1/2010	OATT	14	14			14		14					
176	N/A	NYPA	NMPC	BOC Gases	0.5	Fitzpatrick	NMPC - East	11/1/97	30 days notice	OATT	1	1					1					
177	N/A	NYPA	NMPC	Air Products	13	Fitzpatrick	NMPC - East	5/23/97	1/1/2010	OATT	13	13			13		13					
179	N/A	NYPA	NMPC	Norampac Industries	9.1	Fitzpatrick	NMPC - West	3/1/97	1/1/2010	OATT	9	9	-9	-9								
180	N/A	NYPA	NMPC	Encore Paper	7.5	Fitzpatrick	NMPC - East	5/23/97	1/1/2010	OATT	8	8			8		8					
181	N/A	NYPA	NMPC	Encore Paper	1	Fitzpatrick	NMPC - East	2/15/98	1/1/2010	OATT	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	N/A	NYPA	NMPC	Encore Paper	2	Fitzpatrick	NMPC - East	4/1/99	1/1/2010	OATT	2	2			2		2					
184	110	Expansion Industrials	NYSEG	Expansion Industrials (16)	38	Niagara	NYSEG - West		6/30/2013	Third Party TWA	38	38										
185	N/A	Aloca	NYPA	St. Lawrence	239	Moses 17 - 18	NYPA - North	8/24/81	6/30/2013	Third Party TWA	239	239										
186	N/A	Reynolds	NYPA	St. Lawrence	239	Moses 17 - 18	NYPA - North	8/24/81	6/30/2013	Third Party TWA	239	239										
187	N/A	General Motors	NYPA	St. Lawrence	12	Moses 17 - 18	NYPA - North	6/23/92	6/30/2013	Third Party TWA	12	12										
189	N/A	SENY (5)	NYPA	Niagara OATT Reservation	422	Niagara	Con Edison	7/1/99	12/31/2017	OATT (6) (7)	422	422	422	422	422		422	422	422	422	422	
190	N/A	SENY (5)	NYPA	St. Lawrence OATT Reserv	178	St. Lawrence	Con Edison	7/1/99	12/31/2017	OATT (6) (7)	178	178				178	178	178	178	178	178	
191	N/A	NYPA	CHG&E	Power For Jobs	1	CHG&E	CHG&E	7/1/99	12/31/2003	OATT	1	1										
194	N/A	NYPA	NMPC	Power For Jobs	97	Fitzpatrick	NM - Cent. East	8/1/99	21/31/2003	OATT	97	97			97							
195	N/A	NYPA	NMPC	Power For Jobs	20	Adirondack	NM - Cent. East	8/1/99	12/31/2003	OATT	20	20										
196	N/A	NYPA	NMPC	Power For Jobs	31	CHG&E	NM - East	8/1/99	12/31/2003	OATT	31	31						-31				
197	N/A	NYPA	NYPA	Power For Jobs	1	Fitzpatrick	RG&E	7/1/99	12/31/2003	OATT	1	1										
	N/A	NYPA	RG&E	Power For Jobs	1	RG&E	RG&E	7/1/99	12/31/2003	OATT	1	1										
215	174	Watertown	NMPC	Watertown	1.2	Watertown__HYD	Watertwn Muni Pl	3/19/91	12/31/2040	Third Party TWA	1	1										
216	18	NYPA	NMPC	Adirondack/Marc	0.5	Adirondack	Marcy	8/26/62	Indefinite	Third Party TWA	0	0										

Table 1A - Existing Long Term Transmission Wheeling Agreements																								
Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont.Est. Date	Cont. Exp. Date	Treatment(Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (10)	To (10)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
				y																		
217	N/A	SENY (15)	Con Edison	NYPA Load NYC Pol.	733	Poletti	Con Edison	3/10/89	Beyond 12/31/2004	Third Party TWA	733	765										
218	N/A	SENY (15)	Con Edison	NYPA Load NYC - KIAC	105	KIAC	Con Edison	3/23/93	11/1/2016	Third Party TWA	105	104										

Table 1A 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

Table 1A Notes:

(1) - Con Edison has TCCs/Rights for 300 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 TCC/Rights 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 TCCs is equivalent to the balance of the interface rating.
(3) - Existing agreements between RG&E and NMPC were replaced by a separate Exit Agreement.
(4) - As amended.
(5) - 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.
(6) - Subject to NYPA's obtaining non-discriminatory long term firm reservation through 2017 under their OATT.
(7) - 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 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.
(10) - One proxy bus in each of the neighboring control areas has been designated for any agreement that identifies a Point of Receipt or Point of Withdrawal in that neighboring control area.
(11) - Con Edison has terminated its purchase of Indian Point3 effective January 1, 2000. At that time, the residual amount of available capacity will increase from 800 MW to 912 MW.
(12) - The capacity figures designated under the columns (Sum MW) and (Win MW) 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.
(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 6/30/2011.
(15) - NYPA's Grandfathered Rights 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 will increase from 765 MW to 865 MW for the winter period and from 733 MW to 829 MW for the summer 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.

18.1.2 Table 1B - Existing Short Term Transmission Wheeling Agreements

Table 1B - Existing Short Term Transmission Wheeling Agreements																							
Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont. Est. Date	Cont. Exp. Date	Treatment (Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period										
		Requestor	Provider	Name	MW	From (1)	To (1)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
188	N/A	Con Edison	NYPA	HQ Capacity Purchase	400/208	Beau - E24	Con Ed - Mid Hud	4/1/99	12/31/1999	OATT	400	208				400	400	400				
192	N/A	NYPA	Con Edison	Power For Jobs	1	Con Ed - Mid Hud	Con Ed - North	7/1/99	4/30/2000	OATT	1	1							1			
	N/A	NYPA	Con Edison	Power For Jobs	2	Con Ed - Mid Hud	Con Ed - Central	7/1/99	4/30/2000	OATT	2	2							2	2		
	N/A	NYPA	Con Edison	Power For Jobs	14	Con Ed - Mid Hud	Con Edison	7/1/99	4/30/2000	OATT	14	14							14	14	14	
199	N/A	NYSEG	NYPA	Burlington Electric Dist.	3	NYSEG - North	NE Proxy	11/1/99	1/1/2000	OATT	3	3					3					
202	N/A	US Gen Power Services	NYPA	US Gen Power Services	208	HQ Proxy	NYPA - West	9/1/99	1/1/2000	OATT	208	208	-208	-208	-208	208						
203	N/A	HQ Energy Services	NYPA	HQ Energy Services	208	HQ Proxy	NYPA - E	9/1/99	1/1/2000	OATT	208	208				208						
206	N/A	HQ Energy Services	NYPA	HQ Energy Services	115	HQ Proxy	NE Proxy	11/1/99	1/1/2000	OATT	115	115					115					
208	N/A	US Gen Power Services	NYPA	US Gen Power Services	118	NYPA - North	NE Proxy	1/1/00	12/1/2000	OATT	118	118					118					
209	N/A	US Gen Power Services	NYPA	US Gen Power Services	100	HQ Proxy	Con Ed - Mid Hud	7/1/00	9/1/2000	OATT	100	0				100	100	100				
210	N/A	US Gen Power Services	NYPA	US Gen Power Services	150	HQ Proxy	NYPA - E	7/1/00	9/1/2000	OATT	150	0				150						
211	N/A	US Gen Power Services	NYPA	US Gen Power Services	100	HQ Proxy	NYPA West	7/1/00	9/1/2000	OATT	100	0	-100	-100	-100	100						
212	N/A	Morgan Stanley Capital	NYPA	Morgan Stanley Capital	100	HQ Proxy	NYPA - E	7/1/00	8/1/2000	OATT	100	100				100						

Table 1B - Existing Short Term Transmission Wheeling Agreements

Cont. #	FERC Rate Sch. Designat'n #	Transmission		Agreement				Cont. Est. Date	Cont. Exp. Date	Treatment (Refer to Attachment K)	Sum MW	Win MW	Interface Allocations - Summer Period									
		Requestor	Provider	Name	MW	From (1)	To (1)						DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
	N/A	Morgan Stanley Capital	NYSEG	Morgan Stanley Capital	100	NYPA E	PJM Proxy	7/1/00	8/1/2000	OATT	100	100	-100	-100	-100							
213	N/A	Constellation Power Source	NYPA	Constellation Power Source	235	HQ Proxy	NYPA - E	6/1/00	9/1/2000	OATT	235	235				235						
	N/A	Constellation Power Source	NYSEG	Constellation Power Source	235	NYPA E	PJM Proxy	6/1/00	9/1/2000	OATT	235	235	-235	-235	-235							
214	N/A	Constellation Power Source	NMPC	Constellation Power Source	104	Carr Street_E_Syr	PJM Proxy	6/1/00	10/1/2000	OATT	104	104	-104	-104								

Legend: MWA - Modified Wheeling Agreement
TWA - Transmission Wheeling Agreement
Cont. Est. Date - Contract Establishment Date

Interface Designations:

DE - Dysinger East	US - UPNY/SENY
WC - West Central	UC - UPNY/Con Ed
VE - Volney East	MS - Millwood South
MoS - Moses South	DS - Dunwoodie South
TE - Total East	CE-LI - Con Ed/LIPA

Notes: (1) - One proxy bus in each of the neighboring control areas has been designated for any agreement that identifies a Point of Receipt or Point of Withdrawal in that neighboring control area.

18.2 Table 2 – Existing Transmission Facility Agreements

Table 2 – Existing Transmission Facility Agreements

	FERC Rate Sch. Designation #	Requestor	Provider	Transmission Facility Agreement Name
1	62	CHG&E	NYSEG	Vinegar Hill
2	2	CHG&E	Con Edison	Pleasant Valley
3	123	CHG&E	Con Edison	East Fishkill (Expansion)
4	55	CHG&E	NMPC	North Catskill
5	N/A	NYPA	CHG&E	Marcy South
6	43	Con Edison	CHG&E	Rock Tavern
7	42	Con Edison	CHG&E	Roseton
8	87	Con Edison	NYSEG	Mohansic-Facility
9	125	NYPA	Con Edison	East 13th Street
10	117	LIPA	Con Edison	Y-50 Feeder
11	N/A	LIPA	NYPA	Y-49 Sound Cable
12	26	NYSEG	CHG&E	Woodbourne-Smithfield
13	33	AES	RG&E	Kintigh-Station 80
14	35	NYSEG	RG&E	Quaker Road
15	112	NYPA	NYSEG	Marcy South
16	42	NMPC	CHG&E	Roseton
17	124	O&R	Con Edison	Ladentown Switching Station
18	58	RG&E	NMPC	Clyde
19	127	NYPA	Con Edison	Sprainbrook (Y-49 Exp)
20	117	NY Coop	NYSEG	Delaware Coop/Jefferson
21	72	NY Coop	NYSEG	Bath Muni
22	90	NMPC	NYSEG	Retsof
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
29	36	O&R	RG&E	Station 80 Capacitors

Table 2 – Existing Transmission Facility Agreements

30	36	RG&E	RG&E	Station 80 Capacitors
31	36	NYPA	RG&E	Station 80 Capacitors
42	N/A	O&R	Con Edison	South Mahwah
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
40	126	O&R	Con Edison	Bowline-Ladentown
41	129	O&R	Con Edison	Ramapo-Branchburg
44	N/A	NYPA	Con Edison	Marcy South
45	180	NY Coop	NYSEG	Oneida
46	191	NYCoop	NYSEG	Delaware Coop/Delhi
47	N/A	Con Edison	PSE&G	Hudson - Farragut Interconnection 1
48	N/A	Con Edison	PSE&G	Hudson - Farragut Interconnection 2
49	194	NY Coop	NYSEG	Steuben

18.3 Table 3 - Existing Transmission Capacity for Native Load

	Transmission					Est.		Sum	Win	Interface Allocations - Summer Period									
	Requestor	Provider	Name	From	To	Date	Code	MW	MW	DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
1	Con Edison	Con Edison	Native Load-Bowline	Bowline	Con Edison	N/A	1	801	801							801	768	584	
2	Con Edison	Con Edison	Native Load-HQ Cap. Purchase	Con Ed - Mid Hud	Con Edison	N/A	1	400	208							400	384	292	
3	Con Edison	Con Edison	Native Load-Gilboa	Con Ed - Mid Hud	Con Edison	N/A	1	125	125							125	120	91	
4	Con Edison	Con Edison	Native Load-Roseton	Roseton-GN1	Con Edison	N/A	1	480	480							480	461	351	
5	Con Edison	Con Edison	Native Load-Corinth	Plesnt Vlly 345kV	Con Edison	N/A	1	134	134							134	129	98	
6	Con Edison	Con Edison	Native Load-Sithe	Plesnt Vlly 345kV	Con Edison	N/A	1	837	837							837	803	611	
7	Con Edison	Con Edison	Native Load-Selkirk	Plesnt Vlly 345kV	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	Homer City	NYSEG - Cent.	N/A	1	863	863	863	863								
15	NYSEG	NYSEG	Native Load-Homer City	Homer City	NYSEG - West	N/A	1	100	100										
16	NYSEG	NYSEG	Native Load-Allegheny 8&9	Pierce Rd 230kV	NYSEG - Cent.	N/A	2	37	37	37	37								
17	NYSEG	NYSEG	Native Load-BCLP	Homer City	NYSEG - Cent.	N/A	2	80	80	80	80								
18	NYSEG	NYSEG	Native Load-LEA (Lockport)	Grdnvlle 115 kV	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. If prior to the Centralized TCC Auction, all Grandfathered Transmission Service and the Transmission Capacity on this table are found not to be feasible, then the latter will be reduced until feasibility is ensured. A MW reduction based on a G-Shift Factor Method will be applied to the TCCs of the affected Transmission Providers.
2. 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

18.4 Table 4 - Grandfathered Transmission Service [1] By Interface Summer Capability Period

Table 4 - Grandfathered Transmission Service [1] By Interface
Summer Capability Period

Primary Owner	Interface(Megawatts)									
	DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
Central Hudson	0	0	101	0	126	201	300	0	0	0
Con Edison	0	0	0	0	0	125	10	0	228	0
LIPA	0	0	362	0	362	412	355	355	891	891
NYSEG	277	277	464	328	504	342	327	0	0	0
NMPC	126	126	126	104	0	0	0	0	0	0
O&R	0	0	0	0	0	25	0	0	0	0
RG&E	124	107	107	55	107	0	0	0	0	0
NYPA	422	422	422	178	600	600	600	600	600	0
Third Party	906	916	1716	-108	1378	1840	598	1372	1370	165
TOTAL	1855	1848	3298	557	3077	3545	2190	2327	3089	1056

Winter Capability Period

Primary Owner	Interface(Megawatts)									
	DE	WC	VE	MoS	TE	US	UC	MS	DS	CE-LI
Central Hudson	0	0	101	0	126	201	300	0	0	0
Con Edison	0	0	0	0	0	125	10	0	228	0
LIPA	0	0	326	0	326	376	352	352	881	881
NYSEG	277	277	464	318	504	342	327	0	0	0
NMPC	126	126	126	104	0	0	0	0	0	0
O&R	0	0	0	0	0	25	0	0	0	0
RG&E	124	107	107	55	107	0	0	0	0	0
NYPA	422	422	422	178	600	600	600	600	600	0
Third Party	946	950	1763	-108	1387	1848	606	1380	1379	173
TOTAL	1895	1882	3309	547	3050	3517	2195	2332	3088	1054

LEGEND: 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

NOTES: (1) - Reflects MW amounts for agreements listed in Table 1A.

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 Incremental TCCs pursuant to Section 19.2.2 of this Attachment M; (v) the conversion of ETCNL into ETCNL TCCs; and (vi) 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 Section 19.2.1 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.

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 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 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 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 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 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 Fixed Price TCCs with the same Points of Injection and Points of Withdrawal~~s~~ 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 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 Fixed Price TCCs an option to obtain new 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 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 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 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 Fixed Price TCCs, the ISO shall offer the LSE an option to obtain new 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 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 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 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 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 with a duration of one month in any Reconfiguration Auction(s) held 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 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 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 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 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 Fixed Price TCCs with a Duration Commencing on November 1, 2008

LSEs that obtained 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 Fixed Price TCCs, at no additional cost, with 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 Fixed Price TCCs under this paragraph shall not be eligible to obtain additional Fixed Price TCCs for an additional five year term at the time that their replacement Fixed Price TCCs expire.

LSEs that were eligible to obtain 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 Fixed Price TCCs with a duration of ten years. If an LSE makes this election the duration of the 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 Fixed Price TCCs under this paragraph shall pay the same price that the ISO originally offered for the same Fixed Price TCCs with a duration of five years, *i.e.*, the price that the ISO calculated under Section 19.2.1.2 for 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 Fixed Price TCCs

Except as is specifically noted below, if an LSE chooses to obtain 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 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 Fixed Price TCC would be calculated by summing the Day-Ahead Market Congestion Component for the POW associated with that Fixed Price TCC minus the Day-Ahead Market Congestion Component for the POI associated with that 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.

If an LSE chooses to obtain a Fixed Price TCC with a POW at or inside of Load Zone K (Long Island) pursuant to this Section 19.2.1, it shall pay a base price per MW/year equal to 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 Fixed Price TCC would be calculated by summing the Day-Ahead Market Congestion Component for the POW associated with that 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 applicable 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 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 Fixed Price TCC of less than zero, the price shall be zero.

19.2.1.3 Miscellaneous

The ISO shall post the following information promptly after transmission Capacity associated with expired or terminated ETAs is converted into Fixed Price TCCs: (i) the quantity of TCCs converted (in MW); (ii) the Point of Injection and Point of Withdrawal for each Fixed Price TCC converted; and (iii) the price paid for each Fixed Price TCC.

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. An LSE that has made the required annual payments may reassign, reconfigure, or sell its Fixed Price TCCs for any period of time for which it had made the required annual payment. 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. The ISO shall allocate funds collected pursuant to this provision under the terms of Attachment N to this Tariff. An LSE that fails to make any required annual payment for its Fixed Price TCCs shall permanently surrender those Fixed Price TCCs for that year and for all subsequent years (and shall not have a right to renew for an additional five or seven year term), 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 Fixed Price TCCs before the LSE has its Fixed Priced TCCs permanently surrendered, pursuant to ISO Procedures.

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 this Section 19.2.1, provided it makes all required payments.

To the extent that Fixed Price TCCs are created pursuant to this Section 19.2.1, 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 this Section 19.2.1 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).

19.2.1.4 Responsibilities of LSEs that Obtain Fixed Price TCCs Under Section 19.2.1

Each LSE that obtains a Fixed Price TCC under Section 19.2.1 of this Attachment M 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 TCC conversion deadlines established by the ISO under Section 19.2.1: and (ii) pay the price determined pursuant to Section 19.2.1.

19.2.2 Awards of Incremental TCCs

19.2.2.1 Overview

The ISO shall follow the procedures set forth in this Section 19.2.2 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 19.2.2 (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 19.2.2.5.2 have all been fulfilled.

The ISO shall also follow the procedures in this Section 19.2.2 to determine whether “Partial Outage Incremental TCCs” should be created in connection with final awards of Incremental TCCs.

19.2.2.2 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 19.2.2 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.

19.2.2.3 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 19.2.2.5).

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.

19.2.2.4 Partial Outage Incremental TCCs

The ISO shall use the additional information submitted by certain Expanders regarding partial outage states pursuant to Section 19.2.2.1 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 19.2.2.9.

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 19.2.2.5, 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.

19.2.2.5 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 19.2.2.3 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.

19.2.2.5.1 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.

19.2.2.5.2 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.

19.2.2.6 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.

19.2.2.7 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 19.2.2.

19.2.2.8 Restrictions on Transfers of Incremental TCCs

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, *i.e.*, 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. Transferees of Incremental TCCs 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.

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.

19.2.2.9 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 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.

19.3 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 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:

$$\sum_{j \in N} \int_0^{Aj} \mathbf{Bidsj}$$

Where,

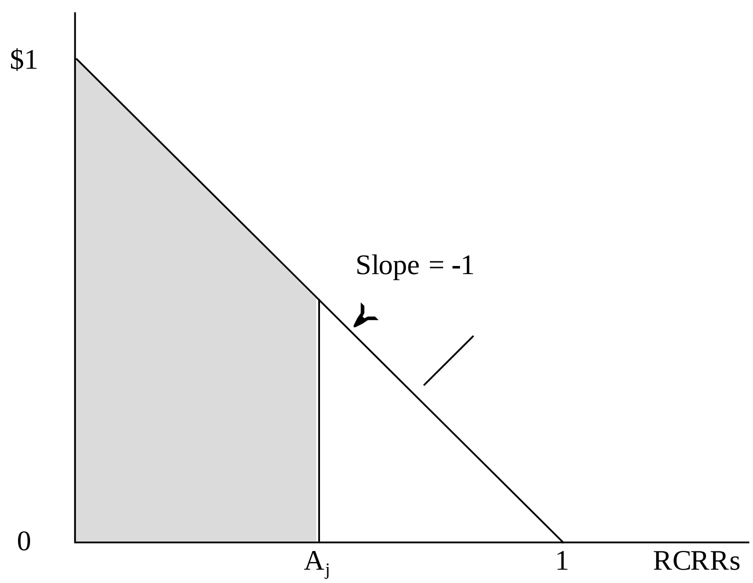
j = A Load Zone pair

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:

$$\text{Allocation Factor}_{t,j} = \frac{\sum_{a \in A} \left(\text{Interface Revenue}_{t,j,a} \right)}{\sum_{\substack{t \in T \\ a \in A}} \left(\text{Interface Revenue}_{t,j,a} \right)}$$

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, that convert their ETAs to Fixed Price TCCs, buyers in the Secondary Market that meet the eligibility criteria listed herein, and Expanders (as defined in Section 19.2.2.1) 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 the 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 that will be valid for the calendar month that follows 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 of this Attachment M and Incremental TCCs awarded pursuant to Section 19.2.2 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:

$$\sum_{j \in N} \int_{0}^{A_j} \mathbf{B}_j$$

Where:

N = The set of Table 1 ETCNL/TCCs

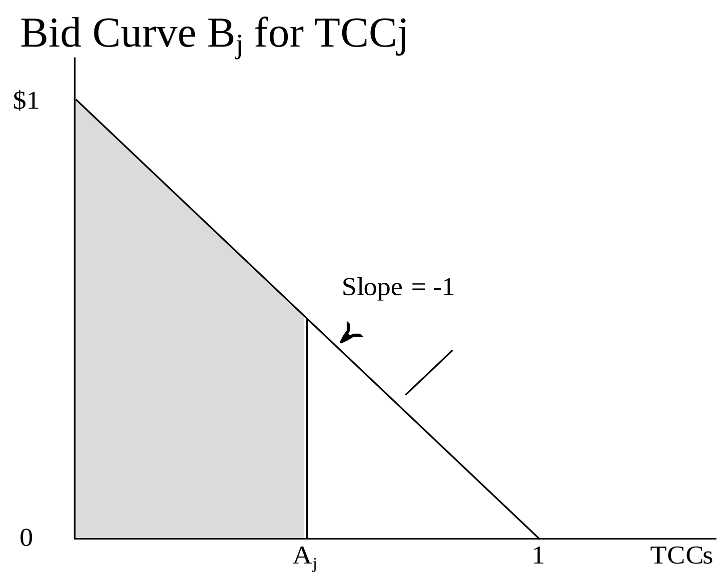
j = Any individual Table 1 ETCNL/TCC

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 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:



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 TO elects to have its ETCNL disaggregated, the number of MW of ETCNL allocated to that TO 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 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 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 Auction, or (b) that the Transmission Owners do not convert to ETCNL TCCs or (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 Auction, 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, provided however that LIPA shall not be required to release available transmission Capacity into the Centralized TCC Auction and shall release available transmission Capacity into the Reconfiguration Auction.

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 this 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 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 monthly TCCs 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 month following the Reconfiguration Auction. A Reconfiguration Auction will consist of a single round. Any Primary Holder of a TCC that is valid for the 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 Owner of an ETCNL TCC or 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, will be available to support TCCs purchased in the Reconfiguration Auction.

LIPA may offer transmission Capacity associated with LIPA's Transmission District in a Reconfiguration Auction.

19.9 Procedures for Sales of TCCs in Each Auction

19.9.1 Auction Structure

Participation in a Sub-Auction-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 Sub-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 Injections 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 Auction in accordance with this Attachment and ISO Procedures. Bidders shall submit Bids such that the sum of the value of its Bids (excluding Bids for TCCs already held by that bidder) 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 Auction and shall be charged the market clearing price for that round, as defined in this Attachment, 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 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 Auction until six months following the date of the Auction. 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 conversion of ETAs into 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 ETAs into Fixed Price TCCs, pursuant to Section 19.2.1 above. The ISO will establish a system to communicate Auction-related information to all Auction participants between rounds of the 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 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 Centralized TCC Auction, the duration in multiples of Capability Periods of the TCC 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 or converting. The aggregate value of the Bids submitted by any bidder into the 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.

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). The market clearing price for each TCC shall be based on the lowest winning Bid made in that round for that TCC (or for other TCCs if injections and withdrawals corresponding to those TCCs would have the same impact on flows over congested Interfaces as injections and withdrawals corresponding to that TCC).

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 the Centralized TCC 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. Charges for Fixed Price TCCs shall be billed in accordance with ISO Procedures.

The ISO shall establish a dispute period following the conclusion of the Centralized TCC 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 Auction or otherwise acquired that are valid for any part of the duration of any TCCs to be sold in that round; (ii) Grandfathered Rights; and (iii) TCCs awarded in the current round. Each injection and withdrawal associated with TCCs and Grandfathered Rights 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 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 average Congestion Component of the LBMP, relative to the Reference Bus, and (b) the average Marginal Losses Component of the LBMP, relative to the Reference Bus;

19.9.8.2 for the previous two Capability Periods, (a) data from which the following can be determined: historical flow for each of the closed Interfaces, and (b) historically, the number of hours that the most limiting facilities were physically constrained;

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);

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 Transmission Owner has elected to convert to RCRR TCCs for the Centralized TCC 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, and (d) the Auction participant awarded the TCC.

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.

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 Auction, which will permit the Bids submitted by Auction participants to determine the lengths of the TCCs sold in the Auction. The End-State Auction will be held annually. The date for the first End-State Auction shall be determined by the ISO. The period during which each TCC sold in an End-State 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 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 Auction. The ISO shall announce these percentages before the Auction. The ISO shall also determine the periods for which TCCs will be sold in End-State 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 Auction to the next End-State Auction.

The End-State 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 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 Auction, and will depend on the Bids submitted by participants in the Auction.

In a given round of the End-State 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 Auction will include multiple rounds of bidding, as described elsewhere in this Attachment.

Transmission Capacity that can be used to support TCCs sold in End-State 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 Auction; any TCCs previously allocated (either in an Auction or through other means) that have not been offered for sale in this Auction; and transmission Capacity needed to support Grandfathered Rights.

The End-State 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 Auction.

If necessary, the ISO may elect to conduct a semi-annual Auction to sell six-month TCCs between annual End-State Auctions. The transmission Capacity that can be used to support TCCs purchased in this Auction shall include the portion of the transmission Capacity sold in the previous End-State Auction as six-month TCCs, as well as any other outstanding TCC whose Primary Holder elects to release it for sale in this Auction.

Attachment M - Table 1

Table 1 - TCC Reservations Subject to MW Reduction

					Sum	Win	Interface Allocations Summer Period									
	Reservation	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	Con Ed - North	Con Edison	400	208							400	384	292	
3	Con Edison	Gilboa	Con Ed - North	Con Edison	125	125							125	120	91	
4	Con Edison	Roseton	Roseton GN1	Con Edison	480	480							480	461	351	
5	Con Edison	Corinth	Con Ed - North	Con Edison	134	134							134	129	98	
6	Con Edison	Sithe	Con Ed - North	Con Edison	837	837							837	803	611	
7	Con Edison	Selkirk	Selkirk	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	Homer City	NYSEG Cent.	863	863	863	863								
15	NYSEG	Homer City	Homer City	NYSEG West	100	100										
16	NYSEG	Allegheny 8&9	Pierce Rd 230kV	NYSEG Cent.	37	37	37	37								
17	NYSEG	BCLP	Homer City	NYSEG Cent.	80	80	80	80								
18	NYSEG	LEA (Lockport)	NYSEG West	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.

Attachment M - Table 2

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	Millwood Zone	33
2.	Con Edison	Native Load-Bowline	Bowline	Dunwoodie Zone	184
3.	Con Edison	Native Load-Bowline	Bowline	NYC Zone	584
4.	Con Edison	Native Load- HQ Capacity Purchase	Pleasant Valley 345kV	Millwood Zone	16/8
5.	Con Edison	Native Load- HQ Capacity Purchase	Pleasant Valley 345kV	Dunwoodie Zone	92/48
6.	Con Edison	Native Load- HQ Capacity Purchase	Pleasant Valley 345kV	NYCZone	292/152
7.	Con Edison	Native Load - Gilboa	Pleasant Valley 345kV	Millwood Zone	5
8.	Con Edison	Native Load - Gilboa	Pleasant Valley 345kV	Dunwoodie Zone	29
9.	Con Edison	Native Load - Gilboa	Pleasant Valley 345kV	NYC Zone	91
10.	Con Edison	Native Load - Roseton	Roseton-#1	Millwood Zone	19
11.	Con Edison	Native Load - Roseton	Roseton-#1	Dunwoodie Zone	110
12.	Con Edison	Native Load - Roseton	Roseton-#1	NYC Zone	351
13.	Con Edison	Native Load - Corinth	Pleasant Valley 345kV	Millwood Zone	5
14.	Con Edison	Native Load - Corinth	Pleasant Valley 345kV	Dunwoodie Zone	31
15.	Con Edison	Native Load - Corinth	Pleasant Valley 345kV	NYC Zone	98
16.	Con Edison	Native Load - Sithe	Pleasant Valley 345kV	Millwood Zone	34
17.	Con Edison	Native Load - Sithe	Pleasant Valley 345kV	Dunwoodie Zone	192
18.	Con Edison	Native Load - Sithe	Pleasant Valley 345kV	NYC Zone	611
19.	Con Edison	Native Load - Selkirk	Pleasant Valley 345kV	Millwood Zone	11
20.	Con Edison	Native Load - Selkirk	Pleasant Valley 345kV	Dunwoodie Zone	61
21.	Con Edison	Native Load - Selkirk	Pleasant Valley 345kV	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 115kV	Central Zone	100
36.	NYSEG	Native Load - Gilboa	Gilboa	Capital Zone	99

Notes: 1. Where two different amounts of transmission Capacity are separated by a "/", the first number shall indicate the transmission Capacity available for conversion to ETCNL TCCs in a Centralized TCC Auction held for a Summer Capability Period, and the second number shall indicate the transmission Capacity available for conversion to ETCNL TCCs in a Centralized TCC Auction held for a Winter Capability Period.

Attachment M - Table 3

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.

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 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 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 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 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 Reconfiguration Auction that occurs for a transmission facility that, in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction, was a Qualifying Auction Outage that qualified as an ISO-Directed Auction Status Change; (2) an Actual Qualifying Auction Uprating for 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 6-month Sub-Auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction, 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 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 6-month Sub-Auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction, 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, in the last Reconfiguration Auction held for TCCs valid for the relevant hour or 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, in the last Reconfiguration Auction held for TCCs valid for the relevant hour or 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, in the last Reconfiguration Auction held for TCCs valid for the relevant hour or 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 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 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 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).

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.

<u>Formula N-1</u>

$$\text{NetCongestionRents}_h = \begin{pmatrix} \text{Congestion Rents}_h \\ -\ \text{TCC Payments}_h \\ -\ \text{O/R-t-S\&U/D CRSC\&CRSP}_h \end{pmatrix}$$

Where,

$\text{NetCongestionRents}_h$	=	The total Net Congestion Rents for hour *h* of the Day-Ahead Market
h	=	An hour of the Day-Ahead Market
$\text{Congestion Rents}_h$	=	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 ($/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.

The ISO shall assess a “Shortfall Reimbursement Surcharge” each month on monthly net positive Congestion payments to Primary Holders of TCCs sold in or after the Autumn 2004 Centralized TCC Auction. The Shortfall Reimbursement Surcharge shall be 0.5% of Congestion payments associated with TCCs that have a Point of Withdrawal outside of Load Zone J and 2.5% of Congestion payments associated with TCCs that have a Point of Withdrawal at, or inside of, Load Zone J.

The Shortfall Reimbursement Surcharge shall not be assessed on Congestion payments to Primary Holders of TCCs that produce net negative Congestion payments, *i.e.*, that oblige the Primary Holder to make payments, in a given month, on Congestion payments to Primary Holders of Grandfathered TCCs, or on Congestion payments to Primary Holders of ETCNL TCCs or RCRR TCCs. The Shortfall Reimbursement Surcharge also shall not be assessed on

Congestion payments to Primary Holders of TCCs sold before the Autumn 2004 Centralized TCC Auction, except to the extent that such TCCs are unbundled or reconfigured at the request of a Primary Holder, and sold, in or after that auction, in which case the Congestion payments associated with them shall be subject to the Shortfall Reimbursement Surcharge.

The ISO shall cease to impose the Shortfall Reimbursement Surcharge when it has collected sufficient funds to: (i) pay refunds for all of the "Historic Shortfall" plus interest pursuant to Article III of the July 13, 2004 Settlement Agreement that was approved by the Commission in Docket Nos. EL04-110, EL04-113, EL04-115, and ER04-983; and (ii) replenished the ISO Working Capital Fund pursuant to Article IV of that Settlement Agreement.

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.

<u>Formula N-5</u>

$$DCR_{a,h} = ShadowPrice_{a,h} * \begin{bmatrix} FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction} \\ + \ UprateDerate_{a,h} * SCUCSignChange_{a,h} \\ + \ UnsoldCapacity_{a,h,RA} * SCUCSignChange_{a,h} \end{bmatrix}$$

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[12] to the set of TCCs and Grandfathered Rights represented in the solution to the most recent

[12] 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.

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 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 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 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* 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 to the set of TCCs and Grandfathered Rights represented 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 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 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* 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 to the set of TCCs and Grandfathered Rights represented 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 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 in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the 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), $UprateDerate_{a,h}$ 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 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 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 in TCC auctions; 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

$$\text{O/R-t-S DCR}_{a,h} = DCR_{a,h} * \left[\frac{FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction}}{FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction} + UprateDerate_{a,h} * SCUCSignChange_{a,h}} \right]$$

Where,

$O/R\text{-}t\text{-}S\ DCR_{a,h}$ = 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

$$U/D\ DCR_{a,h} = DCR_{a,h} * \left[\frac{UprateDerate_{a,h} * SCUCSignChange_{a,h}}{FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction} + UprateDerate_{a,h} * SCUCSignChange_{a,h}} \right]$$

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 in the last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment 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 last auction held for TCCs valid for hour *h*;

(ii) the facility existed but was not modeled as in-service 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 last auction held for TCCs valid for hour *h*;

(iii) the facility was not Normally Out-of-Service Equipment 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 last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment 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 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 last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment 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

$$\text{O/R-t-S NetDAMImpact}_{a,h} = \left(\sum_{\text{for all } o \in O_h} \text{FlowImpact}_{a,h,o} * \text{ShadowPrice}_{a,h} \right) * \text{OPF/SCUCAdjust}_a$$

Where,

O/R-t-S $\text{NetDAMImpact}_{a,h}$ = 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 $\text{NetDAMImpact}_{a,h}$ 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:

$\text{FlowImpact}_{a,h,o} = \text{One-OffFlow}_{a,h,o} – \text{BaseCaseFlow}_{a,h}$

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 to the TCCs and Grandfathered Rights represented 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 schedule determined in the Optimal Power Flow solution for the final round of the last auction held for TCCs valid in hour *h*; and (3) the Transmission System model for 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 schedule 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 schedule 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 $FlowImpact_{a,h,o}$ calculated using the procedures set forth above is less than 1 MWh, then $FlowImpact_{a,h,o}$ shall be set equal to zero;

provided further, $FlowImpact_{a,h,o}$ 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 $ShadowPrice_{a,h}$ and $OPF/SCUCAdjust_a$ are defined as set forth in Formula N-5.

After calculating O/R-t-S $NetDAMImpact_{a,h}$ 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.

<u>Formula N-9</u>

$$\text{O/R-t-S Allocation}_{a,t,h} = \left(\frac{\sum\limits_{\substack{o \in O_h \\ \text{and } q=t}} \text{FlowImpact}_{a,h,o} * \text{Responsibility}_{h,q,o}}{\sum\limits_{\text{for all } o \in O_h} \text{FlowImpact}_{a,h,o}} \right) * \text{O/R-t-S DCR}_{a,h}$$

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

$$\text{O/R-t-S Allocation}_{a,t,h} = \left(\sum_{\substack{o \in O_h \\ \text{and } q=t}} \text{FlowImpact}_{a,h,o} * \text{ShadowPrice}_{a,h} * \text{Responsibility}_{h,q,o} \right) * \text{OPF/SCUCAdjust}_a$$

Where,

the variables $\text{ShadowPrice}_{a,h}$ and OPF/SCUCAdjust_a are defined as set forth in Formula N-5, the variables $\text{O/R-t-S Allocation}_{a,t,h}$ and $\text{Responsibility}_{h,q,o}$ are defined as set forth in Formula N-9, and the variables $\text{FlowImpact}_{a,h,o}$ 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 in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating is included 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 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 in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating is included 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 in the last auction held for TCCs valid for hour *h*;

(iii) this higher rating is included 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 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 in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating for hour *h* is included 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

$$\text{U/D NetDAMImpact}_{a,h} = \left(\sum_{\text{for all } r \in R_{a,h}} \text{RatingChange}_{a,h,r} * \text{ShadowPrice}_{a,h} \right) * \text{SCUCSignChange}_{a,h}$$

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 in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the 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 in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the 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*, $RatingChange_{a,h,r}$ 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 $SCUCSignChange_{a,h}$ and $ShadowPrice_{a,h}$ are defined as set forth in Formula N-5.

After calculating U/D $NetDAMImpact_{a,h}$ pursuant to Formula N-11, the ISO shall determine whether U/D $NetDAMImpact_{a,h}$ for constraint *a* in hour *h* has a different sign than U/D $DCR_{a,h}$ for constraint *a* in hour *h*. If the sign is different, the ISO shall (i) recalculate U/D $NetDAMImpact_{a,h}$ pursuant to Formula N-11 after setting equal to zero each $RatingChange_{a,h,r}$ for which $RatingChange_{a,h,r}$ * $ShadowPrice_{a,h}$ * $SCUCSignChange_{a,h}$ has a different sign than U/D $DCR_{a,h}$, and then (ii) use this recalculated U/D $NetDAMImpact_{a,h}$ and reset value of $RatingChange_{a,h,r}$ 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 $NetDAMImpact_{a,h}$) 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 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

$$\text{U/D Allocation}_{a,t,h} = \left(\frac{\sum_{\substack{r \in R_{a,h} \\ \text{and } q=t}} \text{RatingChange}_{a,h,r} * \text{Responsibility}_{h,q,r}}{\sum_{\text{for all } r \in R_{a,h}} \text{RatingChange}_{a,h,r}} \right) * \text{U/D DCR}_{a,h}$$

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.

<u>Formula N-13</u>

$$\text{U/D Allocation}_{a,t,h} = \left(\sum_{\substack{r \in R_{a,h} \\ \text{and } q=t}} \text{RatingChange}_{a,h,r} * \text{ShadowPrice}_{a,h} * \text{Responsibility}_{h,q,r} \right) * \text{SCUCSignChange}_{a,h}$$

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 in the last Reconfiguration Auction held for TCCs valid for the relevant hour or 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.

20.2.4.4.4 Shared Responsibility For Returns-to-Service and Upratings During a Transitional Period

Notwithstanding any other provision of this Attachment N, a Transmission Owner shall be deemed to be not responsible for a Qualifying DAM Return-to-Service, Qualifying DAM Derating, or Qualifying DAM Uprating for an hour of the Day-Ahead Market if this Attachment N was not in effect at the time of the last Reconfiguration Auction held for TCCs valid for the hour. Instead, the ISO shall allocate any revenue impacts resulting from such a Qualifying DAM Return-to-Service, Qualifying DAM Derating, or Qualifying DAM Uprating 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 such Qualifying DAM Return-to-Service, Qualifying DAM Derating, or Qualifying DAM Uprating during this transitional period 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 20.2.4.4.4 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.

<u>Formula N-14</u>

$$\text{NetDAMAllocations}_{t,h} = \sum_{\text{for all a}} \text{O/R-t-S}\,\text{CRSC}_{a,t,h} + \text{U/D}\,\text{CRSC}_{a,t,h} + \text{O/R-t-S}\,\text{CRSP}_{a,t,h} + \text{U/D}\,\text{CRSP}_{a,t,h}$$

Where,

$\text{NetDAMAllocations}_{t,h}$ = 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

$$\text{AllocationFactor}_{t,m} = \frac{\text{Original Residual}_{t,m} + \text{ETCNL}_{t,m} + \text{NARs}_{t,m} + \text{GFR\&GFTCC}_{t,m}}{\sum_{q \in T} \text{Original Residual}_{q,m} + \text{ETCNL}_{q,m} + \text{NARs}_{q,m} + \text{GFR\&GFTCC}_{q,m}}$$

Where,

Allocation $\text{Factor}_{t,m}$	=	The allocation factor used by the ISO to allocate a share of the Net Congestion Rents to Transmission Owner *t* for month *m*
Original $\text{Residual}_{q,m}$	=	The one-month portion of the revenue imputed to the Direct Sale or the sale in any Centralized TCC Auction Sub-Auction of Original Residual TCCs 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 in the Reconfiguration Auction held for 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 month *m*. For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds.). 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.
$\text{ETCNL}_{q,m}$	=	The sum of the one-month portion of the revenue the Transmission Owner has received as payment for the Direct Sale of ETCNL or for its ETCNL released in the Centralized TCC Auction Sub-Auction held for TCCs valid for month *m*. Each one-month portion of the revenue for ETCNL released in such 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 to the ETCNL sold in the Centralized TCC Auction Sub-Auction.[13] The one-month portion of the revenue imputed to the Direct Sale of ETCNL shall be the value of the TCCs corresponding to that ETCNL in the Reconfiguration Auction held for 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 month *m*). For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds.

$NARs_{q,m}$ = The one-month portion of the Net Auction Revenues the Transmission Owner has received in Centralized TCC Auction Sub-Auction and 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 in each Centralized TCC Auction Sub-Auction or Reconfiguration 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 or Reconfiguration Auction (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) $NetAuctionAllocations_{t,n}$ 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 Reconfiguration Auction *n* held for 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*). For Centralized TCC

2 A TCC corresponds to ETCNL if it has the same POI and POW as the ETCNL.

		Auctions conducted before May 1, 2010, the calculation of (ii) shall incorporate only Stage 1 six month rounds.
$GFR\&GFTCC_{q,m}$	=	The one-month portion of the imputed value of Grandfathered TCCs and Grandfathered Rights, valued at their market clearing prices in the Reconfiguration Auction for 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 month *m*), provided that the Transmission Owner is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in month *m*. For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds.
t	=	Transmission Owner *t*
T	=	The set of all Transmission Owners *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

$$\text{Net Auction Revenue}_n = \begin{bmatrix} \text{TCC Auction Revenue}_n \\ - \text{ETCNL}_n \\ - \text{Primary Holder TCCs Sold}_n \\ - \text{Original Residual TCCs}_n \\ - \text{O/R-t-S\&U/D ARSC\&ARSP}_n \end{bmatrix}$$

Where,

n = A round of a Centralized TCC Auction (which may be either a round of a 6-month Sub-Auction , 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

$\text{Net Auction Revenue}_n$ = 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 $ARSC\&ARSP_n$	=	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 $NetAuctionAllocations_{t,n}$ 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 $ARSC_{a,t,n}$), U/D Auction Revenue Shortfall Charges (U/D $ARSC_{a,t,n}$), O/R-t-S Auction Revenue Surplus Payments (O/R-t-S $ARSP_{a,t,n}$), and U/D Auction Revenue Surplus Payments (U/D $ARSP_{a,t,n}$) for all Transmission Owners *t* (which sum is calculated for each Transmission Owner as $NetAuctionAllocations_{t,n}$ 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.

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 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 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 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 released into the Centralized TCC Auction is insufficient to fund payments at market-clearing prices, the total payments to each Transmission Owner for ETCNL 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.

In the event a Grandfathered TCC[14] is terminated by mutual agreement of the parties to the grandfathered ETA 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

Revenues associated with Original Residual TCCs shall be distributed directly to each Primary Holder for the duration of the LBMP Transition Period. The Primary Holder of such an Original Residual TCC shall be paid the market clearing price of the Original Residual TCC in the round of the Sub-Auction in which that Original Residual TCC was sold.

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

[14] These TCCs include TCCs, if any, associated with those rate schedules to which footnote 9 of Attachment L pertains, whether by mutual agreement or otherwise.

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 Residual TCCs. If the total value of the auction revenues available for payment to the Transmission Owners for 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 Original Residual TCCs 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 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 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 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

$$ACR_{a,n} = ShadowPrice_{a,n} * \left[\begin{array}{l} FLOW_{a,n,actual} - FLOW_{a,n,basecase} \\ + \ ISORatingChange_{a,n} * OPFSignChange_{a,n} \end{array} \right] * \%Sold_n$$

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 Reconfiguration Auction *n*, where *p* is a one-month period for 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 Reconfiguration Auction *n*, (i) the Transmission System model for Reconfiguration Auction *n*, (ii) the set of TCCs and Grandfathered Rights represented in the solution to Reconfiguration Auction *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 determined in the Optimal Power Flow solution 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 schedule 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 Reconfiguration Auction *n*, a Power Flow using the following base case data set: (i) the Transmission System model for Reconfiguration Auction *n*, (ii) the set of TCCs and Grandfathered Rights represented in the solution to the final round of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *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 determined in the Optimal Power Flow solution for the final round of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; 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 schedule 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 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 Reconfiguration Auction *n*, which shall be calculated as follows:

(a) For 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 round *n* or Reconfiguration Auction *n*, $ISORatingChange_{a,n}$ shall be equal to the amount, in MW-*p*, of the change in the rating limit of constraint *a* as shown in the Reconfiguration Auction Interface Uprate/Derate Table applicable for 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* or Reconfiguration Auction *n*, $ISORatingChange_{a,n}$ shall be equal to the amount, in MW-*p*, of the change in the rating limit of constraint *a* 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 Reconfiguration Auction *n*, 1.

Formula N-18

$$ACR_{a,n} = ShadowPrice_{a,n} * \begin{bmatrix} FLOW_{a,n,actual} - FLOW_{a,n,basecase} \\ + \ ISORatingChange_{a,n} * OPFSignChange_{a,n} \\ - \ UnsoldCapacity_{a,n,PriorAuction} * OPFSignChange_{a,n} \end{bmatrix} * \%Sold_n$$

Where,

$UnsoldCapacity_{a,n,PriorAuction}$ = Either:

(a) For Reconfiguration Auction *n*, the rating limit for binding constraint *a* applied in the model used in the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, minus the Energy flow, in MW-*p*, on binding constraint *a* produced in the Optimal Power Flow in the last round of that Centralized TCC Auction; 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 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 ound *n* of a 6-month Sub-Auction or 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 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 Reconfiguration Auction *n*, as the case may be, for constraint *a* shall be determined by applying Formula N-20.

Formula N-19

$$\text{O/R-t-S ACR}_{a,n} = \text{ACR}_{a,n} * \left[\frac{\text{FLOW}_{a,n,actual} - \text{FLOW}_{a,n,basecase} + \text{TotalRatingChange}_{a,n} * \text{OPFSignChange}_{a,n}}{\text{FLOW}_{a,n,actual} - \text{FLOW}_{a,n,basecase} + \text{ISORatingChange}_{a,n} * \text{OPFSignChange}_{a,n}} \right]$$

Where:

O/R-t-S $\text{ACR}_{a,n}$ = The amount of the O/R-t-S Auction Constraint Residual for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, for constraint *a*

$\text{TotalRatingChange}_{a,n}$ = The total change in the rating of constraint *a*, which shall be calculated as follows:

(a) For Reconfiguration Auction *n*, $\text{TotalRatingChange}_{a,n}$ shall be equal to (1) the rating limit, in MW-*p*, of constraint *a* in the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, minus (2) the rating limit, in MW-*p*, of constraint *a* applicable in Reconfiguration Auction *n*

(b) For round *n* of a 6-month Sub-Auction, $\text{TotalRatingChange}_{a,n}$ 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.

<u>Formula N-20</u>

$$\text{U/D ACR}_{a,n} = \text{ACR}_{a,n} * \left[\frac{-\left(\text{TotalRatingChange}_{a,n} - \text{ISORatingChange}_{a,n}\right) * \text{OPFSignChange}_{a,n}}{\text{FLOW}_{a,n,actual} - \text{FLOW}_{a,n,basecase} + \text{ISORatingChange}_{a,n} * \text{OPFSignChange}_{a,n}} \right]$$

Where,

$\text{U/D ACR}_{a,n}$ = The amount of the U/D Auction Constraint Residual for round *n* of a 6-month Sub-Auction or 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 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 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 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 ub-Auction or 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 Reconfiguration Auction *n*, as the case may be:

(a) For Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed and was modeled as in-service in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and

(ii) the facility exists but is not modeled as in-service for Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; 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 Reconfiguration Auction *n*) shall be defined as a transmission facility that, for Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(ii) the facility existed but was not modeled as in-service in Reconfiguration Auction *n* as a result of an Auction Status Change or external event described in Section 20.3.6.4.3 in 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 last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*.

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 Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service for the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and

(ii) the facility exists and is modeled as in-service in Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*.

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 Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(ii) the facility existed but was not modeled as in-service in Reconfiguration Auction *n* as a result of an Auction Status Change or external event described in Section 20.3.6.4.3 in 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 last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*.

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 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 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 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 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 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 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 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 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 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 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

$$\text{O/R-t-SNetAuctionImpact}_{a,n} = \sum_{\text{for all } o \in O_n} \text{FlowImpact}_{a,n,o} * \text{ShadowPrice}_{a,n}$$

Where,

O/R-t-SNetAuctionImpact$_{a,n}$ = The net impact, in dollars, for round *n* of a 6-month Sub-Auction or 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 Reconfiguration Auction *n* having an impact of more than 1 MW-*p* on Energy flow across constraint *a; provided, however*, O/R-t-S NetAuctionImpact$_{a,n}$ 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 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-OffFlow$_{a,n,o}$

Where,

BaseCaseFlow$_{a,n}$ = Either, as the case may be:

(i) for a Reconfiguration Auction, the Energy flow on constraint *a* resulting from a Power Flow using (1) the set of injections and withdrawals corresponding to the actual TCCs and Grandfathered Rights represented in the solution to the last 6-

month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n* (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction); (2) the phase angle regulator schedule determined in the Optimal Power Flow solution for the final round of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and (3) the Transmission System model for the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; 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 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 schedule 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 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 schedule 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 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 schedule 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 Reconfiguration Auction *n*

p = A one-month period for Reconfiguration Auction *n*, or a six-month period for round *n* of a 6-month Sub-Auction

and the variable $ShadowPrice_{a,n}$ is defined as set forth in Formula N-17.

After calculating O/R-t-S $NetAuctionImpact_{a,n}$ pursuant to Formula N-21, the ISO shall determine whether O/R-t-S $NetAuctionImpact_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* has a different sign than O/R-t-S $ACR_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*. If the sign is different, the ISO shall (i) recalculate O/R-t-S $NetAuctionImpact_{a,n}$ pursuant to Formula N-21 after setting equal to zero each $FlowImpact_{a,n,o}$ for which $FlowImpact_{a,n,o}$ * $ShadowPrice_{a,n}$ has a different sign than O/R-t-S $ACR_{a,n}$, and then (ii) use this recalculated O/R-t-S $NetAuctionImpact_{a,n}$ and reset value of $FlowImpact_{a,n,o}$ 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 $NetAuctionImpact_{a,n}$) on constraint *a* of all Qualifying Auction Outages and Qualifying Auction Returns-to-Service for round *n* of a 6-month Sub-Auction or 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 greater than 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 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 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 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

$$\text{O/R-t-S Allocation}_{a,t,n} = \left(\frac{\sum_{\substack{o \in O_n \\ \text{and } q=t}} FlowImpact_{a,n,o} * Responsibility_{n,q,o}}{\sum_{\text{for all } o \in O_n} FlowImpact_{a,n,o}} \right) * \text{O/R-t-S } ACR_{a,n}$$

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 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 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 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

$$\text{O/R-t-S Allocation}_{a,t,n} = \sum_{\substack{o \in O_n \\ \text{and } q=t}} FlowImpact_{a,n,o} * ShadowPrice_{a,n} * Responsibility_{n,q,o}$$

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 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 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 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 Reconfiguration Auction *n* meets each of the following requirements:

For Reconfiguration Auction *n*:

(i) the constraint has a lower rating in Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service 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 Reconfiguration Auction *n*;

(iii) the lower rating resulting from Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was not modeled in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iv) this lower rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint was binding in 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 Reconfiguration Auction *n*) shall be defined as a change in the rating of a constraint that, for a given constraint *a* and a given Reconfiguration Auction *n* meets each of the following requirements:

(i) the constraint has a lower rating in Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service 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 Reconfiguration Auction *n*;

(iii) this lower rating resulting from Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was modeled in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, but responsibility for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* resulting in the lower rating for 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 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iv) this lower rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint is binding in 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 Reconfiguration Auction *n*, as the case may be, meets each of the following requirements:

(i) the constraint has a higher rating for Reconfiguration Auction *n* than it would have absent an Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n*;

(ii) this higher rating resulting from Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was not modeled in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iii) this higher rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(iv) the constraint is binding in 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 Reconfiguration Auction *n*, as the case may be, meets each of the following requirements:

(i) the constraint has a lower rating in Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service 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 Reconfiguration Auction *n*;

(iii) this lower rating resulting from Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was modeled in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, but responsibility for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* resulting in the lower rating for 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 auction held for TCCs valid for hour *h*;

(iv) this lower rating in 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 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 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 Reconfiguration Auction *n* of all Qualifying Auction Deratings *r* and Qualifying Auction Upratings *r* for constraint *a* in 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.

<u>Formula N-24</u>

$$\text{U/D NetAuctionImpact}_{a,n} = \left(\sum_{r \in R_{a,n}} \text{RatingChange}_{a,n,r} * \text{ShadowPrice}_{a,n} \right) * \text{OPFSignChange}_{a,n}$$

Where,

$U/D\ NetAuctionImpact_{a,n}$ = The net impact, in dollars, on constraint *a* in 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 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 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 Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, which in the case of 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, $RatingChange_{a,n,r}$ shall be equal to the amount, in MW-*p*, of the decrease or increase in the rating of binding constraint *a* in 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 Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, which in the case of 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, $RatingChange_{a,n,r}$ 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 Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction

and the variables $ShadowPrice_{a,n}$ and $OPFSignChange_{a,n}$ are defined as set forth in Formula N-17.

After calculating U/D $NetAuctionImpact_{a,n}$ pursuant to Formula N-24, the ISO shall determine whether U/D $NetAuctionImpact_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or 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 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 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 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 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 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 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 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

$$\text{U/D Allocation}_{a,t,n} = \left(\frac{\sum\limits_{\substack{r \in R_{a,n} \\ \text{and } q=t}} RatingChange_{a,n,r} * Responsibility_{n,q,r}}{\sum\limits_{\text{for all } r \in R_{a,n}} RatingChange_{a,n,r}} \right) * \text{U/D } ACR_{a,n}$$

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 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 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 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

$$\text{U/D Allocation}_{a,t,n} = \sum_{\substack{r \in R_{a,n} \\ \text{and } q=t}} \text{RatingChange}_{a,n,r} * \text{ShadowPrice}_{a,n} * \text{Responsibility}_{n,q,r}$$

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) 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 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 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 6-month Sub-Auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction.

The ISO shall not direct that a transmission facility be modeled as in-service or out-of-service for purposes of 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 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 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 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

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 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 $\text{ARSC}_{a,t,n}$, U/D $\text{ARSC}_{a,t,n}$, O/R-t-S $\text{ARSP}_{a,t,n}$, or U/D $\text{ARSP}_{a,t,n}$ 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

$$\text{NetAuctionAllocations}_{t,n} = \sum_{\text{for all a}} \text{O/R-t-S ARSC}_{a,t,n} + \text{U/D ARSC}_{a,t,n} + \text{O/R-t-S ARSP}_{a,t,n} + \text{U/D ARSP}_{a,t,n}$$

Where,

$\text{NetAuctionAllocations}_{t,n}$ = 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 Reconfiguration Auction *n*

O/R-t-S $\text{ARSC}_{a,t,n}$ = 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 Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.2

U/D $\text{ARSC}_{a,t,n}$ = 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 Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.3

O/R-t-S $\text{ARSP}_{a,t,n}$ = 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 Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.2

U/D $\text{ARSP}_{a,t,n}$ = 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 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 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 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 period 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 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 Reconfiguration Auction; *provided, however,* where the Net Auction Revenue is negative for 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 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 Reconfiguration Auction *n* is calculated pursuant to Formula N-28.

<u>Formula N-28</u>

$$FFB_{t,n} = \frac{\sum_{1 \in L_{t,n}} \left| \left(FLOW_{1,n} - FLOW_{1,IC}\right) * \left(\mathrm{Pr}ice_{y,1} - \mathrm{Pr}ice_{x,1}\right) * Share_{n,t,1} \right|}{\sum_{1 \in L_n} \left| \left(FLOW_{1,n} - FLOW_{1,IC}\right) * \left(\mathrm{Pr}ice_{y,1} - \mathrm{Pr}ice_{x,1}\right) \right|}$$

Where,

$FFB_{t,n}$ = The Facility Flow-Based Methodology coefficient for Transmission Owner for Centralized TCC Auction round *n* or Reconfiguration Auction *n*, as the case may be

L_n = The set of all transmission facilities modeled in the Transmission System model for round *n* or for 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 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 and Grandfathered Rights represented in the solution to round *n* or to 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 Reconfiguration Auction *n*, as the case may be, (ii) ETCNL not sold in prior Centralized TCC Auctions or through a Direct Sale, and (iii) Original Residual TCCs not sold in prior Centralized TCC Auctions 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 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 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 Reconfiguration Auction *n*

p = A one-month period for Reconfiguration Auction *n*, or the effective period of TCCs sold in round *n* for round *n*.

Calculation of Negative Net Auction Revenue Coefficient. The negative Net Auction Revenue coefficient for Transmission Owner *t* for Reconfiguration Auction *n* is calculated pursuant to Formula N-29.

Formula N-29

$$NNAR_{t,n} = \frac{\text{Original Residual}_{t,n} + ETCNL_{t,n} + NARs_{t,n} + GFR\&GFTCC_{t,n}}{\sum_{q \in T} \text{Original Residual}_{q,n} + ETCNL_{q,n} + NARs_{q,n} + GFR\&GFTCC_{q,n}}$$

Where,

$NNAR_{t,n}$ = The negative Net Auction Revenue coefficient for Transmission Owner *t* for Reconfiguration Auction *n*

Original $\text{Residual}_{q,n}$ = The one-month portion of the revenue imputed to the Direct Sale or the sale in any Centralized TCC Auction Sub-Auction of Original Residual TCCs that are valid during the month corresponding to 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 month corresponding to Reconfiguration Auction *n*. For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds. 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

$\text{ETCNL}_{q,n}$ = The sum of the one-month portion of the revenues the Transmission Owner has received as payment for the Direct Sale of ETCNL or for its ETCNL released in the Centralized TCC Auction Sub-Auction held for TCCs valid for the month corresponding to Reconfiguration Auction *n*. Each one-month portion of the revenue for ETCNL released in such 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 to the ETCNL sold in the Centralized TCC Auction Sub-Auction.[15] 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 to that ETCNL in the rounds of the 6-month Sub-Auction of the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n.* For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds.

$\text{NARs}_{q,n}$ = The one-month portion of the Net Auction Revenues the Transmission Owner has received in Centralized TCC Auction Sub-Auction and Reconfiguration Auctions held for TCCs valid for the month corresponding to 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 (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 $\text{NetAuctionAllocations}_{t,n}$ 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 month corresponding to Reconfiguration Auction *n*, divided in each case by the duration

[4] **A TCC corresponds to ETCNL if it has the same POI and POW as the ETCNL.**

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) $NetAuctionAllocations_{t,n}$ as calculated pursuant to Formula N-27 and as adjusted for any charges or payments that are zeroed out for Transmission Owner *q* for Reconfiguration Auction *n*. For Centralized TCC Auctions conducted before May 1, 2010, the calculation of (ii) shall incorporate only Stage 1 six month rounds.

GFR& $GFTCC_{q,n}$	=	The one-month portion of the imputed value of Grandfathered TCCs and Grandfathered Rights, valued at one-sixth of the market clearing price in the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, provided that the Transmission Owner is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in the month corresponding to Reconfiguration Auction *n.* For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate Stage 1 six month rounds.
t	=	Transmission Owner *t*
T	=	The set of all Transmission Owners *q*.

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.

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.

<u>Transmission Provider:</u>

New York Independent System Operator
3890 Carman Road
Guilderland, New York 12303

<u>Transmission Customer:</u>

____

____

____

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 – Data Requirements for Bilateral Transactions

Data Requirements for Bilateral Transaction Schedule Requests (Generators Associated with Bilateral Transaction Schedule Requests Must Also Comply with All Applicable Requirements Set Forth in Attachment D to the ISO Services Tariff)				
Data Item	**Cat.**	**Bid Parameters**	**Variability**	**Comments**
Company Names	G/P	--	Static	Both the buyer (LSE receiving the Transaction or Trading Hub Energy Owner) and seller (actual Generator supplying the Transaction or Trading Hub Energy Owner) must be identified.
Point of Injection (Source) Location	C/B	For Internal Generators: Gen I.D. **or** For External Generators: Proxy Gen I.D.	May Vary Daily	Specific location of Internal Generator or Trading Hub within the NYCA; or the identity of the Control Area where an External Generator is located.
Point of Withdrawal (Sink Location)	C/B	For Internal Loads: Load I.D. **or** For External Loads: Proxy Load I.D.	May Vary Daily	Specific location of Internal Load or Trading Hub within the NYCA; or the identity of the Control Area where an External Load is located.
Submitted By	C/B	Name	May vary	
Firm vs. Non-Firm Transmission Service	C/B	Designate whether Firm or non-Firm Transmission Service is desired: also designate NERC Contract Priority.	May vary daily	Firm transmission service may be subject to Congestion charges; non-Firm Transmission Service will avoid Congestion (to the extent feasible.)
Desired Schedule	C/B	MW	May vary for Day-Ahead by hour; if not scheduled may request RTC Schedule	
Decremental Bid	C/B	Generally the same as Energy Bids from Internal and External Generators, bid may be negative.	May vary for Day-Ahead by hour; if not scheduled may submit different RTC Decremental Bid	Decremental Bids may consist of a single price block.
Price Capped Energy Block Bid for Load	C/B	Generally the same as Energy Bids from Internal and External Generators, bid may be negative.	May vary for Day-Ahead by hour.	May consist of a single price block.
Minimum Run Time	C/B	Hours: Minutes	May be changed for any Day-Ahead Commitment. Required	For Day-Ahead multi-hour block transactions only. Duration of time that Transaction must run once started before it can subsequently be decommitted. Minimum Run Time cannot be honored past the end of the Dispatch Day. MW and Bid must be constant over the Bid time period.
<u>Notes:</u> Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.				

23 Attachment Q – Procedures for Reserving and Correcting Erroneous Energy and Ancillary Services Prices

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. These provisions shall control the reservation and correction of Energy and Ancillary Services prices that are posted on OASIS and used in ISO settlements.

23.1 Market Clearing Price Errors Requiring Correction

To be determined in accordance with the ISO tariffs, an Energy and Ancillary Service clearing price must be: (i) calculated correctly according to the relevant provision(s) of the ISO tariffs and (ii) based on the appropriate price-setting resource (*i.e.*, the marginal resource, except as otherwise provided by the ISO tariffs).

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 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 Commitment or Real-Time Dispatch 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);

(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 Methodology for Costs Arising Under the Incentivized Day-Ahead Economic Load Curtailment Program that are Recovered Pursuant to Schedule 1

Under the Incentivized Day-Ahead Economic Load Curtailment Program ("Program"), costs incurred by the ISO in covering Demand Reduction Providers' Curtailment Initiation Costs and making Demand Reduction Incentive Payments, are to be recovered under Schedule 1. These "Schedule 1 Program Costs" 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 known 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).

More specifically, Schedule 1 Program Costs shall be allocated to Transmission Customers, on a monthly basis, 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 NYISO 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.

d) Costs shall be allocated to each Transmission Customer that is deemed to have benefited from the Demand Reduction on a Load Ratio Share basis, using Real-Time metered daily Load data.

The ISO and Market Participants will make an annual determination of which NYCA interfaces were most constrained, and the frequency with which they were constrained, normalized to 100%. Composite Load Zones will be defined based on the location of the most frequently constrained interfaces. Additional information concerning this annual determination shall be set forth in the ISO Procedures.

For reference purposes, the identity of the NYCA interfaces that are currently most frequently constrained, and the equations that will be used to allocate costs to Transmission Customers during the 2001 Summer Capability Period are set forth below. 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, 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.

Based on these factors, Schedule 1 Program Costs shall be allocated to Transmission Customers as follows:

For Transmission Customer m in Load Zones A, B, C, D or E:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ 'no constraints
$a_2 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E) +$ 'above Central-East const
$a_3 * (cost_A+\ldots+cost_I+cost_k) * load_m / (load_A+\ldots+load_I+load_k) +$ 'above S-D constraint
$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)$ 'above CE-LI constraint

For Transmission Customer m in Load Zones F, G, H or I:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ 'no constraints
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +$ 'below Central-East const

$a_3 * (cost_A+\ldots+cost_I+cost_k) * load_m / (load_A+\ldots+load_I+load_k) +$ ‘above S-D constraint
$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)$ ‘above CE-LI constraint

For Transmission Customer m in Load Zone J:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ ‘no constraints
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +$ ‘below Central-East const
$a_3 * cost_J * load_m / load_J +$ ‘below S-D constraint
$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)$ ‘above CE-LI constraint

For Transmission Customer m in Load Zone K:

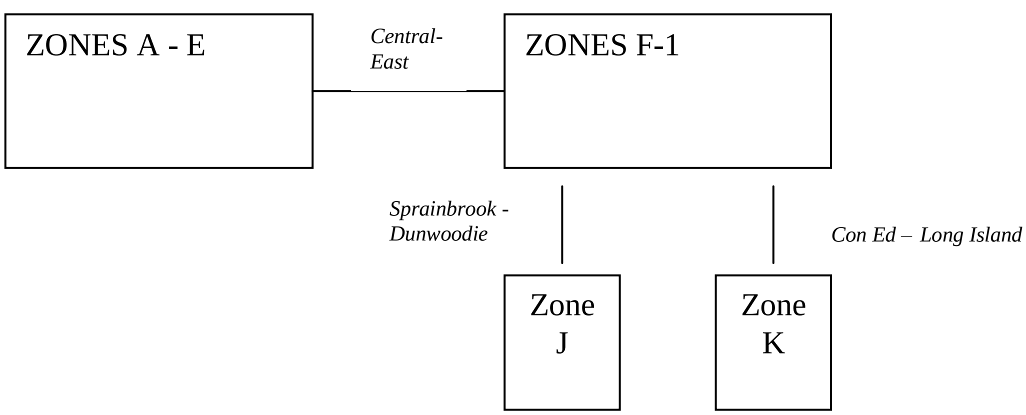
$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ ‘no constraints
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +$ ‘below Central-East const
$a_3 * (cost_A+\ldots+cost_I+cost_k) * load_m / (load_A+\ldots+load_I+load_k) +$ ‘above S-D constraint
$a_4 * cost_K * load_m / load_K$ ‘below CE-LI constraint

where the variables are:

a_1 = fraction of time when none of the three most limiting interfaces are constrained
a_2 = fraction of time when the Central-East interface is constrained
a_3 = fraction of time when the Sprainbrook-Dunwoodie interface is constrained
a_4 = fraction of time when the Con Ed-Long Island interface is constrained
$cost_{A\ldots K}$ = Schedule 1 Program Costs in Load Zones A…K, calculated on a daily basis
$load_m$ = real-time Load for Transmission Customer m, calculated on a daily basis
$load_{A\ldots K}$ = real-time Loads for all Transmission Customers s in Load Zone A…K, calculated on a daily basis

The specific values of a_1, a_2 a_3 and a_4, shall be updated each year and shall be set forth in the ISO Procedures.

Relationship Between Frequently Constrained Interfaces and Composite Load Zones



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 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, and the related interconnection study procedures set out in Attachment X to the NYISO OATT, cover projects larger than 20 MW. Small Generating Facilities no larger than 20 MWs are interconnected to the New York State Transmission System or to the Distribution

System according to the Small Generator Interconnection Procedures ("SGIP") set out in Attachment Z to the NYISO OATT. As described in Section 32.3.5.3 of the SGIP, if the Interconnection Studies in Attachment Z determine that a Small Generating Facility requires a System Upgrade Facility to interconnect, then that Small Generating Facility is placed in the Class Year then open, and cost responsibility is allocated to the Small Generating Facility in accordance with the procedures and methodologies in this Attachment S. As described in Section 32.1.1.7 of the SGIP, Small Generating Facilities larger than 2 MWs wishing to become qualified Installed Capacity Suppliers must elect Capacity Resource Interconnection Service and be evaluated for deliverability in the then open Class Year, pursuant to the Rules in this Attachment S.

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 Transmission System. Transmission Owners are, in accordance with the NYISO 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 NYISO Open Access Transmission Tariff or Attachment X or Attachment Z to the NYISO OATT, or Section 2 of the NYISO Services Tariff.

Acceptance Notice: The notice by which a Developer communicates to the NYISO 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 or System Upgrade Facilities are installed pursuant to Attachment X and Attachment S and Attachment Z of the Tariff.

Annual Transmission Baseline Assessment ("ATBA"): An assessment conducted by the NYISO 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 NYISO 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, 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.

Article X Certificate: The certificate of environmental compatibility and public need required under Article X of the New York State Public Service Law for the siting and construction of a new electric generating facility with 80 megawatts or more 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 or 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 three subsets of the Installed Capacity statewide markets comprised of Rest of State (Zones A through I), Long Island (Zone K), and New York City (Zone J).

Capacity Resource Interconnection Service ("CRIS"): The service provided by NYISO to interconnect the Developer's Large Generating Facility, Merchant Transmission Facility or Small Generating Facility larger than 2 MW to the New York State Transmission System, or to the Distribution System under Attachment Z, in accordance with the NYISO Deliverability Interconnection Standard, to enable the New York State Transmission System to deliver electric capacity from the Large Generating Facility, Small Generating Facility or Merchant Transmission Facility, pursuant to the terms of the NYISO OATT.

Class Year: The group of generation and merchant transmission projects included in any particular Annual Transmission Reliability Assessment and Class Year Deliverability Study, in accordance with the criteria specified herein for including such projects.

Class Year Deliverability Study: An assessment, conducted by the NYISO staff in cooperation with Market Participants, to determine the System Deliverability Upgrades required for each generation and merchant transmission project included in the Class Year to interconnect to the New York State Transmission System in compliance with the NYISO Deliverability Interconnection Standard.

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 at the Point of Interconnection, and (iii) is a Party to the Standard Large 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.

Energy Resource Interconnection Service "(ERIS"): The service provided by NYISO to interconnect the Developer's Large Generating Facility, Merchant Transmission Facility or Small Generating Facility required to participate in a Class Year under Section 32.3.5.3 of Attachment Z to the New York State Transmission System, or to the Distribution System under

Attachment Z, 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 under Section 32.3.5.3 of Attachment Z, pursuant to the terms of the NYISO OATT.

Existing System Representation: The representation of the New York State Power System developed as specified in Section 25.5.5 of these rules.

External CRIS Rights: A determination of deliverability within a New York Capacity Region, awarded by the NYISO 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 NYISO OATT.

Final Decision Round: The round of NYISO-communicated cost estimates and Developer responses for a Class Year, 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, UPNY-SENY 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 NYISO in response to the first Project Cost Allocation issued by the NYISO 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 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 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.

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 NYISO 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 by any generation project larger than 2 MW proposing to interconnect to the New York State Transmission System, or to the Distribution System under Attachment Z, and to become a qualified Installed Capacity Supplier and must be met by any merchant transmission project proposing to interconnect to the New York State Transmission System and receive Unforced Capacity Deliverability Rights. To meet the NYISO Deliverability Interconnection Standard, the Developer of the proposed project must, in accordance with these rules, fund or commit to fund the System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

NYISO Load and Capacity Data Report: The annual NYISO 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 that must be met by any generation project or merchant transmission project, under these rules, proposing to connect to the New York State Transmission System, or to the Distribution System under Attachment Z. The Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System. 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.

Other Interfaces: Interfaces into New York capacity regions, Zone J and Zone K, and external ties into the New York Control Area.

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 transmission 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 NYISO to a Developer following receipt by the NYISO 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 NYISO in response to the Revised Project Cost Allocation issued by the NYISO 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; 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 pursuant to Section 32.3.5.3 of Attachment Z, that is proposed by a generation Developer or merchant transmission Developer, regardless of whether the Developer elects ERIS or CRIS, must meet the New York ISO Minimum Interconnection Standard for reliability described in the Large Facility Interconnection Procedures, that are included in Attachment X to the NYISO OATT or in the Small Generator Interconnection Procedures included in Attachment Z to the NYISO OATT, as applicable. 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 Power 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 Network Upgrades and other new facilities associated with transmission service and the delivery of power across the Transmission System, the reduction of Transmission System 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 generation Developer or merchant transmission Developer must meet the NYISO Deliverability Interconnection Standard before it can become a qualified Installed Capacity Supplier or receive Unforced Capacity Deliverability Rights.

25.3.1.1 The NYISO Deliverability Interconnection Standard is designed to ensure that the proposed project is deliverable throughout the New York Capacity Region where the project will interconnect. 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 interconnecting 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 NYISO 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 NYISO 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 those required for the proposed project to reliably interconnect to the transmission system in a manner that meets the NYISO Minimum Interconnection Standard for ERIS, and 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 three types of facilities: Attachment Facilities, 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 NYISO Open Access Transmission Tariff, 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 NYISO shall include in the Existing System Representation for purposes of the ATBA and ATRA for a given Class Year:

25.5.5.1. (i) All generation and transmission facilities identified in the NYISO's Load and Capacity Data Report as existing as of January 1 of that year, 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 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 Load and Capacity Data Report or reported by Market Participants to the NYISO as scheduled to occur during the five year cost allocation study planning period.

25.5.5.2. 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 NYISO shall independently determine such later date when the System Upgrade Facilities are expected to be in service and represent them according to the NYISO's determination.

25.5.5.3. 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 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.

25.6 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 NYISO staff in cooperation with Market Participants. No Market Participant will have decisional control over any determinative aspect of the Annual Transmission Baseline Assessment. The NYISO and its staff will have decisional control over the entire Annual Transmission Baseline Assessment. If, at any time, the NYISO 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 NYISO will enter into appropriate contracts with such entities for such input. As it conducts each Annual Transmission Baseline Assessment, the NYISO 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 NYISO 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 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, NYISO rules, practices and procedures, and the Connecting Transmission Owner criteria included in FERC Form No. 715 (collectively "Applicable Reliability Requirements"). 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 NYISO staff will first develop the Existing System Representation.

25.6.1.1.1.1.2 The NYISO staff will then utilize the Existing System Representation to develop existing system improvement plans with each Transmission Owner. These improvement plans will use NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO will, as it develops its own generic solutions, also utilize the following procedures.

25.6.1.2.1 The NYISO 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 NYISO 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 NYISO 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 NYISO 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

NYISO with all data necessary for the NYISO to determine the feasibility of such proposed generic solutions.

25.6.1.2.4 The NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO shall eliminate that solution from further review.

25.6.1.2.6.2 If the NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO Annual Transmission Reliability Assessment. The Annual Transmission Reliability Assessment will be conducted by NYISO staff to ensure New York State Transmission System compliance with Applicable Reliability Requirements. The NYISO 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 NYISO and its staff will have decisional control over the entire Annual Transmission Reliability Assessment. If, at any time, the NYISO 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 NYISO will enter into appropriate contracts with such entities for such input. As it conducts each Annual Transmission Reliability Assessment, the NYISO 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 NYISO Board of Directors in accordance with the provisions of the Commission-approved ISO Agreement. The Annual Transmission Reliability Assessment will begin on March 1 each year, with a planned completion date six months after that.

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 NYISO 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 Reliability Impact Study updated, and its project included in the ATRA for a given year (a "Class Year"), if on or before March 1 (i) the Operating Committee has approved the Interconnection System Reliability Impact Study for the project, and (ii) the regulatory milestone has been satisfied, provided that the time period described in either Section 25.6.2.3.2 or 25.6.2.3.3, below, as applicable, are met. To satisfy the regulatory milestone, an applicable regulatory body (*e.g.*, local, state, or federal) must determine on or before March 1 that the permitting application submitted to site and construct the Large Facility is complete, as described below:

25.6.2.3.1.1 The Developer must obtain or achieve at least one of the following regulatory determinations or actions for the Large Facility:

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.

25.6.2.3.1.2 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 NYISO confirms that the Large Facility has satisfied the regulatory milestone, the Developer must inform the NYISO each year, within five business days of March 1, whether or not the Large Facility has satisfied the regulatory milestone described above. If a project fails to inform the NYISO by this date, the Interconnection Request of the project will be deemed to be withdrawn in accordance with Section 3.6 of the Large Facility Interconnection Procedures contained in Attachment X.

25.6.2.3.2 Except as provided in Section 25.6.2.3.3, a project must satisfy the regulatory milestone described in Section 25.6.2.3.1, above, within two years of the Operating Committee's approval of the Interconnection System Reliability Impact Study for the project. 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.

25.6.2.3.3 Projects in the interconnection queue with an Interconnection System Reliability Impact Study approved by the Operating Committee as of January 17, 2010 that have not satisfied the regulatory milestone described in Section

25.6.2.3.1, above, as of January 17, 2010, will have two years from that date to satisfy the regulatory milestone. If such 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 satisfied the eligibility criteria specified in Section 25.6.2.3.1 or Attachment Z for inclusion in the Class Year ATRA, then the project may enter up to two, but no more than two, of the next three consecutive Class Year ATRAs. The first Class Year for which a project qualifies will count as the first of the three consecutive Class Year ATRAs.

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 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 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 Interconnection Facilities Study procedures in Section 30.8 of the Large Facility Interconnection Procedures in Attachment X to the NYISO 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 <u>Short Circuit Contribution</u>: 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 <u>Thermal Loadings</u>: 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 <u>Voltage Effects</u>: 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 <u>Stability Effects</u>: 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 NYISO 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 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 project on the deliverability of the New York State Transmission System, that is, the pro rata contribution of each project in the Class Year 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 proposed generation or merchant transmission 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 Developer's project deliverable in accordance with these rules. The System Deliverability Upgrades on the Byway or Byways will be identified by the

NYISO, with input from the Connecting Transmission Owner and from the Affected Transmission Owner(s), in the Class Year Deliverability Study. A Developer paying to upgrade a Byway will be eligible to receive Headroom payments in accordance with these rules. A Developer paying to upgrade a Byway will receive any Incremental TCCs created. A subsequent Developer paying for use of Headroom on System Deliverability Upgrades will receive the corresponding Incremental TCCs.

25.7.2.2 **Highways.** The Developer of a proposed generation or merchant transmission project will pay an allocated share of the cost of the System Deliverability Upgrades to any Highway needed to make the Developer's 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 NYISO, with input from the Connecting Transmission Owner and from the Affected Transmission Owner(s), in the Class Year Deliverability Study. A Developer paying for Highway System Deliverability Upgrades 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. A Developer paying for Highway System Deliverability Upgrades will receive a share of any incremental TCCs created, in accordance with these rules. A subsequent Developer paying for use of Headroom on System Deliverability Upgrades will receive the corresponding Incremental TCCs, if any, based on its share of the System Deliverability Upgrade costs.

25.7.2.3 Other Interfaces. If the proposed generation or merchant transmission 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 New York Capacity Regions.

The deliverability test will be applied within each of the three (3) New York Capacity Regions: Rest of State, Long Island and New York City. To be declared deliverable a generator or merchant transmission project must be deliverable throughout the NYISO 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 will be required to demonstrate deliverability throughout the Rest of State Capacity Region, but will not be required to demonstrate deliverability to or within either the Long Island Capacity Region or the New York City Capacity Region.

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 elect CRIS. The MW amount of CRIS requested by a Developer, stated in MWs of Installed Capacity, cannot exceed the name plate capacity of its generation or merchant transmission project. The NYISO 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 members of the Class Year that have requested some level of CRIS. The Class Year Deliverability Study will identify and allocate the cost of the System Deliverability Upgrades needed to make deliverable each Class Year member that has requested CRIS. 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 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 partial CRIS for its project. Generators 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. 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 for the Summer Capability Period.

25.7.7 Class Year Deliverability Study Procedures.

The NYISO 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 NYISO and its staff will have decisional control over the entire Class Year Deliverability Study. If, at any time, the NYISO 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 NYISO will enter into appropriate contracts with such entities for such input. As it conducts each Class Year Deliverability Study, the NYISO 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 NYISO Board of Directors in accordance with the provisions of the Commission-approved ISO Agreement.

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 new Large Facilities, new Small Generators larger than 2 MWs, and any existing facility increasing its capacity by more than the 2 MWs allowed by Section 30.3.2.6 of the Large Facility Interconnection Procedures contained in OATT Attachment X, in the Capacity Region(s) 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 proposed projects seeking CRIS 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. 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 NYISO 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" 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.

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~~ing~~ 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 Attachment M-1 of the Services Tariff, (iii) 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, (iv) in Class Year 2008 and 2009, 1090 MW of imports made over the Quebec (via Chateauguay) interface, and (v) 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 study start date for the Class Year ATRA, 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 protocols set forth in Attachment M-1 of the Services Tariff.

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 in the Rest of State Capacity Region, 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 Developers' 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 257.10 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 in at least one of the Capability Period, Monthly or Spot Market Auctions, or through a certified bilateral contract. 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 then open Class Year Deliverability Study. 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 member of the Class Year when the NYISO receives the entity's executed Class Year 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 appropriate Capacity Region, depending on the applicable External Interface. 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 Study Start Date for the Class Year ATRA 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 members 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 member.

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 projects in a Class Year deliverable is ninety percent (90%) or more of the total size (measured in MW) of the System Deliverability Upgrades, the Developer(s) of the 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 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 Developer's generator or merchant transmission facility of the total megawatts provided by the System Deliverability Upgrades. Other generators or merchant transmission projects in the current Class Year may share in the cost of these System Deliverability Upgrades, on the same basis. Projects in the current Class Year 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 Reliability Planning Process ("CRPP") identifies a Reliability Need requiring a Highway facility to be constructed earlier than would be the case pursuant to Section 25.7.12.3.1, the facility will be constructed as determined in the CRPP. 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 will be used as an offset to the total reliability solution upgrade cost, with the remainder of the upgrade cost to be allocated per the requirements of the CRPP, as set forth in Sections 31.4.1, 31.4.2 and 31.4.4 of Attachment Y to the NYISO OATT.

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 Large 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 built, any resulting Incremental TCCs will be distributed to the Developers in proportion to their funding of the Highway System Deliverability Upgrade.

25.7.12.5.1 Incremental TCCs attributable to Load Serving Entity funding will be sold by the NYISO, and the NYISO will credit the Load Serving Entities in proportion to their funding of the Highway System Deliverability Upgrade, in accordance with Section 6.12.3.4 of Schedule 12 of the NYISO OATT.

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 As new Developers make Headroom payments to prior Developers, the related Incremental TCCs previously distributed to the prior Developers will be transferred to the new Developers in proportion to the Headroom use and payments made by the new Developers.

25.7.12.6.2 As new Developers compensate Load Serving Entities for use of their Headroom, the NYISO will continue to sell the Incremental TCCs attributable to Highway System Deliverability Upgrades and Headroom funded by Load Serving Entities, and the NYISO will apportion the revenues among new Developers and Load Serving Entities in accordance with Section 6.12.4.2 of Schedule 12 of the NYISO OATT. The apportionment of these revenues to new Developers will continue beyond the eligibility of Load Serving Entities for such payments.

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 Developer's project in the Class Year Deliverability Study, provided that those upgrades are reasonably related to the Developer's 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

Each Developer in the then current Class Year will specify an Interconnection Service evaluation election when it executes an Interconnection Facilities Study Agreement. If the Developer's 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. If the Developer's facility is already interconnected taking ERIS, and not covered by a new Interconnection Request, the Developer's facility will be evaluated for a MW level of CRIS specified by the Developer, not to exceed the nameplate capacity of its facility.

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 Developer's project ("SDU Project Cost Allocation"), and (ii) the number of megawatts of Installed Capacity, if any, that are deliverable from the Developer's project with no new System Deliverability Upgrades ("Deliverable MWs"). 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 Developer's 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 Developer of the Class Year. Each Class Year Developer will be given the Project Cost Allocation(s) and, Deliverable MWs, 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

Within 30 calendar days following approval of the Annual Transmission Reliability Assessment and Class Year Deliverability Study by the Operating Committee (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 MWs 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 MWs, if any, reported to it by the NYISO. Each Developer may respond with either an Acceptance Notice or a Non-Acceptance Notice to each Project Cost Allocation and Deliverable MWs reported to it by the NYISO. A Developer in its first Class Year 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 MWs. 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.

As soon as practicable following receipt of either an Acceptance Notice or Non-Acceptance Notice from each Class Year Developer, but not later than 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.

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 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 issues an 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 MWs, 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 MWs, or the Developer may provide a Non-Acceptance Notice for both its SDU Project Cost Allocation and its Deliverable MWs and continue its interconnection taking ERIS. If the Developer does provide a Non-Acceptance Notice for both its SDU Project Cost Allocation and Deliverable MWs 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 Developer's 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 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

Immediately following receipt of Non-Acceptance Notices for any SDU Project Cost Allocations or SUF Project Cost Allocations or Deliverable MWs, or upon the occurrence of a Security Posting Default, the NYISO shall update the Class Year Interconnection Facilities Study results for those remaining Developer 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 MWs 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 MWs 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 MWs 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 MWs.

25.8.4 Completion of Decision Process

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.

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 Developer's 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; 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 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 ~~re~~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 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.

25.8.8 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, that Developer may, at any later date, ask the NYISO 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 then 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 and 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 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 and 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 Term of 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 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 deactivated. 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 deactivated on the last day of the month during which (i) it ceases to offer capacity into NYISO 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. 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 MWs.

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. In the case of a deactivation, CRIS status at the capacity level eligible for CRIS found deliverable terminates three years after deactivation unless the deactivated Large Facility or Small Generating Facility takes one of the following actions before the end of the three-year period: (1) returns to service and participation in NYISO capacity auctions or bilateral transactions, or (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 NYISO 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 NYISO 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 NYISO 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.

25.9.4 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 MWs of Installed Capacity. In the case of transfers between the same or different resource types, those MWs 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 MWs 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 NYISO the MW level of capacity rights proposed to be transferred. Capacity rights will be stated in MWs of Installed Capacity. In the case of transfers between different resource types, those MWs 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 MWs 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 NYISO 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 NYISO 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 NYISO 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

NYISO 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 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO Data Requirements

Developers and Transmission Owners shall provide the NYISO 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 Generators and/or Interruptible Load to provide for the safe and reliable operation of the NYS Power System. In cases in which the sum of all Bilateral Schedules, excluding schedules of Bilateral Transactions with Trading Hubs as their POWs, and all Day-Ahead purchases and sales of energy within the NYCA is less than the ISO's Day-Ahead forecast of Load, the ISO will commit Resources in addition to the reserves it normally maintains to enable it to respond to contingencies. Payments for Bid Production Guarantees (BPCG) made to such additional Resources are to be recovered under Schedule 1. These "BPCG to Additional Resources" shall be allocated to Transmission Customers, to the extent they are not acting as Suppliers, pursuant to the methodology set forth below, on the basis of their Real-Time energy purchases in their Load Zones or Composite Load Zones (see below). By design, when the NYISO forecast load exceeds actual load, the methodology below will only be used to allocate part of the BPCG to Additional Resources. Any residual shall be allocated to Transmission Customers according to the provisions of Schedule 1, Section 6.1.2.2.4.2.

More specifically, BPCG to Additional Resources shall be allocated to each Transmission Customer, to the extent that Transmission Customer is not acting as a Supplier as follows:

$$BPCG_c = BPCG_{NYCA} \times \sum_{L \in NYCA} \left(K_L^{fe} \times K_L^{loc} \times K_{c,L}^{customer} \right)$$

Where:

$BPCG_c$	Obligation of Transmission Customer "c" for the Bid Production Cost Guarantees for such additional resources.
$BPCG_{NYCA}$	Total Bid Production Cost Guarantees in the NYCA for such additional resources.
c	Transmission Customer.

L	Load Zone or Composite Load Zone
K^{fe}_{L}	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^{loc}_{L}	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.
$K^{customer}_{c,L}$	A scale factor calculated for 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 distributed according to the methodology set forth in this attachment that shall be allocated to customer "c."

RTP^{act}_{L}	Net purchases of energy from the Real-Time market in Load Zone or Composite Load Zone "L" by Customers to the extent they are not acting as Suppliers, in each hour, summed over the hours of the day in which these purchases are positive.
$RTP^{act}_{c,L}$	Purchases of energy from the Real-Time market in Load Zone or Composite Load Zone "L" by Customer "c," to the extent that customer is not acting as a Supplier, to meet obligations arising from the Day-Ahead sale of energy, in each hour; plus net energy purchases in the Real-Time markets by Customer "c," to the extent that customer is not acting as a Supplier, excluding purchases to meet obligations arising from the Day-Ahead market, in each hour in which these purchases are positive; summed over each hour of the day.
RTP^{fcst}_{L}	The sum of (1) sales for each hour of the day in the Day-Ahead market in Load Zone or Composite Load Zone "L" by Customers, to the extent they are not acting as Suppliers, and (2) the ISO's Load forecast load for that hour of the day less purchases of energy from the Day-Ahead market for that hour, summed over the hours of the day in which the sum of (1) and (2) is positive.

K^{fe}_{L} shall be calculated as shown below except that the value zero shall be used if the expression below yields a negative number and 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^{loc}_{L} shall be calculated as shown below.

$$K_L^{loc} = \frac{RTP_L^{act}}{\sum_{L \in NYCA} RTP_L^{act}}$$

$K^{customer}_{c,L}$ shall be calculated as shown below.

$$K_{c,L}^{customer} = \frac{RTP_{c,L}}{\sum_{c \in L} RTP_{c,L}}$$

The residual between Bid Production Cost Guarantee payments to such additional Resources not allocated according to the methodology described above shall be allocated to Transmission Customers using the methods described in Schedule 1, Section 6.1.2.2.4.2 The residual is determined according to:

$$BPCG_{NYCA} - \sum_{c \in NYCA} BPCG_c$$

Load Zones and Composite Load Zones used in the allocation of Bid Production Cost Guarantees for such 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.

27 Attachment U – Declaration and Recovery of Bad Debt Losses

The provisions of this Attachment U of this ISO OATT shall apply to all bad debt losses recoverable under Rate Schedule 1 of the Services Tariff and Schedule 1 of this ISO OATT.

27.1 Declaration Of A Bad Debt Loss

Section 2.7.3.2. of this ISO OATT requires Transmission Customers to pay monthly settlement invoices by the first banking day common to all parties after the 15^{th} day of the month in which the invoice is rendered by the ISO. 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 such unpaid obligation is a bad debt loss that requires recovery by the ISO under Section 6.1.3 of Rate Schedule 1 of this ISO OATT, and the ISO shall pursue available remedies for customer defaults under the ISO Tariffs. All funds held by the ISO relative to the defaulting Transmission Customer (e.g., working capital, collateral, etc.) shall be set aside pending determination of ISO's counsel and/or the appropriate bankruptcy courts as to the appropriate disposition of such funds.

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 month of services for which settlement invoice obligations remain unpaid and are still owing to the ISO, and the future billing month(s) in which the ISO will recover the bad debt loss through a Rate Schedule 1 charge.

27.3 Recovery of 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, shall utilize the Working Capital Fund to maintain the liquidity of the New York wholesale energy markets and ensure that all Transmission Customers who are owed monies in their settlement invoices under Section 2.7.3. (iii) of this OATT are paid in full. The ISO shall not utilize the Working Capital Fund to satisfy WTSC non-payments.

After the ISO's Chief Financial Officer has declared a bad debt loss (other than a bad debt loss relating to WTSC), and notified Market Participants in accordance with this Attachment U, the ISO will ordinarily first seek to recover the amount of the bad debt loss by drawing upon the entire amount of collateral provided by the defaulting 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 bad debt loss by drawing upon the defaulting Customer's contributions to the Working Capital Fund that is described in Attachment V. 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. In the case of a bad debt loss relating to WTSC, the ISO shall draw upon collateral pursuant to Section 29 of Attachment W. Any remaining losses shall be allocated *pro rata* to all Customers pursuant to the following formula:

$$\textbf{Percentage of Loss to Be Paid by Customer} = \frac{\textbf{CAR + CAP}}{\text{NYAR + NYAP}}$$

Where:

CAR = Customer's gross accounts receivable, including WTSC in the month of loss.

CAP = Absolute value of Customer's gross accounts payable, including WTSC, in the month of loss.

NYAR = ISO's gross accounts receivable plus the Transmission Owners' accounts receivable from WTSC, in the month of loss.

NYAP = Absolute value of ISO's gross accounts payable plus the absolute value of the Transmission Owners' accounts payable from WTSC, in the month of loss.

For purposes of this formula, the "month of loss" shall be the service month in which a bad debt loss occurred.

Notwithstanding any recovery of unpaid WTSC through Rate Schedule 1, a Transmission Owner shall be required to pursue reasonable debt collections efforts and refund through Rate Schedule 1 any such WTSC ultimately collected.

Whenever practicable, the ISO shall recover this Rate Schedule 1 charge in the billing month after the month in which the bad debt loss is declared; provided, however, that the ISO may recover bad debt losses over several months if, in its discretion, the ISO determines such method of recovery to be a prudent course of action.

Customers that are subject to a Rate 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 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 Customers. Any bad debt losses that are later recovered through insurance proceeds or from a defaulting Customer shall be allocated to all 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 this ISO OATT, a Transmission Customer whose previous default resulted in a Rate 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 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 provide to each Customer, in each monthly consolidated billing invoice, 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 within the consolidated billing invoice 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:

$$\textbf{Customer's Percentage of Total Collection} = \frac{\textbf{CAR + CAP}}{\textbf{NYAR + NYAP}}$$

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 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.

28.5 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.

28.5.1 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.

28.5.2 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; *provided, however,* that the ISO shall set aside the nonpaying Customer's contribution to the Working Capital Fund pending determination of ISO's counsel and/or the appropriate bankruptcy courts regarding the appropriate disposition of such funds. 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. Upon the necessary determination from the ISO's counsel and/or the appropriate bankruptcy courts and 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 NYISO, 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 NYISO 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.

28.5.3 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 28.5.3.

28.6 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.

28.7 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 28.7. 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.

28.8 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 30.1 or Attachment S of the NYISO OATT, or in Article 2 of the NYISO 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 or 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 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 three subsets of the Installed Capacity statewide markets comprised of Rest of State (Zones A through I), Long Island (Zone K), and New York City (Zone J).

Capacity Resource Interconnection Service ("CRIS") shall mean the service provided by NYISO to interconnect the Developer's Large Generating Facility or Merchant Transmission Facility to the New York State Transmission System in accordance with the NYISO Deliverability Interconnection Standard, to enable the New York State Transmission System to deliver electric capacity from the Large Generating Facility or Merchant Transmission Facility, pursuant to the terms of the NYISO OATT.

Class Year Deliverability Study shall mean an assessment, conducted by the NYISO staff in cooperation with Market Participants, to determine the System Deliverability Upgrades required for each generation and merchant transmission project included in the Class Year Interconnection Facilities Study to interconnect to the New York State Transmission System in compliance with the NYISO Deliverability Interconnection Standard.

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 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.

Deliverability Interconnection Standard shall mean the standard that must be met by any Large Generating Facility proposing to interconnect to the New York State Transmission System and to become a qualified Installed Capacity Supplier, and must be met by any Merchant Transmission Facility proposing to interconnect to the New York State Transmission System and receive Unforced Capacity Delivery Rights. To meet the NYISO Deliverability Interconnection Standard, the Developer of the proposed project must, in accordance with the rules in Attachment S to the NYISO OATT, fund or commit to fund the System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

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.

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.

Energy Resource Interconnection Service ("ERIS") shall mean the service provided by NYISO to interconnect the Developer's Large Generating Facility or Merchant Transmission Facility to the New York State Transmission 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 NYISO 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 a New York Capacity Region, awarded by the NYISO 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 NYISO OATT.

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.

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, 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, UPNY-SENY 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 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 and 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. 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 4 of the Standard Large Facility Interconnection Procedures for conducting the Interconnection Facilities Study.

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, the scope of which is described in Section 30.6 of the Standard Large Facility Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Facility Interconnection Procedures for conducting the Interconnection Feasibility Study.

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 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.

Interconnection Study shall mean any of the following studies: the 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 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 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 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.

Interconnection System Reliability Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Facility Interconnection Procedures for conducting the Interconnection System Reliability Impact Study.

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.

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.

Minimum Interconnection Standard shall mean the reliability standard that must be met by any Large Generating Facility, or a Merchant Transmission Facility, proposing to connect to the New York State Transmission System. The Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System. The Standard does not impose any deliverability test or deliverability requirement on the proposed interconnection.

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.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Developer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Facility Interconnection Procedures for conducting the Optional Interconnection Study.

Other Interfaces shall mean interfaces into New York capacity regions, Zone J and Zone K, and external ties into the New York Control Area.

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.

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 Interconnection Request by NYISO.

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, NYISO 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. 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 the Standard Large Generator Interconnection Agreement.

Standard Large Facility Interconnection Procedures ("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 NYISO OATT.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean the form of interconnection agreement applicable to a Interconnection Request pertaining to a Large Generating Facility, that is included in Attachment X of the NYISO 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 a Large Generating Facility or Merchant Transmission Facility proposing to interconnect to the New York State Transmission System.

30.2.2 Comparability

The NYISO 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 NYISO 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 NYISO will perform, oversee or review the Interconnection Studies to ensure compliance with the Large Facility Interconnection Procedures. The NYISO 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 NYISO 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 NYISO and Connecting Transmission Owner are permitted to require that the Developer sign a confidentiality 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 NYISO 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 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 NYISO 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.

30.3 Interconnection Requests

30.3.1 General

A Developer proposing to interconnect a new Large Generating Facility or Merchant Transmission Facility to the New York State Transmission System, or proposing to 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 to the New York State Transmission System shall submit to the NYISO a Interconnection Request in the form of Appendix 1 to these Large Facility Interconnection Procedures and a non-refundable application fee of $10,000. The application fee shall be divided equally between the NYISO and Connecting Transmission Owner(s). With the Interconnection Request, the Developer must also submit a refundable study deposit of $30,000 for the Interconnection Feasibility Study. 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.

At Developer's option, the NYISO, Connecting Transmission Owner and Developer will identify 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. Developer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement.

30.3.2 Types of Interconnection Service

30.3.2.1 Two Types of Service

The NYISO offers Energy Resource Interconnection Service under the Large Facility Interconnection Procedures for interconnection in compliance with the NYISO Minimum Interconnection Standard. The NYISO 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. The NYISO evaluates an Interconnection Request for compliance with the Minimum Interconnection Standard throughout the Interconnection Study process. The NYISO 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 Interconnection Feasibility Study and the Interconnection System Reliability Study, the NYISO 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 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 MWs it initially requested to be evaluated for CRIS, and such a reduction shall not constitute a Material Modification. Any increase in the MWs 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 NYISO to reevaluate the Large Facility for CRIS by including the Large Facility in the then currently open Class Year Deliverability Study 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 MWs of Installed Capacity, and cannot exceed the nameplate capacity of the Developer's Large Facility. When a Developer elects CRIS, the NYISO will evaluate the deliverability of the Large Facility by applying the test methodology described in Section 25.7 of Attachment S to the NYISO OATT. The NYISO 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 MWs 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 NYISO 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 MWs 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 NYISO OATT. The CRIS value for the winter capability period, also in MWs of Installed Capacity, will be set at a value that will maintain the same proportion of CRIS to ERIS as the summer capability period.

30.3.2.5 Partial CRIS Service

A Developer may elect partial CRIS, measured in whole MWs 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 NYISO to reevaluate the Large Facility for a higher level of MWs of Installed Capacity, not to exceed the nameplate rating of the Large Facility, by including the Large Facility in the then currently open Class Year Deliverability Study to identify the System Deliverability Upgrades, if any, needed for the Large Facility to be declared deliverable at the higher level of MWs. 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 MWs of Installed Capacity during the operating life of the facility.

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 and System Upgrade Facilities required for the reliable interconnection of Large Facilities to the New York State Transmission 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 study deposit of $30,000; (iii) a completed application in the form of Appendix 1; and (iv) 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 In-Service Date of the new Large Facility or proposed increase in capacity of the existing Large Generating Facility or Merchant Transmission Facility shall be no more than the process window for the regional expansion planning period (or prior to the establishment of a regional planning process, the process window for the NYISO's expansion planning period) not to exceed seven years from the date the Interconnection Request is received by the NYISO, unless the Developer demonstrates that engineering, permitting and construction of the new Large Facility or increase in capacity of the existing Large Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by the NYISO by a period up to ten years, or longer where the Developer and NYISO agree after consultation with the Connecting Transmission Owner, such agreement not to be unreasonably withheld.

30.3.3.2 Acknowledgment and Notification of Interconnection Request

NYISO 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, NYISO 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 NYISO. If an Interconnection Request fails to meet the requirements set forth in Section 30.3.3.1, the NYISO shall notify the Developer and Connecting Transmission Owner within five (5) 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 NYISO the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. NYISO 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, NYISO 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 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. NYISO, 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. NYISO, Connecting Transmission Owner 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.

30.3.4 OASIS Posting

The NYISO 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; (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 NYISO shall post on its OASIS an advance notice of its intent to do so. The NYISO shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to the NYISO password-protected website subsequent to the meeting between the Developer, NYISO and Connecting Transmission Owner to discuss the applicable study results. The NYISO shall also post any known deviations in the Large Facility's In-Service Date.

30.3.5 Coordination with Affected Systems

The NYISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators. The NYISO 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 NYISO will also include results, if available, on other Affected Systems. The NYISO 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 NYISO 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 NYISO 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.

30.3.6 Withdrawal

The Developer may withdraw its Interconnection Request at any time by written notice of such withdrawal to the NYISO. 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 NYISO 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 fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify the NYISO of its intent to pursue Dispute Resolution.

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 NYISO and Connecting Transmission Owner all costs that the NYISO 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 NYISO and Connecting Transmission Owner before it is allowed to obtain any Interconnection Study data or results.

The NYISO shall (i) update the OASIS Queue Position posting and (ii) refund to the Developer any portion of the Developer's deposit or study payments that exceeds the costs that the NYISO has incurred, including interest calculated in accordance with section 35.19a(a)(2) of FERC's regulations. In the event of such withdrawal, the NYISO and Connecting Transmission Owner, subject to the confidentiality provisions of Section 30.13.1, shall provide, at Developer's request, all information that the NYISO 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 NYISO 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 NYISO shall assign the Developer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under Section 30.4.4.3. 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 NYISO’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 NYISO 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 which an Interconnection Study Agreement has been executed during a Queue Cluster Window shall be in accordance with Section 30.7.4, for all Interconnection Requests assigned to the same Queue Cluster Window.

The NYISO 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 NYISO'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 NYISO, in writing, modifications to any information provided in the Interconnection Request. The Developer shall retain its Queue Position if the modifications are 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 NYISO 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 NYISO, Connecting Transmission Owner and Developer, such acceptance not to be unreasonably withheld, NYISO 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 return of the executed Interconnection System Reliability Impact Study Agreement to the NYISO, 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 NYISO, the modifications permitted under this section shall include specifically: (a) additional 15 percent decrease of electrical output (MW), and (b) Large Facility technical parameters associated with modifications to Large Facility technology and transformer impedances; 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 NYISO evaluate whether such modification is a Material Modification. In response to Developer's request, the NYISO 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 NYISO shall commence and perform any necessary additional studies as soon as practicable, but in no event shall the NYISO 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 less than three (3) cumulative years in the Commercial Operation Date of the Large Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing.

30.4.4.6 Any increase by the Developer, when it executes the Interconnection Facilities Study Agreement, in the number of MWs of Installed Capacity that it previously requested to be evaluated for CRIS shall 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 NYISO must offer the Developer the option of either continuing under the NYISO'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 NYISO 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 NYISO; (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 NYISO 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 NYISO Market Services Tariff.

30.5.2 New Transmission Provider

If the NYISO 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 NYISO 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 NYISO shall coordinate with the successor transmission provider to complete any Interconnection Request (including Interconnection Studies), as appropriate, that the NYISO has begun but has not completed. If the NYISO 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 Interconnection Feasibility Study

30.6.1 Interconnection Feasibility Study Agreement

Simultaneously with the acknowledgement of a valid Interconnection Request the NYISO shall provide to Developer and Connecting Transmission Owner an Interconnection Feasibility Study Agreement in the form of Appendix 2. The Interconnection Feasibility Study Agreement shall specify that Developer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting, Developer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection. Within five (5) Business Days following the NYISO's receipt of such designation, NYISO shall tender to Developer the Interconnection Feasibility Study Agreement, which includes a good faith estimate of the cost for completing the Interconnection Feasibility Study. The Developer must provide a $30,000 study deposit, in addition to the $30,000 provided with the Interconnection Request, to the NYISO if the NYISO is responsible for performing the entire study. If the Developer is hiring a third-party consultant to perform the analytical portion of the study, then no additional study deposit is required. The Developer shall execute and deliver to the NYISO the Interconnection Feasibility Study Agreement along with a $30,000 deposit, if required, no later than thirty (30) Calendar Days after its receipt. The NYISO and Transmission Owner shall execute the Interconnection Feasibility Study Agreement within thirty (30) Calendar Days of its receipt by Developer.

On or before the return of the executed Interconnection Feasibility Study Agreement to the NYISO, the Developer shall provide the technical data called for in Appendix 2, Attachment A.

If the 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 NYISO, 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 Re-studies shall be completed pursuant to Section 30.6.4 as applicable. For the purpose of this Section 30.6.1, if the NYISO, 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 Interconnection Feasibility Study Agreement, as specified pursuant to Section 30.3.3.4, shall be the substitute.

If the NYISO, Connecting Transmission Owner and Developer agree to forego the Interconnection Feasibility Study, the NYISO will initiate an Interconnection System Reliability Impact Study under Section 30.7 of these Large Facility Interconnection Procedures and apply the $30,000 deposit provided with the Interconnection Request, towards the Interconnection System Reliability Impact Study.

30.6.2 Scope of Interconnection Feasibility Study

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the New York State Transmission System.

The Interconnection Feasibility Study shall be conducted in accordance with Applicable Reliability Standards.

The 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 Interconnection Feasibility Study Agreement is fully executed: (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. Certain changes have been made, effective January 17, 2010, to the Base Case requirements for Interconnection Feasibility Studies. These changed requirements will be applied prospectively to projects with Interconnection Feasibility Study Agreements fully executed on or after that effective date; provided, however, that Developers with Interconnection Feasibility Studies in progress with Interconnection Feasibility Study Agreements fully executed prior to that effective date may elect, at their own expense, to modify the Base Case assumptions for that study consistent with the changed requirements. Such an election will be memorialized in an amended Interconnection Feasibility Study Agreement.

The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list of facilities and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

30.6.3 Interconnection Feasibility Study Procedures

The NYISO shall utilize existing studies to the extent practicable when it performs the study. The NYISO shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than forty-five (45) Calendar Days after the NYISO receives the fully executed Interconnection Feasibility Study Agreement. At the request of the Developer or at any time the NYISO determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, NYISO shall notify the Developer as to the schedule status of the Interconnection Feasibility Study. If the NYISO is unable to complete the 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 NYISO shall provide the Developer supporting documentation, workpapers and relevant power flow, short circuit and stability databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with Section 30.13.1.

30.6.3.1 Study Report Meeting

Within ten (10) Business Days of providing an Interconnection Feasibility Study report to Developer, the NYISO and Connecting Transmission Owner shall meet with Developer to discuss the results of the Interconnection Feasibility Study.

30.6.4 Re-Study

If the NYISO determines that re-study of the 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 NYISO 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 Interconnection System Reliability Impact Study Agreement

Unless otherwise agreed, pursuant to the Scoping Meeting provided in Section 30.3.3.4, simultaneously with the delivery of the Interconnection Feasibility Study to the Developer, the NYISO shall provide to the Developer and Connecting Transmission Owner an Interconnection System Reliability Impact Study Agreement in the form of Appendix 3 to these Large Facility Interconnection Procedures. The Interconnection System Reliability Impact Study Agreement shall provide that the Developer shall compensate the NYISO and Connecting Transmission Owner for the actual cost of the SRIS. Within three (3) Business Days following the Interconnection Feasibility Study results meeting, the NYISO shall provide to Developer a non-binding good faith estimate of the cost and timeframe for completing the SRIS.

30.7.2 Execution of Interconnection System Reliability Impact Study Agreement

The Developer shall execute the Interconnection System Reliability Impact Study Agreement and deliver the executed Interconnection System Reliability Impact Study Agreement to the NYISO no later than thirty (30) Calendar Days after its receipt along with demonstration of Site Control, and the required deposit.

If the NYISO is responsible for performing the entire study, the required deposit is $120,000. If the Developer is hiring a third-party consultant to perform the analytical portion of the study, the required deposit is $40,000. If the Developer does not provide all such technical data when it delivers the Interconnection System Reliability Impact Study Agreement, the NYISO shall notify the Developer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Reliability Impact Study Agreement and the Developer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection System Reliability Impact Study Agreement or deposit. The NYISO and Transmission Owner shall execute the Interconnection System Reliability Impact Study Agreement within thirty (30) Calendar Days after its receipt by the Developer.

If the Interconnection System Reliability Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Interconnection Feasibility Study, a substitute Point of Interconnection identified by either Developer or Connecting Transmission Owner and NYISO, 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, if the NYISO, 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 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 Interconnection System Reliability Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the New York State Transmission System. The Interconnection System Reliability Impact Study 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; (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. Certain changes have been made, effective January 17, 2010, to the Base Case requirements for Interconnection System Reliability Impact Studies. These changed requirements will be applied prospectively to projects with study scopes for a System Reliability Impact Study approved by the Operating Committee on or after that effective date; provided, however, that Developers with a System Reliability Impact Study in progress and a study scope approved by the Operating Committee prior to that effective date may elect, at their own expense, to modify the Base Case assumptions for that study consistent with the changed requirements. Such an election will be memorialized in a revised study scope subject to the approval of the Operating Committee and, to the extent necessary, an amended System Reliability Impact Study Agreement.

The Interconnection System Reliability Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. 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 NYISO Operating Committee shall approve the specific study scope proposed for each Interconnection System Reliability Impact Study.

30.7.4 Interconnection System Reliability Impact Study Procedures

The NYISO shall coordinate the Interconnection System Reliability Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 30.3.5 above. The NYISO shall utilize existing studies to the extent practicable when it performs the study. The NYISO shall use Reasonable Efforts to complete the SRIS within ninety (90) Calendar Days after the receipt of the fully executed Interconnection System Reliability Impact Study Agreement, study payment, and technical data. If NYISO uses Clustering, the NYISO shall use Reasonable Efforts to deliver a completed SRIS within ninety (90) Calendar Days after the close of the Queue Cluster Window. The NYISO Operating Committee shall approve each final Interconnection System Reliability Impact Study.

At the request of the Developer or at any time the NYISO determines that it will not meet the required time frame for completing the Interconnection System Reliability Impact Study, NYISO shall notify the Developer as to the schedule status of the SRIS. If the NYISO is unable to complete the Interconnection System Reliability Impact Study 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 NYISO 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

Within ten (10) Business Days of providing an Interconnection System Reliability Impact Study report to Developer, NYISO and Connecting Transmission Owner shall meet with Developer to discuss the results of the Interconnection System Reliability Impact Study.

30.7.6 Re-Study

If the NYISO determines that re-study of the Interconnection System Reliability Impact Study is required due to a higher queued project dropping out of the queue, a modification of a higher queued project subject to 30.4.4, or re-designation of the Point of Interconnection pursuant to Section 30.7.2, NYISO 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 Interconnection Facilities Study

30.8.1 Interconnection Facilities Study Agreement

Beginning thirty (30) Calendar Days prior to the study start date of the Annual Transmission Reliability Assessment called for by Attachment S of the NYISO OATT, the NYISO shall provide an Interconnection Facilities Study Agreement for the next Class Year in the form of Appendix 4 to these Large Facility Interconnection Procedures to each Developer who has not previously received an agreement for the next Class Year, upon confirmation by the NYISO that the Developer is an Eligible Developer. Prior to this 30-day period, the NYISO shall tender an Interconnection Facilities Study Agreement to any Developer, confirmed by the NYISO to be an Eligible Developer, that so requests. For purposes of this section only, the term Eligible Developer shall mean a Developer of a project that (1) satisfies the criteria for inclusion in the Annual Transmission Reliability Assessment, for the next Class Year, as those criteria are specified in Section 25.6.2.3 of Attachment S, and (2) either (a) the NYISO determines must enter the next Class Year pursuant to Section 25.6.2.3.1-25.6.2.3.4 of Attachment S, or (b) elects to enter the next Class Year pursuant to Section 25.6.2.3.1-25.6.2.3.4 of Attachment S by providing notice to the NYISO by the study start date of the Annual Transmission Reliability Assessment. When the NYISO provides an Interconnection Facilities Study Agreement to a Developer, the NYISO shall, at the same time, also provide one to that Developer's Connecting Transmission Owner. The Interconnection Facilities Study Agreement shall provide that the Developer shall compensate the NYISO and Connecting Transmission Owner for the actual cost of the Interconnection Facilities Study. When the NYISO provides the Interconnection Facilities Study Agreement to the Developer, the NYISO shall provide to Developer a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study. The

Developer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to the NYISO by the later of (1) the study start date of the Annual Transmission Reliability Assessment, or (2) thirty (30) Calendar Days after the Developer's receipt of the Interconnection Facilities Study Agreement, together with the required technical data, including the Developer's final interconnection service evaluation election and the greater of $100,000 or Developer's portion of the estimated monthly cost of conducting the Interconnection Facilities Study. At the same time the Developer provides the above items to the NYISO, the Developer shall deliver the executed Interconnection Facilities Study Agreement, together with the required technical data, to the Transmission Owner. The NYISO and Transmission Owner shall execute the Interconnection Facilities Study Agreement within ten (10) Business Days of receipt of the Interconnection Facilities Study Agreement executed by the Developer and the required technical data.

30.8.1.1 NYISO shall invoice Developer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Any Developer having elected only ERIS shall not be invoiced for any part of the cost of the Class Year Deliverability Study. Developer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. NYISO shall continue to hold the amounts on deposit until settlement of the final invoice.

30.8.2 Scope of Interconnection Facilities Study

The Interconnection Facilities Studies for a Class Year of Developers, as that Class Year is determined in accordance with Attachment S of the NYISO OATT, shall be performed concurrently as a combined Interconnection Facilities Study for that Class Year 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 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 Large Facility in the Class Year to the Transmission System. The combined 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 and any System Upgrade Facilities and, for Large Facilities seeking CRIS, any System Deliverability Upgrades necessary to accomplish the interconnection of each Large Facility in the Class Year; 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 Large Facility interconnection projects. The schedule shall contain major milestones to facilitate the tracking of the progress of each Large Facility interconnection project.

30.8.2.1 Following commencement of the activities described in this schedule, each Developer, that Developer's Connecting Transmission Owner and each Affected Transmission Owner(s) shall report every other month on the progress of their respective activities to the NYISO 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 Developer 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 Interconnection Facilities Study Procedures

The NYISO shall coordinate the Class Year Interconnection Facilities Study with the Connecting Transmission Owners and Affected Transmission Owners, and with any other Affected System pursuant to Section 30.3.5 above. The NYISO shall utilize existing studies to the extent practicable in performing the Class Year Interconnection Facilities Study. The NYISO shall follow the procedures set forth in Attachment S of the NYISO OATT and shall use Reasonable Efforts to complete the study and issue a Class Year Interconnection Facilities Study report to the Class Year Developers within the timeframe called for in Attachment S.

At the request of any Class Year Developer, or at any time the NYISO determines that it will not meet the required time frame for completing the Class Year Interconnection Facilities Study, NYISO shall notify the Class Year Developers as to the schedule status of the Interconnection Facilities Study. If the NYISO 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 Developers and provide an estimated completion date and an explanation of the reasons why additional time is required.

Upon request, the NYISO shall provide each Class Year Developer supporting documentation, workpapers, and databases or data developed in the preparation of the Class Year

Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 30.13.1.

30.8.4 Study Report Meeting

Within ten (10) Business Days of providing a draft Interconnection Facilities Study report to Class Year Developers, the NYISO and Connecting Transmission Owners and Affected Transmission Owners shall meet with Developers 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, NYISO shall so notify Developers and conduct such re-study in accordance with the requirements of Attachment S. Any cost of re-study shall be borne by the Developers 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 Developer is in Dispute Resolution as a result of an allegation that 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 NYISO 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 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, 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 Developer any amounts paid by 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 Developer shall pay any unpaid balance and cost of delivery of such equipment.

30.10 Optional Interconnection Study

30.10.1 Optional Interconnection Study Agreement

Upon the initiation of a Developer's Interconnection System Reliability Impact Study, the Developer may request, and the NYISO shall perform concurrently with that SRIS a reasonable number of Optional Studies. The request shall describe the assumptions that the Developer wishes the NYISO 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 Study, the NYISO shall provide to the Developer an Optional Interconnection Study Agreement in the form of Appendix 5.

The Optional Interconnection Study Agreement shall: (i) specify the technical data that the Developer must provide for each phase of the Optional Interconnection Study, (ii) specify Developer's assumptions as to which Interconnection Requests with earlier queue priority dates will be excluded from the Optional Interconnection Study case, and (iii) the NYISO's estimate of the cost of the Optional Interconnection Study. To the extent known by the NYISO, such estimate shall include any costs expected to be incurred by any Affected System whose participation is necessary to complete the Optional Interconnection Study. Notwithstanding the above, the NYISO shall not be required as a result of an Optional Interconnection Study request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

The Developer shall execute the Optional Interconnection Study Agreement within ten (10) Business Days of receipt and deliver the Optional Interconnection Study Agreement, the technical data and a $10,000 deposit to the NYISO.

30.10.2 Scope of Optional Interconnection Study

The Optional Interconnection Study will consist of a sensitivity analysis based on the assumptions specified by the Developer in the Optional Interconnection Study Agreement. The Optional Interconnection 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 Study. The Optional Interconnection Study shall be performed solely for informational purposes. The NYISO shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of options that are being studied. The NYISO shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

30.10.3 Optional Interconnection Study Procedures

The executed Optional Interconnection Study Agreement, the prepayment, and technical and other data called for therein must be provided to the NYISO within ten (10) Business Days of Developer receipt of the Optional Interconnection Study Agreement. The NYISO shall use Reasonable Efforts to complete the Optional Interconnection Study within a mutually agreed upon time period specified within the Optional Interconnection Study Agreement. If the NYISO is unable to complete the Optional Interconnection 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 NYISO or refunded to the Developer, as appropriate. Upon request, the NYISO shall provide the Developer supporting documentation and workpapers and databases or data developed in the preparation of the Optional Interconnection Study, subject to confidentiality arrangements consistent with Section 30.13.1.

30.11 Standard Large Generator Interconnection Agreement (LGIA)

30.11.1 Tender

Simultaneously with the completion of the Developer decision process described in Section VIII of OATT Attachment S and acceptance by the Developer of its Attachment S cost allocation, the NYISO and Connecting Transmission Owner shall tender to the Developer a draft Standard Large Generator Interconnection Agreement together with draft appendices completed to the extent practicable. The draft Standard Large Generator Interconnection Agreement shall be in the form of the NYISO's Commission-approved Standard Large Generator Interconnection Agreement, which is in Appendix 6 to this Attachment X. Within thirty (30) Calendar Days after the tender by the NYISO and Connecting Transmission Owner, Developer shall execute and return the completed draft LGIA appendices.

30.11.2 Negotiation

Notwithstanding Section 30.11.1, at the request of the Developer the NYISO and Connecting Transmission Owner shall begin negotiations with the Developer concerning the LGIA and its appendices at any time after the Developer executes the Interconnection Facilities Study Agreement. The NYISO, Connecting Transmission Owner and the Developer shall negotiate concerning any disputed provisions of the draft LGIA and its appendices for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study Report. 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 sixty (60) Calendar days of tender of draft LGIA, it shall be deemed to have withdrawn its Interconnection Request. The NYISO and Connecting Transmission Owner shall provide to the Developer a final LGIA within fifteen (15) Business Days after the completion of the negotiation process.

30.11.3 Execution and Filing

Within fifteen (15) Business Days after receipt of the final LGIA, the Developer shall provide the NYISO 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, Developer also shall provide the NYISO 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 two originals of the tendered Standard Large Generator Interconnection Agreement and return them to the NYISO and Connecting Transmission Owner; or (ii) request in writing that the NYISO 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 NYISO and Connecting Transmission Owner shall file the LGIA with FERC. The NYISO 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 NYISO 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 NYISO 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 Commencement of Interconnection Activities

If the Developer executes the final Standard Large Generator Interconnection Agreement, the NYISO, 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.

30.12 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.

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 NYISO or Connecting Transmission Owner

A Developer with an 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 NYISO 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.

30.13 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 NYISO Code of Conduct contained in Attachment F to the NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO and **C**onnecting 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 NYISO may use the services of subcontractors as it deems appropriate to perform its obligations under these Large Facility Interconnection Procedures. The NYISO 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 NYISO shall charge and Developer shall pay the actual costs of the Interconnection Studies incurred by the NYISO and Transmission Owner. If a number of Interconnection Studies are conducted concurrently as a combined study, except for a 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. Beginning with Class Year 2008, Developers shall be responsible for Facilities Study costs in the following manner: (1) each Developer shall pay the actual cost of studying the Attachment Facilities for its own Large Facility, and (2) the Developer of each Large Facility in a Class Year shall pay an equal share of all other Facilities Study costs (*i.e.*, those not related to Attachment Facilities). However, no Developer electing to be evaluated only for ERIS shall be responsible for any cost of any CRIS evaluation in the Facilities Study. In (1) above, if more than one Large Facility contribute to the need for particular Attachment Facilities, the Developers of those Large Facilities shall share equally in the cost to study those Attachment 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 Developer 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 shall include a detailed and itemized accounting of the cost of each Interconnection Study. Developer shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefore. Neither the NYISO nor Connecting Transmission Owner shall be obligated to perform or continue to perform any studies unless Developer has paid all undisputed amounts in compliance herewith.

30.13.3.2 The study deposit requirements contained in this Attachment X were modified effective January 17, 2010. Developers with projects in the interconnection queue as of January 17, 2010 will be responsible for the modified deposit at the next step in the study process, as more fully described below.

30.13.3.2.1 The $10,000 deposit these Developers provided with their Interconnection Request will be refundable to the extent actual study costs are less than the deposit.

30.13.3.2.2 Such Developers commencing an Interconnection Feasibility Study that do not have a fully executed Interconnection Feasibility Study Agreement as of January 17, 2010 must provide the applicable modified deposit for Interconnection Feasibility Studies.

30.13.3.2.3 Such Developers commencing an Interconnection System Reliability Impact Study that do not have a fully executed Interconnection System Reliability Impact Study Agreement as of January 17, 2010 must provide the applicable modified deposit for Interconnection System Reliability Impact Studies.

30.13.4 Third Parties Conducting Studies

If (i) at the time of the signing of an Interconnection 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 NYISO 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 NYISO to utilize a consultant or other third party reasonably acceptable to Developer and NYISO to perform such Interconnection Study under the direction of the NYISO. At other times, the NYISO 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 NYISO determines that doing so will help maintain or accelerate the study process for the Developer's pending Interconnection Request and not interfere with the NYISO'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, Developer, NYISO 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 NYISO 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 Developer's request subject to the confidentiality provision in Section 30.13.1. In any case, such third party contract may be entered into with either the Developer or the NYISO at the NYISO's discretion. If a Developer enters into a third party study contract, Developer shall provide the study to NYISO and the Connecting Transmission Owner for review, and such third party study contract shall provide for reimbursement by Developer of NYISO'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 NYISO OATT procedures and protocols as would apply if the NYISO 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 NYISO 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, 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 NYISO 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 Connecting Transmission Owner or Affected Transmission Owner(s) determines that the provision of interconnection service requested by 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

Developer and NYISO within thirty (30) Calendar days of receipt of the Interconnection Request.

Developer thereafter may renew its request for interconnection using the process specified in Article 5.2(ii) of the NYISO 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 pursuant to the Large Facility Interconnection Procedures in the NYISO OATT.

2. This Interconnection Request is for (check one):

____ A proposed new Large Generating Facility, named ____________________.

____ A proposed new Merchant Transmission Facility, named _______________.

____ An increase in the capacity of an existing Large Generating Facility or existing Merchant Transmission Facility.

3. The type of interconnection service evaluation requested for Class Year Interconnection Facilities Study:

____ Energy Resource Interconnection Service

____ Capacity Resource Interconnection Service

____ Partial Capacity Resource Interconnection Service

4. The Developer provides the following information:

a. 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;

b. Maximum summer at _______ degrees C and winter at ______ degrees C megawatt electrical output of the proposed new Large Facility or the amount of megawatt increase in the capacity of an existing facility;

c. Megawatt allocation for partial CRIS evaluation;

d. General description of the equipment configuration;

e. In-Service Date, and Commercial Operation Date (Day, Month, and Year);

f. Name, title, company address, telephone number, FAX number and e-mail address of the Developer's contact person;

g. Approximate location of the proposed Point of Interconnection (optional); and

h. Interconnection Customer Data (set forth in Attachment A).

5. Applicable deposit amount as specified in the LFIP.

6. Evidence of Site Control as specified in the LFIP (check one)

____ Is attached to this Interconnection Request
____ Will be provided at a later date in accordance with the Large Facility Interconnection Procedures

7. This Interconnection Request shall be submitted to the representative indicated below:

[To be completed by the NYISO]

8. Representative of the Developer to contact:

[To be completed by Developer]

9. This Interconnection Request is submitted by:

Name of Developer:

____

By (signature): ____

Name (type or print): _____________________________________

Title: ____

Date: ____

LARGE GENERATING FACILITY DATA

UNIT RATINGS

kVA __________ °F ____________ Voltage ___________

Power Factor ___________

Speed (RPM) ___________ Connection (e.g. Wye) ___________

Short Circuit Ratio ___________ Frequency, Hertz ___________

Stator Amperes at Rated kVA ___________ Field Volts ___________

Max Turbine MW ___________ °F ___________

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = ______________________ kW sec/kVA

Moment-of-Inertia, WR2 = ______________________ lb. ft.2

REACTANCE DATA (PER UNIT-RATED KVA)

	DIRECT AXIS	QUADRATURE AXIS
Synchronous - saturated	Xdv ___________	Xqv ___________
Synchronous - unsaturated	Xdi ___________	Xqi ___________
Transient - saturated	X'dv ___________	X'qv ___________
Transient - unsaturated	X'di ___________	X'qi ___________
Subtransient - saturated	X"dv ___________	X"qv ___________
Subtransient - unsaturated	X"di ___________	X"qi ___________
Negative Sequence - saturated	X2v ___________	
Negative Sequence - unsaturated	X2i ___________	
Zero Sequence - saturated	X0v ___________	
Zero Sequence - unsaturated	X0i ___________	
Leakage Reactance	Xlm ___________	

FIELD TIME CONSTANT DATA (SEC)

Open Circuit	T'do __________	T'qo __________
Three-Phase Short Circuit Transient	T'd3 __________	T'q __________
Line to Line Short Circuit Transient	T'd2 __________	
Line to Neutral Short Circuit Transient	T'd1 __________	
Short Circuit Subtransient	T"d __________	T"q __________
Open Circuit Subtransient	T"do __________	T"qo __________

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit	Ta3 __________
Line to Line Short Circuit	Ta2 __________
Line to Neutral Short Circuit	Ta1 __________

NOTE: If requested information is not applicable, indicate by marking "N / A."

MW CAPABILITY AND PLANT CONFIGURATION
LARGE GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive	R1 __________
Negative	R2 __________
Zero	R0 __________

Rotor Short Time Thermal Capacity I_2^2t	=	__________
Field Current at Rated kVA, Armature Voltage and PF	=	__________ amps
Field Current at Rated kVA and Armature Voltage, 0 PF	=	__________ amps
Three Phase Armature Winding Capacitance	=	__________ microfarad
Field Winding Resistance	=	______ ohms _____°C
Armature Winding Resistance (Per Phase)	=	______ ohms _____°C

CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

GENERATOR STEP-UP TRANSFORMER DATA

RATINGS

Capacity Self-cooled/Maximum Nameplate

___________/_________________kVA

Voltage Ratio (Generator Side/System Side/Tertiary)

___________/__________/__________kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))

___________/_________/_________

Fixed Taps Available ____

Present Tap Setting ____

IMPEDANCE

Positive Z1 (on self-cooled kVA rating) ___________ % _________ X/R

Zero Z0 (on self-cooled kVA rating) ___________ % _________ X/R

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request: ______

Elevation: __________ ________ Single Phase _______ Three Phase

Inverter manufacturer, model name, number, and version:

____

List of adjustable setpoints for the protective equipment or software:

____

> 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 with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

INDUCTION GENERATORS:

(*) Field Volts: ________________

(*) Field Amperes: ________________

(*) Motoring Power (kW): ________________

(*) Neutral Grounding Resistor (If Applicable): ________________

(*) I_2^2t or K (Heating Time Constant): ________________

(*) Rotor Resistance: ________________

(*) Stator Resistance: ________________

(*) Stator Reactance: ________________

(*) Rotor Reactance: ________________

(*) Magnetizing Reactance: ________________

(*) Short Circuit Reactance: ________________

(*) Exciting Current: ________________

(*) Temperature Rise ________________

(*) Frame Size: ________________

(*) Design Letter: ________________

(*) Reactive Power Required In Vars (No Load): ________________

(*) Reactive Power Required In Vars (Full Load): ________________

(*) Total Rotating Inertia, H: ___________ Per Unit on KVA Base

Note: Please consult the NYISO prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

MERCHANT TRANSMISSION FACILITIES:

Note: Please consult with the NYISO prior to submitting the Interconnection Request for guidance on the information required for Merchant Transmission Facilities.

____

____

____

____

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 NYISO 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 following NYISO representative:

[To be completed by the NYISO]

5. Representative of the Requestor to contact, including phone number and e-mail address:

[To be completed by the Requestor]

6. This External CRIS Rights Request is submitted by:

Name of Requestor: ____________________________

By (signature): _________________________________

Name (type or print): ______________________________

Title: ____

Date: ____

APPENDIX 2 to LFIP - INTERCONNECTION FEASIBILITY 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, or capacity addition to an existing Generating Facility or Merchant Transmission Facility consistent with the Interconnection Request submitted by Developer dated ______; and

WHEREAS, Developer desires to interconnect the Large Facility with the New York State Transmission System; and

WHEREAS, Developer has requested the NYISO to perform an Interconnection Feasibility Study with the input and assistance of Connecting Transmission Owner to assess the feasibility of interconnecting the proposed Large Facility to the New York State Transmission 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 in the NYISO's Commission-approved Standard Large Facility Interconnection Procedures.

2.0 Developer elects and NYISO shall cause to be performed an Interconnection Feasibility Study consistent with Section 30.6.0 of the Standard Large Facility Interconnection Procedures in accordance with the NYISO OATT. The terms of Sections 30.6, 30.13.1 and 30.13.3 of the LFIP, as applicable, are hereby incorporated by reference herein.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study 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. NYISO reserves the right to request additional information from Developer and Connecting Transmission Owner as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study 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 Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
- preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and
- preliminary description and non-binding estimated cost of facilities required to interconnect the Large Facility to the New York State Transmission System and to address the identified short circuit and power flow issues.

6.0 The Developer shall provide a deposit in accordance with the LFIP for the performance of the Interconnection Feasibility Study.

Upon receipt of the Interconnection Feasibility Study the NYISO shall charge and Developer shall pay to NYISO the actual costs of the Interconnection Feasibility Study incurred by the NYISO and Connecting Transmission Owner as computed on a time and materials basis in accordance with the rates attached hereto.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to the Developer, as appropriate.

7.0 Miscellaneous.

7.1 Accuracy of Information. Except as Developer or Connecting Transmission Owner may otherwise specify in writing when they provide information to the 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.

7.2 Disclaimer of Warranty. In preparing the Interconnection Feasibility 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 Feasibility 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 Feasibility 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.

7.3 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 Feasibility Study or any reliance on the Interconnection Feasibility 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.

7.4 Third-Party Beneficiaries. Without limitation of Sections 30.7.2 and 30.7.3 of this Agreement, Developer and Connecting Transmission Owner further agree that subcontractor consultants hired by NYISO to conduct or review, or to assist in the conducting or reviewing, an Interconnection Feasibility Study shall be deemed third party beneficiaries of these Sections 30.7.2 and 30.7.3.

7.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 30.7.5, shall continue in effect for a term of one year or until the

Interconnection Feasibility Study for Developer's Large Facility is completed, whichever event occurs first. Developer or NYISO may terminate this Agreement upon the withdrawal of Developer's Interconnection Request under Section 30.3.6 of the LFIP.

7.6 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.

7.7 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.

7.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.

7.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing signed by the Parties hereto.

7.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.

7.11 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.

7.12 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.

7.13 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.

NYISO **[Insert name of Connecting Transmission Owner]**

By:	____________________	By:	____________________
Title:	____________________	Title:	____________________
Date:	____________________	Date:	____________________

[Insert name of Developer]

By: ____________________

Title: ____________________

Date: ____________________

ASSUMPTIONS USED IN CONDUCTING THE INTERCONNECTION FEASIBILITY STUDY

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on ______________________:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by Developer and other assumptions to be provided by Developer, NYISO, and Connecting Transmission Owner]

APPENDIX 3 to LFIP - INTERCONNECTION SYSTEM Reliability IMPACT 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, or capacity addition to an existing Generating Facility or Merchant Transmission Facility consistent with the Interconnection Request submitted by the Developer dated ______________; and

WHEREAS, Developer desires to interconnect the Large Facility with the New York State Transmission System;

WHEREAS, the NYISO has completed an Interconnection Feasibility Study (the "Feasibility Study") and provided the results of said study to the Developer (this recital to be omitted if neither the NYISO nor the Connecting Transmission Owner require the Feasibility Study); and

WHEREAS, Developer has requested the NYISO to perform an Interconnection System Reliability Impact Study to assess the impact of interconnecting the Large Facility to the New York State Transmission 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 in the NYISO's Commission-approved Standard Large Facility Interconnection Procedures.

2.0 Developer elects and NYISO shall cause to be performed an Interconnection System Reliability Impact Study consistent with Section 30.7.0 of the Standard Large Facility Interconnection Procedures in accordance with the NYISO OATT. The terms of Sections

30.7, 30.13.1 and 30.13.3 of the LFIP, as applicable, are hereby incorporated by reference herein.

3.0 The scope of the Interconnection System Reliability Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection System Reliability Impact Study will be based upon the results of the Interconnection Feasibility Study, if conducted, and the technical information provided by Developer in the Interconnection Request, subject to any modifications in accordance with Section 30.4.4 of the LFIP. NYISO reserves the right to 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 and such additional information shall be provided in a prompt manner. If Developer modifies its designated Point of Interconnection, or the technical information provided in the Interconnection Request is modified, the time to complete the Interconnection System Reliability Impact Study may be extended.

5.0 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 and
- description and non-binding, good faith estimated cost of facilities required to interconnect the Large Facility to the New York State Transmission System and to address the identified short circuit, instability, and power flow issues.

6.0 The Developer shall provide a deposit in accordance with the LFIP for the performance of the Interconnection System Reliability Impact Study. The NYISO's good faith estimate for the time of completion of the Interconnection System Reliability Impact Study is [insert date].

Upon receipt of the Interconnection System Reliability Impact Study, NYISO shall charge and Developer shall pay to NYISO the actual costs of the Interconnection System Reliability Impact Study incurred by the NYISO and Connecting Transmission Owner, as computed on a time and materials basis in accordance with the rates attached hereto.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to the Developer, as appropriate.

7.0 Miscellaneous.

7.1 Accuracy of Information. Except as Developer or Connecting Transmission Owner may otherwise specify in writing when they provide information to the 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.

7.2 Disclaimer of Warranty. In preparing the Interconnection System Reliability 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 System Reliability 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 SRIS. 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.

7.3 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 System Reliability Study or any reliance on the Interconnection System Reliability 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.

7.4 Third-Party Beneficiaries. Without limitation of Sections 30.7.2 and 30.7.3 of this Agreement, Developer and Connecting Transmission Owner further agree that subcontractor consultants hired by NYISO to conduct or review, or to assist in the conducting or reviewing, an Interconnection System Reliability Study shall be deemed third party beneficiaries of these Sections 30.7.2 and 30.7.3.

7.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 30.7.5, shall continue in effect for a term of one year or until the Interconnection System Reliability Study for Developer's Large Facility is completed [approved by the NYISO Operating Committee], whichever event occurs first. Developer or NYISO may terminate this Agreement upon the withdrawal of Developer's Interconnection Request under Section 30.3.6 of the LFIP.

7.6 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.

7.7 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.

7.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.

7.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing signed by the Parties hereto.

7.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.

7.11 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.

7.12 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.

7.13 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 THEREOF, 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.

NYISO		**[Insert name of Connecting Transmission Owner]**	
By:	____________________	By:	____________________
Title:	____________________	Title:	____________________
Date:	____________________	Date:	____________________

[Insert name of Developer]

By: ____________________

Title: ____________________

Date: ____________________

Attachment A To Appendix 3 - Interconnection System Reliability Impact Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE

INTERCONNECTION SYSTEM RELIABILITY IMPACT STUDY

The Interconnection System Reliability Impact Study will be based upon the results of the Interconnection Feasibility Study, subject to any modifications in accordance with Section 30.4.4 of the LFIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by Developer and other assumptions to be provided by Developer, NYISO and Connecting Transmission Owner]

APPENDIX 4 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 or capacity addition to an existing Generating Facility or Merchant Transmission Facility consistent with the Interconnection Request submitted by the Developer dated ___________; and

WHEREAS, Developer desires to interconnect the Large Facility with the New York State Transmission System;

WHEREAS, the NYISO has completed an Interconnection System Reliability Impact Study and provided the results of said study to the Developer; and

WHEREAS, Developer has requested the NYISO and Connecting Transmission Owner to perform an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Reliability Impact Study in accordance with Good Utility Practice to physically and electrically connect the Large Facility to the New York Transmission 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 in the NYISO's Commission-approved Standard Large Facility Interconnection Procedures.

2.0 Developer elects to be evaluated for [ ] Interconnection Service and NYISO shall cause to be performed an Interconnection Facilities Study consistent with Section 30.8.0 of the Standard Large Facility Interconnection Procedures to be performed in accordance with the NYISO OATT. The terms of Sections 30.8, 13.1 and 30.13.3 of the LFIP, 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 The Interconnection Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the Large Facility to the New York State Transmission System and (ii) shall address the short circuit, instability, and power flow issues identified in the Interconnection System Reliability Impact Study.

5.0 The Developer shall provide a deposit of $100,000 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 the 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 30.7.2 and 30.7.3 of this Agreement, Developer and Connecting Transmission Owner further agree that subcontractor consultants hired 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 30.7.2 and 30.7.3.

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 for a term of one year or until the Interconnection Facilities Study for Developer's Large Facility is completed [approved by the NYISO Operating Committee], whichever event occurs first. Developer or NYISO may terminate this Agreement upon the withdrawal of Developer's Interconnection Request under Section 30.3.6 of the LFIP.

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.

NYISO

By: ____________________

Title: ____________________

Date: ____________________

[Insert name of Connecting Transmission Owner]

By: ____________________

Title: ____________________

Date: ____________________

[Insert name of Developer]

By: ____________________

Title: ____________________

Date: ____________________

Attachment A To Appendix 4 - 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:

- scheduled completion date for Class Year 20__ Interconnection Facility Study for the Annual Transmission Reliability Assessment required by Attachment S to the NYISO OATT: ____/____/________.

Attachment B To Appendix 4 - Interconnection Facilities Study Agreement

DATA FORM TO BE PROVIDED BY DEVELOPER

WITH THE INTERCONNECTION 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.

Finalize and specify your Interconnection Service evaluation election for the Class Year Facilities Study. New Interconnection Requests should specify either Energy Resource Interconnection Service alone, or both Energy Resource Interconnection Service and some MW level of Capacity Resource Interconnection Service, not to exceed the nameplate capacity of your facility (some MW level of Capacity Resource Interconnection Service election is required to become a qualified Installed Capacity Supplier or to receive Unforced Capacity Deliverability Rights)~~,~~. If your facility is already interconnected taking Energy Resource Interconnection Service, and not covered by a new Interconnection Request, you may elect to be evaluated for Capacity Resource Interconnection Service at a MW level you specify, not to exceed the nameplate capacity of your facility. 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:

On the one line indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

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
(Please indicate on one line diagram).

What type of control system or PLC will be located at the Developer's Large Facility?

What protocol does the control system or PLC use?

____

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

____

Physical dimensions of the proposed interconnection station:

____

Bus length from generation to 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*:

____

* To be completed in coordination with Connecting Transmission Owner.

Is the Large Facility in the Transmission Owner's service area?

_____ Yes _____No Local provider: ___________________________

Please provide proposed schedule dates:

Begin Construction	Date: _______________
Generator step-up transformer receives back feed power	Date: _______________
Generation Testing	Date: _______________
Commercial Operation	Date: _______________

APPENDIX 4-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 NYISO OATT, requested External CRIS Rights for a specified number of MW of External CRIS; and

WHEREAS, the 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 the 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 NYISO OATT, or in Article Z of the NYISO Services Tariff.

2.0 Requestor requests that the 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 NYISO 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 $100,000 for the performance of the 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.

The NYISO shall invoice Requestor on a monthly basis for the expenses incurred by the 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 the NYISO within thirty (30) Calendar Days of receipt of invoice. The 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 the 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 30.4.2 and 30.4.3 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 30.4.2 and 30.4.3.

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, [approved by the NYISO Operating Committee], whichever event occurs first. 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 NYISO OATT.

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. The 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.

NYISO

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**

The 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:

> Scheduled completion date for Class Year 20__ Deliverability Study required by Section 25.7.11 Attachment S to the NYISO OATT: ____/____/________.

**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 Winder Capability Period, Requestor must specify months covered by commitment.

c. The External Interface(s) to be used for the External ICAP.

____

OTHER ASSUMPTIONS

APPENDIX 5 to LFIP - OPTIONAL INTERCONNECTION 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, or capacity addition to an existing Generating Facility or Merchant Transmission Facility consistent with the Interconnection Request submitted by the Developer dated __________________;

WHEREAS, Developer is proposing to establish an interconnection with the New York State Transmission System; and

WHEREAS, Developer has submitted to NYISO an Interconnection Request; and

WHEREAS, Developer has further requested that the NYISO prepare an Optional Interconnection Study concurrently with the Interconnection System Reliability Impact Study;

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 meanings indicated in the NYISO's Commission-approved Standard Large Facility Interconnection Procedures.

2.0 Developer elects and NYISO shall cause to be performed an Optional Interconnection Study consistent with Section 30.10 of the Standard Large Facility Interconnection Procedures to be performed in accordance with the NYISO OATT. The terms of Sections 30.10, 30.13.1 and 30.13.3 of the CFIP, as applicable, are hereby incorporated by reference herein.

3.0 The scope of the Optional Interconnection Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Optional Interconnection Study shall be performed solely for informational purposes.

5.0 The Optional Interconnection Study report shall provide a sensitivity analysis based on the assumptions specified by the Developer in Attachment A to this Agreement. The Optional Interconnection Study will identify the Connecting Transmission Owner's Attachment Facilities and System Upgrade Facilities, and the estimated cost thereof, that may be required to provide Network Access Interconnection Service based upon the assumptions specified by the Developer in Attachment A.

6.0 The Developer shall provide a deposit of $10,000 for the performance of the Optional Interconnection Study. The NYISO's good faith estimate for the time of completion of the Optional Interconnection Study is [insert date].

Upon receipt of the Optional Interconnection Study, the NYISO shall charge and Developer shall pay to NYISO the actual costs of the Optional Study incurred by the NYISO and Connecting Transmission Owner, as computed on a time and material basis in accordance with the rates attached hereto.

Any difference between the initial payment and the actual cost of the study shall be paid by or refunded to the Developer, as appropriate.

7.0 Miscellaneous.

7.1 Accuracy of Information. Except as Developer or Connecting Transmission Owner may otherwise specify in writing when they provide information to the 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.

7.2 Disclaimer of Warranty. In preparing the Optional Interconnection 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 Optional Interconnection 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 Optional Interconnection 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.

7.3 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 Optional Interconnection Study or any reliance on the Optional Interconnection System 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.

7.4 Third-Party Beneficiaries. Without limitation of Sections 30.7.2 and 30.7.3 of this Agreement, Developer and Connecting Transmission Owner further agree that subcontractor consultants hired by NYISO to conduct or review, or to assist in the conducting or reviewing, an

Optional Interconnection Study shall be deemed third party beneficiaries of these Sections 30.7.2 and 30.7.3.

7.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 30.7.5, shall continue in effect for a term of one year or until the Optional Interconnection Study for Developer's Large Facility is completed, whichever event occurs first. Developer or NYISO may terminate this Agreement upon the withdrawal of Developer's Interconnection Request under Section 30.3.6 of the LFIP.

7.6 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.

7.7 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.

7.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.

7.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing signed by the Parties hereto.

7.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.

7.11 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.

7.12 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.

7.13 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.

NYISO		**[Insert name of Connecting Transmission Owner]**	
By:	____________________	By:	____________________
Title:	____________________	Title:	____________________
Date:	____________________	Date:	____________________

[Insert name of Developer]

By: ____________________

Title: ____________________

Date: ____________________

Attachment A To Appendix 5 - Optional Interconnection Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE OPTIONAL INTERCONNECTION STUDY

[To be completed by Developer consistent with Section 30.10 of the LFIP.]

Appendix 6 – STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

(Applicable to Generating Facilities that exceed 20 MW)

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 Transmission System and Connecting Transmission Owner owns certain facilities included in the Transmission System; and
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 30.1.0 or Attachment S of the NYISO OATT.

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 or 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 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 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 three subsets of the Installed Capacity statewide markets comprised of Rest of State (Zones A through I), Long Island (Zone K), and New York City (Zone J).

Capacity Resource Interconnection Service ("CRIS") shall mean the service provided by NYISO to interconnect the Developer's Large Generating Facility to the New York State Transmission System in accordance with the NYISO Deliverability Interconnection Standard, to enable the New York State Transmission System to deliver electric capacity from the Large Generating Facility, pursuant to the terms of the NYISO OATT.

Class Year Deliverability Study shall mean an assessment, conducted by the NYISO staff in cooperation with Market Participants, to determine the System Deliverability Upgrades required for each generation and merchant transmission project included in the Class Year Interconnection Facilities Study to interconnect to the New York State Transmission System in compliance with the NYISO Deliverability Interconnection Standard.

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 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 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.

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.

Deliverability Interconnection Standard shall mean the standard that must be met by any Large Generating Facility proposing to interconnect to the New York State Transmission System and become a qualified Installed Capacity Supplier. To meet the NYISO Deliverability Interconnection Standard, the Developer of the proposed Large Generating Facility must, in accordance with the rules in Attachment S to the NYISO OATT, fund or commit to fund the System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

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.

Dispute Resolution shall mean the procedure described in Article 27 of this Agreement for resolution of a dispute between the Parties.

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 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 NYISO 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.

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.

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, UPNY-SENY 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 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 and 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. 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 4 of the Standard Large Facility Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Large Generating Facility to the New York State Transmission System, the scope of which is described in Section 30.6 of the Standard Large Facility Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Facility Interconnection Procedures for conducting the Interconnection Feasibility 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 toincrease 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.

Interconnection Study shall mean any of the following studies: the 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 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 and System Upgrade Facilities are needed for the proposed Large Generation Facility of the Developer to connect reliably to the New York State Transmission System in a manner that meets the NYISO Minimum Interconnection Standard.

Interconnection System Reliability Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Facility Interconnection Procedures for conducting the Interconnection System Reliability Impact Study.

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 I~~i~~ndemnifying 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.

Minimum Interconnection Standard shall mean the reliability standard that must be met by any Large Generating Facility proposing to connect to the New York State Transmission System. The Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System. The Standard does not impose any deliverability test or deliverability requirement on the proposed interconnection.

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.

NYSRC shall mean the New York State Reliability Council or its successor organization.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Developer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Facility Interconnection Procedures for conducting the Optional Interconnection Study.

Other Interfaces shall mean interfaces into New York capacity regions, Zone J and Zone K, and external ties into the New York Control Area.

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.

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 Interconnection Request by NYISO.

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.

Scoping Meeting shall mean the meeting between representatives of the Developer, NYISO 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; (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. 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 ("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 NYISO OATT.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean this Agreement, the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in Attachment X of the NYISO 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 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 permanently ceases Commercial Operations.

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 ~~to~~ 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, **D**eveloper shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equ**i**pment, 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

3.1 Filing.

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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 **m**ust 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 Upgrades 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,

(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;

(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;

(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;

(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) 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;

(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;

(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;

(8) Developer shall transfer control of Connecting Transmission Owner's Attachment Facilities and Stand Alone System Upgrade Facilities to the Connecting Transmission Owner;

(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;

(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

(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 or 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 NYISO 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 the following “as-built” drawings, information and documents for the Connecting Transmission Owner’s Attachment Facilities [include appropriate drawings and relay diagrams].

The Connecting Transmission Owner shall 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 NYISO 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 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 NYISO 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 of Tax Depreciation))/(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. 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. Any settlement without Developer's consent or such written advice will relieve Developer from any obligation to indemnify Connecting Transmission Owner for the tax at issue in the contest.

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 NYISO OATT, except in accordance with the cost allocation procedures in Attachment S of the NYISO OATT. Developer shall be responsible for the costs of any additions, modifications, or replacements to the Developer Attachment Facilities that may be necessary to maintain or upgrade such Developer 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 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 NYISO 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 Attachment Facilities in a safe and reliable manner and in accordance with this Agreement. Developer shall operate the Large Generating Facility and the Developer 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.

Developer shall design the Large Generating Facility to maintain an effective power delivery at demonstrated maximum net capability at the Point of Interconnection at a power factor within the range established by the Connecting Transmission Owner on a comparable basis, until NYISO has established different requirements that apply to all generators in the New York Control Area on a comparable basis.

The Developer shall design and maintain the plant auxiliary systems to operate safely throughout the entire real and reactive power design range.

The Connecting Transmission Owner shall not unreasonably restrict or condition the reactive power production or absorption of the Large Generating Facility in accordance with Good Utility Practice.

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 NYISO 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 criteria A-3.

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 Attachment Facilities. Connecting Transmission Owner shall install at Developer's expense any System Protection Facilities that may be required on the Connecting Transmission Owner Attachment Facilities or the New York State Transmission System as a result of the interconnection of the Large Generating Facility and Developer 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 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.

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 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 NYISO OATT.

Article 11. Performance Obligation

11.1 Developer Attachment Facilities.

Developer shall design, procure, construct, install, own and/or control the Developer 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 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 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 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 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 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 NYISO 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 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 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 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 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 Default.

17.1.1 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.

17.1.2 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 Indemnified 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, maintain in force throughout the period of this Agreement, and until released by the other Parties, the following minimum insurance coverages, with insurers authorized to do business in the state of New York:

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 Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) 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 and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) 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 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public 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 insured. 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.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Developer and Connecting Transmission Owner shall each be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) 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.

18.3.8 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.

18.3.9 Within ten (10) 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 certification of all insurance required in this Agreement, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, Developer and Connecting Transmission Owner may each self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 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 18.3.2 through 18.3.8. 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 18.3.2 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 Article 18.3.9.

18.3.11 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.

Article 19. Assignment

19.1 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

20.1 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

21.1 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.

22.1.1 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.

22.1.2 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 NYISO OATT.

22.1.3 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.

22.1.4 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.

22.1.5 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.

22.1.6 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.

22.1.7 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 NYISO 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 NYISO OATT.

22.1.8 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.

22.1.9 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.

22.1.10 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.

22.1.11 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 NYISO 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.

22.1.12

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 NYISO 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. Environmental Releases

23.1 Developer and Connecting Transmission Owner Notice.

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 Large Facility Interconnection Procedures. It shall also include any additional information provided to Connecting Transmission Owner for the Interconnection Feasibility Study and 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, or System Upgrade Facilities, 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 Large Facility Interconnection Procedures or such Appendix to the 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 NYISO 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 NYISO 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.

NYISO	**[Insert Name of Connecting Transmission Owner]**
By: ______________________________	By: ______________________________

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date: ______________________________

[Insert Name of Developer]

By: ______________________________

Title: ______________________________

Date: ______________________________

Appendices to Appendix 6

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 G – Interconnection Requirements For A Wind Generating Plant

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. <u>Technical Standards Applicable to a Wind Generating Plant</u>

i. <u>Low Voltage Ride-Through (LVRT) Capability</u>

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

<u>Transition Period LVRT Standard</u>

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, finally executed as conforming agreements, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault fvoltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the Connecting Transmission Owner for the Transmission District to which the wind generating plant will

be interconnected. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the Connecting Transmission Owner for the Transmission District to which the wind generating plant will be interconnected. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr

Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. <u>Power Factor Design Criteria (Reactive Power)</u>

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the ISO's System Reliability Impact Study shows that such a requirement is necessary to ensure safety or reliability.

The power factor range standard~~s~~ can be met using, for example without limitation, 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 if agreed to by the Connecting Transmission Owner for the Transmission District to which the wind generating plant will be interconnected, or a combination of the two. The Developer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Reliability Impact Study shows this to be required for system safety or reliability.

iii. **Supervisory Control and Data Acquisition (SCADA) Capability**

The wind plant shall provide SCADA capability to transmit data and receive instructions from the ISO and/or the Connecting Transmission Owner for the Transmission District to which the wind generating plant will be interconnected, as applicable, to protect system reliability. The Connecting Transmission Owner for the Transmission District to which the wind generating plant will be interconnected and the wind plant Developer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

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 General Overview

31.1.1 New York Comprehensive System Planning Process ("CSPP")

31.1.1.1 Reliability Planning Process

Sections 31.2.1 through 31.2.6 of this Attachment describe the process that the NYISO, the Transmission Owners, and Market Participants and other interested parties shall follow for planning to meet the reliability needs of the New York State Bulk Power Transmission Facilities ("BPTFs"). 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 an opportunity for the development of market-based solutions while ensuring the reliability of the BPTFs; and (5) coordinate the NYISO's reliability assessments with neighboring Control Areas.

The NYISO 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.

31.1.1.2 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 Local Transmission Owner Planning Process ("LTPP"), and the plans resulting from the LTPP are referred to herein as Local Transmission Plans ("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 NYISO'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 Reliability Planning Process 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.

31.1.1.3 Economic Planning Process

Sections 31.3.1 and 31.3.2 of this Attachment Y describe the process that the NYISO, the Transmission Owners, and Market Participants shall follow for economic planning to identify and reduce current and future projected congestion on the New York State BPTFs. The objectives of the economic planning process are to: (1) project congestion on the New York State BPTFs over the ten-year planning period of this Comprehensive System Planning Process, (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 NYISO's congestion assessments and economic planning process with neighboring Control Areas.

31.1.1.4 Participation In The ESPWG and TPAS

For purposes of any matter addressed by this Attachment Y, participation in the ESPWG and TPAS shall be open to any interested entity, irrespective of whether that entity has become a Party to the ISO Agreement. Only Parties to the ISO Agreement who have signed the appropriate Non-Disclosure Agreement will have access to CEII data. Access to Confidential

Information shall be in accordance with the provisions of the NYISO's Code of Conduct, as found in Section 12.4 of Attachment F of the NYISO OATT and Article 6 of the Services Tariff.

31.1.2 Definitions

Unless otherwise defined in this document, capitalized terms used herein shall have the meanings ascribed to them in the OATT.

ATRA: The Annual Transmission Reliability Assessment conducted under Attachment S to the NYISO OATT.

CARIS: The Congestion Assessment and Resource Integration Study for economic planning developed by the NYISO in consultation with the Market Participants and other interested parties under this Attachment Y.

CRP: The Comprehensive Reliability Plan as approved by the NYISO Board of Directors pursuant to this tariff.

CSPP: The Comprehensive System Planning Process set forth in this Attachment Y, which covers reliability planning, economic planning, cost allocation and cost recovery, and interregional planning coordination.

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.

Five Year Base Case: The model representing the New York State Power System over the first five years of the Study Period.

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.

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.

LTPP: The Local Planning Process conducted by each Transmission Owner for its own Transmission District.

Other Developers: Parties or entities sponsoring or proposing to sponsor regulated economic projects or regulated solutions to Reliability Needs who are not Transmission Owners.

Management Committee: The standing committee of the NYISO of that name created pursuant to the ISO Agreement.

New York State Bulk Power Transmission Facilities: The facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to NPCC by the NYISO pursuant to NPCC requirements.

NYCA Free Flow Test: A NYCA unconstrained internal transmission interface test, performed by the NYISO 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.

NYPSC: The New York Public Service Commission, as defined in the New York Public Service Law.

Operating Committee: The standing committee of the NYISO of that name created pursuant to the ISO Agreement.

Reliability Criteria: The electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules promulgated by the North American Electric Reliability Council ("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 NYISO in the RNA as a violation or potential violation of Reliability Criteria.

Responsible Transmission Owner: The Transmission Owner or Transmission Owners designated by the NYISO, pursuant to the NYISO Planning Process, to prepare a proposal for a regulated 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 NYISO identifies a Reliability Need.

RNA: The Reliability Needs Assessment as approved by the NYISO Board under this tariff.

Study Period: The ten-year time period evaluated in the RNA.

TPAS: The Transmission Planning Advisory Subcommittee, or any successor work group or committee designated to fulfill the functions assigned to TPAS in this tariff.

31.1.3 NYISO Implementation and Administration

31.1.3.1 The NYISO shall adopt procedures for the implementation and administration of the CSPP set forth in this Attachment Y, and shall revise those procedures as and when necessary. Such procedures will be incorporated in the NYISO's manuals, including NYISO's Comprehensive Reliability Planning Process Manual. The NYISO's 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 NYISO 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 NYISO's tariffs and procedures, including this Attachment Y and Attachment F of the NYISO OATT.

31.1.3.2 The NYISO's 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. Each cycle commences with the LTPP providing input into the Reliability Planning Process. When the Reliability Planning Process is completed, it is then followed by the Economic Planning Process.

31.1.3.3 The NYISO's procedures shall be designed to allow the coordination of the NYISO's planning activities with those of NERC, NPCC, the NYSRC, neighboring Control Areas and other regional reliability organizations so as to develop consistency of the models, databases, and assumptions utilized in making reliability and economic determinations.

31.1.3.4 The NYISO's 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 NYISO 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 NYISO that are the same as those available to Transmission Customers under Article 12.16 of the NYISO OATT. Disputes arising out of the LTPP shall be addressed by the dispute resolution process set forth in Section 31.2.1.3 of this Attachment Y.

31.1.3.5 Except for those cases where the NYISO 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 NYISO 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 NYISO OATT.

31.2 Reliability Planning Process

31.2.1 Local Transmission Owner Planning Process

31.2.1.1 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. A link to each Transmission Owner's website will be posted on the NYISO website.

31.2.1.2 Process Timeline

31.2.1.2.1 Each Transmission Owner, in accordance with a schedule set forth in the NYISO's Comprehensive Reliability Planning Process Manual, 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 NYISO 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,
- issues 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 NYISO's planning process, not already reported by the NYISO in Form 715 and referenced on its website, any such data will be provided to the NYISO 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 NYISO on its website subject to any confidentiality or Critical Energy Infrastructure Information restrictions or requirements.

31.2.1.2.3 Each planning cycle, the NYISO 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 a NYISO location. The NYISO 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 NYISO 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 NYISO as contemplated in Section 31.2.2.4.2 below for timely inclusion in the RNA.

31.2.1.3 LTP Dispute Resolution Process

31.2.1.3.1 Disputes Related to the LTPP; Objective; Notice

Disputes related to the LTPP are subject to the LTP Dispute Resolution Process ("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 Transmission Owner ("Affected TO"), the NYISO, 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.

31.2.1.3.2 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.

31.2.1.3.3 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.

31.2.1.3.4 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.

31.2.1.3.5 Notice of Results of Dispute Resolution

The Affected Transmission Owner shall notify the NYISO and ESPWG and TPAS of the results of the DRP and update its LTP to the extent necessary. The NYISO shall use in its planning process the LTP provided by the Affected TO.

31.2.1.3.6 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.

31.2.1.3.7 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 NYISO under its confidentiality and CEII policies.

31.2.2 Reliability Needs Assessment

31.2.2.1 General

The NYISO shall prepare and publish the RNA as described below. The RNA will identify Reliability Needs and provide an analysis of historic congestion costs. The NYISO shall also designate in the RNA the Responsible TO with respect to each Reliability Need.

31.2.2.2 Interested Party Participation in the Development of the RNA

The NYISO 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 NYISO'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 NYISO staff to allow Market Participants and other interested parties to participate in a meaningful way during each stage of the CSPP. The NYISO 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 NYISO 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 Five Year Base Case will be the system as defined for the ATRA. The details of the development of the Five Year Base Case are contained in the procedures contained in the NYISO's Comprehensive Reliability Planning Process Manual.

31.2.2.3.3 The NYISO shall assess the Five Year 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 NYISO shall perform additional analyses to determine whether additional resources and/or transmission capacity expansion are needed to meet those requirements, and to determine the expected first year of need for those additional resources and/or transmission. 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.

31.2.2.3.4 The NYISO will also evaluate the BPTFs over the second five years of the Study Period to determine whether they meet all Reliability Criteria for both resource and transmission adequacy in each year and report the results of its evaluation in the RNA. A short circuit assessment will be performed for the tenth year of the Study Period. Reliability needs will be defined in terms of total deficiencies relative to Reliability Criteria and not necessarily in terms of specific facilities.

31.2.2.3.5 The NYISO shall develop the system representation to be used for its evaluations of the second five years of the Study Period using (1) the most recent Load and Capacity Data Report published by the NYISO on its web site; (2) the most recent versions of NYISO 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 NYISO determines may impact the BPTFs; and (4) data submitted pursuant to paragraph 31.2.2.4 below.

31.2.2.4 Planning Participant Data Input

31.2.2.4.1 At the NYISO's request, Market Participants, Developers and other parties shall provide, in accordance with the schedule set forth in the NYISO's Comprehensive Reliability Planning Process Manual, the data necessary for the development of the RNA. This input 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); 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 NYISO.

31.2.2.4.2 The Transmission Owners shall submit their current LTPs referenced in Section 31.1.1.2 and Section 31.2.1 to the NYISO. The NYISO will review the Transmission Owners' LTPs, as they related to BPTFs, to determine whether they will meet Reliability Needs, recommend an alternate means to resolve the needs from a regional perspective, where appropriate, or indicate that it is not in agreement with a Transmission Owner's proposed additions. The NYISO shall report its determinations under this section in the RNA and in the CRP.

31.2.2.4.3 All input 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 procedures contained in the NYISO's Comprehensive Reliability Planning Process Manual.

31.2.2.5 Reliability Scenario Development

The NYISO, in consultation-with the ESPWG and TPAS, shall develop reliability scenarios addressing the first five years and the second five years of 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 Alternate Reliability Scenarios

The NYISO will conduct additional reliability analyses for the alternate 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 needs. In addition, the NYISO 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 NYISO shall report the results of these evaluations in the RNA.

31.2.2.7 Reliability Needs Assessment Report Preparation

Once all the analyses described above have been completed, NYISO 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.

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 NYISO 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 subject to such other terms and conditions that the NYISO may reasonably determine are 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 RNA ~~shall be forwarded, along with a summary of all comments of interested parties provided during~~reflecting the revisions resulting from the TPAS and ESPWG review, shall be forwarded to the Operating Committee for discussion and action. The NYISO 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 NYISO 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 NYISO'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 NYISO 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 Attachment Y to the ISO OATT are also addressed in Section 30.4.6.8.2 of the Market Monitoring Plan.

31.2.3.3 Needs Assessment Disputes

Notwithstanding any provision to the contrary in this Attachment, the NYISO 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 NYISO will provide various opportunities for Market Participants and other potentially interested parties to discuss the final RNA. Such opportunities may include presentations at various NYISO 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 Regulated Backstop Solutions

31.2.4.1.1 When a Reliability Need is identified in any RNA issued under this tariff, the NYISO shall request and the Responsible Transmission Owner shall provide to the NYISO, as soon as reasonably possible, 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 NYISO due to the lack of sufficient viable market-based solutions to meet such Reliability Needs identified for the Study Period. Regulated backstop solutions may include generation, transmission, or demand side resources. A proposed regulated backstop solution to address a need in the second five years of the planning period that does not have a trigger date within one year or less of the CRP currently under consideration will not require the same level of detail as a proposed solution for a need in the first five years. The criteria for regulated backstop solutions are included in the NYISO's Comprehensive Reliability Planning Process Manual. Such proposals may include reasonable alternatives that would effectively address the Reliability Need; provided however, the Transmission Owners' obligation to propose and implement regulated backstop solutions under this tariff is limited to regulated transmission solutions. The Responsible Transmission Owner shall also estimate the lead time necessary for the implementation of its proposal. The NYISO will establish a lead time for responses submitted pursuant to Sections 31.2.4.2, 31.2.4.4 and 31.2.5.7 on the basis of the time period required for implementation of the proposed potential backstop solution. 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. Contemporaneous with the request to the Responsible Transmission Owner, the NYISO shall solicit responses using the two-step process defined below, which shall not be a formal RFP process. Should more than one regulated backstop solution be proposed to address a Reliability Need, it will be the responsibility of the Responsible Transmission Owners to determine the regulated backstop solution that will proceed following a finding by the NYISO under Section 31.2.6.4 of this Attachment. The determination by the Responsible Transmission Owners will be made prior to the approval of the CRP in which the regulated backstop solution with the longest lead-time could be triggered.

31.2.4.1.2 Market Participants and other interested parties may submit at any time optional suggestions for changes to NYISO rules or procedures which could result in the identification of additional resources or market alternatives suitable for meeting Reliability Needs.

31.2.4.2 Market-Based Responses

At the same time that a proposal for a regulated backstop solution is requested from the Responsible Transmission Owner under Section 31.2.4.1, the NYISO shall also request market-based responses from the market place. Subject to the execution of appropriately drawn confidentiality agreements and FERC's standards of conduct, the NYISO 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.

31.2.4.3 Qualifications for a Valid Market-Based Response

The NYISO's procedures establishing qualifications and criteria for a valid market-based solution are included in the NYISO's Comprehensive Reliability Planning Process Manual.

Such qualifications recognize the differences between various resources' characteristics and development time lines.

31.2.4.4 Alternative Regulated Responses

31.2.4.4.1 In the event that market-based solutions qualified under Section 31.2.4.3 are proposed, or the NYISO determines that there is imminent need to do so, the NYISO will initiate a second step of the solicitation process by requesting alternative regulated responses to Reliability Needs. Such proposals may include reasonable alternatives that would effectively address the identified Reliability Need.

31.2.4.4.2 In response to the NYISO'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 NYISO. Transmission Owners, at their option, may submit additional proposals for regulated solutions to the NYISO. 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 FERC's standards of conduct, the NYISO 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.

31.2.4.5 Additional Solutions

Should the NYISO determine that it has not received adequate regulated backstop or market-based solutions to satisfy the Reliability Need, the NYISO may, in its discretion, solicit additional regulated backstop or market-based solutions. Other Developers may submit additional alternative regulated solutions for the NYISO's consideration at that time.

31.2.5 NYISO Evaluation of Proposed Solutions to Reliability Needs

31.2.5.1 Comparable Evaluation of All Proposed Solutions

When evaluating proposed solutions to Reliability Needs, all resource types shall be considered on a comparable basis as potential solutions to the Reliability Needs identified: generation, transmission and demand response.

31.2.5.2 Evaluation of Regulated Backstop Solutions

The NYISO shall evaluate a proposed regulated backstop solution submitted by a Responsible Transmission Owner pursuant to Section 31.2.4.1 to determine whether it will meet the identified Reliability Need in a timely manner, and will report the results of its evaluation in the CRP.

31.2.5.3 Evaluation of Market Based Proposals

The NYISO shall review proposals for market-based solutions and determine whether they resolve a Reliability Need. If market-based solutions are found by the NYISO to be sufficient to meet **a** Reliability Need in a timely manner, the NYISO will so state in the CRP. The NYISO will not select from among the market-based solutions if there is more than one proposal which will meet the same Reliability Need.

31.2.5.4 Evaluation of Alternative Regulated Responses

If market-based solutions do not resolve a Reliability Need, the NYISO shall proceed to review the proposed alternative regulated solutions submitted in accordance with Section 31.2.4.4 above, and will report the results of its review in the CRP.

31.2.5.5 Resolution of Deficiencies

Following initial review of the proposals, as described above, NYISO 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 NYISO Staff. Other Developers and Transmission Owners that propose alternative regulated solutions shall have the option to revise and resubmit their proposals to address any identified deficiency. With respect to regulated backstop solutions proposed by a Responsible Transmission Owner pursuant to Section 31.2.4.1, the Responsible Transmission Owner shall make necessary changes to its proposed backstop solution to address any reliability deficiencies identified by the NYISO, and submit a revised proposal to the NYISO for review. The NYISO shall review all such revised proposals to determine that all of the identified deficiencies have been resolved.

31.2.5.6 Designation of Regulated Backstop Solution and Responsible Transmission Owner

If the NYISO determines that a market-based solution 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 implementation of a regulated solution is necessary. The NYISO will also identify in the CRP (1) the regulated backstop solution that the NYISO has determined will meet the Reliability Need in a timely manner, and (2) the Responsible Transmission Owner.

31.2.5.7 Process for Consideration of Regulated Backstop Transmission Solution and Alternative Regulated Transmission Solutions

Upon a finding by the NYISO under Section 31.2.6.4 of this Attachment that a regulated solution should proceed, the Transmission Owner will make a presentation to the ESPWG that will provide a description of the regulated backstop solution. The presentation will include a non-binding preliminary cost estimate of that backstop solution; provided, however, that a

Responsible Transmission Owner shall be entitled to full recovery of all reasonably incurred costs related to the regulated backstop solution. Any Alternative Regulated Solution proponent seeking regulated cost recovery for its project will also make a presentation to the ESPWG at the time of the above finding by the NYISO providing a description of the Alternative Regulated Solution, including a non-binding preliminary cost estimate of the project. The NYISO 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.

31.2.5.8 Regulated Solution to Proceed in Parallel with a Market-based Solution

If the NYISO determines that it is necessary for the Responsible Transmission Owner to proceed with a regulated solution to be conducted in parallel with a market-based solution in order to ensure that a Reliability Need is met in a timely manner, the CRP will so state.

31.2.5.9 Gap Solutions

31.2.5.9.1 If the NYISO determines that neither market-based proposals nor regulated proposals can satisfy the Reliability Needs in a timely manner, the NYISO will set forth its determination that a Gap Solution is necessary in the CRP. The NYISO will also request the Responsible Transmission Owner to seek a Gap Solution**.** GAP Solutions may include generation, transmission, or demand side resources.

31.2.5.9.2 If there is an imminent threat to the reliability of the New York power system, the NYISO 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.

31.2.5.9.3 Upon the NYISO's determination of the need for a Gap Solution, pursuant to either Section 31.2.5.9.1 or 31.2.5.9.2 above, the Responsible Transmission

Owner will propose such a solution, as soon as reasonably possible, for consideration by the NYISO and NYDPS.

31.2.5.9.4 Any party may submit an alternative Gap Solution proposal to the NYISO and the NYDPS for their consideration. The NYISO shall evaluate all Gap Solution proposals to determine whether they will meet the Reliability Need or imminent threat. The NYISO will report the results of its evaluation to the party making the proposal as well as to the NYDPS and/or other appropriate ~~regulatory~~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.

31.2.5.9.5 Gap Solution proposals submitted under Sections 31.2.5.9.3 and 31.2.5.9.4 shall be designed to be temporary solutions and to strive to be compatible with permanent market-based proposals.

31.2.5.9.6 A permanent regulated solution, if appropriate, may proceed in parallel with a Gap Solution.

31.2.5.10 Confidentiality of Solutions

31.2.5.10.1 The term “Confidential Information” shall include all types of solutions to Reliability Needs that are submitted to the NYISO as a response to Reliability Needs identified in any RNA issued by the NYISO as part of the CRPP if the supplier or owner of that solution designates such reliability solutions as “Confidential Information.”

31.2.5.10.2 For regulated backstop solutions and plans submitted by the Responsible Transmission Owner in response to the findings of the RNA, the NYISO shall maintain the confidentiality of same until the NYISO and the Responsible Transmission Owner have agreed that the Responsible Transmission Owner has submitted sufficient regulated backstop solutions and plans to meet the Reliability Needs identified in an RNA. Thereafter, the NYISO shall disclose the regulated backstop solutions and plans to the Market Participants; however, any preliminary cost estimates that may have been provided to the NYISO shall not be disclosed.

31.2.5.10.3 For an alternative regulated response, the NYISO shall determine, after consulting with the owner or supplier thereof, whether the response would meet part or all of the Reliability Needs identified in an RNA, and thereafter 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 NYISO shall not be disclosed.

31.2.5.10.4 For a market-based response, the NYISO shall maintain the confidentiality of same during the CRPP and in the Comprehensive Reliability Plan, except for the following information which may be disclosed by the NYISO: (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.

31.2.5.10.5 In the event that the developer has made a public announcement of its project or has submitted a proposal for interconnection with the NYISO, the

NYISO shall disclose the identity of the market-based developer and the specific project during the CRPP and in the Comprehensive Reliability Plan.

31.2.6 Comprehensive Reliability Plan

Following the NYISO's evaluation of the proposed market-based and regulated solutions to Reliability Needs, the NYISO will prepare a draft Comprehensive Reliability Plan ("CRP"). The draft CRP shall set forth the NYISO's findings and recommendations, including any determination that implementation of a regulated solution (which may be a Gap Solution) is necessary to ensure system reliability.

31.2.6.1 Collaborative Governance Process

The NYISO Staff shall submit the draft CRP to TPAS and ESPWG for review and comment. The NYISO 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 subject to such other terms and conditions that the NYISO may reasonably determine are 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 CRP ~~shall be forwarded, along with a summary of all comments of interested parties provided during~~reflecting the revisions resulting from the TPAS and ESPWG review, shall be forwarded to the Operating Committee for a discussion and action. The NYISO 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.

31.2.6.2 Board Action

Following the Management Committee vote, the draft CRP, with working group, Operating Committee, and Management Committee input, will be forwarded to the NYISO Board for review and action. Concurrently, the draft CRP will also be provided to the Market Monitoring Unit his for its review and consideration of whether market rule changes are necessary to address an identified failure, if any, in one of the NYISO's competitive markets. The Board may approve the draft CRP as submitted or propose modifications on its own motion. 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 NYISO shall issue the CRP to the marketplace by posting on its website. The NYISO will provide the CRP to the appropriate regulatory agency(ies) for consideration in their review of the proposals.

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.

31.2.6.3 Reliability Disputes

Notwithstanding any provision to the contrary in this Attachment, the NYISO OATT, or the NYISO Services Tariff, in the event that a Market Participant or other interested party raises a dispute solely within the NYPSC's jurisdiction concerning NYISO'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 NYISO's Comprehensive Reliability Planning Process Manual. 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.

31.2.6.4 Determination of Necessity

31.2.6.4.1 If the NYISO determines in the CRP that implementation of a regulated solution is necessary, the NYISO will request the Responsible Transmission Owner to submit its proposal for a ~~regulated~~ regulated backstop solution to the appropriate ~~regulatory~~ governmental agency(ies) and/or authority(ies) to begin the necessary approval process. The Responsible Transmission Owner in response to the NYISO request shall make such a submission. Other Developers and Transmission Owners proposing alternative regulated solutions pursuant to Section 31.2.4.4.2 that have completed any changes required by the NYISO under Section 31.2.5.4, which the NYISO has determined will resolve the identified ~~deficiencies~~Reliability Need, may submit these proposals to the appropriate ~~state regulatory~~governmental agency(ies) and/or authority(ies) for review. The appropriate governmental agency(ies) and/or authority(ies) with jurisdiction over the implementation or siting will determine whether the regulated backstop solution or an alternative regulated solution will be implemented to address the identified Reliability Need. If the appropriate ~~state~~governmental agency(ies) and/or authority(ies) makes a final determination that an alternative regulated solution is the preferred solution to a Reliability Need and that the regulated backstop solution should not be implemented, implementation of the alternative regulated solution will be ~~implemented by~~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 ~~with a~~through the implementation of its regulated backstop solution. Should the alternative regulated solution not be implemented, the NYISO may request a Gap solution pursuant to Section 31.2.5.9 of this Attachment.

31.2.6.4.2 If the NYISO determines in the CRP that it is necessary for the Responsible Transmission Owner to proceed with the regulated solution identified in 31.2.6.4.1 in parallel with a market-based solution in order to ensure that a Reliability Need is met in a timely manner, the Responsible Transmission Owner shall proceed with due diligence to develop it in accordance with Good Utility Practice unless or until notified by the NYISO that it has determined that the regulated solution is no longer needed.

31.2.6.4.3 If, after consultation with the Responsible Transmission Owner, the NYISO determines that the Responsible Transmission Owner has not submitted its proposed solution for necessary regulatory action within a reasonable period of time, or that the Responsible Transmission Owner has been unable to obtain the approvals or property rights necessary under applicable law to construct the project, the NYISO shall submit a report to the FERC for its consideration and determination of whether any action is appropriate under federal law.

31.2.7 Monitoring of Reliability Project Status

31.2.7.1 The NYISO will monitor and report on the status of market-based solutions to ensure their continued viability to meet Reliability Needs on a timely basis in the CRP. The NYISO's criteria to assess the continued viability of such projects are included in the NYISO's Comprehensive Reliability Planning Process Manual.

31.2.7.2 The NYISO will monitor and report on the status of regulated solutions to ensure their continued viability to meet Reliability Needs on a timely basis in the CRP. The NYISO's criteria to assess the continued viability of such projects are included in the NYISO's Comprehensive Reliability Planning Process Manual.

31.2.7.3 The NYISO will apply the criteria in this Section 31.3 for halting a regulated solution that is already underway because of the entry of a viable market-based solution that the NYISO has determined will meet the same Reliability Need. These criteria shall also include a cut-off point following which a regulated solution may not be cancelled regardless of the appearance of a market-based solution.

31.2.7.3.1 The NYISO shall review proposals for market-based solutions, pursuant to Section 31.2.5.3 of this Attachment Y. If, based on the availability of market-based solution(s) to meet the identified Reliability Need, the NYISO determines that the regulated backstop solution is no longer needed and should be halted, it will immediately notify the Responsible Transmission Owner and will so state in the CRP. If a regulated backstop solution is halted by the NYISO, 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, will be recoverable by the Responsible Transmission Owner under the cost recovery mechanism in the NYISO tariff regardless of the nature of the solution.

31.2.7.3.2 Once the Responsible Transmission Owner submits its application for state regulatory approval of the regulated backstop solution, pursuant to Section 31.2.6.4.1 of this Attachment Y, or, if state regulatory approval is not required, once the Responsible Transmission Owner submits its application for any necessary regulatory approval, the entry of a market-based solution will not result in the halting by the NYISO of the regulated backstop solution. The NYISO, however, will continue to evaluate proposed market-based solutions to determine their ability to meet the identified Reliability Need in a timely manner, and will provide the results of its review to the Responsible Transmission Owner, Market Participants and the appropriate state regulatory agency(ies).

31.2.7.3.3 If a material modification to the regulated backstop solution is proposed by any federal, state or local agency, the Responsible Transmission Owner will request the NYISO to conduct a supplemental reliability review. If the NYISO identifies any reliability deficiency in the modified solution, the NYISO will so advise the Responsible Transmission Owner and the appropriate federal, state or local regulatory agency(ies).

31.2.7.3.4 If the appropriate federal, state or local agency(ies) does not approve a necessary authorization for the regulated backstop solution, all of the necessary and reasonable costs incurred and commitments made up to the final federal, state or local regulatory decision will be recoverable by the Responsible Transmission Owner under the NYISO cost recovery mechanism regardless of the nature of the solution.

31.2.7.3.5 The NYISO is not required to review market-based solutions to determine whether they will meet the identified Reliability Need in a timely manner after the regulated backstop solution has received federal and state regulatory approval, unless a federal or state regulatory agency requests the NYISO to conduct such a review. The NYISO will report the results of its review to the federal or state regulatory agency, with copies to the Responsible Transmission Owner.

31.2.7.3.6 If a necessary federal, state or local authorization for a regulated 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, will be recoverable under the NYISO cost recovery mechanism by the Responsible Transmission Owner regardless of the nature of the solution. When an alternative regulated solution proposed by a Transmission Owner or Other Developer has been determined by the PSC or other State authorities to be the preferred solution to a Reliability Need and the Transmission Owner or Other Developer makes all best efforts to obtain necessary federal, state or local authorization, but these authorizations are not granted or are withdrawn, then all reasonably incurred expenditures and necessary expenses incurred to implement an orderly termination of the project, will be recoverable under the NYISO cost recovery mechanism by the Transmission Owner or Other Developer, provided that such expenditures and commitments were before the PSC or other State authorities when it made its determination that the alternative regulated solution is the preferred solution.

31.2.7.4 The NYISO will apply the criteria in this Section 31.2.7.4 for determining the cutoff date for a determination that a market-based solution will not be available to meet a Reliability Need on a timely basis.

31.2.7.4.1 In the first instance, the NYISO 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 date on which the NYISO would otherwise have invoked a regulated backstop solution, it becomes even more critical for the NYISO to conduct a continued analysis of the viability of such market-based solutions.

31.2.7.4.2 The developer of such a market-based solution shall submit updated information to the NYISO twice during each CRPP 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 backstop solutions. If no solutions are requested in a particular year, then the second update will be provided during the NYISO'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 reliability need date, and any other information requested by the NYISO.

31.2.7.4.3 The developer shall immediately report to the NYISO when it has any indication of a material change in the project status or that the project in-service date may slip beyond the Reliability Need date. 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.

31.2.7.4.4 Based upon the above information, the NYISO will perform an independent review of the development status of the market-based solution to determine that it remains viable to meet the identified reliability need in a timely manner. If the NYISO, 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.

31.2.7.4.5 The NYISO, prior to making a determination about the viability of a specific proposed solution, will communicate its intended determination to the project sponsor along with the basis for its intended determination. The NYISO shall provide sponsor a reasonable period (not more than 2 weeks) to respond to the NYISO's intended determination, including an opportunity to provide additional information to the NYISO to support the continued viability of the proposed solution.

31.2.7.4.6 If the NYISO determines that a market-based solution that is needed to meet an identified Reliability Need is no longer viable, it will request the Responsible Transmission Owner to invoke the regulated backstop solution, or to seek other measures including but not limited to a Gap Solution, to ensure the reliability of the system within the benchmark timeframe.

31.2.7.4.7 If the NYISO determines that the market-based solution is still viable, but that its in-service date is likely to slip beyond the reliability need date, the NYISO will request the Responsible Transmission Owner to prepare a Gap Solution in accordance with the provisions of this Attachment Y.

31.3 Economic Planning Process

31.3.1 Congestion Assessment and Resource Integration Study for Economic Planning

31.3.1.1 General

The NYISO shall prepare and publish the Congestion Assessment and Resource Integration Study ("CARIS") as described below. The CARIS for economic planning will align with the reliability planning process. Each CARIS will use a ten-year planning horizon consistent with the reliability planning horizon. Each CARIS will be based on the most recently concluded and approved CRP. The base case for each CARIS will assume a reliable system for the ten-year planning horizon based upon the CRP.

31.3.1.2 Interested Party Participation in the Development of the CARIS

31.3.1.2.1 The NYISO 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 NYISO'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 NYISO staff to allow Market Participants and other interested parties to participate in a meaningful way during each stage of the economic planning process. The NYISO 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 NYISO, 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 NYISO, 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 NYISO OATT, or studies that a customer can request related to Network Integration Transmission Service pursuant to Section 4.5 of the NYISO OATT, or studies related to interconnection requests under Attachment X or Attachment Z of the NYISO OATT.

31.3.1.2.4 The NYISO 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 CRP.

31.3.1.3.2 The CARIS will assume a reliable system throughout the Study Period, based upon the solutions identified in the most recently completed and approved CRP. 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 in prior or current CRPs. The NYISO, 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 in the most recent CRP 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 NYISO 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 NYISO, 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 and demand response. 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 NYISO 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 New York 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 NYISO will work with the ESPWG to determine the most useful metrics for each CARIS cycle, given overall NYISO 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 three 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 New York 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 31.4.3.4. 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 ~~in accordance with the NYISO manuals~~as set forth below. The ICAP cost metric will be highly dependent on the rules and procedures guiding the calculation of the IRM, ~~and~~ LCR, and the ICAP Demand Curves, both for the next capability period and future capability periods. In each CARIS cycle, the ~~NY~~ISO will ~~work~~ review, with the ESPWG and, ~~to the extent needed, the ICAP Working Group~~as appropriate, other ISO committees, ~~to determine whether~~ the results of the ICAP cost metric~~should be adjusted~~.

31.3.1.3.5.6.1 ~~For the initial CARIS study cycle, t~~The ICAP metric, in the form of ~~will be based on~~ a megawatt impact, will be computed based on a methodology that: (1) determines the base system loss of load expectation (“LOLE”) for the applicable horizon year; (2) adds the proposed economic project; and (3) calculates the LOLE for the system with the addition of the proposed economic project. If the system LOLE is lower than that of the base system, the NYISO will reduce generation in all New York Control Area ("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 (A) and then:

(1) 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 economic 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 Load and Capacity table 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 economic 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 economic 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 Load and Capacity table 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 economic project and end ten years after the proposed commercial operation date of the proposed economic 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 economic 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 economic 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 Load and Capacity tables developed for the CARIS process.

For each Locality, 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 that Locality under the assumption that the proposed economic 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 Load and Capacity table developed for that year; (ii) subtracting the greater of that forecasted cost per megawatt-year with the proposed economic project in place or the forecasted Rest of State Installed Capacity cost per megawatt-year with the proposed economic project in place from the forecasted cost of Installed Capacity in that Locality calculated in subsection (1) under the assumption that the proposed economic 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 economic project and end with the earlier of: (i) the year when the system, with the proposed economic project in place, reaches an LOLE of 0.1, or (ii) ten years after the proposed commercial operation date of the proposed economic 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 Load and Capacity table 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.

31.3.1.4 Planning Participant Data Input

At the NYISO's request, Market Participants, Developers and other parties shall provide, in accordance with the schedule set forth in the NYISO Comprehensive Reliability Planning Process Manual, the data necessary for the development of the CARIS. This input will include but not be limited to existing and planned additions 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 NYISO. The relevant Transmissions Owners will assist the NYISO in developing the potential solution cost estimates to be used by the NYISO to conduct benefit/cost analysis of each of the potential solutions.

31.3.1.5 Congestion and Resource Integration Scenario Development

The NYISO, in consultation with the ESPWG and TPAS, 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 NYISO resource requirements. The NYISO shall report the results of these scenario analyses in the CARIS.

31.3.1.6 CARIS Report Preparation

Once all the analyses described above have been completed, NYISO 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

31.3.2.1 Collaborative Governance Process

The draft CARIS shall be submitted to both TPAS and the ESPWG for review and comment. The NYISO shall make available to any interested party sufficient information to replicate the results of the draft CARIS. The information made available will be electronically masked and made available subject to such other terms and conditions that the NYISO may reasonably determine are 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 ~~sent~~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 NYISO 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 NYISO 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.

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 NYISO will provide various opportunities for Market Participants and other potentially interested parties to discuss final CARIS. Such opportunities may include presentations at various NYISO 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 its ten-year study period and, for informational purposes, provides benefit/cost analysis and other analysis of potential solutions to the congestion identified. If, in response to the CARIS, a developer proposes an actual project to address specific congestion identified in the CARIS, then the NYISO will process that project proposal in accordance with the relevant provisions of Sections 31.4.1, 31.4.3 and 31.4.4 of this Attachment Y.

Filed December 11, 2009 to comply with order of the Federal Energy Regulatory Commission, Docket Nos. OA08-004,-006, issued October 15, 2009, 129 FERC ¶ 61,044 (2009). Proposed effective date: December 14, 2009

Filed April 13, 2010 to comply with order of the Federal Energy Regulatory Commission, Docket Nos. OA08-52-004 and-006, issued October 15, 2009, 129 FERC ¶ 61,044 (2009). Proposed effective date: April 13, 2010.

31.4 Cost Allocation and Cost Recovery

31.4.1 The Scope of Attachment Y Cost Allocation

31.4.1.1 Regulated Responses

The cost allocation principles and methodologies in this Attachment Y cover only regulated transmission solutions to Reliability Needs and regulated transmission responses to congestion identified in the CARIS, whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer. The cost allocation principles and methodology covering regulated transmission solutions to Reliability Needs are contained in Sections 31.4.2.1 and 31.4.2.2 of this Attachment Y. The separate cost allocation principles and methodology covering regulated transmission responses to congestion identified in the CARIS are contained in Sections 31.4.3.1 and 31.4.3.2 of this Attachment Y.

31.4.1.2 Market-Based Responses

The cost allocation principles and methodologies in this Attachment Y do not apply to market-based solutions to Reliability Needs or to market-based responses to congestion identified in the CARIS. The cost of a market-based project shall be the responsibility of the developer of that project.

31.4.1.3 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 and Attachment X and Attachment Z of the NYISO OATT.

31.4.1.4 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 NYISO OATT.

31.4.1.5 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.

31.4.1.6 Regulated Non-Transmission Solutions to Reliability Needs

Costs related to regulated non-transmission reliability 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.

31.4.2 Regulated Responses to Reliability Needs

31.4.2.1 Cost Allocation Principles

Cost allocation for regulated transmission solutions to Reliability Needs shall be determined by the NYISO based upon the principle that beneficiaries should bear the cost responsibility. The specific cost allocation methodology, to be developed by the NYISO in consultation with the ESPWG, will incorporate the following elements:

31.4.2.1.1 The focus of the cost allocation methodology shall be on solutions to violations of specific Reliability Criteria.

31.4.2.1.2 Potential impacts unrelated to addressing the Reliability Needs shall not be considered for the purpose of cost allocation for regulated solutions.

31.4.2.1.3 Primary beneficiaries shall initially be those Transmission Districts identified as contributing to the reliability violation.

31.4.2.1.4 The cost allocation among primary beneficiaries shall be based upon their relative contribution to the need for the regulated solution.

31.4.2.1.5 The NYISO 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).

31.4.2.1.6 Cost allocation among Transmission Districts shall recognize the terms of prior agreements among the Transmission Owners, if applicable.

31.4.2.1.7 Consideration should be given to the use of a materiality threshold for cost allocation purposes.

31.4.2.1.8 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.4.2.1.9 Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

31.4.2.1.10 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.4.2.1.11 The methodology shall apply, to the extent possible, to Gap Solutions.

31.4.2.1.12 Cost allocation is independent of the actual triggered project(s), except when allocating Minimum Locational Capacity Requirement ("LCR") cost responsibilities, and is based on a separate process that results in NYCA meeting its LOLE requirement.

31.4.2.1.13 The target year is the year in which a need will be met by a backstop solution(s).

31.4.2.1.14 The trigger year is the year in which the backstop solution must begin to be implemented, driven by the project lead time.

31.4.2.1.15 Cost allocation for a solution that meets the needs of a target year assumes that backstop solutions of prior years have been implemented.

31.4.2.1.16 Cost allocation will consider the most recent values for LCRs. LCR must be met for the target year.

31.4.2.2 Cost Allocation Methodology

31.4.2.2.1 General Reliability Solution Cost Allocation Formula:

The cost allocation mechanism for regulated transmission reliability projects, whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer, would be used as a basis for allocating costs associated with projects that are triggered to meet Reliability Needs identified in the RNA. The formula is not applicable to that portion of a project oversized beyond the smallest technically feasible solution that meets 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 NYISO 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. 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. This cost allocation process can be applied to any solution or set of solutions that involve single or multiple cost allocation steps. One formula can be applied to any solution set:

$$\text{Cost Allocation}_i = \left[\frac{\text{LCRdef}_i}{\text{Soln Size}} + \left[\frac{\text{Coincident Peak}_i \times (1 + \text{IRM} - \text{LCR}_i)}{\sum_{k=1}^{n} \text{Coincident Peak}_k \times (1 + \text{IRM-LCR}_k)} \times \frac{\text{Soln STWdef}}{\text{Soln Size}} \right] \right.$$

$$= \qquad + \left[\frac{\text{Coincident Peak}_i \times (1 + \text{IRM} - \text{LCR}_i)}{\sum_{l=1}^{m} \text{Coincident Peak}_l \times (1 + \text{IRM} - \text{LCR}_l)} \times \frac{\text{SolnCIdef}}{\text{Soln Size}} \right] \times 100\%$$

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.

Three step cost allocation methodology for regulated reliability solutions:

31.4.2.2.1.1 Step 1 - LCR Deficiency

31.4.2.2.1.1.1 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:

$$Allocation_i = \frac{LCRdef_i}{Soln\_ Size} \text{ x } 100\%$$

Where *i* is for each applicable LCR zone, $LCRdef_i$ represents the applicable zonal LCR deficiency, and SolnSize represents the total compensatory MW addressed by the applicable project.

31.4.2.2.1.1.2 Prior to the LOLE calculation, voltage constrained interfaces will be recalculated to determine the resulting transfer limits when the LCRdef MW are added.

31.4.2.2.1.2 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.

31.4.2.2.1.2.1 If NYCA is found to be resource limited, the NYISO, 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.

31.4.2.2.1.2.2 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:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i \times \left(1+\text{IRM-}LCR_i\right)}{\sum_{k=1}^{n} \text{Coincident Peak}_k \times \left(1+\text{IRM-}LCR_k\right)} \times \frac{\text{SolnSTWdef}}{\text{Soln Size}} \right] \times 100\%$$

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 SolnSize represents the total compensatory MW addressed by the applicable project.

31.4.2.2.1.3 Step 3 - Constrained Interface Deficiency. If the NYCA is not resource limited as determined by the NYCA Free Flow Test, then the NYISO will examine constrained transmission interfaces, using the Binding Interface Test.

31.4.2.2.1.3.1 The NYISO 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.

31.4.2.2.1.3.2 NYISO 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.

31.4.2.2.1.3.3 Zone(s) within areas isolated from the rest of NYCA as a result of constrained interface limits (the "Bounded Regions") are assigned cost responsibility for the compensatory MW, defined as CIdef, needed to reach an LOLE of 0.1.

31.4.2.2.1.3.4 If one or more Bounded Regions are isolated as a result of binding interfaces identified through the Binding Interface Test, the NYISO 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

31.4.2.2.1.3.5 The Bounded Regions will be identified by the NYISO'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 NYISO 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.

31.4.2.2.1.3.6 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:

$$\text{Allocation}_{i} = \left[\frac{\text{Coincident Peak}_{i} \text{ x } \left(1+\text{IRM-}LCR_{i}\right)}{\sum_{l=1}^{m} \text{Coincident Peak}_{l} \text{ x } \left(1+\text{IRM-}LCR_{l}\right)} \text{ x } \frac{SolnCIdef}{\text{Soln Size}} \right] \text{ x } 100\%$$

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 So1nSize represents the total compensatory MW addressed by the applicable project.

31.4.2.2.1.4 If, after the completion of Steps 1 through 3, there is a thermal or voltage security issue that does not cause an LOLE violation, it will be deemed a local issue and related costs will not be allocated under this process.

31.4.2.2.1.5 Costs related to the deliverability of a resource will be addressed under the NYISO’s deliverability procedures.

31.4.2.2.1.6 This cost allocation methodology would be used for any projects required to meet Reliability Needs identified in the RNA that are triggered prior to January 1, 2016. Costs associated with any projects triggered on or after January 1, 2016 will be allocated according to a methodology, which, after proper consideration within the NYISO stakeholder process, will be filed by the NYISO for FERC approval prior to January 1, 2016, in accordance with the NYISO governance process. The filing may provide for a continuation of the forgoing methodology or a revised methodology.

31.4.3 Regulated Economic Projects

31.4.3.1 The Scope of Section 31.4.3

As discussed in Section 31.4.1 of this Attachment Y, the cost allocation principles and methodologies of this Section 31.4.3 apply only to regulated economic transmission projects proposed in response to congestion identified in the CARIS. This Section 31.4.3 does not apply to generation or demand side management projects, nor does it apply to any market-based projects. This Section 31.4.3 does not apply to regulated backstop solutions triggered by the NYISO pursuant to the Comprehensive Reliability Planning Process, provided, however, the cost allocation principles and methodologies in this Section 31.4.3 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 NYISO 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.

31.4.3.2 Cost Allocation Principles

Cost allocation for regulated transmission responses to NYISO studies of future congestion shall be determined by the NYISO based upon the principle that beneficiaries should bear the cost responsibility. The specific cost allocation methodology in Section 31.4.3.4 incorporates the following elements:

31.4.3.2.1 The focus of the cost allocation methodology shall be on responses to specific conditions identified in studies of future congestion.

31.4.3.2.2 Potential impacts unrelated to addressing the identified congestion shall not be considered for the purpose of cost allocation for regulated economic projects.

31.4.3.2.3 Economic projects that were previously analyzed can proceed on a market basis with willing buyers and sellers at any time.

31.4.3.2.4 Cost allocation shall be based upon a beneficiaries pay approach. Cost allocation under the NYISO tariff for a regulated economic project shall be applicable only when a super majority of the beneficiaries of the project, as defined in Section 31.4.3.6 of this Attachment Y, vote to support the project.

31.4.3.2.5 Beneficiaries of a regulated economic project shall be those entities economically benefiting from the proposed project. The cost allocation among beneficiaries shall be based upon their relative economic benefit.

31.4.3.2.6 Consideration shall be given to the proposed project's payback period.

31.4.3.2.7 The cost allocation methodology shall address the possibility of cost overruns.

31.4.3.2.8 Consideration shall be given to the use of a materiality threshold for cost allocation purposes.

31.4.3.2.9 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.4.3.2.10 Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

31.4.3.2.11 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.4.3.2.12 Benefits determination shall consider various perspectives, based upon the agreed-upon metrics for analyzing congestion.

31.4.3.2.13 Benefits determination shall account for future uncertainties as appropriate (e.g., load forecasts, fuel prices, environmental regulations).

31.4.3.2.14 Benefits determination shall consider non-quantifiable benefits as appropriate (*e.g.*, - system operation, environmental effects, renewable integration).

31.4.3.3 Project Eligibility for Cost Allocation

The methodologies in this Section 31.4.3.3 will be used to determine the eligibility of a regulated economic transmission project to have its cost allocated and recovered pursuant to the provisions of this Attachment Y.

31.4.3.3.1 The NYISO will evaluate the benefits and costs of each regulated economic transmission project 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 NYISO to conduct the ten-year cost/benefit analysis of its project. The NYISO, in conjunction with the ESPWG, will develop methodologies for extending the CSPP study period database as necessary to evaluate the benefits and costs of each regulated economic transmission project.

31.4.3.3.2 The benefit metric for eligibility under the NYISO's cost/benefit 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.

31.4.3.3.3 The cost for the NYISO'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 annual total revenue requirement for the project, reasonably allocated over the first ten years from the proposed commercial operation date for the project.

31.4.3.3.4 For informational purposes only, the NYISO 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.

31.4.3.3.5 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. 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 31.4.3.6 of this Attachment Y.

31.4.3.3.6 In addition to the eligibility benefit metric used in its benefit/cost analysis, the NYISO will calculate the additional metrics to estimate the potential benefits of the proposed project, for information purposes only, in accordance with Section 31.3.1.3, 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 31.4.3.4.2.3. The NYISO will provide information on these additional metrics to the maximum extent practicable considering its overall resource commitments.

31.4.3.3.7 In addition to the benefit/cost analysis performed by the NYISO under this Section 31.4.3.3, the NYISO will work with the ESPWG to consider the development and implementation of scenario analyses, for information only, that shed additional light on the cost and benefit 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 annual resource commitments of the NYISO.

31.4.3.4 Cost Allocation for Eligible Projects

As noted in Section 31.4.3.2 of this Attachment Y, the cost of a regulated economic transmission project will be allocated to those entities that would economically benefit from implementation of the proposed project.

31.4.3.4.1 The NYISO 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 NYISO, in conjunction with the ESPWG, will develop methodologies for extending the CSPP study period database as necessary for this purpose.

31.4.3.4.2 The NYISO will identify beneficiaries of a proposed project as follows:

31.4.3.4.2.1 The NYISO 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 NYISO as set forth in subsection (~~i~~v) 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.

31.4.3.4.2.2 The beneficiaries will be those load zones who 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 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 NYISO will proceed with the development of the zonal cost allocation information to inform the beneficiary voting process.

31.4.3.4.2.3 Net 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, excluding 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. ~~Calculations of net reductions in TCC revenues will be detailed in the NYISO manuals~~These forecasts shall be performed using the procedure described in Appendix B to this Attachment Y.

31.4.3.4.2.4 Estimated TCC revenues from any Incremental TCCs created by a proposed regulated economic transmission project 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.

31.4.3.4.2.5 The NYISO will solicit bilateral contract information from all Load Serving Entities, which will provide the NYISO with bilateral energy contract data for modeling contracts that ~~are~~do not ~~indexed~~receive benefits, in whole or in part, from~~to~~ 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 NYISO will not be included in the calculation of the present value of the annual zonal LBMP savings in section (i) above.~~ Details regarding the information provided on bilateral contracts will be set forth in the NYISO manuals.~~

31.4.3.4.2.5.1 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

31.4.3.4.2.5.2 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 OATT, and Article 6 of the Services Tariff.

31.4.3.4.2.5.3 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.

31.4.3.4.2.5.4 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:

$$AdjLBMPS_{y,z} = \max\left[0, TL_{y,z} - \sum_{b \in B_{y,z}} \left(BCL_{b,y,z} \cdot \left(1 - Ind_{b,y,z}\right)\right) - SG_{y,z}\right] \cdot \left(LBMP1_{y,z} - LBMP2_{y,z}\right),$$

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 31.4.3.4.2.5

$BCL_{b,y,z}$ 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*;

LBMP1y,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.

(vi) NZS_z, the Net Zonal Savings for each Load Zone *z* resulting from a given project, shall be calculated using the following equation:

$$NZS_z = \max\left[0, \sum_{y=PS}^{PS+9} \left(AdjLBMPS_{y,z} - TCCRevImpact_{y,z}\right) \cdot DF_y\right],$$

Where:

PS is the year in which the project is expected to enter commercial operation;

$AdjLBMPS_{y,z}$ is as calculated in Section 31.4.3.4.2.5;

$TCCRevImpact_{y,z}$ is the forecasted impact of TCC revenues allocated to Load Zone *z* in year *y*, calculated using the procedure described in Appendices 30.6 to 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*.

31.4.3.4.3 Load zones not benefiting from a proposed project 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.

31.4.3.4.4 Costs of a project will be allocated to beneficiaries as follows:

31.4.3.4.4.1 For each load zone that would benefit from a proposed project, as determined pursuant to Section 31.4.3.4.2, the NYISO will allocate the cost of the project based on the zonal share of total savings. Total savings will be equal to the sum of load savings for each load zone that experiences net benefits pursuant to Section 31.4.3.4.2. A load zone's cost allocation will be equal to the present value of the following calculation:

$$\text{Zonal Cost Allocation} = \text{Project Cost} \times \left(\frac{\left(\text{Zonal Benefits}\right)}{\text{Total Zonal Benefits for zones with positive net benefits}}\right)$$

31.4.3.4.4.2 Zonal cost allocation calculations for a project 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.

31.4.3.4.4.3 Within zones, costs will be allocated to Load Serving Entities based on MWhs calculated for each LSE for each zone using the most recent calendar year data. Allocations to an LSE will be calculated in accordance with the following formula:

$$\text{LSE Intrazonal Cost Allocation} = \text{Zonal Cost Allocation} \times \left(\frac{\text{LSE Zonal MWh}}{\text{Total Zonal MWh}} \right)$$

31.4.3.4.5 Project costs allocated under this Section 31.4.3.4 will be determined as follows:

31.4.3.4.5.1 The project cost allocated under this Section 31.4.3.4 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 FERC. If there is no formula rate on file at FERC, then the developer shall provide to the NYISO the project-specific parameters to be used to calculate the total project revenue requirement.

31.4.3.4.5.2 Once the cost benefit analysis is completed the amortization period and the other parameters used for cost allocation for the project should not be changed, unless so ordered by FERC or a court of applicable jurisdiction, for cost recovery purposes to maintain the continued validity of the cost benefit analysis.

31.4.3.4.5.3 The NYISO, in conjunction with the ESPWG, will develop procedures to allocate the risk of project cost increases that occur after the NYISO 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 over-runs**.**

31.4.3.4.6 FERC must approve the cost of a proposed economic transmission project for that cost to be recovered through the NYISO tariff. The developer's filing with FERC must be consistent with the project proposal evaluated by the NYISO under this Attachment Y in order to be cost allocated to beneficiaries.

31.4.3.5 Collaborative Governance Process and Board Action

31.4.3.5.1 The NYISO shall submit the results of its project cost/benefit analysis and beneficiary determination to the ESPWG for comment. The NYISO shall make available to any interested party sufficient information to replicate the results of the cost/benefit analysis and beneficiary determination. The information made available will be electronically masked and made available subject to such other terms and conditions that the NYISO may reasonably determine are 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 NYISO's analysis reflecting the revisions resulting from the TPAS and ESPWG review shall be forwarded to the Business Issues Committee and Management Committee for discussion and action.

31.4.3.5.2 Following the Management Committee vote, the NYISO's project cost/benefit analysis and beneficiary determination will be forwarded, with the input of the Business Issues Committee and Management Committee, to the NYISO Board for review and action. The Board may approve the analysis and beneficiary designations as submitted or propose modifications on its own motion. If any changes are proposed by the Board, the revised analysis and beneficiary designations shall be returned to the Management Committee for comment. The Board shall not make a final determination on the project cost/benefit analysis and beneficiary designation until it has reviewed the Management Committee comments. Upon final approval of the Board, project cost/benefit analysis and beneficiary designations shall be posted by the NYISO on its website and shall form the basis of the beneficiary voting described in Section 31.4.3.6 of this Attachment Y.

31.4.3.6 Voting by Project Beneficiaries

31.4.3.6.1 Only Load Serving Entities determined to be beneficiaries of a proposed project in accordance with the procedures in Section 31.4.3.4 of this Attachment Y shall be eligible to vote on a proposed project. The NYISO will, in conjunction with the ESPWG, develop procedures to determine the specific list of voting entities for each proposed project.

31.4.3.6.2 The voting share of each Load Serving Entity shall be weighted in accordance with its share of the total project benefits, as allocated by Section 31.4.3.4 of this Attachment Y.

31.4.3.6.3 For a regulated economic transmission project to have its cost allocated under this Attachment Y, eighty (80) percent or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project.

31.4.3.6.4 If the project 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.

31.4.3.6.5 The NYISO will tally the results of the vote in accordance with procedures set forth in the NYISO manuals, and report the results to stakeholders. Beneficiaries voting against approval of a project must submit to the NYISO 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 NYISO 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 cost/benefit analysis; and (3) where a project is not approved, whether the developer has provided any formal indication to the NYISO as to the future development of the project.

31.4.4 Cost Recovery for Regulated Projects

Responsible Transmission Owners, Transmission Owners and Other Developers will 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 regulated projects, including Gap Solutions, undertaken pursuant to Section 31.2.6.4 of this Attachment Y to meet a Reliability Need. The costs of a regulated reliability project to be recovered pursuant to this Section 16 will be reduced by any amounts that, pursuant to Section 25.7.12 of Attachment S to the NYISO OATT, have been previously committed by or collected from Developers for the installation of System Deliverability Upgrades required for the interconnection of generation or merchant transmission projects. Transmission Owners and Other Developers will be entitled to recovery of costs associated with the implementation of a regulated economic transmission project in accordance with the provisions of Section 31.4.3 of this Attachment Y.

31.4.4.1 The Responsible Transmission Owner, Transmission Owner or Other Developer will receive cost recovery for a regulated solution it undertakes to meet a Reliability Need pursuant to Section 31.2.6.4 of this Attachment Y that is subsequently cancelled in accordance with the criteria established pursuant to Section 31.3 of this Attachment Y. Such costs will include reasonably incurred costs through the time of cancellation, including any forward commitments made.

31.4.4.2 The Responsible Transmission Owner, Transmission Owner or Other Developer will recover its costs described in this Section 31.4.4 incurred with respect to the implementation of a regulated transmission solution in accordance with the provisions of Rate Schedule 10 of this tariff. Provided further that cost recovery for regulated transmission projects undertaken by a TO pursuant to this Attachment Y shall be in accordance with the provisions of the Agreement Between the New York Independent System Operator, Inc. and the New York Transmission Owners on the Comprehensive Planning Process.

31.4.4.3 Costs related to regulated non-transmission reliability 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. 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 same and transmission of electric energy subject to the jurisdiction of the Commission.

31.4.4.4 For a regulated economic transmission project that meets the requirements of Section 31.4.3 of this Attachment Y, the Transmission Owner or Other Developer shall have the right to make a filing with FERC, under Section 205 of the Federal Power Act, for approval of its costs associated with implementation of the project. The filing of the Transmission Owner or Other Developer must be consistent with its project proposal made to and evaluated by the NYISO under Section 31.4.3 of this Attachment Y. The period for cost recovery, if any is approved, will be determined by FERC and will begin if and when the project begins commercial operation. Upon request by NYPA, the NYISO will make a filing on behalf of NYPA.

31.4.4.5 To the extent that Incremental TCCs are created as a result of a regulated economic transmission project that has been approved for cost recovery under the NYISO Tariff, those Incremental TCCs that can be sold will be auctioned or otherwise sold by the NYISO. The NYISO shall determine the amount of Incremental TCCs that may be awarded to an Expansion in accordance with the provisions of Section 19.2.2 of Attachment M of the NYISO OATT. The NYISO will use these revenues to offset the revenue requirements for the project. The Incremental TCCs shall continue to be sold for the depreciable life of the project, and the revenues offset will commence upon the first payment of revenues related to a sale of Incremental TCCs on or after the charge for a specific regulated economic project is implemented.

Filed May 19, 2009 to comply with order of the Federal Energy Regulatory Commission, Docket No. OA08-52-002, issued October 16, 2008, 125 FERC ¶ 61,068 (2008). Proposed effective date: May 19, 2009.

Filed December 11, 2009 to comply with order of the Federal Energy Regulatory Commission, Docket Nos. OA08-004,-006, issued October 15, 2009, 129 FERC ¶ 61,044 (2009). Proposed effective date: December 14, 2009.

Filed April 13, 2010 to comply with order of the Federal Energy Regulatory Commission, Docket Nos. OA08-52-004 and-006, issued October 15, 2009, 129 FERC ¶ 61,044 (2009). Proposed effective date: April 13, 2010.

31.5 Other Provisions

31.5.1 FERC Role in Dispute Resolution

Disputes directly relating to the NYISO's compliance with its tariffs that are not resolved in the internal NYISO collaborative governance appeals process or NYISO dispute resolution process, and all disputes relating to matters that fall within the exclusive jurisdiction of FERC, shall be reviewed at FERC 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 FERC have jurisdiction and responsibility for action may submit a request to FERC for a joint or concurrent hearing to resolve the dispute.

31.5.2 Non-Jurisdictional Entities

LIPA's and NYPA's participation in the NYISO Comprehensive Planning Process 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 FERC's exercise of the Federal Power Act's general ratemaking authority.

31.5.3 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 NYISO Comprehensive 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.

31.5.4 Interregional Planning Coordination

31.5.4.1 The Northeastern ISO/RTO Planning Coordination Protocol

The NYISO will coordinate the transmission system planning activities for the NYCA described in this Attachment Y through the Northeastern ISO/RTO Planning Coordination

Protocol. This protocol describes the committee structure, processes and procedures through which system planning activities are openly and transparently coordinated by the ISOs and RTOs of the northeastern United States and eastern Canada. The activities covered by the protocol are to be conducted in coordination with the Regional Reliability Councils of the northeastern United States and eastern Canada. The primary purpose of the protocol is to contribute, through transparent, coordinated planning based on consistent assumptions and data, to the on-going reliability and the enhanced operational and economic performance of the parties to the protocol. To accomplish this, the parties will coordinate the evaluation of tariff-provided services, such as generation interconnection, to recognize the impacts that result across the different systems. The parties will also produce, on a periodic basis, a Northeastern Coordinated System Plan that integrates the system plans of the parties and includes upgrade projects jointly identified by the parties to enhance the coordinated performance of their systems.

31.6 Appendices

APPENDIX A - REPORTING OF HISTORIC AND PROJECTED CONGESTION

1.0 General

As part of its Comprehensive System Planning Process, the NYISO will prepare summaries and detailed analysis of historic and projected congestion across the New York 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 Congestion

The NYISO 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 NYISO'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 NYISO Operating Committee on January 22, 2004.

3.0 Analysis

Each Reliability Needs Assessment will include the NYISO's summaries and detailed analysis of the prior year's congestion across the New York Transmission System. The NYISO'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 NYISO's analysis conducted in accordance with Section 31.3.1 of this Attachment Y. The NYISO's analysis will identify the significant causes of the projected congestion.

4.0 Detailed Cause Analysis for Unusual Events

The NYISO will perform an analysis to identify the cause of unusual events causing significant congestion levels. Such analysis will include the following elements:
(i) identification or the cause of major transmission outages; and (ii) quantification of the market impact of relieving historic constraints.

Some of the information necessary to this analysis may constitute sensitive electric infrastructure material and will need to be handled with appropriate confidentiality limitations to protect national security interests.

5.0 Summary Reports

The NYISO will prepare various reports of historic and projected congestion costs. Historic congestion reports will be based upon the actual congestion data from the NYISO 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 31.4.3.4.2 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 31.4.3.4.2 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 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 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 NYISO 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.

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) no larger than 2 MW shall be evaluated under the Section 2 Fast Track Process. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kW shall be evaluated under the Appendix 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility larger than 2 MW but no larger than 20 MW or a Small Generating Facility that does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the Section 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 NYISO 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 NYISO's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The NYISO, after consultation with the Connecting Transmission Owner, shall respond within 15 Business Days.

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 make its election known to the NYISO when the Interconnection Customer returns the executed study agreement for the facilities study conducted pursuant to Section 32.3.5 of the SGIP. At that time, the Interconnection Customer must specify the MWs of Capacity Resource Interconnection Service that it is requesting. The NYISO will then place the Small Generating Facility in the then open Class Year and evaluate the Small Generating Facility for deliverability, as a member of the Class Year, Following the same rules and procedures in Attachment S to the NYISO OATT applicable to other members of the Class Year being evaluated for deliverability. Inclusion in the Class Year will only be for the determination of

System Deliverability Upgrade costs and Deliverable MWs 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 IX.C of Attachment S to the NYISO 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 MWs. A Small Generating Facility 2 MWs or smaller may elect Capacity Resource Interconnection Service without being evaluated for deliverability under Attachment S to the NYISO 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 NYISO OATT.

32.1.2 Pre-Application

The NYISO 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 NYISO'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 NYISO, 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.

32.1.3 Interconnection Request

The Interconnection Customer shall submit its Interconnection Request to the NYISO together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be date- and time-stamped by the NYISO upon receipt and a copy shall be sent by the NYISO to the Connecting Transmission Owner. The NYISO'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 NYISO within three Business Days of receiving the Interconnection Request. The NYISO, 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 NYISO 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 NYISO.

32.1.3.1 If the Interconnection Request is to interconnect to a distribution facility, the NYISO will consult with the Connecting Transmission Owner to determine whether the SGIPs apply.

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 NYISO, 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 NYISO, 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 NYISO 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 NYISO OATT will be used to determine the cost responsibility for any System Upgrade Facilities or System Deliverability Upgrades necessary to accommodate the interconnection. The NYISO 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.

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 is no larger than 2 MW and if the Interconnection Customer's proposed Small Generating Facility meets the codes, standards, and certification requirements of Appendices 3 and 4 of these procedures, or the NYISO, 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.

32.2.2 Initial Review

Within 15 Business Days after the NYISO notifies the Interconnection Customer it has received a complete Interconnection Request, the NYISO, 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.[16]

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

[16] 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)

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 NYISO will provide the Interconnection Customer and the Connecting Transmission Owner an executable interconnection agreement within five Business Days after the determination.

32.2.2.3 If the proposed interconnection fails the screens, but the NYISO, 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 NYISO shall provide the Interconnection Customer and the Connecting Transmission Owner an executable interconnection agreement within five Business Days after the determination. To the extent appropriate, the NYISO 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 NYISO, 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 NYISO shall provide the

Interconnection Customer with the opportunity to attend a customer options meeting.

32.2.3 Customer Options Meeting

If the NYISO, in consultation with the Connecting Transmission Owner, determines the Interconnection Request cannot be approved without Minor Modifications at minimal cost; or a supplemental study or other additional studies or actions; or at significant cost to address safety, reliability, or power quality problems, within the five Business Day period after the determination, the NYISO shall notify the Interconnection Customer and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the NYISO's determination, the NYISO 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 NYISO'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; or

32.2.3.2 The NYISO shall offer to perform a supplemental review if the Connecting Transmission Owner concludes that the supplemental review might determine that the Small Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process, and provide a non-binding good faith estimate of the costs of such review; or

32.2.3.3 The NYISO shall offer to continue evaluating the Interconnection Request under the Section 3 Study Process.

32.2.4 Supplemental Review

If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within 15 Business Days of the offer, and submit a deposit to the NYISO for the estimated costs. The Interconnection Customer shall be responsible for the NYISO's and the Connecting Transmission Owner's actual costs for the supplemental review conducted by the NYISO. 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 NYISO will return such excess within 20 Business Days of the invoice without interest.

32.2.4.1 Within ten Business Days following receipt of the deposit for a supplemental review, the NYISO, in consultation with the Connecting Transmission Owner, will determine if the Small Generating Facility can be interconnected safely and reliably.

32.2.4.1.1 If so, the NYISO shall forward an executable an interconnection agreement to the Interconnection Customer and the Connecting Transmission Owner within five Business Days.

32.2.4.1.2 If so, and Interconnection Customer facility modifications are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the NYISO shall forward an executable interconnection agreement to the Interconnection Customer and the Connecting Transmission Owner within five Business Days after receiving written confirmation that the Interconnection Customer has agreed to make the necessary changes at the Interconnection Customer's cost.

32.2.4.1.3 If so, and minor modifications to the Connecting Transmission Owner's electric system are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under the Fast Track Process, the NYISO shall forward an executable interconnection agreement to the Interconnection Customer and the Connecting Transmission Owner within ten Business Days that requires the Interconnection Customer to pay the costs of such system modifications prior to interconnection.

32.2.4.1.4 If not, the Interconnection Request will continue to be evaluated under the Section 3 Study Process.

32.3 Study Process

32.3.1 General Provisions

32.3.1.1 Except as otherwise provided in the SGIPs, the Section 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 (1) is larger than 2 MW but no larger than 20 MW, (2) is 2 MW or less and is not certified, or (3) is 2 MW or less and is certified but 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 NYISO 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 NYISO, 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 NYISO 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 NYISO should perform a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. Unless the Parties agree to skip the feasibility study, the NYISO shall provide the Interconnection Customer and the Connecting Transmission Owner, as soon as possible, but not later than five Business Days after the scoping meeting, a feasibility study agreement (Appendix 6) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the 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 a feasibility study must return the executed feasibility study agreement within 15 Business Days. If the Parties agree not to perform a feasibility study, the NYISO shall provide the Interconnection Customer and the Connecting Transmission Owner, no later than five Business Days after the scoping meeting, a system impact study agreement (Appendix 7) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

32.3.3 Feasibility Study

32.3.3.1 The 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 the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

32.3.3.3 The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (Appendix 6).

32.3.3.4 If the feasibility study shows no potential for adverse system impacts and the Parties agree no system impact study is required, the NYISO shall notify the Interconnection Customer and the Connecting Transmission Owner within 5 Business Days of the completion of the 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 to perform the study. If no additional facilities are required, the NYISO shall send the Parties an executable interconnection agreement within five Business Days.

32.3.3.5 If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

32.3.4 System Impact Study

32.3.4.1 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 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 no transmission system impact study is required, but potential electric power Distribution System adverse system impacts are identified in the scoping meeting or shown in the feasibility study, a Distribution System impact study must be performed. The NYISO shall send the Interconnection Customer and the Connecting Transmission Owner a Distribution System impact study agreement within 15 Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

32.3.4.3 In instances where the feasibility study or the Distribution System impact study shows potential for transmission system adverse system impacts, within 5 Business Days following transmittal of the Interconnection Study report, the NYISO shall send the Interconnection Customer and the Connecting Transmission Owner a transmission system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required. The NYISO shall review and approve the results of the study.

32.3.4.4 If a transmission system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been conducted, the NYISO shall send the Interconnection Customer and the Connecting Transmission Owner a distribution system impact study agreement.

32.3.4.5 If the feasibility study shown no potential for transmission system or Distribution System adverse system impacts, the NYISO shall send the Interconnection Customer and the Connecting Transmission Owner either a facilities study agreement (Appendix 8), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

32.3.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within 30 Business Days.

32.3.4.7 A deposit of the good faith estimated costs for each system impact study may be required from the Interconnection Customer.

32.3.4.8 The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement.

32.3.4.9 Affected Systems shall participate in the study and provide all information necessary to prepare the study.

32.3.4.10 Certain changes have been made, effective January 17, 2010, to the base case requirements for system impact studies. These changed requirements, contained in the system impact study agreement, will be applied prospectively to projects with system impact study agreements fully executed on or after that effective date; provided, however, that Interconnection Customers with system impact studies in progress with system impact study agreements fully executed prior to that effective date may elect, at their own expense, to modify the base case assumptions for that study consistent with the changed requirements. Such an election will be memorialized in an amended system impact study agreement.

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 prepare**d** by the NYISO and transmitted to the Interconnection Customer and the Connecting Transmission Owner along with a facilities study agreement within five Business Days. 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 within five Business Days of 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 to perform the facilities study.

32.3.5.2 In order to remain under consideration for interconnection, or, as appropriate, in the NYISO's interconnection queue, the Interconnection Customer must return the executed facilities study agreement or a request for an extension of time within 30 Business Days.

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.

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 only if the NYISO and Connecting Transmission Owner, based on an Interconnection Study, determine (i) that System Upgrade Facilities are necessary to accommodate the Interconnection Request, and (ii) that the electrical contribution of the project to the need for the System Upgrade Facilities is greater than the *de minimis* impacts defined in Section 25.6.2.6.1 of Attachment S to the NYISO OATT. Such Interconnection Study shall be of sufficient detail and scope to assure that these determinations can be made. If both determinations are made, then 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 that Attachment S. To the extent appropriate, the NYISO 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 closing of the Class Year, 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 NYISO, 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 NYISO, 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 NYISO 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 NYISO 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 NYISO OATT. The NYISO 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 NYISO 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 may be required from the Interconnection Customer.

32.3.5.6 The scope of and cost responsibilities for the facilities study are described in the attached facilities study agreement.

32.3.5.7 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 NYISO shall provide the Interconnection Customer and the Connecting Transmission Owner an executable interconnection agreement within five Business Days.

32.4 Provisions that Apply to All Interconnection Requests

32.4.1 Reasonable Efforts

The NYISO, in consultation with the Connecting Transmission Owner, shall make reasonable efforts to meet all time frames provided in these procedures unless the NYISO, Connecting Transmission Owner and Interconnection Customer agree to a different schedule. If either the NYISO 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 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.

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 NYISO 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 NYISO Code of Conduct contained in Attachment F to the NYISO 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 NYISO shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this document. The NYISO 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 NYISO 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

After receiving an interconnection agreement, the Interconnection Customer shall have 30 Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement, or request that the NYISO file, or cause to be filed, an unexecuted interconnection agreement with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted within 30 Business Days, 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 Coordination with Affected Systems

The NYISO shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The NYISO 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 NYISO 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 NYISO 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.

32.4.10 Capacity of the Small Generating Facility

32.4.10.1 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. The deliverability impact of all increase 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.

32.4.10.2 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.

32.4.10.3 The Interconnection Request shall be evaluated using the maximum rated capacity of the Small Generating Facility.

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 NYISO OATT, or in Article 2 of the NYISO 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 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 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 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 Deliverability Interconnection Standard, to enable the New York State Transmission System to deliver electric capacity from the Small Generating Facility, pursuant to the terms of the NYISO OATT.

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.

Deliverability Interconnection Standard – The standard that must be met by any Small Generating Facility larger than 2MW proposing to interconnect to the New York State Transmission System or Distribution System and to become a qualified Installed Capacity Supplier, and must be met by any merchant transmission project proposing to interconnect to the New York State Transmission System and receive Unforced Capacity Delivery Rights. To meet the NYISO Deliverability Interconnection Standard, the Interconnection Customer must, in accordance with the rules in Attachment S to the NYISO OATT, fund or commit to fund the System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

Distribution System – The Connecting Transmission Owner's facilities and equipment used to distribute electricity that are not under the operational control of the NYISO, and are subject to the SGIP under FERC Order No. 2006. For the purpose of the SGIP, 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 NYISO OATT.

Fast Track Process – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility no larger than 2 MW that includes the Section 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 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 Interconnection Customer, NYISO, 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 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 NYISO Open Access Transmission Tariff.

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 adverse impact on the cost or timing of any Interconnection Request with a later queue priority date.

Minimum Interconnection Standard – The reliability standard that must be met by any Small Generating Facility proposing to connect to the New York State Transmission System or Distribution System. The Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System. The Standard does not impose any deliverability test or deliverability requirement on the proposed interconnection.

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 - 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.

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.

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 NYISO or by the Connecting Transmission Owner under Section 32.1.7.

Small Generating Facility – The Interconnection Customer’s device no larger than 20 MW for the production 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 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 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)

NYISO:____

Designated Contact Person:____

Address:____

Telephone Number:____

Fax:____

E-Mail Address:____

An Interconnection Request 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.

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 hand delivery, mail, e-mail, or fax to the NYISO. The NYISO 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 NYISO a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Service Options

An Interconnection Customer may interconnect its new Small Generating Facility by electing to take either Energy Resource Interconnection Service or Capacity Resource Interconnection Service. 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 NYISO.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name:____

Contact Person:____

Mailing Address:____

City:________________________ State:______________ Zip:__________________

Facility Location (if different from above):____

Telephone (Day):___________________ Telephone (Evening):_________________________

Fax:______________________________ E-Mail Address:_____________________________

Additional Contact Information

Contact Name:____

Title:____

Address:____

____

Telephone (Day):___________________ Telephone (Evening):_________________________

Fax:______________________________ 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___

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)

Contact Name:____

Title:____

Address:____

____

Telephone (Day):____________________ Telephone (Evening):__________________________

Fax:_______________________________ E-Mail Address:______________________________

Requested Point of Interconnection:____

Interconnection Customer's Requested In-Service 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:_______

Interconnection Customer or Customer-Site Load:_________________kW (if none, so state)

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 Power Factor
Rated Power Factor: Leading: _________________ Lagging: ______________________

Total Number of Generators in wind farm to be interconnected pursuant to this Interconnection Request: _________ Elevation: _______ ___Single phase ___Three Phase

Inverter Manufacturer, Model Name & Number (if used):________________________________

List of adjustable set points for the protective equipment or software:_______________________

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

<u>Small Generating Facility Characteristic Data (for inverter-based machines)</u>

Max design fault contribution current: _____________ Instantaneous ___ or RMS? ___

Harmonics Characteristics: ____

Start-up requirements: ____

<u>Small Generating Facility Characteristic Data (for rotating machines)</u>

RPM Frequency:____________________
(*) Neutral Grounding Resistor (If Applicable):________________

<u>Synchronous Generators:</u>

Direct Axis Synchronous Reactance, Xd: ____________ P.U.
Direct Axis Transient Reactance, X'_d: _____________ P.U.
Direct Axis Subtransient Reactance, X''_d: ____________ P.U.
Negative Sequence Reactance, X_2: __________ P.U.
Zero Sequence Reactance, X_o: ___________ P.U.
KVA Base: __________________________
Field Volts: _____________
Field Amperes:______________

<u>Induction Generators:</u>

Motoring Power (kW): __________________________
1_2^2t or K (Heating Time Constant): ________________
Rotor Resistance, Rr: ___________________________

Stator Resistance, Rs: ____________________________
Stator Reactance, Xs: ____________________________
Rotor Reactance, Xr: _____________________________
Magnetizing Reactance, Xm: ______________________
Short Circuit Reactance, Xd": _____________________
Exciting Current: _______________________________

Temperature Rise: ______________________________
Frame Size: ___________________________________
Design Letter: _________________________________
Reactive Power Required In Vars (No Load):__________________
Reactive Power Required In Vars (Full Load):_________________
Total Rotating Inertia, H: _____________________ Per Unit on kVA Base

Note: Please contact the Connecting Transmission Owner and the NYISO prior to submitting the Interconnection Request to determine if the specified information above is required.

<u>Excitation and Governor System Data for Synchronous Generators Only</u>

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling?
___Yes ___No

Will the transformer be provided by the Interconnection Customer? ___Yes ___No

<u>Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):</u>

Is the transformer: ___single phase ______three phase? Size: _____________kVA
Transformer Impedance: _______ % on ________kVA Base

If Three Phase:

Transformer Primary:	_____ Volts	_____ Delta	_____ Wye	_____ Wye Grounded
Transformer Secondary:	_____ Volts	_____ Delta	_____ Wye	_____ Wye Grounded
Transformer Tertiary:	_____ Volts	_____ Delta	_____ Wye	_____ Wye Grounded

<u>Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):</u>

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: __________________ Type: ____________ Size: _________ Speed: _________

Interconnecting Circuit Breaker (if applicable):

Manufacturer:______________________________ Type:______________________________

Load Rating (Amps):______ Interrupting Rating (Amps):_______ Trip Speed (Cycles):______

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

Setpoint Function	Minimum	Maximum
1.________________	__________	__________
2.________________	__________	__________
3.________________	__________	__________
4.________________	__________	__________
5.________________	__________	__________
6.________________	__________	__________

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer:__________ Type:_______ Style/Catalog No.:_______ Proposed Setting:_______
Manufacturer:__________ Type:_______ Style/Catalog No.:_______ Proposed Setting:_______
Manufacturer:__________ Type:_______ Style/Catalog No.:_______ Proposed Setting:_______
Manufacturer:__________ Type:_______ Style/Catalog No.:_______ Proposed Setting:_______
Manufacturer:__________ Type:_______ Style/Catalog No.:_______ Proposed Setting:_______

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer:____
Type:__________________ Accuracy Class:___ Proposed Ratio Connection:____

Manufacturer:____
Type:__________________ Accuracy Class:___ Proposed Ratio Connection:____

Potential Transformer Data (If Applicable):

Manufacturer:____
Type:________________ Accuracy Class:___ Proposed Ratio Connection:___

Manufacturer:____
Type:________________ Accuracy Class:___ Proposed Ratio Connection:___

General 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 documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) ____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ____ Yes ____ No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
Are Schematic Drawings Enclosed? ____ Yes ____ No

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: ______________________________ 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 NYISO. The NYISO will send a copy to the Connecting Transmission Owner.

2.0 The NYISO acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The NYISO, 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 NYISO, 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 NYISO has 15 Business Days to complete this process. Unless the NYISO, in consultation with the Connecting Transmission Owner, determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the NYISO approves the Application and returns it to the Customer, with a copy to the Connecting Transmission Owner. Note to Customer: Please check with the NYISO before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the NYISO, and sends a copy to the Connecting Transmission Owner. Prior to parallel operation, the NYISO, 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 NYISO 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 NYISO 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 NYISO 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 NYISO 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 NYISO Open Access Transmission Tariff.

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: ____

Address: ____

City: ___________________________ State: ____________________ Zip:________________

Telephone (Day): ________________________ (Evening): ______________________________

Fax: __________________________________ E-Mail Address: _________________________

Contact (if different from Interconnection Customer)

Name: ____

Address: ____

City: ___________________________ State: ____________________ Zip:________________

Telephone (Day): ________________________ (Evening): ______________________________

Fax: ____________________________________ 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)

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 NYISO, 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.____________________________	______________________________

<u>Interconnection Customer Signature</u>

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: ________________________

<u>Contingent Approval to Interconnect the Small Generating Facility</u>

(For NYISO 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: ____________________

Application ID number: _________________

Connecting Transmission Owner waives inspection/witness test Yes___ No___

NYISO Signature: ____

Title: _____________________________________ Date: ____________________

Application ID number: _________________

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 (Day):_______________ (Evening):_______________________

Fax:_______________________ E-Mail Address:___________________

Electrician:

Name:____

Address:____

City:_______________________ State:_____________ Zip Code:_______

Telephone (Day):_______________ (Evening):_______________________

Fax:_______________________ E-Mail Address:___________________

License number:_________________________

Date Approval to Install Facility granted by the Connecting Transmission Owner:

Application ID number:_________________________

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/fax a copy of this form along with a copy of the signed electrical permit to the NYISO and the Connecting Transmission Owner (insert contact information below):

Name:____

NYISO:____

Address:____

____

City, State ZIP:_____________________________________

Fax:________________________

Name:____

Connecting Transmission Owner:______________________

Address:____

____

City, State ZIP:_____________________________________

Fax:________________________

Approval to Energize the Small Generating Facility (For NYISO and Connecting Transmission Owner use only)

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

NYISO Signature:____

Title:___________________________________ Date: ______________

Connecting Transmission Owner Signature:__________________________

Title:___________________________________ Date: ______________

Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

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 NYISO 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 NYISO 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 NYISO 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 NYISO 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: ________________________

NYISO

____

By: _________________________

Name: _________________________

Date: _________________________

Appendix 6 - Feasibility 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, NYISO and 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, Interconnection Customer desires to interconnect the Small Generating Facility with **[the New York State Transmission System or the Distribution System]**; and

WHEREAS, Interconnection Customer has requested the NYISO to perform a feasibility study to assess the feasibility of interconnecting the proposed 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 to be performed an interconnection feasibility study consistent the SGIP in accordance with the NYISO Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement and shall be made an exhibit thereto.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The NYISO reserves the right to request additional information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with Attachment Z of the NYISO OATT. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties. The Interconnection Customer shall bear any increased costs to complete the study.

5.0 In performing the study, the NYISO shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report 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:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include 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 and at the Interconnection Customer's cost.

9.0 A deposit or commercially reasonable security in the amount of the lesser of 50 percent of good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 Business Days after the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any Connecting Transmission Owner and NYISO 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 amounts invoiced in accordance with these SGIPs 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________________________________

NYISO

Signed______________________________

Name (Printed):

____

Title________________________________

Attachment A to Feasibility Study Agreement

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on _______________________:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Connecting Transmission Owner.

Appendix 7 - System Impact 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, NYISO and 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, Interconnection Customer desires to interconnect the Small Generating Facility with **[the New York State Transmission System or the Distribution System]**; and

WHEREAS, the NYISO has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the NYISO to perform, or cause to be performed, a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with **[the New York State Transmission System or the Distribution System]**, and of any Affected Systems;

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 to be performed a system impact study(s) consistent with the SGIP in accordance with the NYISO Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement and shall be made an exhibit thereto.

4.0 A system impact study will be based upon the technical information provided by Interconnection Customer in the Interconnection Request and shall build upon the results of the feasibility study, if applicable. The NYISO reserves the right to request additional information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended. The Interconnection Customer shall bear any increased costs to complete the study.

5.0 A system impact study 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. A 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. A system impact study 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.

6.0 A Distribution System impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 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 upon a system impact study that covers potential adverse system impacts on their electric systems, and the NYISO has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 The system impact study shall consider all generating and merchant transmission facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study agreement is executed –

8.1 Are directly interconnected with the New York State Transmission System or distribution facilities; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection;

8.3 Have accepted their cost allocation for System Upgrade Facilities and posted security for such System Upgrade Facilities in accordance with Attachment S; and

8.4 Have no queue position but have executed an interconnection agreement or requested that an unexecuted interconnection agreement be filed with FERC.

9.0 A Distribution System impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by all the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 business days after this Agreement is signed by all the Parties, or in accordance with Attachment Z to the NYISO OATT.

10.0 The Interconnection Customer shall provide to the NYISO a deposit or other commercially reasonable security in an amount equivalent to the good faith estimated cost of a Distribution System impact study and the good faith estimated cost of a transmission system impact study.

11.0 Any Connecting Transmission Owner and NYISO 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 THEREOF, 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 Provider]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed______________________________	Signed______________________________
Name (Printed):	Name (Printed):
______________________________	______________________________
Title______________________________	Title______________________________

NYISO

Signed______________________________

Name (Printed):

____

Title_____________________________

Attachment A to System Impact Study Agreement

Assumptions Used in Conducting the System Impact Study
The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the SGIP, and the following assumptions:
1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Connecting Transmission Owner.

Appendix 8 - 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 and Transmission Provider 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 NYISO 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 Except for study costs allocated to the Interconnection Customer as a member of a Class Year, any Connecting Transmission Owner and NYISO 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.

10.0 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.

11.0 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.

12.0 Amendment. The Parties may amend this Agreement by a written instrument duly executed by the Parties.

13.0 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.

14.0 Waiver

14.1 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.

14.2 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.

15.0 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.

16.0 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.

17.0 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.

18.0 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.

18.1 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.

18.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

19.0 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 Transmission Provider]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed______________________________	Signed______________________________
Name (Printed):	Name (Printed):
______________________________	______________________________
Title______________________________	Title______________________________

NYISO

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 alone, or for both Energy Resource Interconnection Service and some level of Capacity Resource Interconnection Service. Some MW level of Capacity Resource Interconnection Service election is required to become a qualified Installed Capacity Supplier.
Evaluation Election:

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider 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 ____

(Please 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*:

* To be completed in coordination with Connecting Transmission Owner.

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:________________________________
Generator step-up transformers receive back feed power	Date:________________________________
Generation Testing	Date:________________________________

Commercial Operation Date:________________________________

Appendix 9 - STANDARD SMALL GENERATOR INTERCONNECTION AGREEMENT (SGIA) (Applicable To Generating Facilities No Larger Than 20 MW)

This Interconnection Agreement ("Agreement") 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 ______________________ 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."

NYISO Information
Attention:
Address:
City: State: _______________Zip:
Phone: Fax:

Connecting Transmission Owner Information
Connecting Transmission Owner:
Attention:
Address:
City: State: _______________Zip:
Phone: Fax:

Interconnection Customer Information
Interconnection Customer:
Attention:
Address:
City: State: _______________Zip:
Phone: Fax:

Interconnection Customer Application No: _______________

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 Small Generator Interconnection Agreement (“SGIA”) 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 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 NYISO 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.

1.6 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 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 established by the Connecting Transmission Owner on a comparable basis, until NYISO has established different requirements that apply to all similarly situated generators in the New York Control Area on a comparable basis.

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 Section 32.1.0 or Attachment S or Attachment X of the NYISO 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.

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. 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 NYISO 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 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 NYISO 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 NYISO OATT. The Interconnection Customer shall be responsible for its share of any such costs resulting from the final Attachment S process, and Attachment 6 to this Agreement shall be revised accordingly.

5.2.2 Pending the outcome of the Attachment S cost allocation process, 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 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 NYISO OATT. The agreement shall specify the terms governing payments to be made by the Interconnection Customer to Affected System operator as well as the repayment by 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 it will suffer significant uncompensated economic or operational harm from the delay, (1) attainment of the same milestone has previously been delayed, or (2) 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 Security posted for System Upgrade Facilities, or cash or Security provided for System Deliverability Upgrades, shall meet the requirements for Security contained in Attachment S to the NYISO 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 NYISO OATT.

7.5.2 If an event of Force Majeure 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 NYISO 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 NYISO 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 ("Notice") 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: Fax:

If to the Connecting Transmission Owner:
Connecting Transmission Owner:
Attention:
Address:
City: ____________________________________ State:___________ Zip:
Phone: Fax:

If to the NYISO:
Attention:
Address:
City: ____________________________________ State:___________ Zip:
Phone: Fax:

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 telephone, facsimile or 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: Fax:

If to the Connecting Transmission Owner:

Connecting Transmission Owner:
Attention:
Address:
City: ___________________________________ State:__________ Zip:
Phone: Fax:

If to the NYISO:

Attention:
Address:
City: ___________________________________ State:__________ Zip:
Phone: Fax:

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: Fax:

Transmission Provider's Operating Representative:

Transmission Provider:
Attention:
Address:
City: ___________________________________ State:__________ Zip:
Phone: Fax:

NYISO's Operating Representative:

Attention:
Address:
City: ___________________________________ State:__________ Zip:
Phone: Fax:

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 NYISO

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 NYISO 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 NYISO 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 NYISO 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 interconnect the Interconnection Customer's Small Generating Facility to the New York State Transmission System or Distribution System in accordance with the NYISO Deliverability Interconnection Standard, to enable the New York State Transmission System to deliver electric capacity from the Small Generating Facility, pursuant to the terms of the NYISO OATT.

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.

Deliverability Interconnection Standard – The standard that must be met by any Small Generating Facility larger than 2MW proposing to interconnect to the New York State Transmission System or Distribution System and to become a qualified Installed Capacity Supplier, and must be met by any merchant transmission project proposing to interconnect to the New York State Transmission System and receive Unforced Capacity Delivery Rights. To meet the NYISO Deliverability Interconnection Standard, the Interconnection Customer must, in accordance with the rules in Attachment S to the NYISO OATT, fund or commit to fund the System Deliverability Upgrades identified for its project in the Class Year Deliverability Study.

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 Provider's facilities and equipment used to distribute electricity that are not under the operational control of the NYISO, and are subject to the SGIP under FERC Order No. 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 NYISO 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 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 Transmission Provider'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 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 NYISO 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.

Minimum Interconnection Standard – The reliability standard that must be met by any Small Generating Facility proposing to connect to the New York State Transmission System or Distribution System. The Standard is designed to ensure reliable access by the proposed project to the New York State Transmission System. The Standard does not impose any deliverability test or deliverability requirement on the proposed interconnection.

New York State Transmission System – **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.

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 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 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)	

Agreed to by:

For the NYISO ___________________ Date

For the Connecting Transmission Owner ____ Date

Interconnection Customer Date

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 NYISO OATT Attachment S cost allocation process. 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 and System Upgrade Facilities and System Deliverability Upgrades are estimates. The Interconnection Customer is ultimately responsible for the actual cost of the Distribution Upgrades and System Upgrade Facilities and System Deliverability Upgrades needed for its Small Generating Facility, as that is determined under Attachments S and X and Z of the NYISO 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 – <u>Postcontingency</u> 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.

LOPIIPRO
10-20-90

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. <u>ALL</u> MW armed for the Keswick Power Relays must be included as part of the Loss of Phase II Contingency. <u>The maximum Loss of Phase II Contingency allowable is 2,200 MW.</u>

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. <u>Phase II Limit based on NYPP station voltages</u>

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
=

$$\frac{\text{(C/E Crit. Transfer Level- forecasted C/E Transfer)}}{\text{Phase II C/E Distribution Factor}}$$

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. Phase II Limit based on NYPP Central East Flow

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
=
(C/E Crit. Transfer Level- actual C/E Transfer)
Phase II C/E Distribution Factor

3. Phase II Limit based on PJM interface flows

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, 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, 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 and Definitions

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.

35.2.1 Abbreviations and Acronyms.

"ATC" shall mean Available Transfer Capability.

"AFC" shall mean Available Flowgate Capability.

"CPS" shall mean Control Performance Standard.

"DCS" shall mean Disturbance Control Standard.

"EMS" shall mean the respective Energy Management Systems utilized by the Parties to manage the flow of energy within their Regions.

"FERC" shall mean the Federal Energy Regulatory Commission or any successor agency thereto.

"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.

"IROL" shall mean Interconnected Reliability Operating Limit.

"ISO" shall mean Independent System Operator.

"MMWG" shall mean the NERC working group that is charged with multi-regional modeling.

"MVAR" shall mean megavolt ampere of reactive power.

"MW" shall mean megawatt of capacity.

"NERC" shall mean the North American Electricity Reliability Corporation or its successor organization.

"NPCC" shall mean the Northeast Power Coordinating Council, Inc., including the NPCC Cross Border Regional Entity (CBRE), or their successor organizations.

"NYISO" shall have the meaning stated in the preamble of this Agreement.

“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 Tariff on file with FERC for PJM and NYISO.

“PJM” shall have the meaning stated in the preamble of this Agreement.

“RFC” shall mean Reliability First Corporation.

“RTO” shall mean Regional Transmission Organization.

“SDX System” shall mean the system used by NERC to exchange system data.

“SERC” SERC Reliability Corporation or its successor organization.

“SOL” shall mean System Operating Limit.

“TLR” shall mean the NERC Transmission Loading Relief Procedures used in the Eastern Interconnection as specified in NERC Operating Policies.

“TTC” shall mean Total Transfer Capability.

35.2.2 Definitions.

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.

“Agreement” shall have the meaning stated in the preamble.

“Area Control Error” means 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 Transfer Capability” means a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

“Balancing Authority Area” shall mean an electric system or systems, bounded by Interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Balancing Authority Areas and contributing to frequency regulation of the Interconnection Facilities as set forth by NERC.

“Balancing Authority Operator” shall mean the entity responsible for the secure operation of a Balancing Authority Area as set forth by NERC.

"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" shall mean the reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.

"Coordinated Flowgate" shall mean a Flowgate impacted by the flows of a Party as determined by a mutually agreed upon study methodology identified in a congestion management process. A Coordinated Flowgate may be in the footprint of a Party or a third party.

"Coordination Committee" shall mean the jointly constituted PJM and NYISO committee established to administer the terms and provisions of this Agreement pursuant to Article Three.

"Delivery Point" shall mean the point at each of the points of direct Interconnection between PJM and the NYISO Balancing Authority Area. Such Delivery Point(s) shall include the Interconnection Facilities between the PJM and the New York Control Areas.

"Dispute" shall have the meaning stated in Article Fourteen.

"Disturbance Control Standard" 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.

"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 35.18.1.

"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.

"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 35.19.1.

“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.

“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.

“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.

“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.

“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.

“Notice” shall have the meaning stated in Section 35.19.21

“NYISO Tariffs” means the NYISO OATT and the NYISO Market Administration and Control Area Services Tariff (“Services Tariff”), collectively.

“NYSRC Reliability Rules” means 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.

“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.

“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.

“Outages” shall mean the planned unavailability of transmission and/or generation facilities dispatched by PJM or the NYISO, as described in Article Nine of this Agreement.

“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.

“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.

“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.

“Schedule” shall mean a schedule attached to this Agreement and all amendments, supplements, replacements and additions hereto.

“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.

“Standards Authority” shall mean the North American Electric Reliability Council (“NERC”), and the NERC regional councils 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.

“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.

“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.

"Voltage and Reactive Power Coordination Procedures" are the procedures under Article Eleven for coordination of voltage control and reactive power requirements.

35.2.3 Rules of Construction.

35.2.3.1 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.

35.2.3.2 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.

35.2.3.3 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.

35.2.3.4 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.

35.2.3.5 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. This Agreement establishes a structure and framework for the following functions related to the reliability of interconnected operations between the Parties:

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 35.20;

Performance of certain other arrangements among the Parties for administration of this Agreement; and

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.

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 no less than twice yearly 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 Conduct dispute resolution in accordance with Article Fourteen of this Agreement;

35.3.2.1.6 Initiate process reviews at the request of any Party for activities undertaken in the performance of this Agreement;

35.3.2.1.7 Continue the process to define a congestion management process mutually agreed upon by NYISO and PJM; and

35.3.2.1.8 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 in the implementation of 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.

35.3.2.4 Subject to the limitations on its authority as described in Section 35.3.2.3 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:

35.3.2.4.1 Amending, adding or canceling Schedules, or Operating Instructions and providing written notice in accordance with Section 35.19.21 of this Agreement;

35.3.2.4.2 Assessment of non-compliance with this Agreement and, subject to Section 35.14 of this Agreement, the taking of appropriate action in respect thereto;

35.3.2.4.3 Documentation of decisions related to the initial resolution of Disputes as set out in Section 35.14 of this Agreement, or in cases of unresolved Disputes, the circumstances relevant to the Dispute in question as contemplated by the requirements of Section 35.14 of this Agreement; and

35.3.2.4.4 Preparation, documentation, retention and distribution of Coordination Committee meeting minutes and agendas.

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 NERC Regional Councils (RFC, NPCC, SERC, etc.), 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 NERC and its Regional Councils and implemented by the Coordination Committee 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 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 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.

35.7 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 Coordination Committee to perform its duties and for the Parties to 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 and PJM Data Confidentiality Regional Stakeholder Group. The types of data to be exchanged will be maintained and posted by the Parties to this Agreement on their respective OASIS web sites. Such information will 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;

35.7.1.3 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; and

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.

35.7.2 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 NYISO Code of Conduct; and (e) 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 liable for any breach of this section by its employees, its subcontractors and its subcontractors' employees and agents.

35.8.3 Treatment of Confidentiality.

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, or if more restrictive, the governing documents of the Supplying Party sending the Confidential Information.

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 six (6) 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. Regardless of whether a Party is subject to the jurisdiction of the FERC under the Federal Power Act, and regardless of whether a Party is an RTO or an ISO, 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 notice of such request or requirement so that the Supplying Party may seek an appropriate protective order or other appropriate remedy or waive compliance with the provisions of this Agreement. Notwithstanding the absence of a protective order or a waiver, a Disclosing Party shall disclose only such Confidential Information which 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 Open Access Transmission Tariff, 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 Northeast ISO/RTO Coordination of Planning Protocol Agreement, 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.

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 Joint Checkout Procedures

35.12.1 Scheduling Checkout Protocols.

35.12.1.1 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.

35.12.1.2 When there is a transaction scheduling conflict, the Parties will work to modify the schedule as soon as practical.

35.12.1.3 The Parties will perform the following types of checkouts. Checkouts will be consistent with 35.12.1.1 and 35.12.1.2.

(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.

35.13 TTC/ATC/AFC Calculations

35.13.1 TTC/ATC/AFC Protocols.

In accordance with Section 35.9, the Parties will exchange scheduled Outages of all interconnections and other transmission facilities.

35.13.1.1 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.

35.13.1.2 Transmission Interchange Schedules.

Each Party will make available its interchange schedules to permit accurate calculation of TTC and ATC/AFC values.

35.13.2 Configuration/Facility Changes.

Transmission configuration changes and generation additions (or retirements) shall be communicated via the NERC MMWG process.

35.13. 3 Transmission System Impacts.

35.13.3.1 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.

35.13.3.2 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.

35.13.3.3 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.

35.13.3.4 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.

35.14 Dispute Resolution Procedures

35.14.1 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.

35.14.2 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 do not within the same 14 day period agree to refer the matter to some individual or organization for alternate Dispute resolution, 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.

35.15 Interconnection Revenue Metering

35.15.1 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.

35.15.2 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.

35.15.3 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.

35.15.4 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.

35.16 Retained Rights of Parties

35.16.1 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.

35.17 Representations

35.17.1 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.

35.17.2 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.

35.17.3 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.

35.17.4 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.

35.18 Effective Date, Implementation, Term and Termination

35.18.1 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.

35.18.2 Term.

This Agreement shall continue in full force and effect for a term of ten (10) years, and shall continue year to year thereafter, unless terminated earlier in accordance with the provisions of this Agreement.

35.18.3 Right of a Party to Terminate.

35.18.3.1 NYISO may terminate this Agreement at any time upon not less than twelve (12) months' Notice to PJM.

35.18.3.2 PJM may terminate this Agreement at any time upon not less than twelve (12) months' Notice to NYISO.

35.18.3.3 This Agreement may be terminated at anytime by mutual agreement in writing.

35.18.4 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.

35.18.5 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.

35.19 Additional Provisions

35.19.1 *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 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.

35.19.2 *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.

35.19.3 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 35.19.8; 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.

35.19.4 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.

35.19.5 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.

35.19.6 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 incidental, consequential, punitive, special, exemplary or indirect damage.

35.19.7 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.

35.19.8 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.

35.19.9 Governing Law.

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware.

35.19.10 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.

35.19.11 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.

35.19.12 Amendment.

35.19.12.1 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.

35.19.12.2 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.

35.19.12.3 Mutual Agreement.

The Parties may amend this Agreement at any time by mutual agreement in accordance with Section 35.19.12.1 above.

35.19.13 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.

35.19.14 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.

35.19.15 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.

35.19.16 Governmental Authorizations.

This Agreement, including its future amendments is subject to the initial and continuing governmental authorizations, including approval of the Federal Energy Regulatory Commission, 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.

35.19.17 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.

35.19.18 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.

35.19.19 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.

35.19.20 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.

35.19.21 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: Phillip G. Harris
President & CEO
PJM Interconnection L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-4501
Tel: (610) 666-4377
Fax: (610) 666-4281

NYISO: New York System Operator
10 Krey Boulevard
Rensselaer, New York 12144
Attention: Vice President Operations & Reliability

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 J. Kormos, Senior VP – Reliability Services

____
Date: ________________________________

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

By: Mark S. Lynch, President and CEO

____
Date:_________________________________

35.20 Schedules

Schedule A - Description Of Interconnection Facilities

The NYISO – PJM Coordination 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-three (23) alternating current ("AC") *Interconnection Facilities,* seven (7) of which form one (1) AC pseudo-tie[17]; and further contains one (1) HVDC *Interconnection Facility.* These are tabulated below:

NY/PJM AC *Interconnection Facilities*:

PJM	NYISO	Designated	(kV)	Common Meter Point
Branchburg	Ramapo	5018	500	Ramapo
Closter	Sparkill	751	69	Closter
E. Sayre	N. Waverly	956	115	E. Sayre
E. Towanda	Hillside	70	230	Hillside
Erie East	South Ripley	69	230	South Ripley
Franklin	Sugar Loaf	SJ	115	Sugar Loaf
Franklin	Sugar Loaf	SD	115	Sugar Loaf
Harings Corners	Burns	702	138	Harings
Harings Corners	Nanuet	45	34	Harings
Harings Corners	W. Nyak	701	69	Harings
Homer City	Watercure	30	345	Homer
Homer City	Stolle Road	37	345	Homer
Hudson	Farragut	C3403	345	Farragut
Hudson	Farragut	B3402	345	Farragut
Linden	Goethals	A2253	230	Goethals
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	138/345	138/345	S. Mahway
S. Mahwah	Ramapo	51	138	S. Mahwah
Tiffany	Goudey	952	115	Goudey
Warren	Falconer	171	115	Warren
RECO	NYISO	AC Pseudo-Tie	Various	O&R EMS

Sayerville	Newbridge	HVDC-Tie	500	New Bridge

[17] WEQ-007 "Inadvertent Interchange Payback Standards," North American Energy Standards Board (NAESB), on-line at www.naesb.org.

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 Operating Protocol for the Implementation of Commission Opinion No. 476, Docket No. EL02-23-000 (Phase II), New York Independent System Operator, Inc., FERC Electric Tariff, Original Vol. No. 2, Attachment M-1.
4.0 Northeastern ISO/RTO Coordination of Planning Protocol
5.0 Inter Control Area Transaction Agreement
6.0 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).
7.0 Unscheduled Transmission Service Agreement, PJM Interconnection L.L.C, Rate Schedule No. 30, Effective Date January 1, 2001.

Schedule C - Operating Protocol for the Implementation Of Con Ed – PJM Transmission Service Agreements

1.1 This "Operating Protocol" establishes procedures for the planning, operation, control, and scheduling of energy between the New York Independent System Operator, Inc. ("NYISO") and PJM Interconnection, L.L.C. ("PJM") (collectively, the "Parties"), associated with two Long-term Firm Point-to-Point Transmission Service Agreements ("TSAs") entered into by Consolidated Edison Company of New York ("ConEd") and PJM, dated April 18, 2008, executed in connection with the rollover of contracts dated May 22, 1975 (as amended May 9, 1978) and May 8, 1978 between ConEd and Public Service Electric & Gas Company ("PSE&G"). The TSA designated Original Service Agreement No. 1874 is referred to herein as the 400 MW transaction and the TSA designated Original Service Agreement No. 1873 is referred to as the 600 MW transaction. The two contracts are referred to collectively as the "600/400 MW transactions."

1.1.1 The 400 MW transaction. The 400 MW transaction has the same level of firmness as other firm transactions, except as provided in section 1.3 of this Operating Protocol.

1.1.2 The 600 MW transaction. The 600 MW transaction shall have the same level of firmness as other firm transactions.

1.2 This Operating Protocol shall be used by the NYISO and PJM in preparing to operate, and operating in real-time, to the hourly flow of energy between them pursuant to the 600/400 MW transactions as established by this Operating Protocol.

1.3 During system emergencies, the appropriate emergency procedures of the NYISO and PJM, if necessary, shall take priority over the provisions of this Operating Protocol. The NYISO and PJM shall have the authority to implement their respective emergency procedures in whatever order is required to ensure overall system reliability. Without limiting the foregoing, the order of load relief measures and transaction reductions when there is an emergency in the PJM Mid-Atlantic Area will be:

- Calling of Emergency Load Response
- Voltage reduction
- Pro-rata load shed and reduction of the 600/400 MW transactions[18]

In addition, if PJM declares an emergency condition that arises from outages on the PSE&G system, the NYISO and PJM may agree to deliver up to 400 MW to Goethals for re-delivery to Hudson via the NYISO's system. Such emergency re-deliveries shall not be considered in the calculation of the Real-Time Market Desired Flow under Appendices 1 and 3 of this Operating Protocol.

1.4 All aspects of this Operating Protocol are subject to the dispute resolution procedures set forth in the Joint Operating Agreement Among and Between New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.

1.5 The Parties will review all aspects of this Operating Protocol annually.

1.6 Attached and included as part of this Operating Protocol are the following appendices: Appendix 1 – Process Flow, Appendix 2 – Transmission Constraints and Outages Associated with the Contracts, Appendix 3 – The Day-Ahead Market and Real-Time Market Desired Flow Calculation, Appendix 4 – Planning Procedures, Appendix 5 – Operation of the PARs, Appendix 6 – Distribution of Flows Associated with Implementation of Day-Ahead and Real Time Market Desired Flows, Appendix 7 – References, and Appendix 8 – Definitions.

---

18 In a maximum generation emergency in the PJM Mid-Atlantic Area where PSE&G load needs to be curtailed, the PSE&G load would be curtailed pro-rata with curtailment of the ConEd requested service (and other firm service on the system). But, if NYISO is not also in a capacity emergency, the desired flow on ABC will be reduced by up to 400 MW to the extent necessary to avoid a PSEG load curtailment. ConEd may upgrade the transmission service for the 400 MW transaction to eliminate the reduction of the 400 MW transaction prior to load shed as described above by requesting such upgraded service and funding all necessary transmission upgrades as required by Part II and Part VI of the PJM OATT. The 600 MW transaction shall be reduced in the same manner as all other firm transactions in PJM.

35.21 Appendices

Appendix 1- Process Flow

Two Day-ahead Actions:

1. PJM shall post constraint forecast information on its OASIS, or a comparable website, indicating if there is the potential for off-cost operations, two days prior to the operating day by 9 pm (sample at Figure 1 in Appendix 7).

2. PJM shall analyze transmission and generation outages in accordance with Appendix 2B to determine if the 600/400 MW transaction flow is expected to be feasible under a security constrained dispatch in PJM. If any portion of the flow is not expected to be feasible under a security-constrained dispatch, PJM will determine what portion of the flow is expected to be feasible and post that information on the PJM OASIS. This advance notification is not binding on any party.

3. The NYISO shall post transmission outages on its OASIS, or a comparable website, to identify outages that impact the transfer capability of the ISO Secured Transmission System.[19]

Day Ahead Scheduling:

4. ConEd shall submit a contract election (NY-DAE) in the NYISO's Day-Ahead Market for the 600/400 MW transactions prior to the NYISO Day Ahead Market (DAM) deadline (currently 5:00 a.m.).

5. The NYISO shall establish New York (aggregate ABC interface and aggregate JK interface) Desired Flow (NYDF) schedules for NYISO Day Ahead Market using the NY-DAE identified in (4).

6. The NYISO shall establish the distribution of flows for the NYISO DAM in accordance with Appendix 7.

7. The NYISO shall run the New York Day Ahead Market with NYDF schedules determined in (5 and 6).

8. The NYISO shall post DAM results by the deadline established in its market rules (currently prior to 11:00 a.m.). The NYISO shall provide NYDF schedules and post nodal prices for the JK (Ramapo), BC (Farragut) and A (Goethals) pricing points on the NYISO OASIS, or a comparable website (sample at Figure 2 in Appendix 7).

---

19 The ISO Secured Transmission System is defined in the NYISO's Transmission and Dispatching Operations Manual.
See <http://www.nyiso.com/services/documents/manuals/pdf/oper_manuals/trans_disp.pdf>.

9. ConEd shall submit a transaction election (PJM-DAE) in the PJM Day Ahead Market prior to the PJM Day Ahead Market deadline (currently 12 noon):
   a) ConEd shall submit a transaction election for the 600 MW transaction.
   b) ConEd shall submit a transaction election for the 400 MW transaction.

10. PJM shall establish the PJM (aggregate ABC interface and aggregate JK interface) Desired Flow (PJMDF) schedules for PJM Day Ahead Market using PJM-DAE identified in (9).

11. PJM shall establish the distribution of flows for the PJM DAM in accordance with Appendix 7.

12. PJM shall run the PJM Day Ahead Market with the PJMDF schedules determined in (11). The amount of the PJM-DAE which clears will become the PJM Day Ahead Schedule amount (PJM-DAS).

13. PJM Day Ahead results shall be posted by the deadline established in PJM's market rules (currently at 4:00 p.m.), and shall identify the PJM-DAS. The PJM posting will include nodal prices for the JK (Waldwick), BC (Hudson) and A (Linden) pricing points on https://esuite.pjm.com/mui/index.htm or a comparable website (sample at Figure 3 in Appendix 7).

If there is congestion in the PJM Day Ahead Market:

14. If there is congestion in PJM that affects the 600/400 MW transaction, PJM shall re-dispatch.

In Day Operations:

15. Aggregate ABC and aggregate JK Real-Time Market Desired Flow (RTMDF) calculations shall be made in real time, continuous throughout the operating day, by the NYISO and PJM.

16. The desired distribution of flows on the A, B, C, J, and K lines for the in-day markets shall be established by PJM and the NYISO in accordance with Appendix 6.

17. If neither PJM nor the NYISO are off-cost, or if both are off-cost, aggregate actual ABC interface flows shall be within +/- 100 MW of the aggregate RTMDF for the ABC interface and aggregate actual JK interface flows shall be within +/- 100 MW of the aggregate RTMDF for the JK interface[20].

---

20 PJM and NYISO will operate in accordance with the bandwidth requirements of Step 17 to the extent practicable (utilizing PARs, curtailment of third party transactions, and re-dispatch, consistent with the other provisions of the Operating Protocol) recognizing relevant operating conditions that are beyond the control of PJM and NYISO or that are not anticipated by this Operating Protocol. Deviations will be accounted for with in-kind payback using the Auto Correction Factor described in Appendix 3 to this Operating Protocol.

18. ConEd shall have the option to request a modification in the Real-Time Market from its Day Ahead Market election (NY_DAE and PJM_DAE) for each hour.21

  a) ConEd must request a Real-Time election (RTE) modification through NYISO at least 75 minutes prior to the dispatch hour (or a shorter notice period that is agreed upon by the NYISO and PJM.).
  b) The NYISO shall notify PJM of the RTE.
  c) ConEd shall settle with PJM for the balancing market costs for deviations between PJM-DAS and RTE pursuant to the TSAs described in Section 35.1 of this Operating Protocol. ConEd shall settle with the NYISO for balancing market costs for deviations between NY-DAE and RTE. ConEd shall not be responsible for NYISO balancing market costs resulting from NYISO-directed deviations between NY DAE and RTE.

Note - Actions identified in steps 17 and 18 that are taken will be logged, and PSE&G and ConEd will be notified of PAR moves related to these steps.

If there is In-Day congestion:

19. If PJM is off-cost or is expected to go off-cost for two or more consecutive hours in maintaining the RTMDF, and the NYISO is not off-cost, then PJM and NYISO shall consult with each other and shall use reasonable efforts to redirect up to 300 MW (in a mutually agreed upon amount and in mutually agreed upon increments) from the PJM system onto the NYISO system; provided, however, that PJM and the NYISO verify that allowing actual aggregate interface flows to deviate from the RTMDF will not result in violation of applicable PJM or NYISO reliability criteria. PJM and the NYISO shall continue to use reasonable efforts to modify actual interface flows in incremental adjustments until

  a) PJM is no longer off-cost, or
  b) The NYISO is about to go off-cost (i.e., the NYISO expects that it will have to redispatch in response to transmission constraints in order to maintain the RTMDF), or
  c) 300 MW have been redirected.

20. If the NYISO is off-cost or expected to go off-cost for two or more consecutive hours in maintaining the RTMDF, and PJM is not off-cost, then PJM and the NYISO shall consult with each other and shall use reasonable efforts to redirect up to 300 MW (in a mutually agreed upon amount and in mutually agreed upon increments) from the NYISO system onto the PJM system; provided, however, that PJM and NYISO verify that allowing actual aggregate interface flows to deviate from the RTMDF will not result in violation of

---

21 At all times, however, the ConEd election under the 600/400 MW transactions must be the same in PJM and NYISO in In-Day Operations. Absent an in-day change in the election by ConEd, the ConEd Real-Time election shall be the PJM-DAS.

applicable PJM or NYISO reliability criteria. PJM and the NYISO shall continue to use reasonable efforts to modify actual interface flows in incremental adjustments until:

a) The NYISO is no longer off-cost, or

b) PJM is about to go off-cost (*i.e*., PJM expects that it will have to redispatch in response to transmission constraints in order to maintain the RTMDF), or

c) 300 MW have been redirected

Appendix 2 - Transmission Constraints and Outages - Associated with the Contracts

A. Constraints

A list of constraints identified as potential constraints that may result in off-cost operation due to transfers associated with the 600/400 MW transactions will be posted on the PJM and NYISO OASIS or web page. The constraints included in the listing should be considered representative of the kinds of constraints that may exist within PJM or the NYISO. If such transmission constraints are limiting, then the affected ISO/RTO may be subject to off-cost operation due to transfers associated with the 600/400 MW transactions. Other constraints, not listed on the web site, may arise that could cause either ISO/RTO to operate off-cost. The list may be revised by NYISO/PJM to reflect system changes or security monitoring technique changes in their respective Control Areas.

B. Outages

The NYISO and PJM will identify critical outages that may impact redispatch costs incurred for the delivery of energy, under the 600/400 MW transactions. Identified outages may have the following consequences:

The outage of any A, B, C, J, or K facility will result in the NY-DAE, PJM-DAE, and/or RTE (as appropriate) being limited to a value no greater than the remaining thermal capability of the most limiting of the ABC interface or the JK interface. The remaining thermal capability of either the ABC interface or the JK interface may be limited by other facilities directly in series with the A, B, C, J, or K lines.

1. It is not anticipated that one primary facility outage will preclude PJM from providing redispatch for the 600 MW or 400 MW transaction. However, combinations of two or more outages of the facilities, listed on the PJM OASIS or web page, could preclude PJM from accommodating all or part of the delivery, even with redispatch. In this case, PJM will provide notification to NYISO.

   PJM will provide notification22 of all outages by posting these outages (transmission only) on the PJM OASIS or web site.

   NYISO will provide notification of all outages by posting these outages (transmission only) on the NYISO OASIS or web site.

   PJM and the NYISO will review and revise, as necessary, the list of primary and secondary facilities on an annual basis.

22 PJM can also provide the option of automated email outage notification through the PJM eDart tool.

Appendix 3 - The Day-Ahead Market and Real-Time Market - Desired Flow Calculation

The following shall be the formula for calculating Day-Ahead Market (DAM) and Real-Time Market (RTM) desired flows:

$NYDF_{ABC}$ = [NY-DAE] + [A]*[PJM-NYISO DAM Schedule] + [B] *[OH-NYISO DAM Schedule] + [C] *[West-PJM DAM Schedule] + [D]*[DAM Lake Erie Circulation]

$NYDF_{JK}$ = [NY-DAE] - [A]*[PJM-NYISO DAM Schedule] - [B] *[OH-NYISO DAM Schedule] - [C] *[West-PJM DAM Schedule] - [D]*[DAM Lake Erie Circulation]

$PJMDF_{ABC}$ = [PJM-DAE] + [A]*[PJM-NYISO DAM Schedule] + [B] *[OH-NYISO DAM Schedule] + [C] *[West-PJM DAM Schedule] + [D]*[DAM Lake Erie Circulation]

$PJMDF_{JK}$ = [PJM-DAE] - [A]*[PJM-NYISO DAM Schedule] - [B] *[OH-NYISO DAM Schedule] - [C] *[West-PJM DAM Schedule] - [D]*[DAM Lake Erie Circulation]

RTMDFABC = [RTE] + [A]*[PJM-NYISO RTM Schedule] + [B] *[OH-NYISO RTM Schedule] + [C] *[West-PJM RTM Schedule] + [D]*[RTM Lake Erie Circulation] + Auto Correction Factor

RTMDFJK = [RTE] - [A]*[PJM-NYISO RTM Schedule] - [B] *[OH-NYISO RTM Schedule] - [C] *[West-PJM RTM Schedule] - [D]*[RTM Lake Erie Circulation] + Auto Correction Factor

- The DAM and RTM desired flows will be limited to the facility rating.
- The Auto Correction Factor component of the desired flow is the on-peak and off-peak aggregations of MW deviation in a calendar day to be included in a subsequent day's on-peak or off-peak period as applicable and agreed upon by PJM and NYISO. The Auto Correction Factor "pays-back" MW in kind during a subsequent day on-peak or off-peak period as agreed upon by NYISO and PJM. On-peak aggregation shall be paid back in a subsequent day on-peak period. Off-peak aggregation shall be paid back in a subsequent day off-peak period.

A	13 %	Adjustment for NYISO-PJM Schedule
B	0 %	Adjustment for OH-NYISO Schedule
C	0 %	Adjustment for West-PJM Schedules
D	0 %	Adjustment for Lake Erie Circulation

Other impacts will be part of the real time bandwidth operation – not the desired flow calculation. These impacts will be reviewed by PJM and the NYISO on an annual basis.

The above distribution factors (A, B, C, D) will be used in the calculation unless otherwise agreed by PJM and the NYISO based upon operating analysis conducted in response to major topology changes or outages referenced in Appendix 2. Such modifications will be posted by PJM and the NYISO on the PJM and NY OASIS sites or web sites.

Appendix 4 - Planning Procedures

The procedures for identifying and remedying impairments shall be handled on a planning basis. The impairment process is not directly applicable to DAM or RT operations under the 600/400 MW transactions.

EXISTING IMPAIRMENTS

- PJM and the NYISO are not aware of any existing impairments that would preclude provision of transmission service under the 600 MW / 400 MW transaction.

NOTIFICATION PROCEDURES

- ConEd and PSE&G shall notify the NYISO and PJM respectively under their existing ISO/RTO interconnection procedures when interconnecting new generation facilities to their transmission systems.

PROCEDURES FOR DETERMINATION OF FUTURE IMPAIRMENTS

- The procedures to be used by the NYISO and PJM for the determination of future impairments shall be in accordance with:
  - The PJM Regional Transmission Expansion Planning Process;
  - The NYISO Comprehensive Reliability Planning Process; and
  - The Northeast ISO/RTO Planning Coordination Protocol executed by PJM, the NYISO and ISO-New England Inc.
- The Northeast ISO/RTO Planning Coordination Protocol contains provisions for the coordination of interconnection requests received by one ISO/RTO that have the potential to cause impacts on an adjacent ISO/RTO to include the handling of firm transmission service.
- The Northeast ISO/RTO Planning Coordination Protocol has provisions for notification, development of screening procedures, and coordination of the study process between the ISO/RTOs.
- The Northeast ISO/RTO Planning Coordination Protocol also provides that all analyses performed to evaluate cross-border impacts on the system facilities of one of the ISOs/RTOs will be based on the criteria, guidelines, procedures or standards applicable to those facilities.
- Future planning studies by the ISOs/RTOs shall include 1,000 MW[23] of firm delivery from the NYISO at Waldwick and 1,000 MW of re-delivery from PJM at

23 1,000 MW will also be included in the FTR simultaneous feasibility analysis.

the Hudson and Linden interface independent of the amount of off-cost operation that is required to meet reliability criteria. For PJM load deliverability planning studies, which simulate a capacity emergency situation, the system shall be planned to include 1,000 MW of firm delivery from the NYISO at Waldwick and 600 MW of re-delivery from PJM at the Hudson and Linden interface.

Appendix 5 – Operation of the PARs

General

This procedure outlines the steps taken to coordinate tap changes on the PARs in order to control power flow on selected transmission lines between New York and New Jersey. The facilities are used to provide transmission service and to satisfy the 600/400 MW transactions, other third party uses, and to provide emergency assistance as required. These tie-lines are part of the interconnection between the PJM and NYISO. These PAR operations will be coordinated with the operation of other PAR facilities including the 5018 PARs. The 5018 PAR will be operated taking into account this Operating Protocol. The ties are controlled by PARs at the following locations:

- Waldwick (F-2258, E-2257, O-2267)
- Goethals (A-2253)
- Farragut (C-3403, B-3402)

This appendix addresses the operation of the PARs at Waldwick, Goethals, and Farragut as these primarily impact the delivery associated with the 600/400 MW transactions .

PJM and the NYISO will work together to maintain reliable system operation, and to implement the RTMDF within the bandwidths established by this Operating Protocol while endeavoring to minimize the tap changes necessary to implement these contracts.

RTMDF calculations will be made for the 'ABC Interface', and the 'JK Interface'. Desired line flow calculations will be made for A, B, and C lines (initial assumption is balanced each 1/3 of the ABC Interface), and for the J and K lines (initial assumption is balanced each ½ of the JK Interface).

Normal Operations

The desired flow calculation process is a coordinated effort between PJM and the NYISO. PJM and the NYISO have the responsibility to direct the operation of the PARs to ensure compliance with the requirements of the Operating Protocol. However, one of the objectives of this procedure is to minimize the movement of PARs while implementing the 600/400 MW transactions. PJM and the NYISO will employ a +/- 100 MW bandwidth at each of the ABC and JK Interfaces to ensure that actual flows are maintained at acceptable levels.

PJM and the NYISO have operational control of the PARs and direct the operation of the PARs, while PSE&G and ConEd have physical control of the PARs. The ConEd dispatcher sets the PAR taps at Goethals and Farragut at the direction of the NYISO. The PSE&G dispatchers set the PAR taps at Waldwick at the direction of PJM.

Tap movements shall be limited to 400 per month based on 20 operations (per PAR) in a 24-hour period. If, in attempting to maintain the desired bandwidth, tap movements exceed these limits, then the bandwidth shall be increased in 50 MW increments until the tap movements no longer exceed 20 per day, unless PJM and the NYISO agree otherwise.

Emergency Operations
If an emergency condition exists in either the NYISO or PJM, the NYISO dispatcher or PJM dispatcher may request that the ties between New York and New Jersey be adjusted to assist directing power flows in the respective areas to alleviate the emergency situation. The taps on the PARs at Waldwick, Goethals, and Farragut may be moved either in tandem or individually as needed to mitigate the emergency condition. Responding to emergency conditions in either the NYISO or PJM overrides any requirements of this Operating Protocol and the appendices hereto.

PAR Movement Scenarios

Case 1 — Aggregate actual flow on the JK interface (at Waldwick) or the ABC interface (at Farragut and Goethals) is higher or lower than RTMDF, but within the bandwidth.

No action taken. Flows will continue to be monitored, but action will only be taken if the flows get above or below the bandwidth.

Case 2 — Aggregate actual flow on the JK interface (at Waldwick) or the ABC interface (at Farragut and Goethals) is higher or lower than the RTMDF, and outside the bandwidth.

PJM and the NYISO will coordinate the following procedures:

- PJM shall determine the Waldwick PAR tap change(s) that change the aggregate actual flow to be within the bandwidth, considering the impact that the proposed tap changes have on the NYISO. If the PJM analysis indicates that the tap changes can be made without causing an actual or contingency constraint in the NYISO that would result in NYISO off-cost operation, PJM will inform the NYISO of the proposed PAR moves, obtain the NYISO's concurrence, and direct PSE&G to implement the PAR tap changes.

- The NYISO shall determine the Farragut and Goethals PAR tap change(s) that change the aggregate actual flow to be within the bandwidth, considering the impact that the proposed tap changes have on PJM. If the NYISO analysis indicates that the tap changes can be made without an actual or contingency constraint in PJM that would result in PJM off-cost operation, the NYISO will inform PJM of the proposed PAR moves, obtain PJM concurrence, and direct ConEd to implement the PAR tap changes.

- If PJM is off-cost or expected to go off-cost in maintaining the RTMDF and the NYISO is not off-cost, then PJM/NYISO shall agree to allow actual aggregate interface flows to deviate from the RTMDF in order to re-direct up to 300 MW from the PJM system onto the NYISO system. PJM and the NYISO shall continue to use reasonable efforts to modify actual interface flows in incremental adjustments until 1) PJM is no longer off-cost; or 2) the NYISO is about to go off-cost (i.e., the NYISO expects that it will have to redispatch in response to transmission constraints in order to maintain the RTMDF).

If the NYISO is off-cost or expected to go off-cost and PJM is not off-cost in maintaining the RTMDF, then PJM/NYISO shall agree to allow actual aggregate interface flows to deviate from the RTMDF in order to re-direct up to 300 MW from the NYISO system onto the PJM system. PJM and the NYISO shall continue to use reasonable efforts to modify actual interface flows in incremental adjustments until 1) NYISO is no longer off-cost; or 2) PJM is about to go off-cost (i.e., PJM expects that it will have to redispatch in response to transmission constraints in order to maintain the RTMDF).

- If the ABC actual interface flows cannot be maintained within the interface desired flow range due to the following system conditions: (1) insufficient PAR angle capability resulting from any of the A, B, C, J, or K PARs being at their maximum tap setting, and (2) PJM's inability to redispatch in response to transmission constraints to support ABC deliveries to New York, then PJM and the NYISO shall consider using other available facilities, including the other PARs, to create flow capability to permit the necessary tap changes to bring the actual flow within the tolerances of the desired flow calculation, provided that this can be done without creating additional redispatch costs in either the NYISO or PJM. If after such actions have been taken, including the use of other facilities, and ABC/JK actual interface flows still cannot be maintained within the interface desired flow range, then an adjustment to the desired flow calculation (a desired flow offset, with the amount agreed to by PJM and the NYISO) shall be made such that both the ABC and JK actual interface flows are within +/- 100 MW of the ABC and JK interface RTMDF respectively.

- If the JK actual interface flows cannot be maintained within the interface desired flow range due to the following system conditions: (1) insufficient PAR angle capability resulting from any of the A, B, C, J, or K PARs being at their maximum tap setting, and (2) the NYISO's inability to re-dispatch in response to transmission constraints to support JK deliveries to PJM then PJM and NYISO shall consider using other available facilities, including the other PARs to create flow capability to permit the necessary tap changes to bring the actual flow within the tolerances of the desired flow calculation, provided that this can be done without creating additional redispatch costs in either the NYISO or PJM. If after such actions have been taken, including the use of other facilities, and ABC/JK actual interface flows still cannot be maintained within the interface desired flow range, then an adjustment to the desired flow calculation (a desired flow offset, with the amount agreed to by PJM and NYISO) shall be made such that both the ABC and JK actual interface flows are within +/- 100 MW of the ABC and JK interface RTMDF respectively.

Case 3 — If PJM or NYISO analysis reveals that future system conditions (within the next several hours) may reasonably be expected to require that a PAR will need to change by more than 3 taps in order to remain within the bandwidth, then PJM and NYISO shall consider pre-positioning the system to address these future conditions. Both PJM and the NYISO must agree to any decision to re-position the taps to address expected future conditions.

PJM and the NYISO will coordinate with each other and may mutually agree to position the respective PARs on each system to be within two tap changes in anticipation of changes to RTMDF for the next several hours to ensure that the PARs are positioned such that they are able to meet the anticipated RTMDF.

Appendix 6 – Distribution of Flows Associated with Implementation of Day-Ahead and Real Time Market Desired Flows

In general, the ability to maintain the ABC / JK actual interface flows at their corresponding ABC/JK Day-Ahead and Real Time Market Desired Flow (RTMDF) values should not be impacted by individual line flow constraints. The Operating Protocol will ordinarily be considered satisfied if the ABC/JK actual interface flows are each equal to the desired flow values plus or minus the 100 MW bandwidth.

The initial estimate of individual line flow distribution for the ABC / JK interfaces shall be based on an equal flow assumption among the lines comprising the interface. Under outage conditions of the A, B, C, J, or K lines, the initial estimate of individual line flow distribution shall be based on an assumption that flows should be equalized among those remaining lines comprising the interface. Further, the ISOs shall adjust (from RTMDF) the flow distribution for ABC (move flow from the A line to the B and C lines) upon the NYISO's request, provided that the adjustment shall not exceed 125 MW if PJM is off-cost or is expected to be off-cost. Con Ed shall not be responsible for balancing charges resulting from changes in the individual line flow distribution between the PJM Day-Ahead and Real-Time Markets.

For example:

If the ABC interface RTMDF is 900 MW, then the initial estimate of line flow on A is 1/3 * 900=300 MW, B is 1/3 * 900=300 MW, and C is 1/3 * 900=300 MW.

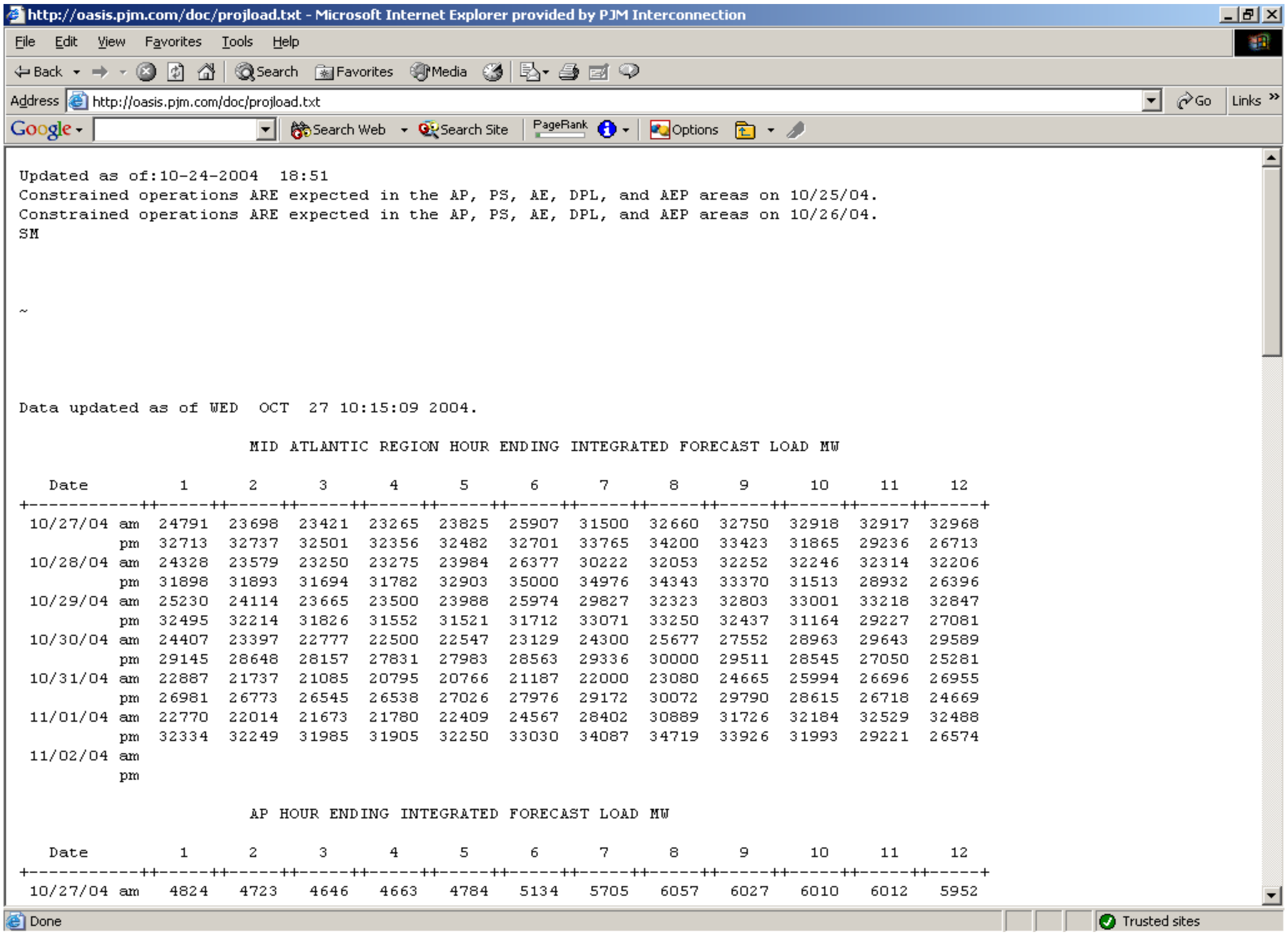
If the J, K interface RTMDF is 900 MW, then the initial estimate of line flow on J is 1/2 * 900=450 MW, K is 1/2 * 900=450 MW.

However, if the ABC/JK actual interface flows cannot be maintained within the 100 MW bandwidth of desired flows due to the following system conditions: 1) insufficient PAR angle capability and an inability to redispatch in response to transmission constraints in PJM; or 2) upon implementing a NYISO request to adjust the distribution of flow on the A line (move flow from the A line to the B and C lines) in excess of 125 MW as described above, then the actual ABC and/or JK interface flow shall be adjusted to be as close as feasible to the interface desired flow values for each of the JK and ABC interfaces.

> For example:
>
> Assume the ABC interface RTMDF = 900 MW, then the initial estimate of line flow on A is 1/3* 900=300 MW, B is 1/3 * 900=300 MW, and C is 1/3 * 900=300 MW. Further assume that the NYISO requests that the distribution of flow over the A line be limited to 100 MW, then the resulting system conditions are an actual ABC interface flow of 825 MW with individual PAR flows of A=100 MW, B=362.5 MW, C=362.5 MW.

In this example, the actual ABC interface flow is as close as feasible to the ABC RTMDF assuming off-cost operation in the PJM area and the NYISO request that the distribution of flow over the A line be limited to 100 MW, which is in excess of the 125 MW distribution adjustment (300 MW-100 MW = 200 MW). PJM and the NYISO's obligations under this Operating Protocol will be deemed to be satisfied even though the ABC/JK actual interface flows are not equal to the RTMDF plus or minus the 100 MW bandwidth.

Appendix 7 – References



Updated as of:10-24-2004 18:51
Constrained operations ARE expected in the AP, PS, AE, DPL, and AEP areas on 10/25/04.
Constrained operations ARE expected in the AP, PS, AE, DPL, and AEP areas on 10/26/04.
SM

~

Data updated as of WED OCT 27 10:15:09 2004.

MID ATLANTIC REGION HOUR ENDING INTEGRATED FORECAST LOAD MW

Date		1	2	3	4	5	6	7	8	9	10	11	12
10/27/04	am	24791	23698	23421	23265	23825	25907	31500	32660	32750	32918	32917	32968
	pm	32713	32737	32501	32356	32482	32701	33765	34200	33423	31865	29236	26713
10/28/04	am	24328	23579	23250	23275	23984	26377	30222	32053	32252	32246	32314	32206
	pm	31898	31893	31694	31782	32903	35000	34976	34343	33370	31513	28932	26396
10/29/04	am	25230	24114	23665	23500	23988	25974	29827	32323	32803	33001	33218	32847
	pm	32495	32214	31826	31552	31521	31712	33071	33250	32437	31164	29227	27081
10/30/04	am	24407	23397	22777	22500	22547	23129	24300	25677	27552	28963	29643	29589
	pm	29145	28648	28157	27831	27983	28563	29336	30000	29511	28545	27050	25281
10/31/04	am	22887	21737	21085	20795	20766	21187	22000	23080	24665	25994	26696	26955
	pm	26981	26773	26545	26538	27026	27976	29172	30072	29790	28615	26718	24669
11/01/04	am	22770	22014	21673	21780	22409	24567	28402	30889	31726	32184	32529	32488
	pm	32334	32249	31985	31905	32250	33030	34087	34719	33926	31993	29221	26574
11/02/04	am												
	pm												

AP HOUR ENDING INTEGRATED FORECAST LOAD MW

Date		1	2	3	4	5	6	7	8	9	10	11	12
10/27/04	am	4824	4723	4646	4663	4784	5134	5705	6057	6027	6010	6012	5952

Figure 1 - PJM Constraints

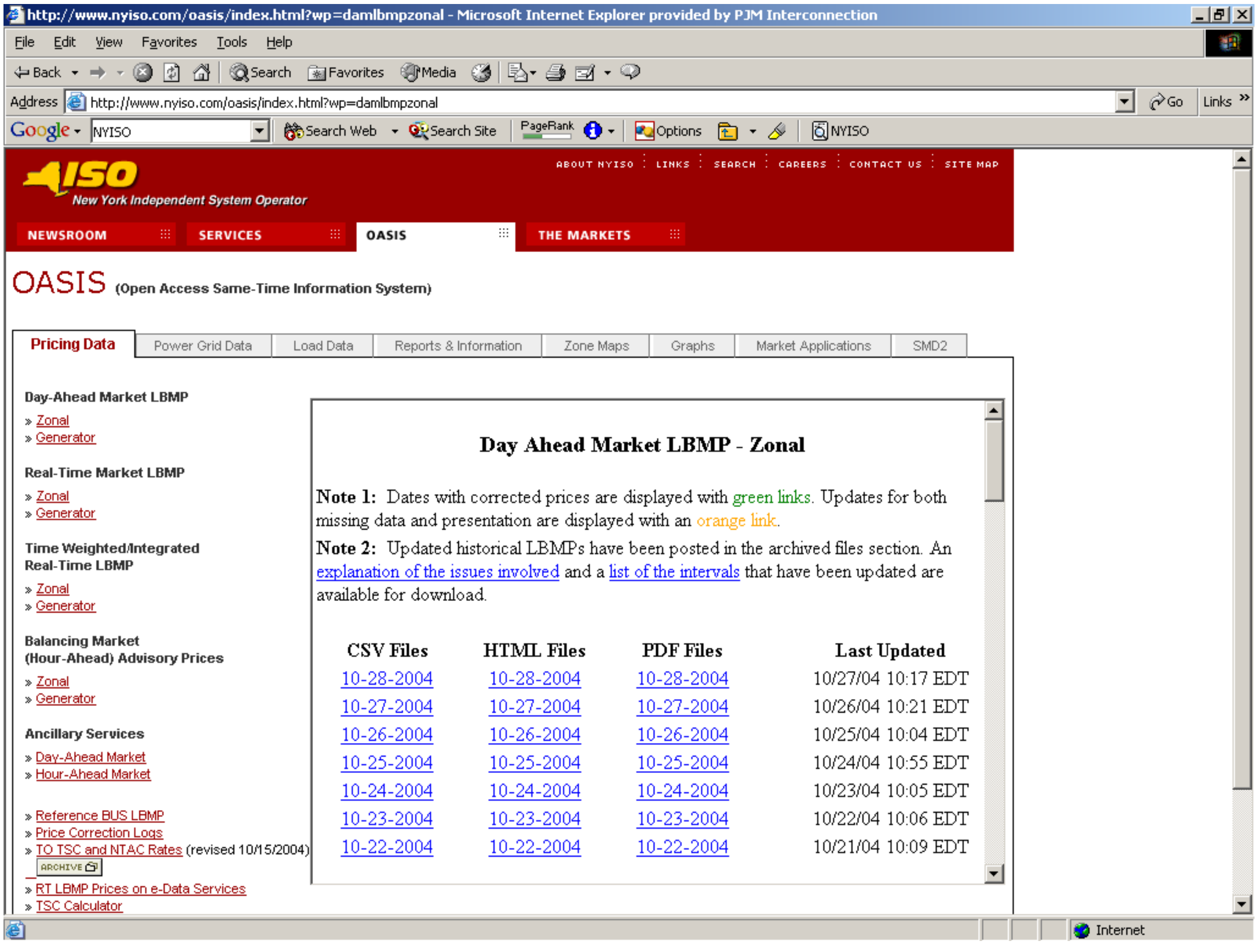


Figure 2 - NYISO Day Ahead Results

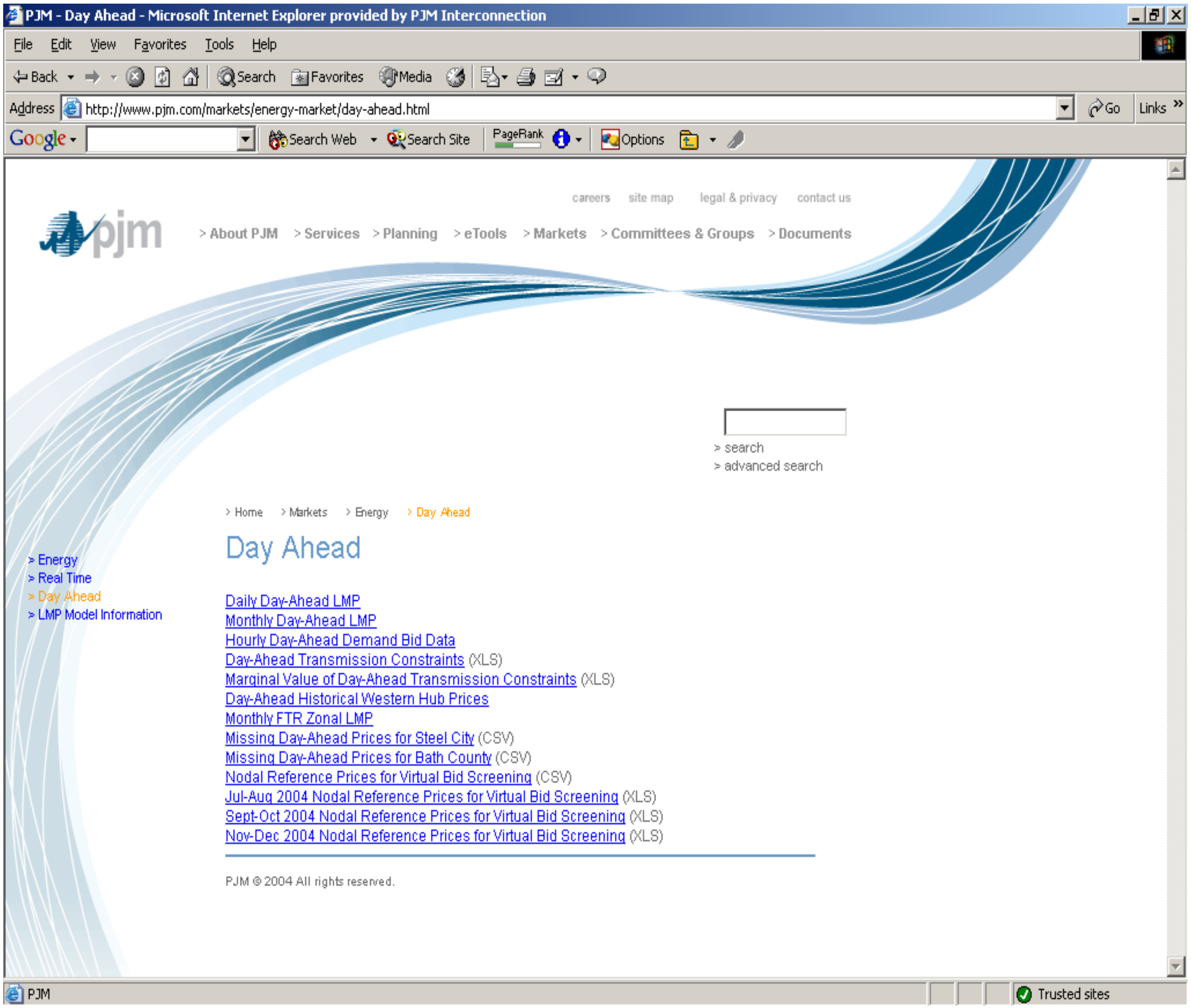


Figure 3 - PJM Day Ahead Market Results

Appendix 8 – Definitions

Off-cost: the weighted LMP of JK is less than the weighted LMP of ABC by more than $5 and/or the weighted nodal pricing of Ramapo is less than the weighted nodal pricing of the aggregate of Farragut and Goethals by more than $5 (with a reasonable expectation of the appropriate cost differential continuing for at least two consecutive hours). However, for the evaluation of a PJM request for a redirect, the Off-cost value for PJM shall be more than $5 (with a reasonable expectation of the appropriate PJM cost differential continuing for at least two consecutive hours) and the Off-cost value for the NYISO shall be $0. For the evaluation of a NYISO request for a redirect, the Off-cost value for NYISO shall be more than $5 (with a reasonable expectation of the appropriate NYISO cost differential continuing for at least two consecutive hours) and then Off-cost value for the PJM shall be $0.

Mid-Atlantic Area: Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Metropolitan Edison Company, PECO Energy Company, PPL Electric Utilities Corporation, Pennsylvania Electric Company, Potomac Electric Power Company, Public Service Electric and Gas Company, and Rockland Electric Company.

New York ISO Day Ahead Election (NY-DAE): election by ConEd – submitted in the NYISO Day-Ahead Market prior to 5 a.m..

NY Desired Flow (NYDF): desired flow calculation by NYISO based on NY-DAE for input to NYISO Day Ahead Market.

PJM Day Ahead Market Election (PJM-DAE): election by the ConEd – submitted in the PJM Day Ahead Market prior to 12 noon.

PJM Desired Flow (PJMDF): desired flow calculation by PJM based on PJM-DAE for input to PJM Day Ahead Market.

ConEd Real-Time election (RTE): option by ConEd to request Real-Time Market modification from its Day Ahead Market election.

Real Time Market Desired Flow (RTMDF): Desired flow for real time operations.

Impairments: Conditions determined during the NYISO's and PJM's respective planning analyses that will cause implementation of the 600/400 MW transactions to result in violations of established reliability criteria.

Active Load Management (ALM): Active Load Management is end-use customer load which can be interrupted at the request of PJM. Such PJM request is considered an Emergency action and is implemented prior to a voltage reduction.

Pricing points: aggregate nodal points for the ABC interface and JK interface at the respective locations in both PJM and NYISO regions. These points will be defined and posted.

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.

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.

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.

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.

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 Reserves: For purposes of determining the Real-Time Locational Based Marginal Price in any Real-Time Dispatch interval: the capability of all Suppliers that submit Incremental Energy Bids to provide Spinning Reserves, Non-Synchronized 10-Minute Reserves, and 30-Minute Reserves in that interval and in the relevant location, and the quantity of recallable External ICAP Energy sales in that interval.

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.

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.

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 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 Energy and Ancillary Services, after applying the Price Adjustment, was greatest.

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 purchase and/or sell Energy, Demand Reductions, Transmission Congestion Contracts and/or Ancillary Services at a specified price that is duly submitted to the ISO pursuant to ISO Procedures.

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.

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 26.3.3 of Attachment K to this Services Tariff.

Bilateral Transaction: A Transaction between two or more parties for the purchase and/or sale of Capacity, Energy, and/or Ancillary Services other than those in the ISO Administered Markets.

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 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: 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 of the 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"): The **process** by which TCCs are released for sale for the Centralized TCC Auction period, through a bidding process administered by the ISO or an auctioneer.

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 it has offered Energy: i) by a Supplier; or ii) by an Intermittent Power Resource depending on wind as its fuel for which the ISO has imposed a Wind Output Limit after October 31, 2009 in the given RTD interval, 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 ISO Procedures, provided that the excess Energy injection does not exceed the Supplier's Real-Time Scheduled Energy Injection over that interval, plus a tolerance. The tolerance shall initially be set at 3% of a given Supplier's Normal Upper Operating Limit and may be modified by the ISO if necessary to maintain good Control Performance. For Generators operating in Start-Up or Shutdown Periods, or Testing Periods, and for Intermittent Power Resources not described in Subsection (ii) of this definition that depend on wind as their fuel and Limited Control Run of River Hydro Resources, not bidding in a manner that indicates they are available to provide Regulation Service or Operating Reserves, that were in operation on or before November 18, 1999 within the NYCA, plus an additional 3,300 MW of such Resources~~.~~, and for Intermittent Power Resources that depend on solar energy or landfill gas for their fuel and that are not bidding in a manner that indicates they are available to provide Regulation Service or Operating Reserves, Compensable Overgeneration shall mean that quantity of Energy injected by a Generator, over a given RTD interval in which it has offered Energy, 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. 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.

Congestion Rent: The opportunity costs of transmission Constraints on the NYS Transmission System. Congestion Rents are collected by the ISO from Loads 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 ISO OATT 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 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.

Credit Assessment: An assessment of a Customer's creditworthiness, conducted by the ISO in accordance with Section 26.4.3 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.

Curtailment or Curtail: A reduction in Firm or Non-Firm 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 26.3.2 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 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 in a manner that reduces 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 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 Bilateral Wheel Through Transaction to indicate the Congestion Component cost 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 that are not supplied by a Local Generator. 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 Resources: A Resource located in the NYCA that is capable of controlling demand in a responsive, measurable and verifiable manner within time limits, and that 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 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 only manually in real-time.

Direct Sale: The sale of TCCs directly to a buyer by the Primary Owner through a non-discriminatory auditable sale conducted on the ISO's OASIS, in compliance with the requirements and restrictions set forth in Commission Order Nos. 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 Generators may be either ISO-Committed Flexible or 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 period commencing at the beginning of each day (0000 hour).

Dispute Resolution Administrator ("DRA"): An individual hired by the ISO to administer the Dispute Resolution Process established in the ISO Tariffs and ISO Agreement.

Dispute Resolution Process ("DRP"): The procedures: (1) described in the ISO Tariffs and the ISO Agreement that are used to resolve disputes between Market Participants and the ISO involving services provided under the ISO Tariffs (excluding applications for rate changes or other changes to the ISO Tariffs or rules relating to such services); and (2) described in the ISO/NYSRC Agreement that are used to resolve disputes between the ISO and NYSRC involving the implementation and/or application of the Reliability Rules.

DMNC Test Period: The period within a Capability Period during which a Resource required to do so pursuant to ISO procedures shall conduct a DMNC test if that DMNC test is to be valid for purposes of determining the amount of Installed Capacity used to calculate the Unforced Capacity that this Resource is permitted to supply to the NYCA. Such periods will be established pursuant to the ISO Procedures.

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 26.3.2 of Attachment K to this 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: A point on the eleven constant cost steps that comprise a Supplier's Incremental Energy Bid, established pursuant to the ISO Procedures, that is a function of the Real-Time LBMP at the Supplier's bus, the Supplier's real-time Energy injection, real-time schedule, stated response rate and Economic Operating Point in the previous RTD interval, which may be the Supplier's Real-Time Scheduled Energy Injection. A Supplier's Economic Operating Point may be above, below, or equal to its Real-Time Scheduled Energy Injection.

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 indicates it expects to be able to reach, 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 Generator or Demand Side 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 26.3.2 of Attachment K to this Services Tariff.

Energy Limited Resource: Capacity 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: A 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 Customer to hold all of the rights and obligations associated with Fixed Price TCCs, as provided for in this Services Tariff.

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 the 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: 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 TCCs and Grandfathered Rights that have been allocated at the completion of the last Centralized TCC Auction.

Existing Transmission Capacity for Native Load ("ETCNL"): Transmission Capacity reserved 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). This includes transmission Capacity required: (1) to deliver the output from operating facilities 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 of the ISO OATT.

Existing Transmission Agreement ("ETA"): An agreement between two or more Transmission Owners, or between a Transmission Owner and another entity, as defined in the ISO Agreement and the ISO OATT.

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 5.16) and the Customer settlements provisions of this ISO Services Tariff (as set forth in Section 7.4.3).

Exports: A Bilateral Transaction or purchases 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).

2.6 Definitions - F

Facility Flow-Based Methodology: The methodology, as described in Section 17.5.3.7 of Attachment B, used to allocate Net Auction Revenue among Transmission Owners.

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: A series of TCCs, each with a duration of one year, renewable annually for a period of at least five years at a fixed price that is obtained through the conversion of expired or expiring ETAs in accordance with Section 19.2.1 of Attachment M of the ISO OATT.

2.7 Definitions - G

GADS Data: Data submitted to the NERC for collection into the NERC's Generating Availability Data System ("GADS").

Generator: A facility 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.

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: The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party Transmission Wheeling Agreements ("TWA") 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 those rights to 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 by the Tariff, to convert those rights to TCCs.

2.8 Definitions - H

2.9 Definitions - I

ICAP Demand Curve: A series of prices which decline until reaching zero as the amount of Installed Capacity increases.

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.

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

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 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 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.

Installed Capacity: 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, Special Case Resource, Intermittent Power Resource, Limited Control Run of River Hydro Resource, municipally-owned generation, 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: The procedure used to allocate Original Residual TCCs determined prior to the first Centralized TCC Auction to Transmission Owners.

Intermittent Power Resource: Capacity resources that depend upon wind, solar energy or landfill gas for their fuel and that such dependence precludes accurate prediction of the facility's real-time output. 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 26.2 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.

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.

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.

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 one Transmission District within which a minimum level of Installed Capacity must be maintained.

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 Minimum Installed Capacity Requirement: The portion of the NYCA Minimum Installed Capacity Requirement that must be electrically located within a Locality, or possess an approved Unforced Capacity Deliverability Right, 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 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.

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 specified minimum operating level or to provide a Demand Side Resource's specified minimum quantity of Demand Reduction.

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.

Minimum Payment Nomination: An offer, submitted 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.

Modified Wheeling Agreement ("MWA"): A Transmission Agreement in existence, as amended, between Transmission Owners, that is associated with existing Generators or power supply contracts, that will be modified effective upon LBMP implementation. The terms and conditions of the MWA will remain the same as the original agreement, except as noted in the ISO OATT.

Monthly Auction: An auction administered by the ISO pursuant to Section 5.13.3 of the ISO Services Tariff.

2.14 Definitions - N

Native Load Credit Requirement: The amount of credit support required to purchase Energy, Ancillary Services, and Capacity to meet the reliable electric needs of Native Load Customers.

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.

Net Auction Revenue: The total amount, in dollars, as calculated pursuant to Section Part 17.5.3.1 of Attachment B, 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 17.5.2.1 of Attachment B, 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 Congestion Rent Surplus Payments and U/D Congestion Rent Surplus Payments. Net Congestion Rent may be positive or negative.

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

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 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) The Proxy Generator Bus(es) for the Hydro Quebec Control Area; (b) the Proxy Generator Bus associated with the Dennison Scheduled Line; and (c) any other Proxy Generator Bus(es) for an area outside of the New York Control Area that have been identified by the ISO as characterized by non-competitive Import or Export prices, and that have been approved by the Commission for designation as a Non-Competitive Proxy Generator Bus(es).

Non-Firm-Point-To-Point Transmission Service: Point-To-Point Transmission Service under the Tariff for which a Customer is not willing to pay Congestion. Such service is available absent constraint under Part 3 of the ISO OATT. Non-Firm-Point-To-Point Transmission Service is available on a stand-alone basis for individual one-hour periods not to exceed twenty-four (24) consecutive hours.

Non-Investment Grade Customer: A Customer that does not meet the criteria necessary to be an Investment Grade Customer, as set forth in Section 26.2 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 indicates it expects to be able to reach, 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. 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.

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 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 26.3.2 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;

(2) 10-Minute Non-Synchronized Reserve: Operating Reserves provided by Generators, 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 and Demand Side Resources that are not Local Generators; or non-synchronized Operating Reserves provided by Generators 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 nine 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.

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

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.

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 provide quantitative comparisons of actual values versus expected and forecasted values for Generators and Loads. This system will be used by the ISO to measure compliance with criteria associated with, but not limited to, the provision of Regulation Service.

Point to Point Transmission Service: The reservation and transmission of Capacity and Energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part 3 of the ISO OATT.

Point(s) of Injection ("POI" or "Point of Receipt"): The point(s) on the NYS Transmission System 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. The Point(s) of Injection shall be specified in the Service Agreement.

Point(s) of Withdrawal ("POW" or "Point of Delivery"): The point(s) on the NYS Transmission System where Energy, Capacity and Ancillary Services will be made available to the receiving party under the ISO OATT or the ISO Services Tariff. The Point(s) of Withdrawal shall be specified in the Service Agreement.

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.

Pre-Scheduled Transaction Request: An offer submitted, pursuant to ISO Procedures, for priority scheduling of Transactions between the ISO and neighboring Control Areas to: (i) purchase Energy from the LBMP Market at the LBMP Market Price and deliver it to an External Control Area; (ii) sell Energy delivered from an External Control Area to the LBMP Market at the LBMP Market Price; or (iii) wheel Energy through the New York Control Area from one External Control Area to another External Control Area at the market-determined Transmission Usage Charge. Pre-Scheduled Transaction Requests accepted for scheduling reserve Ramp Capacity and Transfer Capability and receive priority scheduling in the LBMP Market.

Pre-Scheduled Transaction: A Transaction accepted for scheduling in the designated LBMP Market pursuant to a Pre-Scheduled Transaction Request. Pre-Scheduled Transactions may be withdrawn only with the approval of the ISO pursuant to the ISO Procedures.

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: A Primary Holder of each TCC is the Primary Owner of that TCC or the party that purchased that TCC at the close of the Centralized TCC Auction. With respect to each TCC, a Primary Holder must be: (1) a Transmission Customer that has purchased the TCC in the Centralized TCC Auction, and that has not resold it in that same Auction; (2) a Transmission Customer that has purchased the TCC in a Direct Sale with another Transmission Customer; (3) the Primary Owner who has retained the TCC; or (4) Primary Owners of the TCC that allocated the TCC to certain customers or sold it in the Secondary Market or sold through a Direct Sale to an entity other than a Transmission Customer. The ISO settles Day-Ahead Congestion Rents pursuant to Attachments M and N to the ISO OATT with the Primary Holder of each TCC.

Primary Owner: The Primary Owner of each TCC is the Transmission Owner or other Transmission Customer that has acquired the TCC through conversion of rights under an Existing Transmission Agreement to Grandfathered TCCs (in accordance with Attachment K of the ISO OATT), or through the conversion of Existing Transmission Agreements upon their expiration (in accordance with Attachment B), or the Transmission Owner that acquired the TCC through the ISO's allocation of Original Residual TCCs or through the conversion of ETCNL or an RCRR.

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 for 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 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, or an External Control Area operator, 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:: A zone-to-zone TCC created when a Transmission Owner with a RCRR exercises its right to convert the RCRR into a TCC pursuant to Section 19.5.4 of Attachment M of 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 at least seventy-five minutes before the start of a dispatch hour, or at least eighty-five minutes before the start of a dispatch hour if the Bid seeks to schedule an External Transaction at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line.

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 External Transaction schedules. 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. 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.

Reconfiguration Auction: The monthly auction administered by the ISO in which Market Participants may purchase and sell one-month TCCs.

Reduction or Reduce: The partial or complete reduction in Non-Firm Transmission Service as a result of transmission Congestion (either anticipated or actual).

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 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.

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"):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 Transmission Owner allocated the RCRR pursuant to Section 19.5 of Attachment M of the ISO OATT.

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.

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, Demand Side Resource or Control Area System Resource.

Rest of State: The set of all non-Locality NYCA LBMP Load Zones. As of the 2002-2003 Capability Year, Rest of State includes all NYCA LBMP Load Zones other than LBMP Load Zones J and K.

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.

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 following transmission facilities are Scheduled Lines: the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Dennison Scheduled Line, the Northport Norwalk Scheduled Line, and the Linden VFT Scheduled Line.

Scheduling Differential: A monetary amount, to be defined by the ISO pursuant to ISO Procedures, that is assigned to, or defines Bid Price limits applicable to, Decremental Bids and Sink Price Cap Bids at Proxy Generator Buses, in order to establish an appropriate scheduling priority for the Transaction or Firm Transmission Service associated with each such Bid. The Scheduling Differential shall be no larger than one dollar ($1.00).

SCUC: Security Constrained Unit Commitment, described in Section 4.2.4 of this ISO Services Tariff.

Secondary Holders: Entities that: (1) purchase TCCs in the Secondary Market; (2) purchase TCCs in a Direct Sale from a Transmission Owner and have not been certified as a Primary Holder by the ISO; or (3) receive an allocation of Native Load TCCs from a Transmission Owner (See Attachment M). A Transmission Customer purchasing TCCs in a Direct Sale may qualify as a Primary Holder with respect to those TCCs purchased in that Direct Sale.

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: A market in which Primary and Secondary Holders sell TCCs by mechanisms other than through the Centralized TCC Auction or by Direct Sale. Buyers of TCCs in the Secondary Market shall neither pay nor receive Congestion Rents directly to or from the ISO.

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 Bid Price 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.

Special Case Resource: Demand Side Resources capable of being interrupted upon demand, and Local Generators, rated 100 kW or higher, that are not visible to the ISO's Market Information System and that 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. Special Case Resources that are not Local Generators, may be offered as synchronized Operating Reserves and Regulation Service and Energy in the Day-Ahead Market. Special Case Resources, 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.

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.

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.

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 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 Owner or between a Transmission Owner and an entity that is not a Transmission Owner 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. These agreements are listed in Table 1 of Attachment L to the ISO OATT.

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.

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 26.3.2 of Attachment K to this 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 entity (or its designated agent) that receives Transmission Service pursuant to a Service Agreement and the terms of the ISO OATT.

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 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 Tariffs 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 Facility Agreement: The agreements listed in Attachment L, Table 2 of the ISO OATT governing the use of specific or designated transmission facilities charges all, or a portion, of the costs to install, own, operate, or maintain said transmission facilities, to the customer under the agreement. These agreements may or may not have provisions to provide Transmission Service utilizing said transmission facilities.

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 Owner's transmission system.

Transmission Shortage Cost: The maximum reduction in system costs resulting from an incremental relaxation of a particular Constraint that will be used in calculating LBMP. The Transmission Shortage Cost is set at $4000/MWh.

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 Tables 1A and 1B 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.

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 new incremental controllable transmission projects that provide a transmission interface to a NYCA Locality (i.e., an area of the NYCA in which a minimum amount of Installed Capacity must be maintained). 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 with the UDR transmission facility, UDRs allow such Unforced Capacity to be treated as if it were located in the NYCA Locality, thereby contributing to an LSE's Locational 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 26.3.2 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 26.4 of Attachment K to this Services Tariff.

2.22 Definitions - V

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 26.3.2 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.

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 26.3.2 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 26.3.2, 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 or partial unit outages that resulted in a significant reduction in a generating unit'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, sells or purchases Capacity, or provides Ancillary Services in the ISO Administered Markets utilizes Market Services and must take service as a Customer under the Tariff.

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

Each Customer shall be subject to a minimum Transaction size of one (1) megawatt ("MW") between each Point of Injection and Point of Withdrawal in any given hour. Each Transaction must be scheduled in whole megawatts.

4.1.5 Communication Requirements for Market Services

Customers may utilize a variety of communications facilities to access the ISO's OASIS and Bid/Post System, including but not limited to, conventional Internet service providers, wide area networks such as NERC net, and dedicated communications circuits. 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 provided, however, that Demand Side Resources offering Operating Reserves or

Regulation Service shall pay the Market Administration and Control Area Services Charge based only on their withdrawal billing units. Limited Energy Storage Resources shall pay the Market Administration and Control Area Services Charge, as specified in Rate Schedule 1 of this ISO Services Tariff, based only on their Actual Energy Injections.

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

Generating units committed by the ISO for service to ensure NYCA or local system reliability will recover startup and minimum generation costs not recovered in the Dispatch Day. Payment for such costs shall be determined pursuant to the provisions of Attachment C of this Tariff. Such payments shall be recovered by the ISO from the local customers for whose benefit the generation was committed 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 Incremental Cost Recovery for Units Responding to Local Reliability Rule I-R3 or I-R5

Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rule I-R3 -- Loss of Generator Gas Supply (New York City) or I-R5 -- Loss of Generator Gas Supply (Long Island), as being required to burn an alternate fuel at designated minimum levels 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 the variable operating costs associated with burning the required alternate fuel pursuant to the provisions of this Section 4.1.9. For purposes of this Section 4.1.9, the periods of time for which Consolidated Edison invokes Local Reliability Rule I-R3 or LIPA invokes Local Reliability Rule I-R5 and in which the eligible unit burns its required alternate fuel, including that period of time required to move into and out of Rule I-R3 or I-R5 compliance, shall be referred to as the "Eligibility Period." For Eligibility Periods, the eligible unit shall recover its variable operating costs associated with burning the required alternate fuel if and to the extent that such variable operating costs are not reflected in the reference level for that unit for the hours included in the Eligibility Period, pursuant to ISO procedures. To be recoverable, variable operating costs associated with burning the required alternate fuel must be incurred during an Eligibility Period and must be incurred only because Local Reliability Rule I-R3 or I-R5 was invoked.

Rules for determining: (i) variable operating costs associated with burning the required alternate fuel that would not have been incurred but for the requirement to burn the required alternate fuel as established by Local Reliability Rules I-R3 and I-R5; and (ii) Eligibility Periods shall be specified in ISO Procedures. Payments made by the ISO to the eligible unit to reimburse the variable operating costs paid 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.

There shall be no recovery of costs pursuant to this Section 4.1.9 for any hour for which the indexed variable operating costs of the required alternate fuel that is being burned pursuant to Rule I-R3 or I-R5 is less than the indexed variable operating costs for natural gas, as determined by the ISO.

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 variable operating costs associated with burning the required alternate fuel pursuant to the provisions of this section; (ii) the start and stop hours for each claimed Eligibility Period and (iii) the amount of alternative fuel for which the Generator has sought to recover variable operating costs.

4.2 Day-Ahead Markets and Schedules

4.2.1 Pre-Scheduled Transaction Requests

Pre-Scheduled Transaction Requests shall be submitted, pursuant to ISO Procedures, no earlier than eighteen (18) months prior to the Dispatch Day, and shall include hourly Transaction quantities (in MW) at each affected External Interface for each specified Dispatch Day.

Customers may submit Pre-Scheduled Transaction Requests for scheduling in the Day-Ahead Market. The ISO shall determine, pursuant to ISO Procedures, the amount of Total Transfer Capability at each External Interface to be made available for scheduling. The ISO shall evaluate Pre-Scheduled Transaction Requests in the order in which they are submitted for evaluation until the Pre-Scheduled Transmission Request expires, pursuant to ISO Procedures, prior to the close of the Day-Ahead Market for the specified Dispatch Day. Modification of a Pre-Scheduled Transaction Request shall constitute a withdrawal of the original request and a submission of a new Pre-Scheduled Transaction Request. At the request of a Customer, the ISO shall continue to evaluate a Pre-Scheduled Transaction Request that was not accepted for scheduling in the priority order in which the Request was originally submitted until it is either accepted for scheduling, is withdrawn or expires, pursuant to ISO Procedures, prior to the close of the Day-Ahead Market for the specified Dispatch Day. The ISO shall accept Pre-Scheduled Transaction Requests for scheduling, pursuant to ISO Procedures, provided that there is Ramp Capacity, and Transfer Capability at each affected External Interface, available in the NYCA for each hour requested. If Ramp Capacity or Transfer Capability, on the designated External Interface, is unavailable in the NYCA for any hour of the Pre-Scheduled Transaction Request, the request shall not be scheduled. The ISO shall confirm the Transaction with affected Control

Areas, as necessary, pursuant to ISO Procedures and may condition acceptance for scheduling on such confirmation.

The ISO shall provide the requesting Customer with notice, as soon as is practically possible, as to whether the Pre-Scheduled Transaction Request is accepted for scheduling and, if it is not scheduled, the ISO shall provide the reason.

The ISO shall reserve Ramp Capacity, and Transfer Capability on affected Interfaces, for each Pre-Scheduled Transaction. The ISO shall evaluate requests to withdraw Pre-Scheduled Transactions pursuant to ISO Procedures. The ISO shall submit Pre-Scheduled Transactions to the appropriate LBMP Market for the designated Dispatch Day.

Prescheduled Transactions that are submitted for scheduling in the Day-Ahead Market shall be assigned a Decremental Bid or Sink Price Cap Bid, as appropriate, to provide the highest scheduling priority available.

Prescheduled Transactions may not be scheduled at Proxy Generator Buses that are associated with Scheduled Lines.

4.2.2 Day-Ahead Load Forecasts, Bids and Bilateral Schedules

4.2.2.1 General Customer Forecasting and Bidding Requirements

By 5 a.m., on the day prior to the Dispatch Day (or by 4:50 a.m. for Eligible Customers seeking to schedule External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line):
(i) All LSEs serving Load in the NYCA shall provide the ISO with Day-Ahead and seven (7) day Load forecasts; and (ii) Customers submitting Bids in the Day-Ahead Market, other than Pre-scheduled Transaction Requests, shall provide the ISO, consistent with ISO Procedures:

4.2.2.1.1 Bids to supply Energy, including Bids to supply Energy in Virtual Transactions;

4.2.2.1.2 Bids to supply Ancillary Services;

4.2.2.1.3 Requests for Bilateral Transaction schedules;

4.2.2.1.4 Bids to purchase Energy, including Bids to purchase Energy in Virtual Transactions; and

4.2.2.1.5 Demand Reduction Bids.

In general, the information provided to the ISO shall include the following:

4.2.2.2 Load Forecasts

The Load forecast shall indicate the predicted level of Load in MW by Point of Withdrawal for each hour of the following seven (7) days.

4.2.2.3 Bids by Dispatchable and ISO-Committed Fixed Resources to Supply Energy and/or Ancillary Services

4.2.2.3.1 General Rules

Day-Ahead Bids by Dispatchable or ISO-Committed Fixed Suppliers 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. Bids to supply Energy at Proxy Generator Buses shall be priced no lower than the Bid that provides the highest scheduling priority for sales to the relevant LBMP Market plus the product of (i) the Scheduling Differential and (ii) three.

If the Supplier is ISO-Committed Flexible or Self-Committed Flexible, and 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 shall specify the quantity of Regulation Service it is making available and 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 and Attachment D to 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 Supplier may resubmit a complete Day-Ahead Bid, provided that the new Bid is timely.

4.2.2.3.2 Bid Parameters

Day-Ahead Bids by Dispatchable or ISO-Committed Fixed Suppliers, may identify variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, and other parameters described in Attachment D of this ISO Services Tariff and the 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 $75/MW hour. Day-Ahead offers by Intermittent Power Resources that depend on wind as their fuel shall be ISO-Committed Flexible and shall not include a Minimum Generation Bid or a Start-Up Bid.

Day-Ahead Bids by ISO-Committed Fixed and ISO-Committed Flexible Generators 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 or Self-Committed Flexible.

4.2.2.3.3 Upper Operating Limits

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.

4.2.2.4 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 4.4.4 of this ISO Services Tariff.

4.2.2.5 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.

4.2.2.6 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.

4.2.2.7 Bilateral Transactions

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 provide other information (as described in Attachment D). Decremental Bids and Sink Price Cap Bids shall be subject to the bid limitations and pricing rules set forth in Section 17.3.2.7 of Attachment B to this ISO Services Tariff.

4.2.2.8 Bids to Purchase 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 Curtail the Transaction, provided however that Bids from External purchasers to purchase Energy in the Day-Ahead Market shall be priced no higher than the Bid that provides the highest scheduling priority for purchases in the LBMP Market, minus the product of (i) the Scheduling Differential and (ii) three.

4.2.2.9 Day-Ahead Bids from Demand Reduction Providers to Supply Energy from Demand Reductions

Demand Reduction Providers offering Energy from Demand Side Resources shall: (i) bid in whole megawatts and, as described in Attachment D, shall: (ii) identify the amount of demand, in whole megawatts, that is available for commitment in the Day-Ahead Market (for every hour of the dispatch day) and (iii) identify the prices at which the Demand Reduction Provider will voluntarily enter into dispatch commitments to reduce demand provided, however, the price at which the Demand Reduction Provider will voluntarily enter into dispatch commitments to reduce demand shall be no lower than $75/MW hour. The Bids will identify the minimum period of time that the Demand Reduction Provider is willing to reduce demand. 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.

4.2.3 ISO Responsibility to Establish a Statewide Load Forecast

By 8 a.m., 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.

4.2.4 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 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. 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; (vii) Ancillary Services in support of Bilateral Transactions; and (viii) 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 twenty-four (24) hourly injections and withdrawals for: (a) each Customer whose Bid the ISO accepts for the following 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 the ISO shall commit zero megawatts of Energy for Demand Side Resources committed to provide Operating Reserves and Regulation Service.

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.

4.2.4.1 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 4.2.4.1 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 4.2.4.1 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

4.2.5 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 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 the Generator is still needed, it will continue to accrue start-up cost payments on a linear basis. 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, and its start-up payment entitlement will cease at that point.

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. Supplemental payments to these Generators, if necessary, will be determined pursuant to the provisions of Attachment C and 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.

The bidding requirements and the Bid tables in Attachment D indicate that Energy Bids are to be provided for days one (1) through seven (7). 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).

4.2.6 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) and Load (Day-Ahead scheduled and forecast) 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. 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.

4.2.7 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. 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 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 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 scheduling horizon (nominally twenty-four (24) hours). The ISO shall then close the Day-Ahead Settlement.

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 In-Day Pre-Scheduled Transactions

For any hour in which the operator of an External Control Area informs the ISO that it must call on a Supplier located in the NYCA to provide the External Control Area with Energy, and that Supplier has previously committed to provide installed capacity to the External Control Area, then the ISO shall ensure, to the extent possible, that the required quantity of Energy will flow to the External Control Area in the hour. If the Supplier has already submitted an Export to the External Control Area for evaluation by the ISO, the ISO shall treat the Export as an in-day Pre-Scheduled Transaction. Such a Transaction shall be assigned a Sink Price Cap Bid that provides the highest scheduling priority available. If the Supplier has not previously submitted an Export for evaluation by the ISO it shall immediately submit such a bid into RTC. The ISO shall schedule the proposed Export as an in-day Pre-Scheduled Transaction, with the highest scheduling priority available, unless there is no Ramp Capacity or Transfer Capability on the relevant External Interface, in which case the Export will not be scheduled. To the extent that Ramp Capacity or Transfer Capability are available to support only a portion of an in-day Pre-Scheduled Transaction the ISO will schedule that portion of the Transaction.

In-day Pre-Scheduled Transactions will only be subject to Curtailment in the same limited circumstances as other Pre-Scheduled Transactions.

In-day Pre-Scheduled Transactions may not be scheduled at Proxy Generator Buses that are associated with Scheduled Lines.

4.4.2 Real-Time Commitment ("RTC")

4.4.2.1 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 hour. RTC will co-optimize 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 will consider SCUC's Resource commitment for the day, load and loss forecasts that RTC itself will produce each quarter hour, binding transmission constraints, and all Real-Time Bids and Bid parameters submitted pursuant to Section 4.4.2.2 below.

4.4.2.2 Bids and Other Requests

After the Day-Ahead schedule is published and no later than seventy-five (75) minutes before each hour (or no later than eighty-five 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, or the Linden VFT Scheduled Line), Customers may submit Real-Time Bids into RTC for real-time evaluation.

4.4.2.2.1 Real-Time Bids to Supply Energy and Ancillary Services

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 not include a Minimum Generation Bid or a Start-Up Bid. 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 RTC than they did Day-Ahead. ISO-Committed Fixed Generators, ISO-Committed Flexible Generators and Demand Side Resources, and Self-Committed Flexible Generators may not increase their Day-Ahead Incremental Energy Bids that are applicable to any portion of their Capacity that was scheduled Day-Ahead, and may not increase their Minimum Generation Bids, or Start-Up Bids, for any hour in which they received a Day-Ahead Energy schedule. 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 4.2.2 above and in Attachment D to this ISO Services Tariff.

Generators that did not submit a Day-Ahead Bid for a given hour may offer to be ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed or, with ISO approval, as ISO-Committed Fixed in real-time. Demand Side Resources that did not submit a Day-Ahead Bid to provide Operating Reserves or Regulation Service for a given hour or that submitted a Day-Ahead Bid to provide Operating Reserves or Regulation Service but did not receive a Day-Ahead schedule for a given hour may offer to provide Operating Reserves or Regulation Service as ISO-Committed Flexible 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. Generators that submitted a Day-Ahead Bid but did not receive a Day-Ahead schedule for a given hour may change their bidding mode for that hour to be ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed or, with ISO approval, ISO-Committed Fixed in real-time without restriction.

Generators that received a Day-Ahead schedule for a given hour may not change their bidding mode between Day-Ahead and real-time 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.

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).

4.4.2.2.2 Bids Associated with Internal and External Bilateral Transactions

Customers may 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 4.2.2.7.

Except as noted in Attachment N to this ISO Services Tariff, Sink Price Cap Bids or Decremental Bids for External Transactions may be submitted into RTC up to seventy five minutes before the hour in which the External Transaction would flow. External Transaction Bids must have a one hour duration, must start and stop on the hour, and must have constant magnitude for the hour. Intra-hour schedule changes, or Bid modifications, associated with External Transactions will not be accommodated.

4.4.2.2.3 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.

4.4.2.2.4 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 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 as ISO-Committed in the Real-Time Market. Real-Time Bids by ISO-Committed Fixed Generators shall identify variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, and other parameters described in Attachment D of this ISO Services Tariff and the ISO Procedures. Real-Time Bids by ISO-Committed Fixed Generators shall also include Minimum Generation Bids and hourly Start-Up Bids. ISO-Committed Fixed Bids shall specify that the Generator is offering to be ISO-Committed Fixed.

RTC shall schedule ISO-Committed Fixed Generators.

4.4.2.3 External Transaction Scheduling

RTC_{15} will schedule External Transactions on an hour-ahead basis as part of its development of a co-optimized least-bid cost real-time commitment. 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.

4.4.2.4 Posting Commitment/De-Commitment and External Transaction Scheduling Decisions

Except as specifically noted in Section 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.

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 minimum 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 minimum 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 Pre-Scheduled Transaction and economic External Transactions to run during the entirety of the next hour; and

(vi) 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 RTC_{15} to flow in the next hour should flow, or inform the ISO that External Transactions may need to be reduced; and

(vi) Schedule ISO-Committed Fixed Resources.

4.4.2.5 External Transaction Settlements

RTC_{15} will calculate the Real-Time LBMP for all External Transactions if constraints at the interface associated with that External Transaction are binding. In addition, RTC_{15} will calculate Real-Time LBMPs at Proxy Generator Buses for any hour in which: (i) proposed economic Transactions over the Interface between the NYCA and the External Control Area that the Proxy Generator Bus is associated with would exceed the Available Transfer Capability for the Proxy Generator Bus or for that Interface; (ii) 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; or (iii) proposed interchange schedule changes pertaining to the Interface between the NYCA and the External Control Area that the Proxy Generator Bus is associated with would exceed any Ramp Capacity limit imposed by the ISO for the Proxy Generator Bus or for that Interface. Finally, Real-Time LBMPs will be determined at certain times at Non-Competitive Proxy Generator Buses and Proxy Generator Buses associated with designated Scheduled Lines that are subject to the Special Pricing Rules as is described in Attachment B to this ISO Services Tariff.

Real-Time LBMPs will be calculated by RTD for all other purposes, including for pricing External Transactions during intervals when the interface associated with an External Transaction is not binding pursuant to Section 4.4.3.2.

4.4.3 Real-Time Dispatch

4.4.3.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and Demand Side Resources, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and 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 4.4.3.3 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). RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

4.4.3.2 Calculating Real-Time Market LBMPs and Advisory Prices

With the exceptions noted above in Section 4.4.2.5, 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.

4.4.3.3 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 at each Generator Bus, and for each Load Zone.

4.4.3.4 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 Special Case Resources 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 4.4.3.4, 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 applying Real-Time special scarcity pricing rules described in Attachment B of this 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.

4.4.3.5 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 4.4.3.4, 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 applying Real-Time special scarcity pricing rules described in Attachment B of this 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.

4.4.3.6 Real-Time Scarcity Pricing Rules Applicable to Regulation Service and Operating Reserves During EDRP and/or SCR Activations

Under Sections 17.1.1.2 and 17.1.1.3 of Attachment B to this ISO Services Tariff, and Sections 16.1.1.2 and 16.1.1.3 of Attachment J to the ISO OATT, the ISO will use special scarcity pricing rules to calculate Real-Time LBMPs during intervals when it has activated the EDRP and/or SCRs in order to avoid reserves shortages. During these intervals, the ISO will also implement special scarcity pricing rules for real-time Regulation Service and Operating Reserves. These rules are set forth in Section 15.3.2.5.2 of Rate Schedule 15.3 and Section 15.4.6.2 of Rate Schedule 15.4 of this ISO Services Tariff.

4.4.4 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. 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 all 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.

4.4.4.1 RTD-CAM Modes

4.4.4.1.1 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, but will suspend Regulation Service requirements. 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. As is explained in Section 4.10 below, the distinction also has significance with respect to Resources’ eligibility to receive Bid Production Cost guarantee payments.

4.4.4.1.2 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, 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, but will suspend its Regulation Service requirements.

4.4.4.1.3 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.

4.4.4.1.4 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.

4.4.4.1.5 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.

4.4.4.2 Calculating Real-Time LBMPs

When RTD-CAM is activated, except when it is in reserve pickup mode, it shall calculate *ex ante* Real-Time LBMPs at each Generator bus, and for each Load Zone, every five minutes, in accordance with the procedures set forth above in Section 4.4.3.2 When it is in reserve pickup mode, RTD-CAM will calculate *ex ante* Real-Time LBMPs every ten minutes, but shall otherwise follow the procedures set forth above in Section 4.4.3.2 In addition, RTD-CAM will calculate Bid Production Cost payments for eligible Generators during large event, but not small event, reserve pickups and during maximum generation pickups. These payments are described in Section 4.10, and in Rate Schedule 15.4, of this ISO Services Tariff.

4.4.4.3 Posting Commitment Decisions

To the extent that RTD-CAM makes commitment and de-commitment decisions they will be posted at the same time as Real-Time LBMPs.

4.5 Real-Time Market Settlements

Transmission Customers taking service under the Tariff, shall be subject to the Real-Time Market Settlement. Settlements for Limited Energy Storage Resources are governed by Rate Schedule 15.3 of this Services Tariff and are not governed by this Section 4.5. All withdrawals and injections not scheduled on a Day-Ahead basis, including Real-Time deviations from any Bilateral 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 External Suppliers or External Loads will be based upon hourly 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 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 499 MW of such units.

This procedure shall not apply to a Generator for those hours it has bid in a manner that indicates it is available to provide Regulation Service or Operating Reserves.

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 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 Section 15.4.6 of 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.

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 after RTC_{15}, 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 difference computed by subtracting the RTC price from the RTD price 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 scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of its real-time Bid and zero; and (b) the scheduled Energy injections minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour.

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 Service; 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 the first paragraph of this Section 4.5.3.

For any day in which: (i) an Energy Limited Resource is scheduled to supply Energy, Operating Reserve Service 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 Energy

Limited Resource requests a reduction for Energy limitation reasons; and (iv) the ISO modifies the Energy Limited Resource's Day-Ahead upper operating limit; the imbalance charge imposed upon the Energy Limited Resource shall be equal to the sum of its Energy, Operating Reserve Service and Regulation Service imbalances across all twenty four hours of the Energy day, multiplied by the Real-Time price for each service in each hour at its location. However, if the total margin received by the Energy Limited Resource for the twenty four hour day is less than its Day-Ahead margin than it shall receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this Services Tariff.

4.5.3.4 Demand Reductions

When 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 actual Demand Reduction in that hour.

When 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 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 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 SCD interval are less than its Energy withdrawals scheduled Day-Ahead over that SCD 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.

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 after RTC_{15}, 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 greater of the difference computed by subtracting the RTD price in the relevant interval from the RTC price, 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 scheduled Energy injection over that RTD interval. 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. Generators will not be compensated for Energy produced during their start-up sequence.

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.

4.6 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

If an eligible Supplier is forced to buy out of a Day-Ahead Energy, Regulation Service or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin, that Supplier shall receive a Day-Ahead Margin Assurance Payment. Such payments shall be calculated pursuant to Attachment J of this ISO Services Tariff.

4.6.6 Bid Production Cost Guarantee and Curtailment Initiation Cost Payments

The ISO shall determine, on a daily basis, if any ISO-Committed Fixed or ISO-Committed Flexible Generator, other than a Limited Energy Storage Resource, or Customer that schedules imports, that is committed by the ISO in the Day-Ahead Market will not recover its Minimum Generation Bid, Start-Up Bid, and Energy Bid Price through Day-Ahead LBMP and Day-Ahead Ancillary Services revenues. If the sum of the Minimum Generation Bid, Start-Up Bid and the net Energy Bid Price over the twenty-four (24) hour day of such a Generator or Importer exceeds its Day-Ahead LBMP revenue over the twenty-four (24) hour day, then that Generator or Importer's Day-Ahead LBMP revenue may be augmented by a supplemental Day-Ahead Bid Production Cost guarantee payment calculated pursuant to the provisions of Attachment C to this ISO Services Tariff. However, the amount of the shortfall of such a Generator will be compared to the margin that the Generator receives from being scheduled to provide Ancillary Services that it can provide only if scheduled to operate. The Generator's Ancillary Service margin is equal to the revenue it would have received for providing these Ancillary Services prior to any reductions based on a failure to provide these services less its Bid to provide these services, if any. If, and only to the extent that, the shortfall exceeds these Ancillary Service margins, the Generator will receive a payment pursuant to the provisions of Attachment C to this ISO Services Tariff. 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.

The ISO shall make a supplemental payment pursuant to the terms of Attachment C to this Tariff if any Demand Side Resource scheduled to provide synchronized Operating Reserves in the Day-Ahead Market will not recover its synchronized Operating Reserves offers through its Day-Ahead synchronized Operating Reserves revenues and Regulation Service margin.

Demand Side Resources committed Day-Ahead to provide non-synchronized Operating Reserves shall be treated the same as Generators with respect to the determination of supplemental payments.

In addition, the ISO shall: (i) use Real-Time Market prices and schedules to calculate and pay real-time Bid Production Cost guarantee payments to ISO-Committed Flexible Generators and to Customers that schedule imports provided however, no real-time Bid Production Cost guarantee payment shall be made to a Limited Energy Storage Resource; (ii) use RTD prices and schedules to calculate and pay real-time Bid Production Cost guarantee payments to any Self-Committed Flexible Generator if its self-committed minimum generation level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; and (iii) use RTD prices and schedules to calculate and pay real-time Bid Production Cost guarantee payments for Minimum Generation Bids and Start-Up Bids to ISO-Committed Fixed Generators. All such payments shall be calculated in the manner described in Attachment C to this ISO Services Tariff. No such payments shall be made to Customers that schedule Exports or Wheels-Through.

Except as expressly noted in this Section 4.6.6, Self-Committed Flexible and Self-Committed Fixed Resources shall not be eligible to receive Bid Production Cost guarantee payments.

Resources committed via SRE, or committed or dispatched by the ISO as Out-of-Merit Generation to ensure NYCA or local system reliability, shall remain eligible to receive a real-time Bid Production Cost guarantee payment for the hours of the day that they are committed via SRE or are committed or dispatched by the ISO as Out-of-Merit Generation to meet NYCA or local reliability without regard to the Bid mode(s) employed during the Dispatch Day.

Generators that Bid in Self-Committed mode only during ISO authorized Start-Up, Shutdown or Testing Periods, and hours when they are committed via SRE or are committed or dispatched by the ISO as Out-of-Merit Generation to meet NYCA or local reliability, will not be precluded from receiving a real-time Bid Production Cost guarantee payment for the other hours of the Dispatch Day due to these Self-Committed mode Bids.

Both Bid costs, and LBMP and Ancillary Services revenues received during ISO authorized Start-Up, Shutdown or Testing Periods shall be excluded from the calculation of the daily Bid Production Cost guarantee payment.

The ISO shall make a supplemental payment pursuant to the terms of Attachment C to this Tariff if any Demand Side Resource scheduled to provide synchronized Operating Reserves in the Real-Time Market will not recover its synchronized Operating Reserves offers through its Real-Time synchronized Operating Reserves revenues and Regulation Service margin.

An ISO-Committed Flexible Generator that is eligible to receive a Day-Ahead Bid Production Cost guarantee payment but that then self-commits in certain hours, thus becoming ineligible for a real-time Bid Production Cost guarantee payment, shall not be disqualified from receiving a Day-Ahead Bid Production Cost guarantee payment. Any Supplier that provides Energy during a large event reserve pickup or a maximum generation event, as described in Sections 4.4.4.1, 4.4.4.1.1 and 4.4.4.1.2 of this ISO Services Tariff shall be eligible for a Bid Production Cost guarantee payment calculated, under Attachment C, for the duration of the large event reserve pickup or maximum generation pickup and the three RTD intervals following the termination of the large event reserve pickup or maximum generation pickup. Such payments shall be excluded from the ISO's calculation of real-time Bid Production Cost guarantee payments otherwise payable to Suppliers on that Dispatch Day.

The ISO shall determine, on a daily basis, if any Demand Reduction Provider committed to provide Energy by the ISO in the Day-Ahead Market will not recover its Curtailment Initiation Cost and its Demand Reduction Bid price through Day-Ahead LBMP revenues. If a Demand Reduction Provider's Curtailment Initiation Cost Bid plus its Demand Reduction Bid Price over the twenty-four (24) hour day exceeds its Day-Ahead LBMP revenue over the twenty-four (24) hour day, its Day-Ahead LBMP revenue may be augmented by a supplemental Bid Production Cost guarantee payment pursuant to the provisions of Attachment C.

The ISO shall determine, on a daily basis, if any Special Case Resource committed by the ISO will not recover its Minimum Payment Nomination through LBMP revenues. If a Special Case Resource's Minimum Payment Nomination over the period of requested performance, or four (4) hour period, whichever is greater, exceeds the LBMP revenue received as a Special Case Resource over that same period, its LBMP revenue may be augmented by a supplemental payment pursuant to the provisions of Attachment C, provided however, that the ISO shall set to zero the Minimum Payment Nomination for that amount of Special Case Resource Capacity in each interval that was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy.

Each Generator committed by the ISO in the Real-Time Market whose Real-Time LBMP payments for Energy produced are less than its Minimum Generation and Start-Up Bids to produce that Energy will be compensated by the ISO for the shortfall, in accordance with Attachment C. When a Non-Competitive Proxy Generator Bus or the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located is export constrained due to limits on Available Interface Capacity or Ramp Capacity limits for that Interface in an hour, External Generators and other Suppliers scheduling Imports at such Non-

Competitive Proxy Generator Bus in that hour will not be eligible for Real-Time shortfall payments for those Transactions.

When a Proxy Generator Bus that is associated with a designated Scheduled Line is export constrained due to limits on Available Interface Capacity in an hour, External Generators and other Suppliers scheduling Imports at such Proxy Generator Bus in that hour will not be eligible for real-time shortfall payments for those Transactions.

The ISO shall recover supplemental payments and Demand Reduction Incentive Payments to Demand Reduction Providers pursuant to Rate Schedule 6.1 of its Open Access Transmission Services Tariff, from all Loads excluding exports and Wheels Through on a zonal basis in proportion to the benefits received after accounting for, pursuant to ISO Procedures, Demand Reduction imbalance charges paid by Demand Reduction Providers pursuant to Section 4.4.4.1.5.

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 month 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 and the NYSRC Reliability Rules 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 Interregional Congestion Management Pilot Program

The following procedures shall govern the redispatch of generation to alleviate transmission congestion on selected pathways on the transmission systems operated by the ISO and PJM Interconnection, L.L.C. ("PJM") pursuant to an Interregional Congestion Management Pilot Program ("Pilot Program"). The procedures shall be used solely when, in the exercise of Good Utility Practice, the ISO or PJM determines that the redispatch of generation units on the other's transmission system would reduce or eliminate the need to resort to Transmission Loading Relief or other transmission-related emergency procedures.

5.1.2.1 Identification of Transmission Constraints

(a) On a periodic basis determined by the ISO and PJM, the ISO and PJM shall identify potential transmission operating constraints that could result in the need to use Transmission Loading Relief or other emergency procedures in order to alleviate the transmission constraints.

(b) In addition to the identification of such potential transmission operating constraints, the ISO and PJM shall identify generation units on the other's system, the redispatch of which would eliminate the identified transmission constraints.

(c) From the identified transmission constraints, the ISO and PJM shall agree in writing on the transmission operating constraints and redispatch options that shall be subject to this Section 5.1.2. In reaching such agreement, the ISO shall endeavor reasonably to limit the number of transmission constraints that are subject to this Section 5.1.2 so as to minimize potential cost shifting among Market Participants in the ISO and PJM Control Areas resulting from the redispatch of generation under the Pilot Program. The ISO shall post the transmission operating constraints that are subject to the Pilot Program on its website.

5.1.2.2 Redispatch Procedures

If (i) a transmission constraint subject to this Section 5.1.2 occurs and continues or reasonably can be expected to continue after the exhaustion of all economic alternatives that are reasonably available to the transmission system on which the constraint occurs and (ii) the ISO or PJM, as applicable, has determined that it must use either Transmission Loading Relief or other emergency procedures, then (iii) the affected entity may request the other to redispatch one or more of the previously identified generation units to eliminate the transmission constraint. Upon such request, the ISO or PJM, as applicable, shall redispatch such generation if it is then subject to its dispatch control and such redispatch is consistent with Good Utility Practice.

5.1.2.3 Locational Based Marginal Price

In the event that a Generator is redispatched by the ISO in response to a request from PJM under Section 5.1.2, the Generator's bid for the Energy made available by the redispatch shall not be included in the determination of the Locational Based Marginal Price at that Generator's bus.

5.1.2.4 Generator Compensation

Generators that have increased or decreased generation output above or below the level that would otherwise represent the economic dispatch level as a result of a request made pursuant to the Pilot Program (the "MWh Adjustment") shall be compensated, on an interval-by-interval basis, based on the following formulas:

(a) For a positive MWh Adjustment: Payment to Generator = MWh Adjustment * (unit offer price - marginal price at the generator bus). In addition the Generator shall be paid any applicable Minimum Generation Bid, Start-Up Bid, and Energy Bid price costs not covered by the LBMP revenue for the 24 hour day or not covered by the marginal price, as appropriate.

(b) For a negative MWh Adjustment: Payment to Generator = MWh Adjustment * (marginal price at the generator bus - unit offer price). In addition the Generator shall be paid any applicable minimum generation, start-up and Energy Bid price costs not covered by the LBMP revenue for the 24 hour day or not covered by the marginal price, as appropriate.

(c) MWh adjustment payments to Generators pursuant to this subsection shall not be considered LBMP revenue for purposes of calculating minimum generation, start up and Energy bid price guarantees.

5.1.2.5 Settlements

(a) If PJM redispatches generation, the ISO shall include in its monthly accounting and billing a payment to PJM for the costs of such redispatch as determined in accordance with Section 5.1.2.4

(b) If the ISO redispatches generation under the Pilot Program, then it shall include in its monthly accounting and billing a credit to each redispatched Generator calculated in accordance with Section 5.1.2. 4 The ISO shall invoice PJM and PJM shall collect from its market participants and pay to the ISO an amount equal to all such credits to Generators.

(c) Unless there is a separate Emergency Energy Transaction accompanying a generation adjustment under the Pilot Program there shall be no adjustment in interchange between the ISO and PJM as a result of redispatch under the Pilot Program. In the event that an Emergency Energy Transaction accompanies a generation adjustment under the Pilot Program, compensation for the Emergency Energy Transaction shall be at the rates for emergency purchases and sales which have been approved by the Commission, as they may be amended from time-to-time.

5.1.2.6 Incorporation of Certain Business Practice Standards

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

Business Practices for Open Access Same-Time Information Systems (OASIS), Version 1.4 (WEQ-001, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 001-0.2 through 001-0.8, 001-0.14 through 001-0.20;

Business Practices for Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.4 (WEQ-002, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 002-1 through 002-5.10, except as provided below;

Coordinate Interchange (WEQ-004, Version 001, October 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 004-0.1 through 004-17.2, and 004-A through 004-D, except as provided below;

Area Control Error (ACE) Equation Special Cases Standards (WEQ-005, Version 0010, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 005-0.1 through 005-3.1.3, and 005-A;

Manual Time Error Correction (WEQ-006, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 006-0.1 through 006-12;

Inadvertent Interchange Payback (WEQ-007, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 007-0.1 through 007-2, and 007-A;

Transmission Loading Relief - Eastern Interconnection (WEQ-008, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 008-0.1 through 008-3.11.2.8, and 008-A through 008-D;

Gas/Electric Coordination (WEQ-011, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 011-0.1 through 011-1.6;

Public Key Infrastructure (PKI) (WEQ-012, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Recommended Standard, Certification, Scope, Commitment to Open Standards, and Standards 012-0.1 through 012-1.26.5; and

Business Practices for Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.4 (WEQ-013, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Introduction and Standards 013-0.1 through 013-4.2, except as provided below.

(b) The ISO is not required to comply with the following Standards:

Business Practices for Open Access Same-Time Information Systems (OASIS), Version 1.4 (WEQ-001, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007): Standards 001-2.0 through 001-12.5.2, and Appendices 001-A and 001-B;

Business Practices for Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.4 (WEQ-002, Version 001, Oct. 31, 2007 with minor corrections applied on Nov. 16, 2007): Standards 002-4.2.10, 002-4.2.11, 002-4.2.12, 002-4.3, *et seq.*, and 002-4.4;

Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.4 (WEQ-003, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007): Standard 003-0;

Coordinate Interchange (WEQ-004, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007): Standards 004-3, 004-3.1, 004-8.2, 004-11.1(a) Appendices 004-A, and 004-C to the extent they govern physical transmission reservations; and

Business Practices for Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.4 (WEQ-013, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007): Standard 013-4.1.

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 interact with other Control Area operators as required to effect 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.

5.3 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 Meteorological 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 and wind direction data in the manner identified by the ISO, provided however this requirement shall not apply any Intermittent Power Resource in commercial operation as of January 1, 2002 with nameplate capacity of 12 MWs or fewer. 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 - Implementation of Revised Installed Capacity Market Provisions

Sections 5.10 through 5.16 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.

5.10 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 5.16 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 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 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 5.16 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 5.16 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 Obligation.

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 5.16 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 5.16 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 5.16 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 the NYCA Localities 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 (with or without the UDRs if there is a capability year adjustment election by a rights holder) 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. 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.

~~Unforced Capacity associated with certain generation located in the New York City Locality that is subject to capacity market mitigation measures may not be sold at a price greater than the annual mitigated price cap, except as explicitly provided in Sections 5.13.2, 5.13.3 and 5.14.1 of this Tariff.~~

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.

5.12 Requirements Applicable to Installed Capacity Suppliers

5.12.1 Installed Capacity Supplier Qualification Requirements

In order to qualify as an Installed Capacity Supplier in the NYCA, each generator and merchant transmission facility interconnected to the New York State Transmission System must, commencing with the 2009 Summer Capability Period, have elected Capacity Resource Interconnection Service and been found deliverable, or must have been grandfathered as deliverable, pursuant to the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT. In addition, to qualify as an Installed Capacity Supplier in the NYCA, Energy Limited Resources, Generators, Installed Capacity Marketers, Intermittent Power 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, and other than Special Case Resources, 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 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 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, prior to the commencement of the Annual Transmission Reliability Assessment on March 1, of any transfers of deliverability rights to be carried out pursuant to Sections 25.9.4 - 25.9.6 of Attachment S to the ISO OATT;

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 499 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.

The ISO shall inform each potential Installed Capacity Supplier that is required to submit DMNC data of its approved DMNC 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.

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 ~~person or entity that is an~~ 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~~, or that serves as its agent for purposes of submitting bids in an ICAP Spot Market Auction~~. The names of entities that are Affiliated~~s~~ Entities~~or bidding agents~~ 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

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. 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 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 Capacity Region where the External Interface is located 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.

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:

$$\text{Rights allocated to entity } i = 1090 * \frac{(MWi * \text{contract/commitment length}i)}{\sum_j (MWj * \text{contract/commitment length}j)}$$

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 Demand Curve for that Period and for the Capacity Region in which the Interface of entry is located; 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 Special Case Resources, 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 re-scheduling of outages. In the case of Generators actually supplying Unforced Capacity to the NYCA, if voluntary re-scheduling is ineffective, the ISO will invoke forced re-scheduling 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 re-scheduling 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.

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 shall 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, Special Case Resources, 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, Special Case Resources, 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 Operating Data Default Value and Collection

5.12.6.1 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, 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. 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.

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.

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.

5.12.6.2 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.

5.12.6.3 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. 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.

If an Energy Limited Resource's, Generator's, System Resource's or Control Area System Resource's DMNC rating 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 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 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 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 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, 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.

If an Installed Capacity Supplier's Exports are Curtailed in-hour to resolve a New York reserves shortage, the Transmission Customer scheduling such Exports shall be paid, for the remainder of the hour, the higher of the Real-Time LBMP at the New York proxy bus associated with the Exports, or the real-time price at the relevant proxy bus used by the External Control Area for Transactions with New York.

5.12.11 Special Case Resources, Municipally-Owned Generation, Energy Limited Resources and Intermittent Power Resources

5.12.11.1 Special Case Resources

Special Case Resources 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: (i) they are available to operate for a minimum of four (4) consecutive hours each day, at the direction of the ISO, 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; and (ii) they were not operated as a Load modifier coincident with the peak upon which the LSE Unforced Capacity Obligation of the LSE that serves that customer is based, unless that LSE's LSE Unforced Capacity Obligation is adjusted upwards to prevent double-counting.

Special Case Resources 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 distributed Generators that are incapable of starting in two (2) hours from the requirement to operate on two (2) hours notification. Distributed Generators 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.

Special Case Resources 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.

Distributed Generators 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 comply with the ISO notification requirements for Special Case Resources. LSEs and Installed Capacity Marketers may 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.

Special Case Resources 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 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 Special Case Resource it shall have the right to recover it either by reducing other payments to that Special Case Resource or by resolving the issue pursuant to other provisions of this Services Tariff or other lawful means.

Provided the Special Case Resource supplies evidence of such reductions in 75 days, the ISO shall pay Special Case Resources that cause 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, Special Case Resources shall be paid the zonal Real-Time LBMP for the duration of their verified Load reduction 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 Special Case Resource's Minimum Payment Nomination 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 NYISO 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 distributed 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.

5.12.11.2 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 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, 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, 5.12.1.7, 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 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, 5.12.1.7, 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.

Filed May 6, 2008 to comply with order of the Federal Energy Regulatory Commission, Docket No. EL07-39-000, issued March 7, 2008, 122 FERC ¶ 61,211 (2008). Proposed effective date: November 1, 2008.

Filed March 20, 2008 to comply with order of the Federal Energy Regulatory Commission, Docket No. EL07-39-000, issued March 7, 2008, 122 FERC ¶ 61,211 (2008). Proposed effective date: March 27, 2008.

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 their 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.

~~Unforced Capacity associated with In-City generation that is subject to FERC-approved capacity market mitigation measures is required to be offered for sale in the ICAP Spot Market Auction to the extent that such Unforced Capacity has not sold in prior auctions for the Obligation Procurement Period.~~

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, ~~except in the case of In City generation that is subject to capacity market mitigation measures, which shall receive the lesser of the applicable Market-Clearing Price or the annual mitigated price cap, as applied in accordance with the ISO Procedures. Any entity that resells Unforced Capacity associated with In-City generation that is subject to capacity market mitigation measures shall receive no greater than the annual mitigated price cap, as applied in accordance with the ISO Procedures for that Unforced Capacity. If the Market-Clearing Price exceeds the total amount paid to Installed Capacity Suppliers, the ISO shall rebate the Excess Amount pursuant to Section 5.15 of this Tariff.~~

~~In-City generation that is subject to capacity market mitigation measures are restricted from selling Unforced Capacity to entities for use outside the New York City Locality 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. ~~or the annual mitigated price cap, as applied in accordance with the ISO Procedures. Any entity that resells Unforced Capacity associated with In-City generation that is subject to capacity market mitigation measures shall receive no greater than the annual mitigated price cap, as applied in accordance with the ISO Procedures for that Unforced Capacity. If the Market-Clearing Price exceeds the total amount paid to Installed Capacity Suppliers, the ISO shall rebate the Excess Amount pursuant to Section 5.15 of this Tariff.~~ ~~In-City generation that is subject to capacity market mitigation measures are restricted from selling Unforced Capacity to entities for use outside the New York City Locality in the Monthly Auctions.~~

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 ~~their~~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. The ISO shall also receive offers of Unforced Capacity from any LSE for any amount of Unforced Capacity that 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 Sport 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 Installed Capacity Suppliers that are selected to provide Unforced Capacity the Market-Clearing Price determined in the ICAP Spot Market Auction using the applicable ICAP Demand Curve.~~, except in the case of Unforced Capacity associated with In-City generation that is subject to capacity market mitigation measures, which shall receive no greater than the annual mitigated price cap. The In-City capacity bid and price caps applicable to certain In-City generation will be applied monthly in accordance with the ISO Procedures to account for differences between the amount of Unforced Capacity provided during the Summer Capability Period and the Winter Capability Period such that owners of In-City generation that is subject to capacity market mitigation measures shall have an opportunity to receive the annual mitigated price cap. Any entity that resells Unforced Capacity associated with In-City generation that is subject to capacity market mitigation measures shall receive no greater than the annual mitigated price cap, as applied in accordance with the ISO Procedures for that Unforced Capacity. If the Market-Clearing Price exceeds the total amount paid to Installed Capacity Suppliers, the ISO shall rebate the Excess Amount pursuant to Section 5.15 of this Tariff. In-City generation that is subject to capacity market mitigation measures may be sold to~~

~~meet NYCA LSE Unforced Capacity Obligations in the ICAP Spot Market Auction, provided the New York City Locational Unforced Capacity Requirement has been met.~~

5.14.1.2 Demand Curve and Adjustments

Three ICAP Demand Curves will be established: one to determine the locational component of LSE Unforced Capacity Obligations for each of the two Localities, and one to determine the total LSE Unforced Capacity Obligations for all LSEs. The ICAP Demand Curves for the 2007/2008, 2008/2009, 2009/2010, and 2010/2011 Capability Years shall be established at the following points:

Capability Year	5/1/2007 to 4/30/2008	5/1/2008 to 4/30/2009	5/1/2009 to 4/30/2010	5/1/2010 to 4/30/2011
NYCA	Max @ $11.54 $7.30 @ 100% $0.00 @ 112%	Max @ $11.55 $8.19 @ 100% $0.00 @ 112%	Max @ $12.45 $9.13 @ 100% $0.00 @ 112%	Max @ $13.42 $9.90 @ 100% $0.00 @ 112%
NYC	Max @ $23.34 $14.77 @ 100% $0.00 @ 118%	Max @ $23.51 $13.36 @ 100% $0.00 @ 118%	Max @ $25.34 $14.40 @ 100% $0.00 @ 118%	Max @ $27.32 $15.99 @ 100% $0.00 @ 118%
LI	Max @ $20.55 $13.52 @ 100% $0.00 @ 118%	Max @ $20.87 $7.48 @ 100% $0.00 @ 118%	Max @ $22.50 $8.06 @ 100% $0.00 @ 118%	Max @ $24.25 $8.69 @ 100% $0.00 @ 118%
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 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 to the NYCA Minimum Installed Capacity Requirement and the Locational Minimum Installed Capacity Requirement by the ICAP Demand

Curves 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.

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 unit in each NYCA Locality and the Rest of State to meet minimum capacity requirements; (ii) the likely projected annual Energy and Ancillary Services revenues of the peaking unit over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services, under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement; (iii) 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; and (iv) the appropriate translation of the annual net revenue requirement of the peaking unit 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. For purposes of this 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.

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 (xi) below. The schedule and procedures shall provide for:

5.14.1.2.1 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;

5.14.1.2.2 Selection of an independent consultant in accordance with the request for proposals;

5.14.1.2.3 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;

5.14.1.2.4 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;

5.14.1.2.5 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;

5.14.1.2.6 Issuance by the independent consultant of a final report;

5.14.1.2.7 Issuance of a draft of the ISO's recommended adjustments to the ICAP Demand Curves for stakeholder review and comment;

5.14.1.2.8 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;

5.14.1.2.9 Submission of stakeholder requests for the ISO Board of Directors to review and adjust the ISO's proposed ICAP Demand Curves;

5.14.1.2.10 Presentations to the ISO Board of Directors of stakeholder views on the ISO's proposed ICAP Demand Curves; and

5.14.1.2.11 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.

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.

5.14.1.3 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 Payments

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 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.

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~~s~~ of MWs of 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 it 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, the Installed Capacity Supplier shall be assessed the applicable deficiency charge equal to the applicable Market-Clearing Price of Unforced Capacity determined in the 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 in the ICAP Spot Market Auction for each month the Installed Capacity Supplier is deemed to have a shortfall.

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.

5.14.3 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.

(iii) 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) 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 two Localities, New York City and Long Island, 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 Expedited Dispute Resolution Procedures

5.16.1 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").

5.16.2 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.

5.16.3 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.

5.16.4 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.

5.16.5 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.

5.16.6 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.

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 Clearing Account

The ISO will establish an account (the “ISO Clearing Account”), and Customers shall make payments into or receive payments from 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 ISO Clearing Account established herein shall be opened and operated by the ISO as trustee in trust for ISO creditors and ISO debtors in accordance with this ISO Services Tariff. The account shall be maintained at a bank or other financial institution in New York State as a trust account. Such account shall not be commingled with any other ISO accounts. The ISO will not take title to the funds held in the ISO Clearing Account. Nor will the ISO take title to any Energy, Capacity, Ancillary Services, or TCCs.

7.2 Billing Procedures and Payments

7.2.1 Invoices 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. For each service provided for under this ISO Services Tariff or the ISO OATT, the payments due to the ISO shall be netted against the corresponding amounts due to the Customer for providing service. Such information shall be electronically transmitted to the Customer.

Within five (5) business days after the first day of each month, the ISO shall submit an invoice to the Customer that indicates the net amount owed by or owed to the Customer for each of the services furnished under this ISO Services Tariff and the ISO OATT during the preceding month; provided, however, that allocation of Centralized TCC Auction or Reconfiguration Auction revenues to Transmission Owners shall be provided in invoices in accordance with the timeline set forth in ISO Procedures. The ISO shall use meter data submitted to the ISO in accordance with Article 13 of the ISO Services Tariff; provided, however, that the ISO may use estimates in whole or in part, in accordance with ISO Procedures, to settle an invoice. Any charges based on estimates shall be subject to true-up, including interest calculated from the first due date after the service was rendered in accordance with Section 7.3 of this ISO Services Tariff, in invoices subsequently issued by the ISO after the ISO has obtained the requisite actual information, provided that the actual information is supplied to the ISO within the timeframes established in Section 7.4 of this ISO Services Tariff. The ISO may net any overpayment, including interest calculated from the date the overpayment was made in accordance with Section 7.3 of this ISO Services Tariff, 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. The ISO's invoices to Customers will be submitted only by electronic means via the ISO's Bid/Post System.

7.2.2 Payment by the Customer

A Customer owing payments on net shall make those payments to the ISO Clearing Account by the first banking day common to all parties after the 15th day of the month that the invoice is rendered by the ISO. All payments shall be made by wire transfer in immediately available funds payable to the ISO as trustee of the ISO Clearing Account.

Customers owing payments as a result of their activity in a Centralized TCC Auction or Reconfiguration Auction, pursuant to an award notice rendered by the ISO shall make those payments to the ISO Clearing Account in accordance with the timeline set forth in ISO Procedures. All payments shall be made by wire transfer in immediately available funds payable to the ISO as trustee of the ISO Clearing Account.

7.2.3 Payments by the ISO

The ISO shall pay all net monies owed to a Customer from the ISO Clearing Account by the first banking day common to all parties after the 19th day of the month that the invoice is rendered by the ISO; provided, however, payments in connection with the allocation of Centralized TCC Auction or Reconfiguration Auction revenues to Transmission Owners shall be paid in accordance with the timeline set forth in ISO Procedures. All payments shall be made by wire transfer in immediately available funds payable to the Customer by the ISO as trustee of the ISO Clearing Account unless other arrangements are made.

The ISO shall pay all net monies owed to Customers as a result of their activity in a Centralized TCC Auction or a Reconfiguration Auction, pursuant to an award notice rendered by the ISO, from the ISO Clearing Account in accordance with ISO Procedures. All payments shall be made by wire transfer in immediately available funds payable to the Customer by the ISO as trustee of the ISO Clearing Account unless other arrangements are made.

7.2.4 Verification of Payments

The ISO shall verify that all payments owed by Customers in accordance with his ISO Services Tariff and the ISO OATT to the ISO Clearing Account have been paid in a timely manner in accordance with ISO Procedures. If a Customer fails to make a payment within the time period established in Section 7.2.2 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. 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 in accordance with ISO Procedures.

7.2.5 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 as trustee of the ISO Clearing Account (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 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 month following the month 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 Between January 1, 2007, and December 31, 2008

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

Settlement information for services furnished between January 1, 2007, and December 31, 2008, 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 seven (7) months from the date of the initial invoice for the month in which the service is rendered 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-one (71) 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.

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-one (131) days from the date of the initial invoice. Customers may then review, comment on, and challenge the LSE bus metering data for an additional fourteen (14) 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.

7.4.1.1.5 At one hundred fifty (150) days from the date of the initial invoice, the ISO shall post updated advisory settlement information. Customers may review, comment on, and challenge this settlement information, except for Generator, tie-line, sub-zone Load, and LSE bus metering data, after which the ISO shall process and correct the data and issue an updated corrected invoice with the regular monthly invoice issued on or about one hundred eighty (180) days from the date of the initial invoice.

7.4.1.1.6 Following the ISO's issuance of an updated corrected invoice, Customers may continue to review, comment on, and challenge settlement information, excepting Generator, tie-line, sub-zone Load, and LSE bus metering data, until the end of the seven-month review period.

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

7.4.2.1 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 and as further provided in Section 7.4.2.2, subject to the following requirements and limitations:

7.4.2.1.1 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.

7.4.2.1.2 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.

7.4.2.1.3 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.

7.4.2.1.4 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 7.4.2.1.

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 7.4.2.1; *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 7.4.2.1. 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 7.4.2.2. 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 7.4.3 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.

7.4.3 Expedited Dispute Resolution Procedures for Unresolved Settlement Challenges

7.4.3.1 Applicability of Expedited Dispute Resolution Procedures

This Section 7.4.3 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 or Section 7.4.2.1 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 or Section 7.4.2.2 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.

7.4.3.2 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 or Section 7.4.2.2 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.

7.4.3.3 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 or Section 7.4.2.1 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 7.4.3.3, the ISO will accept the Customer's request to participate in the dispute resolution proceeding.

7.4.3.4 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 7.4.3.2, 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.

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 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 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.

7.4.3.6 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.

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 the Service Agreement between the ISO and the Defaulting Party immediately upon notice to the Commission.

(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 Article 26.4 of Attachment K to the ISO Services Tariff, or (b) as a result of a material adverse change as determined in accordance with Article 26.10 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 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 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 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 ISO Setoff Rights

The ISO shall have the right to apply any amounts owed a Customer pursuant to this Tariff against any amounts owed to the ISO by a Customer.

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.

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.

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.

8.2 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 Procedures

11.1 Applicability of Dispute Resolution Provisions

The dispute resolution provisions in this Article 11 shall apply to any dispute arising under this Tariff with the exception of those disputes subject to Expedited Dispute Resolution Procedures.

11.2 Internal Dispute Resolution Procedures

Any dispute between or among Customers and/or the ISO involving service under the ISO Services Tariff (excluding applications for rate changes or other changes to the Tariff), ISO Procedures or to any Service Agreement entered into under the Tariff shall be presented directly to a senior representative of each party to the dispute for resolution on an informal basis as promptly as practicable.

If the designated representatives are unable to resolve the dispute within thirty (30) days by mutual agreement, the dispute may be submitted to the ISO's Dispute Resolution Administrator ("DRA"). The party submitting the matter to the DRA shall include a written statement describing the nature of the dispute and the issues to be resolved. Any subsequent mediation or arbitration process shall be limited to the issues presented for resolution.

The DRA may submit disputes to non-binding, mediation where the subject matter of the dispute involves the proposed change or modification of a rule, rate, Service Agreement or ISO Services Tariff provision. The DRA may submit disputes to binding arbitration which involve interpretation of a rule, rate, Service Agreement or ISO Services Tariff provision. Both the mediator and the arbitrator shall have the authorization to dismiss a dispute if:

1. The dispute did not arise under the ISO Services Tariff; or
2. The claim is de minimis.

11.3 Non-Binding Mediation

If the DRA refers the dispute to non-binding mediation, then the following procedure will be followed:

The DRA shall have ten (10) days from the date of such referral to distribute a list of ten (10) qualified mediators to the disputing parties. Absent the express written consent of all disputing parties, as to any particular individual, no person shall be eligible for selection as mediator who is a past or present officer, employee or consultant to any of the disputing parties, or of any entity related to or Affiliated with any of the disputing parties or is otherwise interested in the matter to be mediated. Any individual designated as mediator shall make known to the disputing parties any such disqualifying relationship and a new mediator shall be designated.

If the disputing parties cannot agree upon a mediator, the disputing parties shall take turns striking names from a list supplied by the DRA with a disputing party chosen by lot, first striking a name. The last remaining name shall be designated as the mediator. If that individual is unable or unwilling to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected that is able and willing to serve.

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 written statements of issue(s) and position(s);
2. meet for discussions;
3. provide expert testimony and exhibits; and

4. comply with the mediation procedures designated by the DRA and/or 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 disputing parties and the DRA 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 to the dispute. The parties to the dispute 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.

If the parties are still unable to resolve the dispute, then:

A. any dispute not involving a proposed change or modification of a rule, rate, Service Agreement or ISO Services Tariff provision may be referred to the arbitration process described below; or

B. any disputing party may resort to regulatory or judicial proceedings as provided for under the ISO Services Tariff; and

C. 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.

Each party to the dispute will bear a pro rata portion 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.

11.4 Arbitration

If the DRA refers the dispute to arbitration, then the following procedure will be followed:

The DRA shall have ten (10) days from the date of such decision to distribute a list of qualified arbitrators to the disputing parties. 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 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 designated as an arbitrator shall make known to the disputing 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 disputing parties cannot agree upon an arbitrator, the disputing parties shall take turns striking names from a list of ten (10) qualified individuals supplied by the DRA. The party to first strike a name should be chosen by lot. The last-remaining name not stricken shall be designated as the arbitrator. If that individual is unable or unwilling to serve, the individual last stricken from the list shall be designated and the process repeated until an individual is selected that is able and willing to serve.

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 to the dispute 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 disputing 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 disputing 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 disputing parties, no person or entity that is not a party to the dispute shall be permitted to intervene. 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.

Under the following circumstances, the decision of the arbitrator shall be final and binding upon the parties:

1. all parties agree that the decision will be binding; or
2. the dispute involves a claim that a party owes another party a sum of money less than $500,000.

If the arbitrator concludes that no proposed award is consistent with the ISO Services Tariff, the FPA and Commission’s then-applicable standards and policies, or would address all issues in dispute, the arbitrator shall develop a compromise solution consistent with the terms of the ISO Services Tariff. A written decision explaining the basis for the award shall be provided by the arbitrator to the parties and the DRA. No award shall be deemed to be precedential in any other arbitration related to a different dispute.

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.

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 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;
4. based on conduct by an arbitrator that is violative of the Federal Arbitration Act or Administrative Dispute Resolution Act; or
5. involves a dispute in excess of $500,000.

Nothing in this section 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 FPA.

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 - Market Administration and Control Area Services Charge

15.1.1 Parties to Which Charges Apply

15.1.1.1 The ISO shall charge and each Customer taking service under the ISO Services Tariff, the ISO OATT, or both, shall pay the applicable "ISO Services Charge" on all services provided under the Tariff. Market Participants taking service under both the ISO Services Tariff and the ISO OATT shall pay the applicable ISO Services Charges as calculated under Sections 15.1.3.1 through 15.1.3.3 of this Rate Schedule and under Sections 6.1.2.2.3 and 6.1.2.2.4 of Rate Schedule 1 of the ISO OATT. Market Participants taking service under the ISO OATT only shall pay the applicable ISO Services Charges as calculated under Rate Schedule 1 of the ISO OATT.

15.1.1.2 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 enter into a Service Agreement under the Tariff, as set forth in Attachment A; and 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, and must enter into a Service Agreement under this Tariff, as set forth in Attachment A; 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 [the date that the Commission issues an order approving these revisions], utilizes Market Services and must enter into a Services Agreement under this Tariff, as set forth in Attachment A.

15.1.2 Billing

For the ISO Services Charges calculated under Section 15.1.3.1 of this Rate Schedule, the ISO shall charge each Customer based on the product of: (i) the applicable ISO Services Charges rates; and (ii) the Customer's applicable injection billing units and/or withdrawal billing units for the month. The Customer’s injection billing units shall be based on its 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 wheel throughs. The Customer’s withdrawal billing units shall be based on the Actual Energy Withdrawals for all Transactions to supply Load in the NYCA and hourly Energy schedules for all Wheels Through and Exports.

For the ISO Services Charges calculated under Section 15.1.3.2 and 15.1.3.3 of this Rate Schedule, the ISO shall charge each Customer based on the product of: (i) the applicable ISO Services Charges rate; and (ii) the Customer’s Actual Energy Withdrawals for all Transactions to supply Energy to the LBMP market in the NYCA and all other purchases from the LBMP markets to supply Load outside the NYCA.

For Customers participating in the ISO’s Special Case Resources program or its Emergency Demand Response Program the ISO Services Charge~~s~~ calculated under Section 15.1.3.1 of this Rate Schedule shall be the product of: (i) the applicable ISO Services Charge rates and (ii) the Customer’s applicable billing units for the month. The Customer’s billing units shall be based on the total compensable injection MWh.

For Customers purchasing Transmission Congestion Contracts or engaged in Virtual Transactions, the ISO Services Charge~~s~~ calculated under Section 15.1.3.1 of this Rate Schedule shall be the product of: (i) the applicable ISO Services Charge~~s~~ rate; and (ii) the Customer's applicable billing units for the month.

For Customers purchasing Transmission Congestion Contracts, the Customer's billing units shall be based on the settled Transmission Congestion Contract MWh. For Customers engaging in Virtual Transactions, the Customer's billing units shall be based on total cleared virtual bid MWh.

15.1.3 Computation of Rate

The ISO Services Charge shall consist of three components and shall be recovered on a monthly basis in accordance with the following processes:

15.1.3.1 ISO Annual Budget and FERC Regulatory Fees Component

15.1.3.1.1 The responsibility for the sum of (i) the ISO's annual budget including the costs listed in Section 15.1.4.1 of this Rate Schedule; and (ii) the ISO's FERC Regulatory fees, shall be allocated 20% to all injection billing units as described in Section 15.1.2 of this Rate Schedule and 80% to all withdrawal billing units as described in Section 15.1.2 of this Rate Schedule. The current 80%/20% cost allocation shall remain unchanged through at least December 31, 2011 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 80%/20% 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 80%/20% cost allocation on a going forward basis:

15.1.3.1.1.1 A vote of the Management Committee will be taken in the third calendar quarter of 2010 on whether a new study should be conducted during late-2010 and 2011 to allow modification of the 80%/20% cost allocation, if warranted by the results of the study, to be implemented by January 1, 2012. 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.

15.1.3.1.1.2 If the Management Committee vote discussed in Section 15.1.3.1.1.1 above determines that a study should not be conducted, the 80%/20% cost allocation between withdrawal billing units and injection billing units shall be extended through at least December 31, 2012. In the third calendar quarter of 2011, a vote will be taken on whether a new study should be conducted during late-2011 and 2012 to allow modification of the percentage allocation, if warranted by the results of the study, to be implemented by January 1, 2013. 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.

15.1.3.1.1.3 If the Management Committee vote in the third calendar quarter of 2011 discussed in Section 15.1.3.1.1.2 above determines that a study should not be conducted, the current 80%/20% 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 2011 discussed in Section 15.1.3.1.1.2 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 gets 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 2011 discussed in Section 15.1.3.1.1.2 above.

15.1.3.1.1.4 If, and when, the Management Committee determines a study shall be conducted:

15.1.3.1.1.4.1 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

15.1.3.1.1.4.2 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.

15.1.3.1.2 The rate for injection billing units shall be the quotient of 20% of the sum of the ISO's annual budget and FERC regulatory fees divided by the total annual estimated injection billing units, as described in Section 15.1.2 of this Rate Schedule. The rate for withdrawal billing units shall be the quotient of 80% of the sum of the ISO's annual budget and FERC regulatory fees divided by the total annual estimated withdrawal billing units as described in Section 15.1.2 of this Rate Schedule.

15.1.3.1.3 The rates derived in pursuant to Sections 15.1.3.1.1 and 15.1.3.1.2 above shall then be multiplied by each customer's injection billing units and withdrawal billing units, as appropriate, for the month, as described in Section 15.1.2 of this Rate Schedule.

15.1.3.1.4 For Customers that purchase Transmission Congestion Contracts or engage in Virtual Transactions their portion of the sum of (i) the ISO's annual budget including the costs listed in Section 15.1.4.1 of this Rate Schedule; and (ii) the ISO's FERC Regulatory fees, shall be calculated and billed as follows:

15.1.3.1.4.1 For Calendar Year 2010:

15.1.3.1.4.1.1 $0.020 per MWh for Transmission Congestion Contracts for calendar year 2010, based on a $6.7 million projected 2010 annual revenue requirement.

15.1.3.1.4.1.2 $0.065 per cleared MWh for Virtual Transactions for calendar year 2010 based on a $2.0 million projected 2010 annual revenue requirement.

15.1.3.1.4.2 For Subsequent Calendar Years

Each Customer shall be charged a rate computed annually based on the product of the annual revenue requirement adjusted for the over or under collection of the prior year's annual revenue requirement, divided by the three year rolling average of the billing units, where:

15.1.3.1.4.2.1 the annual revenue requirement is determined using an escalation factor calculated as the percentage change in the originally-approved ISO budget between the calendar year two years prior to the current calendar year ("Calendar Year Minus 2") and the calendar year one year prior the current calendar year ("Calendar Year Minus 1");

15.1.3.1.4.2.2 the over/under collection of the prior year's annual revenue requirement is calculated for the period between July of Calendar Year Minus 2 and June of Calendar Year Minus 1. For the purpose of this calculation the annual revenue requirement will be converted to a monthly requirement and then aggregated across the 12 months;

15.1.3.1.4.2.3 the three year rolling average of billing units is calculated using an annual average of the 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.

However, the annual rate computed will be subject to a 25% maximum increase or decrease for each year. Revenue collected pursuant to this Section 15.1.3.1.4 will be disbursed monthly to all withdrawal billing units as described in Section 15.1.2 of this Rate Schedule and to all injection billing units as described in Section 15.1.2 of this Rate Schedule on the same basis described in Section 15.1.3.1.1 of this Rate Schedule.

15.1.3.1.5 For Customers participating in the ISO's Special Case Resource program or its Emergency Demand Response Program their portion of the sum of (i) the ISO's annual budget including the costs listed in Section 15.1.4.1 of this Rate Schedule; and (ii) the ISO's FERC Regulatory fees, shall be billed at the same rate charged to injection billing units as described in Section 15.1.2 of this Rate Schedule. The rate will be reset annually to match the current calendar year's rate for injections. Revenue collected pursuant to this Section 15.1.3.1.5 will be disbursed monthly to all withdrawal billing units as described in Section 15.1.2 of this Rate Schedule and to all injection billing units as described in Section 15.1.2 of this Rate Schedule on the same basis described in Section 15.1.3.1.1 of this Rate Schedule.

15.1.3.2 Unbudgeted Costs Component

Except with respect to bad debt loss and working capital contribution costs, the responsibility for those costs listed in Section 15.1.4.1 of this Rate Schedule that are neither (i) included in the ISO's annual budget nor (ii) FERC assessed regulatory fees, shall be allocated 100% to all withdrawal billing units. The rate to be applied to withdrawal billing units in each month shall be the quotient of the amount of these costs to be included in the month, as determined by the ISO, divided by the total estimated withdrawal billing units for the month, as described in Section 15.1.2 of this Rate Schedule. This rate shall then be multiplied by each Customer's withdrawal billing units for the month. The responsibility for costs associated with bad debt losses and working capital contributions shall be allocated pursuant to Attachments U and V of the ISO OATT.

15.1.3.3 ISO Start-Up and Formation Costs Component

The costs listed in Section 15.1.4.2 of this Rate Schedule shall be estimated each month for the following month, shall be divided by the total estimated withdrawal billing units as described in Section 15.1.2 of this Rate Schedule, for the following month and shall be posted on the ISO's website prior to the start of the subject month. This rate is then multiplied by each customer's withdrawal billing units for the subject month.

15.1.4 ISO Costs

15.1.4.1 ISO costs to be recovered through this ISO Services Charge shall include the costs listed in Section 6.1.3.1 of Rate Schedule 1 of the ISO OATT and the costs incurred by the ISO that are "directly assignable" to the services provided by the ISO under this Tariff that are not recoverable under Rate Schedule 1 of the ISO OATT. Costs recoverable under this charge shall include costs related to: the ISO's administration of the LBMP Markets; the ISO's administration of

Installed Capacity requirements and an Installed Capacity Market; the ISO's administration of Control Area Services, other than Ancillary Services provided under the ISO OATT; the ISO's administration of the ISO Market Power Monitoring Program; other activities related to the maintenance of reliability in the NYCA; and costs related to any indemnification of or by the ISO pursuant to Section 12.4 of this Tariff, together the annual ISO budget; and

15.1.4.2 Fifty (50) percent of the costs associated with the start-up and formation of the ISO, plus interest, equaling $27.45 million, plus interest, less one-half of the start-up costs already collected by the ISO under the ISO OATT. These costs will be amortized over a period from September 1, 2000 through December 31, 2004.

Where costs or expenses or receipts are incurred on a basis other than a monthly basis, the ISO shall use reasonable judgment consistent with commonly accepted accounting practices to develop the monthly components.

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 will purchase Voltage Support Service from the ISO under the ISO OATT.

The rate provided in this Rate Schedule shall be used to calculate payments to all eligible Suppliers providing Voltage Support Service as applied on a Resource-specific basis (or Qualified Non-Generator Voltage Support Resource-specific). 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. 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 Resource that has an AVR, or a Qualified Non-Generator Voltage Support Resource. 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 Resources and Qualified Non-Generator Voltage Support Resources within these demonstrated reactive capability limits. Suppliers of Voltage Support Service will test their Resources and Qualified Non-Generator Voltage Support Resources and provide these services in accordance with ISO Procedures.

Voltage Support Service includes the ability to produce or absorb Reactive Power within the Resource's or Qualified Non-Generator Voltage Support Resource’s 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 Resource's stated reactive capability. The requirement for a Resource or Qualified Non-Generator Voltage Support Resource ("Resource") to absorb Reactive Power may be set aside by the ISO with input from the Transmission Owner in whose Transmission District the 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 Resource be able to absorb Reactive Power, the ISO shall have determined that: 1) the resource is unable, due to transmission system configuration, to absorb Reactive Power; 2) the ability of the Resource to produce Reactive Power is needed for system reliability; and 3) for purposes of system reliability the Resource does not need to have the ability to absorb Reactive Power.

15.2.2 Payments

Each month, Suppliers whose Resource(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 ($1/12^{th}$) of the annual payment calculated under Section 15.2.2.1 of this Rate Schedule, for Voltage Support Service. To the extent Suppliers of Installed Capacity are electrically located outside the NYCA, payments for Voltage Support Service will be subject to criteria established by the ISO.

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 ($1/12^{th}$) 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 ($1/12^{th}$) 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 the 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 resource to reduce its real power (MW) output below its Economic Operating Point in order to allow the resource 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 product of: (a) the MW of output reduction; (b) the time duration of reduction in hours or fractions thereof; and (c) the Real-Time LBMP at the Generator bus minus the Generator’s Energy Bid for the reduced output of the Generator. The details of the Lost Opportunity Cost payments are as follows:

The formula below describes the calculation of LOC as applied to each Generator supplying Voltage Support Service.

$$LOC = P_{RT}\,(D_1 - D_2) - \int_{D_2}^{D_1} Bid$$

Where:

P_{RT} = Real-Time LBMP

D_1 = Original dispatch point, which shall be equal to the Generator's Economic Operating Point.

D_2 = New dispatch point, which shall be the greater of the Generator's Real-Time Scheduled Energy Injection, the Generator's Actual Energy Injection, or the amount of Energy the Generator is scheduled to produce for the hour in the Day-Ahead Market.

Bid = Bid curve or Generation supplying Voltage Support Service

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).

Incremental Bid Curve Used to Calculate LOC

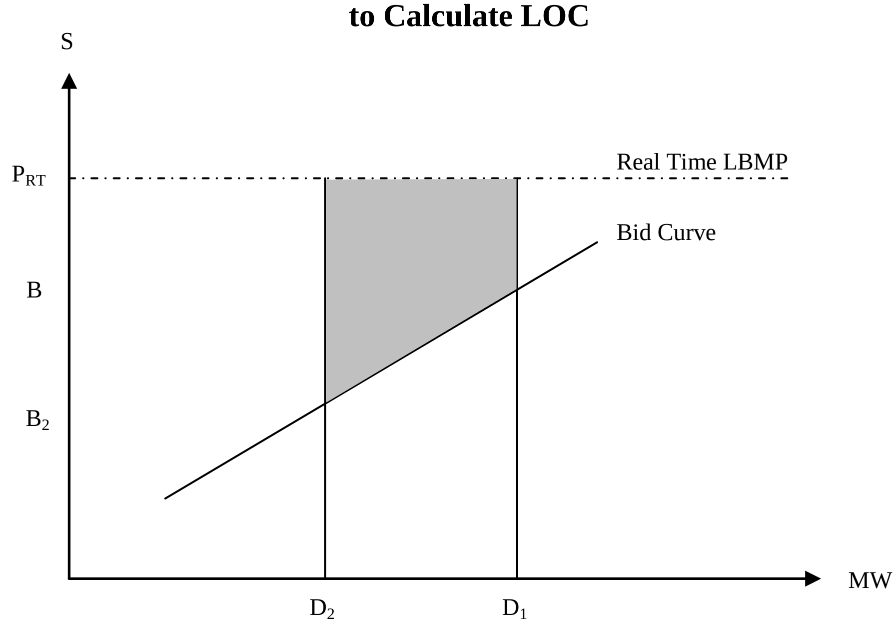


Figure 2.0(b)- Incremental Bid Curve Used to Calculate LOC

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.

15.2.2.4 Failure to Perform by Suppliers

A Resource or a Qualified Non-Generator Voltage Support Resource will have failed to provide voltage support if it:

15.2.2.4.1 fails at the end of 10 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 for levels below it's Normal Operating limit which must be at least 90% of its Dependable Maximum Net Capability (DMNC).

15.2.2.4.2 fails at the end of 10 minutes to be at 95% or greater of the Resource's demonstrated Reactive Power capability (tested at its Normal Operating Limit or at 90% of its DMNC, whichever is greater in MW) 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.

Whether the Resource or Qualified Non-Generator Voltage Support Resource has failed to provide Voltage Support Service in a Contingency shall be defined by ISO Procedures. 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 15.2.2.5 and 15.2.2.6 below.

15.2.2.5 Failure to Respond to ISO's Request for Steady-State Voltage Control

Initial Failure: If a Resource or a 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 one-twelfth (1/12th) of the annual payment for that specific Resource or a 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). 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.

Repeated Failures: For each instance of failure to perform, the non-complying Supplier will be subject to the charges described herein. If a Resource fails to comply with the ISO's request on three (3) separate days, within a thirty (30) day period, then upon the third occurrence, the non-complying Supplier will no longer be eligible for Voltage Support Service payments for service provided by that Resource 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:

15.2.2.5.1 the Supplier's Resource or Qualified Non-Generator Voltage Support Resource must successfully perform a Reactive Power (MVAr) capability test, and

15.2.2.5.2 the Resource 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 during this period.

15.2.2.6 Failure to Provide Voltage Support Service When a Contingency Occurs on the NYS Power System

If a Supplier's Resource 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 Resource 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 Resource 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 Resource or Qualified Non-Generator Voltage Support Resource until the Supplier complies with the following conditions to the ISO's satisfaction:

15.2.2.6.1 the Supplier's Resource or Qualified Non-Generator Voltage Support Resource shall successfully perform a Reactive Power (MVAr) capability test, and

15.2.2.6.2 the Resource 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 during this period.

15.2.3 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. 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, as described in Section 15.3.2 of this Rate Schedule;

(f) Pay Suppliers for providing Regulation Service as described in Sections 15.3.4, 15.3.5, 15.3.6 and 15.3.7 of this Rate Schedule; and

(g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 15.3.3 of this Rate Schedule.

15.3.1.2 Each Supplier shall:

(a) Register with the ISO the capacity its resources are qualified to bid in the Regulation Services market;

(b) 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;

(c) Not use, contract to provide, or otherwise commit Capability that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to any party other than the ISO;

(d) Pay any charges imposed under this Rate Schedule including, if they are re-instituted the charges described in Section 15.3.8 of this Rate Schedule;

(e) 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, from those that have Bid to provide Regulation Service from Resources that meet the qualification standards and criteria established in Section 15.3.1 of this Rate Schedule and in the ISO Procedures.

(b) Real-Time Market: The ISO shall establish a Real-Time Market for Regulation Service and will establish a real-time Regulation Service market clearing price in each interval. During any period when the ISO suspends Resources' obligation to follow the AGC Base Point Signals sent to Regulation Service providers, pursuant to Section 15.3.9 of this Rate Schedule, the Real-Time Market clearing price for Regulation Service shall automatically be set at zero, which shall be the price used for real-time balancing and settlement purposes. The ISO shall select Suppliers for Regulation Service from those that have Bid to provide Regulation Service from Resources that meet the qualification standards and criteria established in the ISO Procedures.

(c) The ISO shall establish separate market clearing prices for Regulation Service 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. 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 for Regulation Service; (ii) the Resource’s regulation response rate (in MW/Minute) which must be sufficient to permit that Resource to provide the offered amount of Regulation Service within an RTD interval provided, however, that the regulation response rate for Demand Side Resources shall be at least equal to its energy response rate; (iii) the Supplier's Availability Bid Price (in $/MW); 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 Performance Tracking System shall compute the difference between the Energy actually supplied and the Energy scheduled by the

ISO for all Suppliers serving Load within the NYCA as set forth in the ISO Procedures. The ISO shall use these values to reduce Regulation Service payments pursuant to Section 15.3.5.5 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 Clearing Prices

The ISO shall calculate a Day-Ahead Market clearing price for Regulation Service each hour of the following day. The Day-Ahead Market clearing 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. 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 17.1.2 of Attachment B to this ISO Services Tariff, and Section 16.1.2 of Attachment J to the ISO OATT. As a result, the Shadow Price shall include the Day-Ahead Regulation Service Bid of the marginal Resource selected to provide Regulation Service (or in the applicable price on the Regulation Service Demand Curve during shortage conditions), 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. Shadow Prices shall also be consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule, which will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Regulation Service Demand Curve indicates should be paid. Each Supplier that is scheduled Day-Ahead to provide Regulation Service shall be paid the Day-Ahead Market clearing price in each hour, multiplied by the amount of Regulation Service that it is scheduled to provide in that hour.

15.3.4.2 Other Day-Ahead Payments

As provided in Article 4 and Attachment C of the Services Tariff, the ISO shall compensate each ISO-Committed Flexible Generator that provides Regulation Service, other than a Limited Energy Storage Resource, if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Day-Ahead Market, including start-up costs, minimum Load costs, and Availability Bids, exceeds the revenues it receives from the sale of Energy and Ancillary Services.

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 Clearing Prices

The ISO shall calculate a Real-Time Market clearing price for Regulation Service for every RTD interval, except as noted in Section 15.3.9 of this Rate Schedule. Except when the circumstances described below in Section 15.3.5.2 apply, the Real-Time Market clearing 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. 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 calculated during the third RTD pass described in Section 17.1.1.1.2.3 of Attachment B to this ISO Services Tariff, and Section 16.1.1.1.2.3 of Attachment J to the ISO OATT. As a result, the Shadow Price shall include the Real-Time Regulation Service Bid of the marginal Resource selected to provide Regulation Service (or the applicable price on the Regulation Service Demand Curve during shortage conditions), 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. Shadow Prices shall also be consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule, which will ensure that Regulation Service is not scheduled by RTC at a cost greater than the Demand Curve indicates should be paid.

15.3.5.2 Calculation of Real-Time Market Clearing Prices for Regulation Service During EDRP/SCR Activations

During any interval in which the ISO is using scarcity pricing rule "A" or "B" to calculate LBMPs under Sections 17.1.1.2 or 17.1.1.3 of Attachment B to this ISO Services Tariff, and Sections 16.1.1.2 or 16.1.1.3 of Attachment J to the ISO OATT, the real-time Regulation Service market clearing price may be recalculated in light of the Availability Bids of Suppliers and Lost Opportunity Costs of Generators scheduled to provide Regulation Service in real-time.

Specifically, when either scarcity pricing rule is applicable, the real-time Regulation Service clearing price shall be set to the higher of: (i) the highest total Availability Bid and Lost Opportunity Cost of any Regulation Service provider scheduled by RTD; and (ii) the market clearing price calculated under Section 15.3.5.1 of this Rate Schedule.

15.3.5.3 Real-Time Regulation Service Balancing Payments

Any deviation from a Supplier's Day-Ahead schedule to provide Regulation Service shall be settled pursuant to the following rules.

(a) When the Supplier's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Market clearing price for Regulation Service; and (ii) the difference between the Supplier's Day-Ahead Regulation Service schedule and its real-time Regulation Service schedule (subject to possible adjustments pursuant to Section 15.3.5.5 of this Rate Schedule.)

(b) When the Supplier's real-time Regulation Service schedule is greater than its Day-Ahead Regulation Service 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 Regulation Service; and (ii) the difference between the Supplier's real-time Regulation Service schedule and its Day-Ahead Regulation Service schedule(subject to possible adjustments pursuant to Section 15.3.5.5 of this Rate Schedule.)

15.3.5.4 Other Real-Time Regulation Service Payments

As is provided in Article 4 and Attachment C of the Services Tariff, the ISO shall compensate each ISO-Committed Flexible Generator that provides Regulation Service, other than a Limited Energy Storage Resource, if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Real-Time Market, including start-up costs, minimum Load costs, and Availability Bids, exceeds the revenues it receives from the sale of Energy and Ancillary Services.

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.

Finally, whenever a Supplier's real-time Regulation Service schedule is reduced by the ISO to a level lower than its Day-Ahead schedule for that product, the Supplier's Day-Ahead Margin shall be protected after accounting for any margin associated with other products that the Supplier's is scheduled to provide in real-time, provided however, that the Day-Ahead Margin of a Limited Energy Storage Resource may not be protected if the ISO has reduced its real-time Regulation Service offer to a level lower than its Day-Ahead schedule to account for the Energy storage capacity of such Limited Energy Storage Resource. The rules governing the calculation of these Day-Ahead Margin Assurance Payments are set forth in Attachment J to this ISO Services Tariff.

15.3.5.5 Performance-Based Adjustments to Regulation Service Payments

The amount paid to each Supplier for providing Regulation Service in each RTD interval i shall be reduced to reflect the Supplier's performance pursuant to the following formula:

$$\text{Total Payment} = \Sigma_i(\text{Total Payment}_i * (s_i/3600))$$

Where:

$\text{Total Payment}_i = (DAMCPreg_i \times DARcap_i) + ((RTRcap_i \times K_{PI}) - DARcap_i) \times RTMCPreg_i)$

$DAMCPreg_i$ is the applicable market clearing price for Regulation Service (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;

$DAR\mathit{cap}_i$ is the Regulation Service Capability (in MW) offered by the Resource and selected by the ISO in the Day-Ahead Market in the hour that includes RTD interval i;

$RTMCPreg_i$ is the applicable market clearing price for Regulation Service (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 Service Capability (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in RTD interval i;

s_i is the number of seconds in interval i; and

K_{pi} is a factor, 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 determined pursuant to the following equation:

$$K_{PI} = \frac{PI - PSF}{1 - PSF}$$

Where:

PI is the performance index of the Resource; and

PSF is the payment scaling factor, established pursuant to ISO Procedures.

The PSF shall be set between 0 and the minimum performance index required for payment of Availability payments. 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. The factor K_{PI} shall initially be set at 1.0 for Limited Energy Storage Resources.

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 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:

$$\text{Energy Settlement}_h = \text{Net MWHR}_h * \text{LBMP}_h$$

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 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 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. 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:

$$\text{Payment/Charge} = \int_{\text{RTD Base Point Signal}}^{\max(\text{RTD Base Point Signal},\min(\text{AGC Base Point Signal},\text{Actual Output}))} \left(\text{Bid} - \text{LBMP}\right) * s/3600$$

Where:

s is 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.

15.3.6.3 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:

$$\text{Payment/Charge} = \int_{\min(\text{RTD Base Point Signal},\max(\text{AGC Base Point Signal},\text{Actual Output}))}^{\text{RTD Base Point Signal}} -\left(\text{Bid} - \text{LBMP}\right) * s/3600$$

Where:

s is 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 Service markets. The market clearing prices for Regulation Service 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 Service is not purchased by SCUC or RTC 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 Service that the ISO would seek to maintain in that hour. The ISO will then define a Regulation Service demand curve for that hour as follows:

For quantities of Regulation Service that are less than or equal to the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be $300/MW.

For quantities of Regulation Service 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 $250/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 Service 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 Reinstating Performance Charges

The ISO will monitor, on a real-time hourly or daily basis, as appropriate, its compliance with the standards established by NERC and NPCC and with the standards of Good Utility Practice for Control Performance, area control error, disturbance control standards, reserve pickup performance and system security. Should it appear to the ISO that degradation in performance threatens compliance with one or more of the established standards for these criteria or compromises reliability, and that reinstating the performance charges that were originally part of the ISO's market design, would assist in improving compliance with established standards for these criteria, or would assist in re-establishing reliability, the ISO may require Suppliers of Regulation Service, as well as Suppliers not providing Regulation Service, to pay a performance charge. Any reinstatement of Regulation penalties pursuant to this Section shall not override previous Commission-approved settlement agreements that exempt a particular unit from such penalties. The ISO shall provide notice of its decision to reinstate performance charges to the Commission, to each Customer and to the Operating Committee and the Business Issues Committee no less than seven days before it re-institutes the performance charges.

If the ISO determines that performance charges are necessary, Suppliers of Regulation Service shall pay a performance charge per interval to the ISO as follows:

Performance Charge = Energy Deviation x MCP_{reg} x (Length of Interval/60 minutes)

Where:

Energy Deviation (in MW) is the absolute difference between the actual Energy supplied by the Supplier and the Energy required by the AGC Base Point Signals, whether positive or negative, averaged over each RTD interval; and

MCP_{reg} is the market clearing price ($/MW) which applies to the RTD interval for this Service in the Real-Time Market or the Day-Ahead Market, if appropriate.

The method used by the ISO to calculate the Energy Deviation will permit Suppliers a certain period of time to respond to AGC Base Point Signals. Initially this time period will be thirty (30) seconds, although the ISO will have the authority to change its length. If the Supplier's output at any point in time is between the largest and the smallest of the AGC Base Points sent to that Supplier within the preceding thirty (30) seconds (or such other time period length as the ISO may define), the Supplier's Energy Deviation at that point in time will be zero. Otherwise, the Supplier may have a positive Energy Deviation. However, in cases in which responding to the AGC Base Point within that time period would require a Supplier to change output at a rate exceeding the amount of Regulation it has been scheduled to provide, the Supplier will have a zero Energy Deviation if it changes output at the rate equal to the amount of Regulation it is scheduled to provide.

15.3.9 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 suspend Generators’ obligation to follow the AGC Base Point Signals sent to Regulation Service providers, freeing them to provide Energy and will suspend the real-time Regulation Service market. The ISO will not procure any Regulation Service and will establish a real-time Regulation Service market clearing price of zero for settlement and balancing purposes. The ISO will resume sending AGC Base Point Signals and restore the real-time Regulation Service market 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.3.3 of this Rate Schedule, that is not providing Regulation Service and that persistently operates at a level below its 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:

$$\text{Persistent undergeneration charge} = \text{Energy Difference x } MCP_{reg} \text{ x Length of Interval/60 Minutes}$$

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; and

MCP_{reg} is the market clearing price ($/MW) which applies to the dispatch interval for which Regulation Service in the Real-Time Market, or, if applicable, the Day-Ahead 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:

Overgeneration charge = Energy Difference x MCP_{reg} x Length of Interval/60 Minutes

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; and

MCP_{reg} is the market clearing price ($/MW) which applies to the dispatch interval for Regulation Service in the Real-Time Market, or, if applicable, the Day-Ahead Market.

15.3A.2 Restoration of Performance Charges

The persistent undergeneration charges described in Section 15.3A.1 above shall be suspended in the event that the ISO re-institutes Regulation performance charges pursuant to Section 15.3.8 of Rate Schedule 3 of this Services Tariff. If the ISO re-institutes performance charges then Suppliers that sell Energy through the LBMP Markets or that supply Bilateral Transactions that serve Load in the NYCA, but do not provide Regulation Service, shall pay a performance charge per interval to the ISO as follows:

Performance Charge = Energy Difference x MCP_{reg} x Length of SCD Interval/60 minutes

Where:

Energy Difference (in MW) is the absolute difference between the actual Energy supplied by the Supplier and the Energy is directed to produce by its RTD Base Point Signals, whether positive or negative, averaged over each RTD interval; and

MCP_{reg} is the market clearing price ($/MW) which applies to the interval for which Regulation Service was provided in the Real-Time Market, or, if appropriate, the Day-Ahead Market.

In cases in which the Energy Difference that would be calculated using the procedure described above is less than the tolerance set forth in the ISO Procedures, the ISO shall set the Energy Difference for that interval equal to zero.

15.3A.3 Exemptions

The following types of Generator shall not be subject to persistent undergeneration charges, or, if they are restored by the ISO, to performance charges:

15.3A.3.1 Generators 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.3.2 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 499 MW of such units;

15.3A.3.3 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.3.4 Intermittent Power Resources that depend on landfill gas or solar energy as their fuel;

15.3A.3.5 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.3.6 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.3.7 Generators operating during a Testing Period.

For Generators and Resources described in Sections 15.3A.3.1, 15.3A.3.2, 15.3A.3.3, and 15.3A.3.4 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. These quantities shall be established under Section 15.4.7 of this Rate Schedule. 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 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, 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 select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves 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 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).

15.4.1.2.2 10-Minute Non-Synchronized Reserve:

Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes and that meet the criteria set forth in the ISO Procedures, and, Demand Side Resources that are capable of reducing their Energy usage within ten (10) minutes and 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:

(i) Generators 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; (ii) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes and that meet the criteria set forth in the ISO Procedures, and Demand Side Resources that are capable of reducing their Energy usage within thirty (30) minutes and 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 not increase their Energy Bids or Demand Reduction Bids for portions of their Resources that have been scheduled through those processes, or reduce their 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 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.

15.4.3.6 Performance Index for Demand Side Resource Suppliers of Operating Reserves

The ISO shall produce a performance index for purposes of calculating a Day Ahead Margin Assurance payment for a Demand Side Resource providing Operating Reserves. The 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 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 covert its Operating Reserves to Demand Reduction, the 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 Performance Index shall be calculated pursuant to the following formula, provided however when UAGi is zero or less, the Reserve PI shall be set to zero:

$$\text{Reserve PI} = \text{Min}\left[(\text{UAGi} / \text{ADGi} + .1), 1\right]$$

Where:

Reserve PI = Reserve Performance Index

UAGi = Average actual demand reduction for interval i, represented as a positive generation value

ADGi = Average scheduled demand reduction for interval i, represented as a positive generation base point

15.4.4 Operating Reserves Settlements - General Rules

15.4.4.1 Establishing Locational Reserve Prices

Except as noted below, the ISO shall calculate separate Day-Ahead Market and Real-Time Market prices for each of the products f three locations: (i) West of Central-East ("West" or "Western"); (ii) East of Central-East excluding Long Island; and (iii) Long Island ("L.I.").

The ISO will thus calculate nine different locational Operating Reserve prices in both the Day-Ahead Market and the Real-Time Market. Day-Ahead locational reserve prices shall be calculated pursuant to Section 15.4.5 of this Rate Schedule. Real-Time locational reserve 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 the East. The ISO will calculate separate locational Long Island Operating Reserves prices 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 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. 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 L.I. 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

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 or L.I. 30-Minute Reserve requirement constraint for the hour

SP5 = Shadow Price for Eastern or L.I. 10-Minute Reserve requirement constraint for the hour

SP6 = Shadow Price for Eastern or L.I. Spinning Reserve requirement constraint for the hour

SP7 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour

SP8 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour

SP9 = 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 17.1.2 of Attachment B to this Services Tariff, and Section 16.1.2 of Attachment J to the ISO OATT. 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

As is provided in Section 4.6.6 and Attachment C of this ISO Services Tariff, the ISO shall compensate each ISO-Committed Flexible Generator providing Operating Reserves if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Day-Ahead Market, including start-up costs, minimum Load costs, and Availability Bids, exceeds the revenues it receives from the sale of Energy and Ancillary Services. As is provided in Attachment C of this ISO Services Tariff, the ISO shall compensate ISO-Committed Demand Side Resources providing Operating Reserves if their Bids to provide Operating Reserves scheduled in the Day-Ahead Market exceed the revenues received from the sale of Operating Reserves and from any margin earned on the sale of Regulation Service in the Day-Ahead Market settlement.

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. Except when the circumstances described below in Section 15.4.6.2 apply, each real-time market-clearing price shall equal the sum of the relevant real-time locational 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 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 that location 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 L.I. 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Where:

SP1 = Shadow Price for total 30-Minute 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 or L.I. 30-Minute Reserve requirement constraint for the interval

SP5 = Shadow Price for Eastern or L.I. 10-Minute Reserve requirement constraint for the interval

SP6 = Shadow Price for Eastern or L.I. Spinning Reserve requirement constraint for the interval

SP7 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the interval

SP8 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP9 = Shadow Price for Long Island Spinning Reserve requirement constraint for the interval

Real-time locational Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price for each Operating Reserves 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 third RTD pass described in Section 17.1.1.1.2.3 of Attachment B to this ISO Services Tariff, and Section 16.1.1.1.2.3 of Attachment J to the ISO OATT. As a result, the Shadow Price for each Operating Reserves 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 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 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 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 then the Shadow Price for that Operating 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.

15.4.6.2 Calculation of Real-Time Market Clearing Prices for Operating Reserves During EDRP/SCR Activations

15.4.6.2.1 During Intervals When Scarcity Pricing Rule "A" Applies

During any interval in which the ISO is using scarcity pricing rule "A" to calculate LBMPs under Section 17.1.1.2 of Attachment B to this ISO Services Tariff, and Section 16.1.1.2 of Attachment J to the ISO OATT, the real-time market clearing prices for some Operating Reserves products may be recalculated by in light of the Lost Opportunity Costs of Resources that are scheduled to provide Spinning Reserves and synchronized 30-Minute Reserves in the manner described below. The ISO shall also consider the Lost Opportunity Costs of Resources providing lower quality Operating Reserves to ensure that the requirements of Section 15.4.4.3 of this Rate Schedule are not violated. Specifically:

The Eastern Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Spinning Reserve or synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.

The Eastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.

The Eastern 30-Minute Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.

The Western Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Western Spinning Reserve or Western synchronized 30- Minute Reserves that is scheduled by RTD; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.

The Western 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Western synchronized 30 Minute-Reserve that is scheduled by RTD; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.

The Western 30-Minute Reserve market clearing price shall be the higher of: i) the highest Lost Opportunity Cost of any provider of Western synchronized 30-Minute Reserve that is scheduled by RTD; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.

15.4.6.2.2 During Intervals When Scarcity Pricing Rule "B" Applies

During any interval in which the ISO is using scarcity pricing rule "B" to calculate LBMPs under Section 17.1.1.3 of Attachment B to this ISO Services Tariff, and Section 16.1.1.3 of Attachment J to the ISO OATT, the real-time market clearing prices for some Operating Reserves products may be recalculated in light of the Lost Opportunity Costs of Resources scheduled to provide Spinning Reserve and synchronized 30-Minute Reserve in order to satisfy Eastern Operating Reserve requirements in the manner described below. The ISO shall also consider the Lost Opportunity Costs of Resources providing lower quality Operating Reserves to ensure that the requirements of Section 15.4.4.3 of this Rate Schedule are not violated. Specifically:

The Eastern Spinning Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern Spinning Reserve or Eastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.

The Eastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.

The Eastern 30-Minute Reserve market clearing price shall be the higher of: (i) the highest Lost Opportunity Cost of any provider of Eastern synchronized 30-Minute Reserve that is scheduled by RTD and is not located on Long Island; and (ii) the original market clearing price calculated under Section 15.4.6.1 above.

Real-Time Market clearing prices for Western Reserve shall not be affected under scarcity pricing rule "B".

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; 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; 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, 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 schedule.

As is provided in Section 4.6.6 and Attachment C of this ISO Services Tariff, the ISO shall compensate each eligible Generator providing Operating Reserves if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Real-Time Market, including Minimum Generation Bid and Start-Up Bid costs exceeds the revenues it receives from the sale of Energy and Ancillary Services. Any Generator that provides Energy during a large event reserve pickup or a maximum generation event, as described in Sections 4.4.4.1.1 and 4.4.4.1.2 of this ISO Services Tariff shall be eligible for a Bid Production Cost guarantee payment calculated, under Attachment C, solely for the duration of the large event reserve pickup or maximum generation pickup. Such payments shall be excluded from the ISO's calculation of real-time Bid Production Cost guarantee payments otherwise payable to Suppliers on that Dispatch Day.

Finally, whenever a Supplier's real-time Operating Reserves schedule is reduced by the ISO to a level lower than its Day-Ahead schedule for that product, the Supplier's Day-Ahead Margin shall be protected after accounting for any margin associated with other products that the Resource is scheduled to provide in real-time for that time period. The rules governing the calculation of these Day-Ahead Margin Assurance Payments are set forth in Attachment J to this ISO Services Tariff.

15.4.7 Operating Reserve Demand Curves

The ISO shall establish nine Operating Reserve Demand Curves, one for each Operating Reserves requirement. Specifically, there shall be a demand curve for: (i) Total Spinning Reserves; (ii) Eastern or Long Island Spinning Reserves; (iii) Long Island Spinning Reserves; (iv) Total 10-Minute Non-Synchronized Reserves; (v) Eastern or Long Island 10-Minute Non-Synchronized Reserves; (vi) Long Island 10-Minute Non-Synchronized Reserves; (vii) Total 30-Minute Reserves; (viii) Eastern or Long Island 30-Minute Reserves; and (ix) Long Island 30-Minute Reserves. Each Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location.

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 or RTC 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 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. 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 requirement, the price on the total Spinning Reserves demand curve shall be $500/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be $0/MW.

(b) Eastern or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Eastern or Long Island Spinning Reserves requirement that are less than or equal to the target level for that requirement, the price on the Eastern or Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern or Long Island Spinning Reserves demand curve shall be $0/MW.

(c) 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 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.

(d) 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 requirement, the price on the total 10-minute reserves demand curve shall be $150/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be $0/MW.

(e) Eastern or Long Island 10-Minute Reserves. For quantities of Operating Reserves meeting the Eastern or Long Island 10-minute reserves requirement that are less than or equal to the target level for that requirement, the price on the Eastern or Long Island 10-minute reserves demand curve shall be $500/MW. For all other quantities, the price on the Eastern or Long Island 10-Minute Reserves demand curve shall be $0/MW.

(f) 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 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.

(g) 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 requirement minus 400 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 requirement minus 200 MW but that exceed the target level for that requirement minus 400 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 requirement but that exceed the target level for that requirement minus 200 MW, the price on the total 30-Minute Reserves demand curve shall be $50/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.

(h) Eastern or Long Island 30-Minute Reserves. For quantities of Operating Reserves meeting the Eastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that requirement, the price on the Eastern or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

(i) 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 requirement, the price on the Long Island 30-Minute Reserves demand curve shall be $300/MW. For all other quantities, the price on the Long Island 30-Minute Reserves 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.

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 Certain Charges For Black Start and System Restoration Services

This Rate Schedule applies to payments to Generators who provide Black Start and System Restoration Services to transmission facilities that are part of the ISO's Black Start and System Restoration plan ("the ISO Plan"); to payments to existing Generators of such services that are part of Transmission Owners' individual Black Start and System Restoration Services plans for their Transmission Districts; and to charges for such services that are allocated to Transmission Customers in the Consolidated Edison Company of New York, Inc.'s ("Consolidated Edison") Transmission District.

15.5.1 Requirements

The ISO shall develop and periodically review the ISO Plan. The ISO may amend the ISO Plan to account for changes in system configuration if the ISO determines that additional Black Start and System Restoration Services are needed. The ISO shall have the flexibility to seek bids for new resources when it amends the current ISO Plan. The ISO shall establish procedures for acquiring Black Start and System Restoration Services and testing selected Generators providing this service. The ISO shall make Black Start and System Restoration Services payments only to those selected Generators that have appropriate equipment installed and available for service at the request of the ISO.

The full restoration of the NYS Power System may require additional Black Start and System Restoration Services from Generators, which are located in local Transmission Owner areas and which are not presently listed in the ISO Plan. Although the ISO Plan will restore a major portion of the NYS Power System there are portions of the NYS Power System that will remain under Transmission Owner restoration control. Where the Transmission Owner's restoration plan requires additional Black Start and System Restoration Services, the ISO will make payments for such local services directly to the Generators that provide it, under the terms of this Rate Schedule. The LSEs in those local Transmission Owner areas will be additionally charged for those services by the ISO under the ISO OATT. Generators~~,~~ which are obligated to provide Black Start and System Restoration Services as a result of divestiture contract agreements will not receive ISO payments for those services if they are already compensated for such service as part of those divestiture contracts.

15.5.2 Payment to Generators Under the Black Start and System Restoration Services Plans Developed by the ISO and by Individual Transmission Owners Except for Existing Generators Under the Consolidated Edison Plan

By May 1st of each year, Generators which were selected to provide Black Start and System Restoration Services under the Black Start and System Restoration Services plans developed by the ISO and by individual Transmission Owners, except for existing Generators within the Consolidated Edison Transmission District, 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 Black Start and System Restoration Services capability;
- Annual costs associated with training operators in Black Start and System Restoration Services; and
- Annual costs associated with Black Start and System Restoration Services testing in accordance with the ISO Plan or the plan of an individual Transmission Owner.

Each Generator will be paid on the basis of its costs filed with the ISO. The daily rate for Black Start and System Restoration Services 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 Black Start and System Restoration Services shall conduct 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 Black Start and System Restoration Services payments and that fails a test shall forfeit all payments for such services since its last successful test. Payments to that Generator shall not resume until it successfully passes the test.

15.5.3 Payments to and Charges for Existing Generators Providing Black Start and System Restoration Services Under the Consolidated Edison Transmission District

Generators that are in-service as of October 1, 2005 and are listed in the Consolidated Edison Black Start and System Restoration Services plan filed with the ISO as of that date shall be paid for those services in accordance with Section 15.5.3.1 below. Charges to fund such payments shall be allocated among Transmission Customers in the Consolidated Edison Transmission District under Section 15.5.3.2 below. Generators that are in service as of October 1, 2005 and are listed in the Consolidated Edison Black Start and System Restoration Services plan are deemed to have satisfied testing requirements for the testing period that ends April 30, 2005.

15.5.3.1 Payments to Existing Generators Under the Consolidated Edison Plan

Existing Generators shall be eligible for Black Start and System Restoration Services payments, provided that they: (i) successfully test all necessary equipment in compliance with the Consolidated Edison testing criteria that are included in the ISO Procedures and provided that the testing criteria conform to Appendix I to this Rate Schedule; and (ii) commit to be available to provide these services for an initial minimum period of three years. At the end of the second year of the initial three year period a Generator, or Consolidated Edison, may give notice that the Generator will no longer be part of the Consolidated Edison Black Start and System Restoration Services plan, effective at the end of third year. For subsequent periods, each Generator, or Consolidated Edison, may give one year’s advance notice at the end of every subsequent two year-period, that the Generator will no longer be part of the Consolidated Edison plan, so that a rolling three-year commitment is maintained.

Eligible existing Generators in the Consolidated Edison Transmission District shall receive annual compensation for providing Black Start and System Restoration Services based on unit type and the level of their interconnection to the New York State Transmission System pursuant to the following table.

	Steam Turbine	**Gas Turbine**
345 kV	$350,000/yr/unit	$350,000/yr/site
138 kV	$300,000/yr/unit	$300,000/yr/site

These annual amounts will be paid to existing Generators in twelve equal monthly payments. The monthly payments shall also include compensation for legitimate, verifiable, and adequately documented operator training costs associated with readiness to provide Black Start Service and System Restoration Services, and for legitimate, verifiable, and adequately documented variable costs associated with annual tests of Black Start and System Restoration Services capability, that existing Generators invoice to the ISO, subject to the ISO's independent review.

Eligible existing Generators shall conduct annual Black Start and System Restoration Services capability tests and shall ensure that all relevant personnel are trained in black start and restoration operations. Detailed information about the tests and training standards shall be set forth in the ISO Procedures, which shall incorporate criteria developed by Consolidated Edison. The core features of the testing criteria are included in this ISO Services Tariff as Appendix I to this Rate Schedule and the ISO Procedures may not be revised in a manner that creates an inconsistency between them and Appendix I. Upon successful completion of a test, a Generator shall submit a certification form to the ISO in the form provided in Appendix II to this Rate Schedule. If a Generator fails a Black Start and System Restoration Services capability test, it shall be subject to a *pro rata* reduction in its annual payments based on the elapsed time between the unsuccessful test and a subsequent successful test.

The ISO shall also reimburse existing Generators for equipment damage that the ISO reasonably finds: (1) to have resulted from operating such equipment in response to operational orders from the ISO, or Consolidated Edison, pursuant to the ISO Services Tariff or the ISO OATT, (2) that reasonably available and customary insurance was not available for the damages incurred and (3) would not have occurred but for the Generator's provision of Black Start and System Restoration Services. Further, the ISO shall reimburse the owners of the Astoria Station steam units 3, 4 and 5 and Astoria Station gas turbines 4-3 and 4-4 for equipment upgrades that the ISO reasonably finds are needed to minimize the risk of equipment damage at the Astoria Station site in the Consolidated Edison Transmission District. The burden of making such showings will be upon the owners of the specified Generators. Any such reimbursement shall be made available for review by the Commission upon request by a Market Participant.

15.5.3.2 Charges to Support Payments to Existing Generators Under the Consolidated Edison Plan

The ISO shall collect, on a monthly basis, a charge from each Transmission Customer in the Consolidated Edison Transmission District in order to fund the payments described above in Section 15.5.3.1. The charge shall be equal to the product of (a) the Transmission Customer's hourly Load Ratio Share of Load in the Consolidated Edison Transmission District, and (b) the total payments for existing Black Start and System Restoration Services in that Transmission District under Section 15.5.3.1, divided by the total number of hours in the month.

15.5.3.3 Payments to New Generators that Provide Black Start and System Restoration Services in the Consolidated Edison Transmission District

New Generators that agree to provide Black Start and System Restoration Services within the Consolidated Edison Transmission District shall be treated as set forth in Section 15.5.2 above.

Rate Schedule 5. Appendix I
Core Features of Testing Criteria Black Start and Restoration Services Testing Requirements Consolidated Edison Transmission District

General

1. Testing shall be performed annually, consistent with Consolidated Edison Company of New York, Inc. ("Consolidated Edison") system operation requirements to qualify for Black Start and Restoration Services payments during the annual compensation period, which shall be May 1st through April 30th.
2. A test will be considered successful if it is completed in accordance with the written black start test procedures that have been adopted by the plant.

Scheduling a Test

1. The annual test period shall be November 1st to April 30^{th,} and may be reasonably extended by mutual agreement among the plant owner, Consolidated Edison and the ISO, without financial penalty.
2. The test date must be agreed upon by Consolidated Edison, the plant owner and the ISO.
3. An annual black start test may be performed prior to a maintenance outage only if there is no other scheduling option within the test period.

4 If the annual test is unable to be completed during the test period due to a forced outage or force majeure event, Consolidated Edison and the plant owner will conduct the test outside the test period without a *pro rata* reduction in annual payments.

5. If a black start test is not successful, the plant owner will have a reasonable opportunity to reschedule and conduct a subsequent test.

Gas Turbine Facility Testing Requirements

1. A qualifying test of a gas turbine must be conducted when the unit is in a cold condition, *i.e.*, the unit will be off line and will be brought on line specifically to conduct the black start tests.

2. The gas turbine-Generator units to be tested will be off line at the start of the test and will be isolated from all external Consolidated Edison light and power sources.

3. The black start test must demonstrate that (i) the designated black start unit can be started and can energize the isolated light and power bus; and (ii) that the light and power source is adequate for the purpose of bringing the other units on line. Part (ii) must be demonstrated by starting up an additional gas turbine from the light and power bus that has been energized through Part (i) of the test. Site specific appendices will be developed to reflect these general criteria.

4. Once isolated from Consolidated Edison's light and power, the gas turbine facility will have 90 minutes to ready the equipment and to request permission to synchronize the additional generating unit to a live bus on the Consolidated Edison transmission system. When authorized by the Consolidated Edison System Operator, the gas turbine-generator will be asked to close its breaker. Once the gas turbine-generator unit has synchronized and closed its breaker onto the transmission bus, the test will be considered successful.

5. A maximum of two (2) Consolidated Edison System Operations or Engineering personnel are allowed to be onsite to witness the test. At its discretion, the ISO may have its representatives onsite to witness the test. If an ISO representative is not onsite, a representative from Consolidated Edison and the plant owner will

initiate calls to ISO operations personnel to signal the start time, completion time and outcome of the test.

6. Upon successful completion of the test, the generator owner shall submit a certification form, the template of which shall be included in the ISO tariff, to the ISO and Consolidated Edison.

7. Consistent with past practice, plant owners will continue to test on a monthly basis their standby diesel generators, black start gas turbines and UPS/battery back up systems. If any of these critical systems are found to be non-operational or otherwise unavailable, the plant owner will notify Consolidated Edison and the ISO within 36 hours and provide a schedule for their repair and return to service.

Steam Turbine Facility Testing Requirements

1. A qualifying test of a steam turbine must be conducted while the unit is in a hot condition, *i.e.*, the unit must be on line and firm to the system prior to the test. The plant owner, the ISO and Consolidated Edison shall agree on a schedule for this test. The agreed upon test date shall be deemed firm as of 48 hours prior to the scheduled beginning of the test. A firm test may not be called off or deferred except (1) by the ISO, for system or local reliability reasons; or (2) if the unit is unable to be in hot condition because it was not selected by the ISO to run on the day prior to the test. As is the case for any ISO-approved outage, the plant owner shall not offer the unit into the Day Ahead Market for operation during the test the day, and such non-offering into the market shall be deemed not to diminish the unit's availability.

2. The steam unit will be required to start up using energy and voltage control from a gas turbine-generator to energize its internal light & power bus, and be ready to

synchronize to an energized transmission system when directed by the Consolidated Edison System Operator.

3. A test shall be considered successful if, after isolation from the Consolidated Edison transmission system, the hot steam unit is synchronized to the transmission system in no more than 6 hours after the completion of the isolation and is firm to the system and operating at minimum load in no more than 8 hours after the completion of the isolation.

4. A maximum of two (2) Consolidated Edison System Operations or Engineering personnel will be allowed onsite to witness the test. ISO representatives may be onsite to witness the test. If an ISO representative is not onsite, a representative from Consolidated Edison and the plant owner will initiate calls to ISO operations personnel to signal the start time, completion time and outcome of the test.

5. Upon successful completion of the test, Consolidated Edison shall SRE the unit until midnight of the test day or until the unit's reference minimum run time has elapsed, whichever is earlier.

6. Upon successful completion of the test, the generator owner shall submit a certification form, the template of which shall be included in the ISO Services Tariff, to the ISO and Consolidated Edison.

7. Consistent with past practice, plant owners will continue monthly tests of standby diesel generators; black start gas turbines and UPS/battery back up systems. If any of these critical systems are found to be non-operational or otherwise unavailable, the plant owner will notify Consolidated Edison and the ISO within 36 hours and provide a schedule for their repair and return to service.

Rate Schedule 5. Appendix II

[Name of Generator Owner] hereby certifies that the **[name/location of generation equipment]** successfully performed a Black Start and System Restoration Services test on **[date]** in accordance with the ISO Procedures. [Name of Generator Owner] further certifies that it identifies and maintains a list of critical components in its black start facilities (e.g., batteries, diesel back-up generators, inverters etc.) and has performed tests to verify the condition of these critical components in accordance with good industry 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 month a payment for each block of generator units that provided Quick Start Reserves in any hour of the previous month, unless the block of generator units also produced Energy during the hour. The amount of this payment shall equal:

$$\sum_h (C_h(0.85P_{10MNSR,h} + 0.15P_{30MR,h}) - Q_h P_{30MR,h})$$

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 (East) in the Day-Ahead Market
P_{30MR}	=	Price of 30-Minute Reserves (East) 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 month 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 monthly.

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 monthly.

15.7.2 Charges

The ISO shall assess the following wind forecasting charges monthly to each Wind Generator as of the effective date of these changes:

- $500.00 as a fixed fee and
- $7.50 / MW of name plate capacity

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 Method

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 either the Real-Time Dispatch program, or during intervals when it is activated, the RTD-CAM program (together "RTD"), 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 at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Availability 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 and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively 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 as determined by the ISO and capable of starting in ten minutes pursuant to Section 4.4.3.3 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 Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Sections 17.1.1.1.1-17.1.1.1.5 to calculate Real-Time LBMPs, the Marginal Losses Component, and the Congestion Component at each Load Zone and Generator bus. In addition, when certain conditions exist, as defined in the table below, the ISO shall employ the special scarcity pricing rules described in Sections 17.1.1.2 and 17.1.1.3. Procedures governing the calculation of LBMPs at External locations are set forth below in Section 17.1.5.

		SCR/EDRP NYCA Called and Needed	**SCR/EDRP East Called and Needed**	**Scarcity Pricing Rule to be Used in the West**	**Scarcity Pricing Rule to be Used in the East**
		NO	**NO**	**NONE**	**NONE**
			YES	**NONE**	**B**
		YES	**NO**	**A**	**A**
			YES	**A**	**A**

Where:

SCR/EDRP NYCA, Called and Needed	Is "YES" if the ISO has called SCR/EDRP resources and determined that, but for the Expected Load Reduction, the Available Reserves would have been less than the NYCA requirement for total 30-Minute Reserves; or is "NO" otherwise.
SCR/EDRP East, Called and Needed	Is "YES" if the ISO has called SCR/EDRP from resources located East of Central-East and determined that, but for the Expected Load Reduction, the Available Reserves located East of Central-East would have been less than the requirement for 10-Minute Reserves located East of Central-East; or is "NO" otherwise.
Pricing Rule West	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Load Zones located West of Central-East, including the Reference Bus.
Pricing Rule East	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Load Zones

	located East of Central-East.

17.1.1.1 General Procedures

17.1.1.1.1 Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes of each Real-Time Dispatch run, except as noted below in Section 17.1.1.1.3. A new Real-Time Dispatch run will begin every five minutes and each run will produce prices and schedules for five points in time. Only the prices and schedules determined for the first point in time of a Real-Time Dispatch run will be binding. Prices and schedules for the other four points in time shall be advisory only.

Each Real-Time Dispatch 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 point in time that it addresses. The first and second points of time in each Real-Time Dispatch run will be five minutes apart. The remaining points in time in each run 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 run 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.

17.1.1.1.2 Description of the Real-Time Dispatch Process

17.1.1.1.2.1 The First Pass

The first Real-Time Dispatch 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 run. 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 Real-Time Dispatch run at its specified response rate.

17.1.1.1.2.1.1 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 Resource's lower and upper dispatch limits. A 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 Real-Time Dispatch 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 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 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, or, to the extent that the ISO's software can support demand side participation, Demand Reduction level; 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 the extent that the ISO's software can support demand side participation, 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.

17.1.1.1.2.1.2 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 depending 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.

17.1.1.1.2.1.3. 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.

17.1.1.1.2.2 The Second Pass

The second Real-Time Dispatch 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. This pass shall establish "hybrid base points" (i.e., real-time Energy schedules) that are used in the third pass to determine whether minimum run-time constrained Fixed Block Units should be blocked on at their UOL_N or UOL_E, whichever is applicable, or dispatched flexibly. 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.

17.1.1.1.2.2.1 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 Real-Time Dispatch immediately prior to the previous Real-Time Dispatch minus the Resource's metered output level at the time that the current Real-Time Dispatch 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 Real-Time

Dispatch run was initialized minus the physical base point established during the first pass of the Real-Time Dispatch immediately prior to the previous Real-Time Dispatch; 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.

17.1.1.1.2.2.2 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.

17.1.1.1.2.3 The Third Pass

The third Real-Time Dispatch pass is the same as the second pass with three variations. First, the third pass treats Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO that received a non-zero physical base point in the first pass, and that received a hybrid base point of zero in the second pass, as blocked on at their UOL_N or UOL_E, whichever is applicable. Second, the third pass produces "pricing base points" instead of hybrid base points. Third, and finally, the third 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 shall not use schedules for Energy, Regulation Service and Operating Reserves that are established in the third pass to dispatch Resources.

17.1.1.1.3 Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 17.1.1.1.1 and 17.1.1.1.2 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 Regulation Service markets will be temporarily suspended 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 Real-Time Dispatch 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 Regulation Service markets will be temporarily suspended 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 Real-Time Dispatch 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 Real-Time Dispatch 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.

17.1.1.1.4 Calculating the Marginal Losses and Congestion Components

The Marginal Losses Component of the price at each location shall be calculated as the product of the price at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one (1).

The Congestion Component of the price at each location shall be calculated as the price at that location, minus the Marginal Losses Component of the price at that location, minus the price at the Reference Bus.

17.1.1.1.5 The Real-Time Commitment ("RTC") Process and Automated Mitigation

Attachment H to the 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 the ISO Services Tariff (as well as the corresponding provisions of Attachment J to the ISO OATT).

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 $RT\text{-}AMP_{15}$ will perform Resource commitment evaluations simultaneously. $RT\text{-}AMP_{15}$ 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).

17.1.1.2 Scarcity Pricing Rule "A"

The ISO shall implement the following price calculation procedures for intervals when scarcity pricing rule "A" is applicable.

17.1.1.2.1 Except as noted in 17.1.1.2.2 below:

- The LBMP at the Reference Bus shall be determined by dividing the lowest offer price at which the quantity of Special Case Resources offered is equal to $RREQ_{NYCA} – (RACT_{NYCA} – ELR_{NYCA})$, or \$500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{NYCA} – (RACT_{NYCA} – ELR_{NYCA})$, by the weighted average of the delivery factors produced by RTD that the ISO uses in its calculation of prices for Load Zone J in that RTD interval,

where:

- $RACT_{NYCA}$ equals the quantity of Available Reserves in the RTD interval;
- $RREQ_{NYCA}$ equals the 30-Minute Reserve requirement set by the ISO for the NYCA; and
- ELR_{NYCA} equals the Expected Load Reduction in the NYCA from the Emergency Demand Response Program and Special Case Resources in that RTD interval. The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one. The LBMP at each location shall be the sum of the Marginal Losses Component of the LBMP at that location, plus the LBMP at the Reference Bus.

- The Congestion Component of the LBMP at each location shall be set to zero.

17.1.1.2.2 However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section 17.1.1.1, above. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location pursuant to Section 17.1.1.1; or the LBMP calculated for that location using the scarcity pricing rule “A” procedures.

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one.

- The Congestion Component of the LBMP at each location shall be calculated as the LBMP at that location, minus the LBMP at the Reference Bus, minus the Marginal Losses Component of the LBMP at that location.

17.1.1.3 Scarcity Pricing Rule "B"

17.1.1.3.1 Except as noted in Pricing Rule 17.1.1.3.2 below:

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section 17.1.1.1) and a quantity equal to the delivery factor produced by RTD for that location minus one.

- The Congestion Component of the LBMP at each location shall be equal to the lowest offer price at which the quantity of Special Case Resources offered is equal to $RREQ_{East}$ – ($RACT_{East}$ – ELR_{East}), or $500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{East}$ – ($RACT_{East}$– ELR_{East}), minus the LBMP calculated for the Reference Bus (according to Section 17.1.1.1), minus the Marginal Losses Component of the LBMP for Load Zone J,

where:

- $RACT_{East}$ equals the quantity of Available Reserves located East of Central-East in that RTD interval;

- $RREQ_{East}$ equals the 10-Minute Reserve requirement set by the ISO for the portion of the NYCA located East of the Central-East interface; and

- ELR_{East} equals the Expected Load Reduction East of Central-East from the Emergency Demand Response Program and Special Case Resources in that RTD interval.

The LBMP at each location shall be the sum of the LBMP calculated for the Reference Bus (according to Section 17.1.1.1) and the Marginal Loss Component and the Congestion Component for that location.

17.1.1.3.2 However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section 17.1.1.1, above. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each such location shall be set to the LBMP calculated for that location pursuant to Section 17.1.1.1
- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section 17.1.1.1) and a quantity equal to the delivery factor produced by RTD for that location minus one.
- The Congestion Component of the LBMP at each such location shall be calculated as the LBMP at that location, minus the LBMP calculated for the Reference Bus (according to Section 17.1.1.1), minus the Marginal Losses Component of the LBMP at that location.

17.1.2 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 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 Security Constrained Unit Commitment 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 Security Constrained Unit Commitment 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, Importss, 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.

17.1.3 LBMP 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:

$$\gamma_i = \lambda^R + \gamma^L_i + \gamma^C_i$$

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 within the NYCA 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 = system 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:

$$\gamma_i = \lambda^R + (DF_i - 1)\lambda^R - \sum_{k \in K} GF_{ik}\,\mu_k$$

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.

17.1.4 Determination of Transmission Shortage Cost

The Transmission Shortage Cost represents the limit on system costs associated with efficient dispatch to meet a particular Constraint. It is the maximum Shadow Price that will be used in calculating LBMPs. The Transmission Shortage Cost is set at $4000 / MWh.

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 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 consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Attachment B to the Services Tariff are also addressed in Section 30.4.6.5.1 of the Market Monitoring Plan.

17.1.5 Zonal LBMP Calculation Method

The computation described above 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 zone. The Load weights which will sum to unity will be predetermined by the ISO. 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:

γ_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;

$\gamma_j^{C,Z} = \sum W_i \gamma_i^C$ 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 zonal LBMPs will be a weighted average of the Load bus LBMPs in the zone. The weightings will be predetermined by the ISO.

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 General Rules

External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. External Generators may arrange Bilateral Transactions with Internal or External Loads and External Loads may arrange 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 buses External to the NYCA. LBMPs will be calculated for each bus within this limited set. The three components of LBMP will be calculated from the results of RTD, or, except as set forth in Sections 17.1.6.2 and 17.1.6.3 below, in the case of a Proxy Generator Bus, from the results of RTC_{15} during periods in which (1) proposed economic transactions over the Interface between the NYCA and the Control Area with which that Proxy Generator Bus is associated would exceed the Available Transfer Capability for the Proxy Generator Bus or for that Interface, (2) 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, or (3) proposed interchange schedule changes pertaining to the Interface between the NYCA and the Control Area with which that Proxy Generator Bus is associated would exceed any Ramp Capacity limit imposed by the ISO for the Proxy Generator Bus or for that Interface.

17.1.6.2 Rules for Non-Competitive Proxy Generator Buses

Real-Time LBMPs for a Non-Competitive Proxy Generator Bus shall be determined as follows. When (i) proposed Real-Time Market economic net Import transactions into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located or would exceed the Available Transfer Capability of the Non-Competitive Proxy Generator Bus, or (ii) proposed interchange schedule changes pertaining to increases in Real-Time Market net imports into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the ISO for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located or would exceed the Ramp Capacity limit imposed by the ISO for the Non-Competitive Proxy Generator Bus, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the higher of (i) the RTC-determined price at that Non-Competitive Proxy Generator Bus or (ii) the lower of the LBMP determined by RTD for that Non-Competitive Proxy Generator Bus or zero.

When (i) proposed Real-Time Market economic net Export Transactions from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located or would exceed the Available Transfer Capability of the Non-Competitive Proxy Generator Bus, or (ii) proposed interchange schedule changes pertaining to increases in Real-Time Market net Exports from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the ISO for the Interface between the NYCA and the Control Area in which that Non-Competitive Proxy Generator Bus is located or would exceed the Ramp

Capacity limit imposed by the ISO for the Non-Competitive Proxy Generator Bus, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the lower of (i) the RTC-determined price at the Non-Competitive Proxy Generator Bus or (ii) the higher of the LBMP determined by RTD for the Non-Competitive Proxy Generator Bus or the Day-Ahead LBMP determined by SCUC for the Non-Competitive Proxy Generator Bus. At all other times, the Real-Time LBMP shall be calculated as specified in Section 17.1.6.1 above.

17.1.6.3 Special Pricing Rules for Scheduled Lines

Real-Time LBMPs for the Proxy Generator Buses associated with designated Scheduled Lines shall be determined as follows:

When proposed Real-Time Market economic net Import Transactions into the NYCA associated with a designated Scheduled Line would exceed the Available Transfer Capability of the designated Scheduled Line, the Real-Time LBMP at the Proxy Generator Bus associated with the designated Scheduled Line will be the higher of (i) the RTC-determined price at that Proxy Generator Bus or (ii) the lower of the LBMP determined by RTD for that Proxy Generator Bus or zero.

When proposed Real-Time Market economic net Export Transactions from the NYCA associated with a designated Scheduled Line would exceed the Available Transfer Capability of the designated Scheduled Line, the Real-Time LBMP at the Proxy Generator Bus associated with the designated Scheduled Line will be the lower of (i) the RTC-determined price at the Proxy Generator Bus or (ii) the higher of the LBMP determined by RTD for the Proxy Generator Bus or the Day-Ahead LBMP determined by SCUC for the Proxy Generator Bus. At all other times, the Real-Time LBMP shall be calculated as specified in Section 17.1.6.1 above.

The Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line are designated Scheduled Lines.

17.1.6.4 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 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 17.1.6.2 and 17.1.6.3, 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-Time LBMP = $\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$; and

Congestion Component of the Real-Time LBMP = - ($\text{Energy}_{\text{RTC REF BUS}}$ + $\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$).

When the Real-Time LBMP is set to the Day-Ahead LBMP:

Marginal Losses Component of the Real-Time LBMP = $\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$; and

Congestion Component of the Real-Time LBMP = Day-Ahead $\text{LBMP}_{\text{PROXY GENERATOR BUS}}$ - ($\text{Energy}_{\text{RTC REF BUS}}$ + $\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$).

where:

$\text{Energy}_{\text{RTC REF BUS}}$ = marginal Bid cost of providing Energy at the reference Bus, as calculated by RTC_{15} for the hour;

$\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$ = Marginal Losses Component of the LBMP as calculated by RTC_{15} at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line for the hour; and

Day-Ahead LBMP $_{\text{PROXY GENERATOR BUS}}$ = Day-Ahead LBMP as calculated by SCUC for the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line for the hour.

17.1.6.5 The Marginal Losses Component of LBMP at Proxy Generator Buses

The components of LBMP will be posted in the Day-Ahead and Real-Time Markets as described above, except that the Marginal Losses Component of LBMP will be calculated differently for Internal locations. The Marginal Losses Component of the LBMP at each bus, as described above, includes the difference between the marginal cost of losses at that bus and the Reference Bus. If this formulation were employed for an External bus, then the Marginal Losses Component would include the difference in the cost of Marginal Losses for a section of the transmission system External to the NYCA. Since the ISO will not charge for losses incurred Externally, the formulation will exclude these loss effects. To exclude these External loss effects, the Marginal Losses Component will be calculated from points on the boundary of the NYCA to the Reference Bus.

The Marginal Losses Component of the LBMP at the External bus will be a weighted average of the Marginal Losses Components of the LBMPs at the Interconnection Points. To derive the Marginal Losses Component of the LBMP at an External location, a Transaction will be assumed to be scheduled from the External bus to the Reference Bus. The Shift Factors for this Transaction on the tie lines into these Interconnection buses, which measure the per-unit effect of flows over each of those tie lines that results from the hypothetical transaction, will provide the weights for this calculation. Since all the power from this assumed Transaction crosses the NYCA boundary, the sum of these weights is unity.

The sum of the products of these Shift Factors and the Marginal Losses Component of the LBMP at each of these Interconnection buses yields the Marginal Losses Component of the

LBMP that will be used for the External bus. Therefore, the Marginal Losses Component of the LBMP at an External bus E is calculated using the equation:

$$\gamma_E^L = \sum_{b \in I} F_{Eb}(DF_b - 1)\lambda^R$$

where:

γ_E^L	=	Marginal Losses Component of the LBMP at an External bus E;
F_{Eb}	=	Shift Factor for the tie line going through bus b, computed for a hypothetical Bilateral Transaction from bus E to the Reference Bus;
$(DF_b - 1)\lambda^R$	=	Marginal Losses Component of the LBMP at bus b; and
I	=	The set of Interconnection buses between the NYCA and adjacent Control Areas.

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, Scheduling and Curtailment

17.3.1 Pre-Scheduled Transaction Requests

Pre-Scheduled Transaction Requests shall include the following information that shall be submitted to the ISO no earlier than eighteen (18) months prior to the Dispatch Day:

1) Point of Injection location;

2) Point of Withdrawal location;

3) Desired Dispatch Days;

4) Hourly MW schedules;

5) Other data as required by the ISO.

Pre-Scheduled Transaction Requests accepted for scheduling may be withdrawn only with the approval of the ISO, pursuant to ISO Procedures.

17.3.2 Requests for Bilateral Transaction Schedules

Transmission Customers scheduling Transmission Service or to support a Bilateral Transaction with Energy supplied by an External Generator or Internal Generator shall submit the following information to the ISO:

17.3.2.1 Point of Injection location. For Transactions with Internal sources, the Point of Injection is the LBMP 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; however, based upon such an advance notification to the ISO, an External Supplier will have the additional option of being modeled at a specific External LBMP bus (rather than an External Proxy Generator Bus) and being able to submit a bid curve. Otherwise, an External Supplier with Incremental or Decremental Bids at an External Proxy Generator Bus will be modeled as a single point price curve at that bus. An LBMP bus is a specific bus at which a Generator Shift Factor has been calculated, and for which LBMP will be calculated.

17.3.2.2 Point of Withdrawal location. For Internal Load, the Point of Withdrawal is the Load Zone in which the Load is situated or the bus at which that Load is interconnected to the Transmission System, if there is a revenue-quality real-time meter located at that bus (software constraints may initially limit the ability to specify buses as Points of Withdrawal); for delivery points outside the NYCA, the Point of Withdrawal is the Proxy Generator Bus; for Transactions with Trading Hubs as their sinks, the Point of Withdrawal is the Trading Hub Load bus;

17.3.2.3 Hourly MW schedules;

17.3.2.4 Minimum run times for Firm Point to Point Transmission Service, if any;

17.3.2.5 Whether Firm or Non-Firm Transmission Service is requested,

17.3.2.6 NERC Transaction Priorities for Bilateral Transactions involving External Generators, Exports, and Wheels Through;

17.3.2.7 A Sink Price Cap Bid for Export transactions up to the MW level of the desired schedule, a Decremental Bid for Import and Wheels Through transactions up to the MW level of the desired schedule provided however that Sink Price Cap Bids and Decremental Bids shall be subject to the following limitations. Day-Ahead Bids for (a) Imports, and Wheels Through at the Proxy Generator Bus designated as the source of the Transaction, shall be priced no lower than the Bid that provides the highest scheduling priority for sales to the LBMP Market plus the product of (i) the Scheduling Differential and (ii) three; and (b) Exports shall be priced no higher than the Bid that provides the highest scheduling priority for purchases from the LBMP Market minus the product of (i) the Scheduling Differential and (ii) three. Real-Time Bids submitted for evaluation in RTC_{15} for

(a) Imports, and Wheels Through at the Proxy Generator Bus designated as the source of the Transaction, shall be priced no lower than the Bid that provides the highest scheduling priority for sales to the LBMP Market plus the product of (i) the Scheduling Differential and (ii) three; and (b) Exports shall be priced no higher than the Bid that provides the highest scheduling priority for purchases to the LBMP Market minus the product of (i) the Scheduling Differential and (ii) three;

17.3.2.8 For an Internal Generator, whether the Generator is On-Dispatch or Off-Dispatch;

17.3.2.9 The amount and location of any Ancillary Services the Transmission Customer will Self-Supply in accordance with and to the extent permitted by each of the Rate Schedules under the ISO OATT; and

17.3.2.10 Other data required by the ISO.

17.3.3 Pre-Scheduled Transaction Requests and Bilateral Transaction Scheduling

17.3.3.1 ISO's General Responsibilities

Pre-Scheduled Transaction Requests shall be submitted, pursuant to ISO Procedures, no earlier than eighteen (18) months prior to the Dispatch Day, and shall include hourly transaction quantities (in MW) at each affected by External Interface for each specified Dispatch Day. Customers may submit Pre-Scheduled Transaction Requests for scheduling in the Day-Ahead Market.

The ISO shall determine, pursuant to ISO Procedures, the amount of Total Transfer Capability at each External Interface to be made available for scheduling. The ISO shall evaluate Pre-Scheduled Transaction Requests submitted in the order in which they are submitted for evaluation until the Pre-Scheduled Transaction Request expires, pursuant to ISO Procedures, prior to the close of the Day-Ahead Market for the specified Dispatch Day. Modification of a Pre-Scheduled Transaction request shall constitute a withdrawal of the original request and a submission of a new Pre-Scheduled Transaction Request. At the request of a Customer, the ISO shall continue to evaluate a Pre-Scheduled Transaction Request that was not accepted for scheduling in the priority order in which the Request was originally submitted until it is either accepted for scheduling, is withdrawn or expires, pursuant to ISO Procedures, prior to the close of the Day-Ahead Market for the Specified Dispatch Day. The ISO shall accept Pre-Scheduled Transaction Requests for scheduling, pursuant to ISO Procedures, provided that there is Ramp Capacity, and Transfer Capability available at each affected External Interface, in the NYCA for each hour requested.

If Ramp Capacity or Transfer Capability, on the designated External Interface, is unavailable in the NYCA for any hour of the Pre-Scheduled Transaction Request, the request shall not be scheduled. The ISO shall confirm the Transaction with affected Control Areas, as necessary, pursuant to ISO Procedures and may condition acceptance for scheduling on such confirmation.

The ISO shall provide the requesting Customer with notice, as soon as is practically possible, as to whether the Pre-Scheduled Transaction Request is accepted for scheduling and, if it is not scheduled, the ISO shall provide the reason.

The ISO shall reserve Ramp Capacity, and Transfer Capability on affected Interfaces, for each Pre-Scheduled Transaction. Pre-Scheduled Transactions shall be automatically submitted for scheduling in the appropriate LBMP Market for the designated Dispatch Day. The ISO shall evaluate requests to withdraw Pre-Scheduled Transactions pursuant to ISO Procedures.

Pre-Scheduled Transactions for Wheels Through in the Day-Ahead Market shall be assigned a Decremental Bid at the Proxy Generator Bus designated as the source of the Transaction that provides the highest scheduling priority available for Firm Transmission

Service. The ISO shall evaluate requests for Transmission Service submitted in the Day-Ahead scheduling process using SCUC, and will subsequently establish a Day-Ahead schedule. During the Dispatch Day, the ISO shall use RTC_{15} to establish schedules for each hour of dispatch in that day.

The ISO shall use the information provided by RTC when making Curtailment decisions pursuant to the Curtailment rules described in this Attachment B.

17.3.3.2 Use of Decremental Bids to Dispatch Internal Generators

When dispatching Generators taking service under the ISO OATT to match changing conditions, the ISO shall treat Decremental Bids and Incremental Energy Bids simultaneously and identically as follows: (i) a generating facility selling Energy in the

LBMP Market may be dispatched downward if the LBMP at the Point of Receipt falls below the generating facility's Incremental Energy Bid; (ii) a Generator serving a Transaction scheduled under the ISO OATT may be dispatched downward if the LBMP at the Generator's Point of Receipt falls below the Decremental Bid for the Generator; (iii) a Supplier's Generator may be dispatched upward if the LBMP at the Generator's Point of Receipt rises above the Decremental or Incremental Energy Bid for the Generator regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a Transaction scheduled under the ISO OATT.

17.3.3.3 Scheduling of Bilateral Transactions

Transmission Service for Bilateral Transactions shall be scheduled as follows:

(i) The ISO shall, following evaluation of the Bids submitted, schedule Transmission Service to support Transactions for the hours in which those Transactions may be accommodated.

(ii) The ISO shall treat all Internal Generators as dispatchable and all External Generators as non-dispatchable.

(iii) The ISO will use SCUC and RTD to determine schedules for Internal Generators and schedules for DNI with other Control Areas so that Firm Transmission Service will be provided to any Bilateral Transaction Customer requesting Firm Transmission Service to the extent that is physically feasible.

(iv) The ISO shall not schedule Non-Firm Transmission Service Day-Ahead for a Transaction if Congestion Rents associated with that Transaction are positive, nor will the ISO schedule Non-Firm Transmission Service in the RTC if Congestion Rents associated with that Transaction are expected to be positive. All schedules for Non-Firm Point-to-Point Transmission Service are advisory only and are subject to Reduction if real-time Congestion Rents associated with those Transactions become positive. Transmission Customers receiving Non-Firm Transmission Service will be required to pay Congestion Rents during any delay in the implementation of Reduction (e.g., during the nominal five-minute RTD intervals that elapse before the implementation of Reduction).

17.3.3.4 Day-Ahead Bilateral Transaction Schedules

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 and Network Integration Transmission Service schedules, Load forecasts, and submitted Incremental Energy Bids, Decremental Bids and Sink Price Cap Bids.

In the Day-Ahead schedule, the ISO shall use the SCUC to determine Generator schedules, Transmission Service schedules and DNIs with adjacent Control Areas. The ISO shall not use Decremental Bids submitted by Transmission Customers for Generators associated with Non-Firm Point-to-Point Transmission Service in the determination of the Day-Ahead schedule.

17.3.3.5 Reduction and Curtailment

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, the ISO shall not reduce the Transmission Service.

If the Transaction was scheduled in the Day-Ahead Market, and the Day-Ahead Schedule for the Generator designated as the Supplier of Energy for that Bilateral Transaction called for that Generator to produce less Energy than was scheduled Day-Ahead to be consumed in association with that Transaction, the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Day-Ahead LBMP Market.

The Transmission Customer shall continue to pay the Day-Ahead TUC and, in addition, if it takes service under this Tariff, the Supplier of Energy for the Bilateral Transaction shall pay the Day-Ahead LBMP price, at the Point of Receipt for the Transaction, for the replacement amount of Energy (in MWh) purchased in the LBMP Market. If the Supplier of Energy for the Bilateral Transaction does not take service under this Tariff, it shall pay the greater of 150 percent of the Day-Ahead LBMP at the Point of Receipt for the Transaction or $ 100/MWh for the replacement amount of energy, as specified in the OATT. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with the Transaction was located inside or outside the NYCA.

If the Transaction was scheduled following the Day-Ahead Market, or the schedule for the Transaction was revised following the Day-Ahead Market, then the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Real-Time LBMP Market, at the Real-Time LBMP, if necessary, if (1) the Generator designated to supply the Transaction is an Internal Generator, and it has been dispatched to produce less than the amount of Energy that is scheduled hour-ahead to be consumed in association with that Transaction; or (2) the Generator designated to supply the Transaction is an External Generator, and the amount of Energy it has been scheduled an hour ahead to produce (modified for within-hour changes in DNI, if any) is less than the amount of Energy scheduled hour-ahead to be consumed in association with that Transaction; then the Transmission Customer shall pay the Real-Time TUC for the amount of Energy withdrawn in real time in association with that Transaction minus the amount of Energy scheduled Day-Ahead to be withdrawn in association with that Transaction. In addition, to the extent that it has not purchased sufficient replacement Energy in the Day-Ahead Market, the Supplier of Energy for the Bilateral Transaction, if it takes service under this Tariff, shall pay the Real-Time LBMP price, at the Point of Injection for the Transaction, for any additional replacement Energy (in MWh) necessary to serve the Load. If the Supplier of Energy for the Bilateral Transaction does not take service under this Tariff, it shall pay the greater of 150 percent of the Real-Time LBMP at the Point of Injection for the Transaction or $100/MWh for the replacement amount of Energy, as specified in the OATT. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with that Transaction was located inside or outside the NYCA. Notwithstanding the foregoing, the amount of Transmission Service scheduled hour-ahead in the RTC for Transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each RTD interval:

(i) 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;

(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 499 MW of such units; and

(iii) Existing intermittent (i.e., non-schedulable) renewable resource Generators in operation on or before November 18, 1999 within the NYCA, plus up to an additional 1000 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. If the Energy injections scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier or Transmission Customer whose transaction is Curtailed, in addition to paying the charge for replacement Energy necessary to serve the Load and the charge to balance the TUC, as appropriate, shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of the Real-Time Bid price and zero; and (b) the scheduled Energy injection minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour.

If the Transmission Customer was receiving Non-Firm Point-to-Point Transmission Service, and its Transmission Service was Reduced or Curtailed, the replacement Energy may be purchased in the Real-Time LBMP Market, at the Real-Time LBMP, by the Internal Load. An Internal Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed may sell its excess Energy in the Real-Time LBMP Market.

The ISO shall not automatically reinstate Non-Firm Point-to-Point Transmission Service that was Reduced or Curtailed. Transmission Customers may submit new schedules to restore the Non-Firm Point-to-Point Transmission Service in the next RTC_{15} execution.

If a security violation occurs or is anticipated to occur, the ISO shall attempt to relieve the violation using the following procedures:

(i) Reduce Non-Firm Point-to-Point Transmission Service: Partially or fully physically Curtail External Non-Firm Transmission Service (Imports, Exports and Wheels-Through) by changing DNI schedules to (1) Curtail those in the lowest NERC priority categories first; (2) Curtail within each NERC priority category based on Incremental Energy Bids, Decremental Bids, or Sink Price Cap Bids; and (3) prorate Curtailment of equal cost transactions within a priority category.

(ii) Curtail Non-Firm Point-to-Point Transmission Service: Curtail (through changing DNI) unscheduled Non-Firm Transactions which contribute to the violation, starting with the lowest NERC priority category.

(iii) Dispatch Internal Generators, based on Incremental Energy Bids and Decremental Bids, including committing additional resources, if necessary;

(iv) Adjust the DNI associated with Transactions supplied by External resources: Curtail External Firm Transactions until the Constraint is relieved by (1) Curtailing based on Incremental Energy Bids, Decremental Bids or Sink Price Cap Bids, and (2) except for External Transactions with minimum run times, prorating Curtailment of equal cost transactions;

(v) 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 the one percent minimum ramp rate set forth in Article 4 of the ISO Services Tariff, nor will they be required to respond to RTD Base Point Signals;

(vi) In overgeneration conditions, decommit Internal Generators based on Minimum Generation Bid rate in descending order; and

(vii) Invoke other emergency procedures including involuntary Load Curtailment, if necessary.

17.3.3.6 Scheduling Transmission Service for External Transactions

The amount of Firm Transmission Service scheduled Day-Ahead for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions Day-Ahead. The amount of Firm Transmission Service scheduled in the RTC_{15} for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions in RTC_{15}. 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. Additionally, any Curtailment or Reductions of schedules for Export Transactions will cause the scheduled amount of Transmission Service to change.

To the extent possible, Curtailments of External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT 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, or the Linden VFT Scheduled Line (as appropriate).

The ISO shall use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy those Generators are scheduled Day-Ahead to produce in each hour. This in turn will determine the Firm Transmission Service scheduled Day-Ahead to support those Transactions. The ISO shall also use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy these Generators are scheduled to produce in RTC_{15}, which, in turn, will determine the Transmission Service scheduled in RTC_{15} to support those Transactions.

The ISO will not schedule a Bilateral Transaction which crosses an Interface between the NYCA and a neighboring Control Area if doing so would cause the DNI to exceed the Transfer Capability of that Interface.

The ISO shall not permit Market Participants to schedule External Transactions over the following eight 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.

External Transactions at the Proxy Generator Buses that are associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line shall also be governed by Attachment N to the ISO Services Tariff.

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

17.5.1 Overview and Definitions

17.5.1.1 Overview

This Part 17.5 of this Attachment B 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 Part 17.5 of this Attachment B.

Section 17.5.2 addresses the Congestion settlements related to each hour of the Day-Ahead Market. These settlements include, as applicable pursuant to this Part 17.5 of this Attachment B, 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 Part 17.5 of this Attachment B, 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 Part 17.5 of this Attachment B.

Section 17.5.3 addresses the settlements in each round of each Centralized TCC Auction and in each Reconfiguration Auction. These settlements include, as applicable pursuant to this Part 17.5 of this Attachment B, 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 Part 17.5 of this Attachment B, 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 Part 17.5 of this Attachment B.

Provisions of this Part 17.5 of this Attachment B 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 Part 17.5 of this Attachment B shall be made to a Transmission Owner for a transmission facility derating or uprating only as specified in Sections 17.5.2.4.3 and 17.5.3.6.3.

17.5.1.2 Defined Terms Used in Part 17.5 of this Attachment B

Capitalized terms used in this Part 17.5 of this Attachment B shall have the meaning specified below in this Section 17.5.1.2, and capitalized terms used in this Part 17.5 of this Attachment B but not defined below shall have the meaning given to them in Section 2 of the Services Tariff:

Actual Qualifying Auction Derating: As defined in Section 17.5.3.6.3.1.

Actual Qualifying Auction Outage: As defined in Section 17.5.3.6.2.1.

Actual Qualifying Auction Return-to-Service: As defined in Section 17.5.3.6.2.1.

Actual Qualifying Auction Uprating: As defined in Section 17.5.3.6.3.1.

Actual Qualifying DAM Derating: As defined in Section 17.5.2.4.3.1.

Actual Qualifying DAM Outage: As defined in Section 17.5.2.4.2.1.

Actual Qualifying DAM Return-to-Service: As defined in Section 17.5.2.4.2.1.

Actual Qualifying DAM Uprating: As defined in Section 17.5.2.4.3.1.

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 17.5.2.4.1.

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 17.5.3.6.3.1.

Deemed Qualifying Auction Outage: As defined in Section 17.5.3.6.2.1.

Deemed Qualifying Auction Return-to-Service: As defined in Section 17.5.3.6.2.1.

Deemed Qualifying Auction Uprating: As defined in Section 17.5.3.6.3.1.

Deemed ISO-Directed Auction Status Change: Any of the following: (1) an Actual Qualifying Auction Return-to-Service for a Reconfiguration Auction that occurs for a transmission facility that, in the last 6-month sub-auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction, was a Qualifying Auction Outage that qualified as an ISO-Directed Auction Status Change; (2) an Actual Qualifying Auction Uprating for 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 6-month sub-auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction, 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 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 6-month sub-auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction, 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, in the last Reconfiguration Auction held for TCCs valid for the relevant hour or 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, in the last Reconfiguration Auction held for TCCs valid for the relevant hour or 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, in the last Reconfiguration Auction held for TCCs valid for the relevant hour or 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 17.5.1.2, have the meaning given in the ISO's March 17, 2006, filing.)

Deemed Qualifying DAM Derating: As defined in Section 17.5.2.4.3.1.

Deemed Qualifying DAM Outage: As defined in Section 17.5.2.4.2.1.

Deemed Qualifying DAM Return-to-Service: As defined in Section 17.5.2.4.2.1.

Deemed Qualifying DAM Uprating: As defined in Section 17.5.2.4.3.1.

ISO-Directed Auction Status Change: Either of the following: (1) an Actual Qualifying Auction Outage for 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 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 17.5.3.6.1.

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 17.5.3.6.2.

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 17.5.3.6.2.

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 17.5.2.4.2.

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 17.5.2.4.2.

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 17.5.2.4.1.

Qualifying Auction Derating: As defined in Section 17.5.3.6.3.1.

Qualifying Auction Outage: As defined in Section 17.5.3.6.2.1.

Qualifying Auction Return-to-Service: As defined in Section 17.5.3.6.2.1.

Qualifying Auction Uprating: As defined in Section 17.53.6.3.1.

Qualifying DAM Derating: As defined in Section 17.5.2.4.3.1.

Qualifying DAM Outage: As defined in Section 17.5.2.4.2.1.

Qualifying DAM Return-to-Service: As defined in Section 17.5.2.4.2.1.

Qualifying DAM Uprating: As defined in Section 17.5.2.4.3.1.

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 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 17.5.3.6.1.

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 17.5.3.6.3.

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 17.5.3.6.3.

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 17.5.2.4.3.

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 17.5.2.4.3.

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 17.5.2.4.1.

For purposes of this Part 17.5 of this Attachment B, the term "transmission facility" shall mean any transmission line, phase angle regulator, transformer, series reactor, circuit breaker, or other type of transmission equipment.

All references in this Part 17.5 of this Attachment B to sections shall be construed to be references to a section of this Part 17.5 of this Attachment B.

17.5.2 Congestion Settlements Related to the Day-Ahead Market

17.5.2.1 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 Part 17.5 of this Attachment B: (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 B-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 B-1.

Formula B-1

$$\text{NetCongestionRents}_h = \begin{pmatrix} \text{Congestion Rents}_h \\ -\ \text{TCC Payments}_h \\ -\ \text{O/R-t-S\&U/D CRSC\&CRSP}_h \end{pmatrix}$$

Where,

Net Congestion Rents$_h$	=	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 17.5.2.2
TCC Payments$_h$	=	The sum for all TCCs of all payments and charges made pursuant to Section 17.5.2.3 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 B-14), reduced by any zeroing out of such charges or payments pursuant to Section 17.5.2.4.5

The ISO shall allocate the Net Congestion Rents calculated in each hour to Transmission Owners pursuant to Section 17.5.2.5.

17.5.2.2 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 Part 17.1 of this Attachment B. The total Congestion Rents for all Energy Transactions scheduled in the Day-Ahead Market in hour *h* are calculated pursuant to Formula B-2.

<u>Formula B-2</u>

$$\sum_{W} MWh_{W,h} * CCPOW_{W,h} - \sum_{I} MWh_{I,h} * CCPOI_{I,h}$$

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 the OATT. Total Congestion Rents for all Bilateral

Transactions scheduled in the Day-Ahead Market in hour *h* are calculated pursuant to Formula B-3.

Formula B-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*.

17.5.2.3 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 B-4

Congestion Payment (\$/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 Part 17.1 of this Attachment B 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 17.5.2.5.

The ISO shall assess a "Shortfall Reimbursement Surcharge" each month on monthly net positive Congestion payments to Primary Holders of TCCs sold in or after the Autumn 2004 Centralized TCC Auction. The Shortfall Reimbursement Surcharge shall be 0.5% of Congestion payments associated with TCCs that have a Point of Withdrawal outside of Load Zone J and 2.5% of Congestion payments associated with TCCs that have a Point of Withdrawal at, or inside of, Load Zone J.

The Shortfall Reimbursement Surcharge shall not be assessed on Congestion payments to Primary Holders of TCCs that produce net negative Congestion payments, *i.e.*, that oblige the Primary Holder to make payments, in a given month, on Congestion payments to Primary Holders of Grandfathered TCCs, or on Congestion payments to Primary Holders of ETCNL TCCs or RCRR TCCs. The Shortfall Reimbursement Surcharge also shall not be assessed on Congestion payments to Primary Holders of TCCs sold before the Autumn 2004 Centralized TCC Auction, except to the extent that such TCCs are unbundled or reconfigured at the request of a Primary Holder, and sold, in or after that auction, in which case the Congestion payments associated with them shall be subject to the Shortfall Reimbursement Surcharge.

The ISO shall cease to impose the Shortfall Reimbursement Surcharge when it has collected sufficient funds to: (i) pay refunds for all of the "Historic Shortfall" plus interest pursuant to Article III of the July 13, 2004 Settlement Agreement that was approved by the Commission in Docket Nos. EL04-110, EL04-113, EL04-115, and ER04-983; and (ii) replenished the ISO Working Capital Fund pursuant to Article IV of that Settlement Agreement.

17.5.2.4 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 17.5.2.4. 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 17.5.2.4.1. 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 17.5.2.4.2 and 17.5.2.4.4, each of which shall be subject to being reduced to zero pursuant to Section 17.5.2.4.5. 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 17.5.2.4.3 and 17.5.2.4.4, each of which shall be subject to being reduced to zero pursuant to Section 17.5.2.4.5.

17.5.2.4.1 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 B-5; *provided, however,* where $DCR_{a,h}$ calculated using Formula B-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 B-5

$$DCR_{a,h} = Shadow\ Price_{a,h} * \left[\begin{array}{l} FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction} \\ + \ UprateDerate_{a,h} * SCUCSignChange_{a,h} \\ + \ UnsoldCapacity_{a,h,RA} * SCUCSignChange_{a,h} \end{array} \right]$$

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[24] to the set of TCCs and Grandfathered Rights represented 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 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 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 in the most recent auction in which TCCs valid in hour *h* were

[24] 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.

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* 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 to the set of TCCs and Grandfathered Rights represented 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 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 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* 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 to the set of TCCs and Grandfathered Rights represented 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 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 in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the 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), $UprateDerate_{a,h}$ 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 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 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 in TCC auctions; 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 B-6. The amount of each U/D DAM Constraint Residual for hour *h* and for constraint *a* shall be determined by applying Formula B-7.

Formula B-6

$$\text{O/R-t-S DCR}_{a,h} = \text{DCR}_{a,h} * \left[\frac{\text{FLOW}_{a,h,DAM} - \text{FLOW}_{a,h,TCCAuction}}{\text{FLOW}_{a,h,DAM} - \text{FLOW}_{a,h,TCCAuction} + \text{UprateDerate}_{a,h} * \text{SCUCSignChange}_{a,h}} \right]$$

Where,

$\text{O/R-t-S DCR}_{a,h}$ = 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 B-5.

Formula B-7

$$\text{U/D DCR}_{a,h} = \text{DCR}_{a,h} * \left[\frac{\text{UprateDerate}_{a,h} * \text{SCUCSignChange}_{a,h}}{\text{FLOW}_{a,h,DAM} - \text{FLOW}_{a,h,TCCAuction} + \text{UprateDerate}_{a,h} * \text{SCUCSignChange}_{a,h}} \right]$$

Where,

$\text{U/D DCR}_{a,h}$ = 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 B-5.

17.5.2.4.2 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 17.5.2.4.2. 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 17.5.2.4.2 is subject to being set equal to zero pursuant to Section 17.5.2.4.5.

17.5.2.4.2.1 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 17.5.2.4.4, 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 17.5.2.4.2.2 or 17.5.2.4.2.3.

17.5.2.4.2.1.1 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 Part 17.5 of this Attachment B, "*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 in the last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment 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 last auction held for TCCs valid for hour *h*;

(ii) the facility existed but was not modeled as in-service in hour *h* as a result of a DAM Status Change or external event described in Section 17.5.2.4.4.3 for which responsibility was assigned pursuant to Section 17.5.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 17.5.2.4.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service for the last auction held for TCCs valid for hour *h*;

(iii) the facility was not Normally Out-of-Service Equipment 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.

17.5.2.4.2.1.2 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 Part 17.5 of this Attachment B, "*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 last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment 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 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 17.5.2.4.4.3 for which responsibility is assigned pursuant to Section 17.5.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 17.5.2.4.4) other than the Transmission

Owner assigned responsibility for the facility not being modeled as in-service for the last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last auction held for TCCs valid for hour *h*.

17.5.2.4.2.2 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 17.5.2.4.2.2 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 17.5.2.4.4, 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 17.5.2.4.4, 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.

17.5.2.4.2.3 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 17.5.2.4.2.3 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 17.5.2.4.4, 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 17.5.2.4.4, 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 B-8, and then applying either Formula B-9 or Formula B-10, as specified herein, to assess O/R-t-S Congestion Rent Shortfall Charges and O/R-t-S Congestion Rent Surplus Payments.

Formula B-8

$$\text{O/R-t-S NetDAMImpact}_{a,h} = \left(\sum_{\text{for all } o \in O_h} \text{FlowImpact}_{a,h,o} * \text{ShadowPrice}_{a,h} \right) * \text{OPF/SCUCAdjust}_a$$

Where,

O/R-t-S $\text{NetDAMImpact}_{a,h}$ = 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 $\text{NetDAMImpact}_{a,h}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula B-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 FlowImpacta,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,

$BaseCaseFlow_{a,h}$ = The Energy flow on binding constraint *a* resulting from a Power Flow or similar analysis using (1) the set of injections and withdrawals corresponding to the TCCs and Grandfathered Rights represented 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 schedule determined in the Optimal Power Flow solution for the final round of the last auction held for TCCs valid in hour *h*; and (3) the Transmission System model for the last auction held for TCCs valid in hour *h*;

$One\text{-}OffFlow_{a,h,o}$ = 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 $BaseCaseFlow_{a,h}$ 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 schedule 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 $BaseCaseFlow_{a,h}$ 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 schedule 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 $FlowImpact_{a,h,o}$ calculated using the procedures set forth above is less than 1 MWh, then $FlowImpact_{a,h,o}$ shall be set equal to zero; *provided further*, $FlowImpact_{a,h,o}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula B-8

O_h = The set of all Qualifying DAM Outages *o* and Qualifying DAM Returns-to-Service *o* in hour *h*

and the variables $ShadowPrice_{a,h}$ and $OPF/SCUCAdjust_a$ are defined as set forth in Formula B-5.

After calculating O/R-t-S $NetDAMImpact_{a,h}$ pursuant to Formula B-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 B-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 B-9 or Formula B-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 B-8 (or recalculated pursuant to Formula B-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 B-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 B-8 (or recalculated pursuant to Formula B-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 B-10.

Formula B-9

$$\text{O/R-t-S Allocation}_{a,t,h} = \left(\frac{\sum\limits_{\substack{o \in O_h \\ \text{and } q=t}} \text{FlowImpact}_{a,h,o} * \text{Responsibility}_{h,q,o}}{\sum\limits_{\text{for all } o \in O_h} \text{FlowImpact}_{a,h,o}} \right) * \text{O/R-t-S DCR}_{a,h}$$

Where,

O/R-t-S $\text{Allocation}_{a,t,h}$ = 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 $\text{Allocation}_{a,t,h}$ is negative, then O/R-t-S $\text{Allocation}_{a,t,h}$ shall be an O/R-t-S Congestion Rent Shortfall Charge, O/R-t-S $\text{CRSC}_{a,t,h}$, charged to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market; or

(b) If O/R-t-S $\text{Allocation}_{a,t,h}$ is positive, then O/R-t-S $\text{Allocation}_{a,t,h}$ shall be an O/R-t-S Congestion Rent Surplus Payment, O/R-t-S $\text{CRSP}_{a,t,h}$, paid to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market

$\text{Responsibility}_{h,q,o}$ = 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 17.5.2.4.4.2, 17.5.2.4.4.3, or 17.5.2.4.4.4) for Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* in hour *h*, as determined pursuant to Section 17.5.2.4.4

and the variable O/R-t-S $\text{DCR}_{a,h}$ is defined as set forth in Formula B-6 and the variables

$\text{FlowImpact}_{a,h,o}$ and O_h are defined as set forth in Formula B-8.

Formula B-10

$$\text{O/R-t-S Allocation}_{a,t,h} = \left(\sum_{\substack{o \in O_h \\ \text{and } q=t}} \text{FlowImpact}_{a,h,o} * \text{ShadowPrice}_{a,h} * \text{Responsibility}_{h,q,o} \right) * \text{OPF/SCUCAdjust}_a$$

Where, the variables $\text{ShadowPrice}_{a,h}$ and OPF/SCUCAdjust_a are defined as set forth in Formula B-5, the variables $\text{O/R-t-S Allocation}_{a,t,h}$ and $\text{Responsibility}_{h,q,o}$ are defined as set forth in Formula B-9, and the variables $\text{FlowImpact}_{a,h,o}$ and O_h are defined as set forth in Formula B-8.

17.5.2.4.3 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 17.5.2.4.3. Each U/D Congestion Rent Shortfall Charge and each U/D Congestion Rent Surplus Payment allocated to a Transmission Owner pursuant to this Section 17.5.2.4.3 is subject to being set equal to zero pursuant to Section 17.5.2.4.5.

17.5.2.4.3.1 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 17.5.2.4.4, 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 17.5.2.4.4, for the Qualifying DAM Uprating shall be allocated a U/D Congestion Rent Surplus Payment pursuant to Section 17.5.2.4.3.2.

17.5.2.4.3.1.1 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 Part 17.5 of this Attachment B, "*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 in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating is included 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 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 17.5.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 17.5.2.4.4) other than the Transmission Owner responsible for the lower rating in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating is included 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*.

17.5.2.4.3.1.2 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 Part 17.5 of this Attachment B, "*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 in the last auction held for TCCs valid for hour *h*;

(iii) this higher rating is included 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 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 17.5.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner for the purpose of applying Section 17.5.2.4.4) other than the Transmission Owner responsible for the lower rating in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating for hour *h* is included 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*.

17.5.2.4.3.2 Allocation of U/D DAM Constraint Residuals

This Section 17.5.2.4.3.2 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 B-11 and then applying either Formula B-12 or Formula B-13, as specified herein, to assess U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments.

Formula B-11

$$\text{U/D NetDAMImpact}_{a,h} = \left(\sum_{\text{for all } r \in R_{a,h}} \text{RatingChange}_{a,h,r} * \text{ShadowPrice}_{a,h} \right) * \text{SCUCSignChange}_{a,h}$$

Where,

U/D $\text{NetDAMImpact}_{a,h}$ = 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 $\text{NetDAMImpact}_{a,h}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula B-11

$\text{RatingChange}_{a,h,r}$ = Either

(a) If Qualifying DAM Derating *r* or Qualifying DAM Uprating *r* is a Deemed Qualifying DAM Derating or a Deemed Qualifying DAM Uprating, $\text{RatingChange}_{a,h,r}$ 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 in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the 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, $\text{RatingChange}_{a,h,r}$ 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 in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the 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, $RatingChange_{a,h,r}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula B-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 $SCUCSignChange_{a,h}$ and $ShadowPrice_{a,h}$ are defined as set forth in Formula B-5.

After calculating U/D $NetDAMImpact_{a,h}$ pursuant to Formula B-11, the ISO shall determine whether U/D $NetDAMImpact_{a,h}$ for constraint *a* in hour *h* has a different sign than U/D $DCR_{a,h}$ for constraint *a* in hour *h*. If the sign is different, the ISO shall (i) recalculate U/D $NetDAMImpact_{a,h}$ pursuant to Formula B-11 after setting equal to zero each $RatingChange_{a,h,r}$ for which $RatingChange_{a,h,r}$ * $ShadowPrice_{a,h}$ * $SCUCSignChange_{a,h}$ has a different sign than U/D $DCR_{a,h}$, and then (ii) use this recalculated U/D $NetDAMImpact_{a,h}$ and reset value of $RatingChange_{a,h,r}$ to allocate U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments pursuant to Formula B-12 or Formula B-13, as specified below.

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 B-11 (or recalculated pursuant to Formula B-11 using a reset value of $RatingChange_{a,h,r}$ 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 B-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 B-11 (or recalculated pursuant to Formula B-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 B-13.

<u>Formula B-12</u>

$$\text{U/D Allocation}_{a,t,h} = \left(\frac{\sum\limits_{\substack{r \in R_{a,h} \\ \text{and } q=t}} \text{RatingChange}_{a,h,r} * \text{Responsibility}_{h,q,r}}{\sum\limits_{\text{for all } r \in R_{a,h}} \text{RatingChange}_{a,h,r}} \right) * \text{U/D DCR}_{a,h}$$

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 17.5.2.4.4.2, 17.5.2.4.4.3, or 17.5.2.4.4.4) for Qualifying DAM Derating *r* or Qualifying DAM Uprating *r* in hour *h*, as determined pursuant to Section 17.5.2.4.4

and the variable U/D $DCR_{a,h}$ is defined as set forth in Formula B-7 and the variables $RatingChange_{a,h,r}$ and $R_{a,h}$ are defined as set forth in Formula B-11.

Formula B-13

$$\text{U/D Allocation}_{a,t,h} = \left(\sum_{\substack{r \in R_{a,h} \\ \text{and } q=t}} \text{RatingChange}_{a,h,r} * \text{ShadowPrice}_{a,h} * \text{Responsibility}_{h,q,r} \right) * \text{SCUCSignChange}_{a,h}$$

Where,

the variables $ShadowPrice_{a,h}$ and $SCUCSignChange_{a,h}$ are defined as set forth in Formula B-5, the variables U/D $Allocation_{a,t,h}$ and $Responsibility_{h,q,r}$ are defined as set forth in Formula B-12, and the variables $RatingChange_{a,h,r}$ and $R_{a,h}$ are defined as set forth in Formula B-11.

17.5.2.4.4 Assigning Responsibility for Outages, Returns-to-Service, Deratings, and Upratings

17.5.2.4.4.1 General Rule for Assigning Responsibility; Presumption of Causation

Unless the special rules set forth in Sections 17.5.2.4.4.2 through 17.5.2.4.4.4 apply, a Transmission Owner shall for purposes of this Section 17.5.2.4 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 17.5.2.4.6.1) 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 17.5.2.4.4.2, 17.5.2.4.4.3, or 17.5.2.4.4.4, 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 17.5.2.4.4.2, 17.5.2.4.4.3, or 17.5.2.4.4.4; or (iii) FERC orders otherwise.

17.5.2.4.4.2 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 17.5.2.4.2 and Section 17.5.2.4.3, 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 17.5.2.4.2 and Section 17.5.2.4.3; *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 17.5.2.4.4.2 shall ultimately be allocated to the Transmission Owners as Net Congestion Rents pursuant to Section 17.5.2.5.

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 in the last Reconfiguration Auction held for TCCs valid for the relevant hour or the last 6-month sub-auction of a Centralized TCC Auction held for TCCs valid for the relevant hour.

17.5.2.4.4.3 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 17.5.2.4.2 and Section 17.5.2.4.3 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 17.5.2.4.2 and Section 17.5.2.4.3;

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 17.5.2.4.4.3 shall ultimately be allocated to the Transmission Owners as Net Congestion Rents pursuant to Section 17.5.2.5.

17.5.2.4.4.4 Shared Responsibility For Returns-to-Service and Upratings During a Transitional Period

Notwithstanding any other provision of this Part 17.5 of this Attachment B, a Transmission Owner shall be deemed to be not responsible for a Qualifying DAM Return-to-Service, Qualifying DAM Derating, or Qualifying DAM Uprating for an hour of the Day-Ahead Market if this Part 17.5 of this Attachment B was not in effect at the time of the last Reconfiguration Auction held for TCCs valid for the hour. Instead, the ISO shall allocate any revenue impacts resulting from such a Qualifying DAM Return-to-Service, Qualifying DAM Derating, or Qualifying DAM Uprating 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 17.5.2.4.2 and Section 17.5.2.4.3, and any such Qualifying DAM Return-to-Service, Qualifying DAM Derating, or Qualifying DAM Uprating during this transitional period shall be attributed to the ISO when performing the calculations described in Section 17.5.2.4.2 and Section 17.5.2.4.3; *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 17.5.2.4.4.4 shall ultimately be allocated to the Transmission Owners as Net Congestion Rents pursuant to Section 17.5.2.5.

17.5.2.4.5 Exceptions: Setting Charges and Payments to Zero

17.5.2.4.5.1 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 B-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 B-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 17.5.2.4.4) 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 17.5.2.4.4) 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 17.5.2.4.5.1 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 17.5.2.4.4.2, an external event described in Section 17.5.2.4.4.3, or an event occurring during a transitional period as described in Section 17.5.2.4.4.4.

<u>Formula B-14</u>

$$\text{NetDAMAllocations}_{t,h} = \sum_{\text{for all a}} \text{O/R-t-S CRSC}_{a,t,h} + \text{U/D CRSC}_{a,t,h} + \text{O/R-t-S CRSP}_{a,t,h} + \text{U/D CRSP}_{a,t,h}$$

Where,

$\text{NetDAMAllocations}_{t,h}$ = 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*

$O/R\text{-}t\text{-}S\ CRSC_{a,t,h}$ = 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 17.5.2.4.2

$U/D\ CRSC_{a,t,h}$ = 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 17.5.2.4.3

$O/R\text{-}t\text{-}S\ CRSP_{a,t,h}$ = 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 17.5.2.4.2

$U/D\ CRSP_{a,t,h}$ = 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 17.5.2.4.3.

17.5.2.4.5.2 Zeroing Out of Charges and Payments Resulting from Formula Failure

Notwithstanding any other provision of this Part 17.5 of this Attachment B, 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 17.5.2.4, 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 17.5.2.4.5.2 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 17.5.2.4.5.2 in the same hour of the Day-Ahead Market.

17.5.2.4.6 Information Requirements

17.5.2.4.6.1 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.

17.5.2.4.6.2 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.

17.5.2.5 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 B-15.

Formula B-15

$$\text{AllocationFactor}_{t,m} = \frac{\text{Original Residual}_{t,m} + \text{ETCNL}_{t,m} + \text{NARs}_{t,m} + \text{GFR\&GFTCC}_{t,m}}{\sum_{q \in T} \text{Original Residual}_{q,m} + \text{ETCNL}_{q,m} + \text{NARs}_{q,m} + \text{GFR\&GFTCC}_{q,m}}$$

Where,

Allocation $\text{Factor}_{t,m}$	=	The allocation factor used by the ISO to allocate a share of the Net Congestion Rents to Transmission Owner *t* for month *m*
Original $\text{Residual}_{q,m}$	=	The one-month portion of the revenue imputed to the Direct Sale or the sale in any Centralized TCC Auction sub-auction of Original Residual TCCs 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 in the Reconfiguration Auction held for month *m* (or one-sixth of the average market clearing price in the stage 1 rounds of the 6-month sub-auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for 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
$\text{ETCNL}_{q,m}$	=	The sum of the one-month portion of the revenues the

Transmission Owner has received as payment for the Direct Sale of ETCNL or for its ETCNL released in the Centralized TCC Auction sub-auctions held for TCCs valid for month *m*. Each one-month portion of the revenue for ETCNL released in such 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 to the ETCNL sold in the Centralized TCC Auction sub-auction.25 The one-month portion of the revenue imputed to the Direct Sale of ETCNL shall be the value of the TCCs corresponding to that ETCNL in the Reconfiguration Auction held for month *m* (or one-sixth of the average market clearing price of such TCCs in stage 1 rounds of the 6-month sub-auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for month *m*)

$NARs_{q,m}$ = The one-month portion of the Net Auction Revenues the Transmission Owner has received in Centralized TCC Auction sub-auctions and 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 in each Centralized TCC Auction sub-auction or Reconfiguration Auction from the allocation of Net Auction Revenue pursuant to Section 17.5.3.7, divided by the duration in months of the TCCs sold in the Centralized TCC Auction sub-auction or Reconfiguration Auction (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 B-27 (as adjusted for any charges or payments that are zeroed out) for Transmission Owner *q* for all 6-month sub-auction stage 1 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) $NetAuctionAllocations_{t,n}$ as calculated pursuant to Formula B-27 and as adjusted for any charges or payments that are zeroed out for Transmission Owner *q* for the Reconfiguration Auction *n* held for month *m* (or, to the extent

[2] A TCC corresponds to ETCNL if it has the same POI and POW as the ETCNL.

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, valued at their market clearing prices in the Reconfiguration Auction for month *m* (or one-sixth of the average market clearing price in stage 1 rounds in the 6-month sub-auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for month *m*), provided that the Transmission Owner is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in month *m*
t	=	Transmission Owner *t*
T	=	The set of all Transmission Owners *q*.

Each Transmission Owner's share of Net Congestion Rents allocated pursuant to this Section 17.5.2.5 shall be incorporated into its TSC or NTAC, as the case may be.

17.5.3 Settlement of TCC Auctions

17.5.3.1 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 Part 17.5 of this Attachment B: (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 B-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 B-16.

Formula B-16

$$\text{Net Auction Revenue}_n = \begin{bmatrix} \text{TCC Auction Revenue}_n \\ -\ \text{ETCNL}_n \\ -\ \text{Primary Holder TCCs Sold}_n \\ -\ \text{Original Residual TCCs}_n \\ -\ \text{O/R-t-S\&U/D ARSC\&ARSP}_n \end{bmatrix}$$

Where,

n	=	A round of a Centralized TCC Auction (which may be either a stage 1 round of a 6-month sub-auction, a stage 1 round of a sub-auction in which TCCs with a duration greater than 6 months are sold, or a stage 2 round) 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 17.5.3.2
ETCNL_n	=	Either (i) if round *n* is a stage 1 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 17.5.3.3; (ii) if round *n* is a stage 2 round of a Centralized TCC Auction, 0; or (iii) 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 17.5.3.4

Original Residual $TCCs_n$	=	Either (i) if round *n* is a stage 1 round of a Centralized TCC Auction, the total payments the ISO makes in round *n* pursuant to Section 17.5.3.5 to Transmission Owners that release into round *n* Original Residual TCCs; (ii) if round *n* is a stage 2 round of a Centralized TCC Auction, 0; or (iii) for Reconfiguration Auction *n*, 0
O/R-t-S&U/D $ARSC\&ARSP_n$	=	Either (i) if round *n* is a stage 1 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 $NetAuctionAllocations_{t,n}$ pursuant to Formula B-27) for all Transmission Owners *t*, reduced by any zeroing out of such charges or payments pursuant to Section 17.5.3.6.5; (ii) if round *n* is a stage 2 round of a Centralized TCC Auction or a stage 1 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 $ARSC_{a,t,n}$), U/D Auction Revenue Shortfall Charges (U/D $ARSC_{a,t,n}$), O/R-t-S Auction Revenue Surplus Payments (O/R-t-S $ARSP_{a,t,n}$), and U/D Auction Revenue Surplus Payments (U/D $ARSP_{a,t,n}$) for all Transmission Owners *t* (which sum is calculated for each Transmission Owner as $NetAuctionAllocations_{t,n}$ pursuant to Formula B-27), reduced by any zeroing out of such charges or payments pursuant to Section 17.5.3.6.5

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 17.5.3.7.

17.5.3.2 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 Part 17.4 of this Attachment B, for the TCCs purchased.

17.5.3.3 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 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 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 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 released into the Centralized TCC Auction is insufficient to fund payments at market-clearing prices, the total payments to each Transmission Owner for ETCNL 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.

17.5.3.4 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.

In the event a Grandfathered TCC26 is terminated by mutual agreement of the parties to the grandfathered ETA prior to the conditions specified within Attachments K and L of the ISO OATT, 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 of the ISO OATT, until such time as the conditions specified within Attachments K and L of the ISO OATT are met. Upon such time that the conditions within Attachments K and L of the ISO OATT 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 17.5.3.7 of this Part 17.5 of this Attachment B.

17.5.3.5 Allocation of Revenues from the Sale of Original Residual TCCs

Revenues associated with Original Residual TCCs shall be distributed directly to each Primary Owner for the duration of the LBMP Transition Period. The Primary Owner of such an Original Residual TCC shall be paid the market clearing price of the Original Residual TCC in the round of the sub-auction in which that Original Residual TCC was sold.

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 Residual TCCs. If the total value of

[3] These TCCs include TCCs, if any, associated with those rate schedules to which footnote 9 of Attachment L of the ISO OATT pertains, whether by mutual agreement or otherwise.

the auction revenues available for payment to the Transmission Owners for 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 Original Residual TCCs 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.

17.5.3.6 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 17.5.3.6. To do so, the ISO shall calculate the Auction Constraint Residual for each constraint for each stage 1 round *n* of a Centralized TCC Auction 6-month sub-auction or Reconfiguration Auction *n*, as the case may be, pursuant to Section 17.5.3.6.1 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 17.5.3.6.1. 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 17.5.3.6.2 and 17.5.3.6.4, each of which shall be subject to being reduced to zero pursuant to Section 17.5.3.6.5. 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 17.5.3.6.3 and 17.5.3.6.4, each of which shall be subject to being reduced to zero pursuant to Section 17.5.3.6.5. 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 stage 1 rounds of the 6-month sub-auction.

17.5.3.6.1 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 stage 1 round *n* of a 6-month sub-auction of a Centralized TCC Auction or for Reconfiguration Auction *n*, as the case may be. For each binding constraint *a* and for each stage 1 round *n* of a 6-month sub-auction of a Centralized TCC Auction or Reconfiguration Auction *n*, the ISO shall calculate the Auction Constraint Residual, $ACR_{a,n}$, using Formula B-17; *provided, however,* the ISO shall recalculate $ACR_{a,n}$ using Formula B-18 if (i) $ACR_{a,n}$ is positive based on the calculation using Formula B-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 B-17.

<u>Formula B-17</u>

$$ACR_{a,n} = ShadowPrice_{a,n} * \left[\begin{array}{l} FLOW_{a,n,actual} - FLOW_{a,n,basecase} \\ + \; ISORatingChange_{a,n} * OPFSignChange_{a,n} \end{array} \right] * \%Sold_{n}$$

Where,

$ACR_{a,n}$ = The Auction Constraint Residual, in dollars, for binding constraint *a* in stage 1 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 stage 1 round *n* of a 6-month sub-auction or in Reconfiguration Auction *n*, where *p* is a one-month period for Reconfiguration Auction *n* and *p* is a six-month period for stage 1 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 stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* as described in Part 17.4 of this Attachment B, 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 Reconfiguration Auction *n*, (i) the Transmission System model for Reconfiguration Auction *n*, (ii) the set of TCCs and Grandfathered Rights represented in the solution to Reconfiguration Auction *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 determined in the Optimal Power Flow solution for Reconfiguration Auction *n*; or

(b) For stage 1 round *n* of a 6-month sub-auction, (i) the Transmission System model for stage 1 round *n*, (ii) the set of TCCs (scaled appropriately) and Grandfathered Rights represented in the solution to stage 1 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 schedule produced in the Optimal Power Flow solution for stage 1 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 Reconfiguration Auction *n*, a Power Flow using the following base case data set: (i) the Transmission System model for Reconfiguration Auction *n*, (ii) the set of TCCs and Grandfathered Rights represented in the solution to the final round of the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n* (including those pre-existing TCCs (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 final round of the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; or

(b) For stage 1 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 schedule produced in a single simulated TCC auction administered for all stage 1 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 stage 1 rounds of the sub-auction that includes round *n*

$ISORatingChange_{a,n}$ = The total change in the rating of constraint *a* for stage 1 round *n* or Reconfiguration Auction *n* resulting from ISO-Directed Auction Status Changes or Deemed ISO-Directed Auction Status Changes described in Section 17.5.3.6.4.2, external events described in Section 17.5.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for stage 1 round *n* or Reconfiguration Auction *n*, which shall be calculated as follows:

(a) For 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 17.5.3.6.4.2, external events described in Section 17.5.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for stage 1 round *n* or Reconfiguration Auction *n*, $ISORatingChange_{a,n}$ shall be equal to the amount, in MW-*p*, of the change in the rating limit of constraint *a* as shown in the Reconfiguration Auction Interface Uprate/Derate Table applicable for Reconfiguration Auction *n*

(b) stage 1 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 17.5.3.6.4.2, external events described in Section 17.5.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for stage 1 round *n* or Reconfiguration Auction *n*, $ISORatingChange_{a,n}$ shall be equal to the amount, in MW-*p*, of the change in the rating limit of constraint *a* as shown in the Centralized TCC Auction Interface Uprate/Derate Table applicable for stage 1 round *n*

$OPFSignChange_{a,n}$ = 1 if $ShadowPrice_{a,n}$ is greater than zero; otherwise, -1

$\%Sold_n$ = Either (i) for stage 1 round *n* of a 6-month sub-auction, the percentage of transmission Capacity sold in stage 1 round *n*, divided by the percentage of transmission Capacity sold in all stage 1 rounds of the sub-auction of which stage 1 round *n* is a part; or (ii) for Reconfiguration Auction *n*, 1.

Formula B-18

$$ACR_{a,n} = ShadowPrice_{a,n} * \begin{bmatrix} FLOW_{a,n,actual} - FLOW_{a,n,basecase} \\ + \ ISORatingChange_{a,n} * OPFSignChange_{a,n} \\ - \ UnsoldCapacity_{a,n,PriorAuction} * OPFSignChange_{a,n} \end{bmatrix} * \%Sold_{n}$$

Where,

$UnsoldCapacity_{a,n,PriorAuction}$ = Either:

(a) For Reconfiguration Auction *n*, the rating limit for binding constraint *a* applied in the model used in the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, minus the Energy flow, in MW-*p*, on binding constraint *a* produced in the Optimal Power Flow in the last round of that Centralized TCC Auction; or

(b) For stage 1 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 B-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 B-17

and each of the other variables is as set forth in Formula B-17; *provided, however*, if $ACR_{a,n}$ is less than zero when calculated using this Formula B-18, $ACR_{a,n}$ shall be set equal to zero.

Following calculation of the Auction Constraint Residual for each constraint *a* for each stage 1 round *n* of a 6-month sub-auction or each 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 stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*, as the case may be. The amount of each O/R-t-S Auction

Constraint Residual for stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*, as the case may be, for constraint *a* shall be determined by applying Formula B-19. The amount of each U/D Auction Constraint Residual for stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*, as the case may be, for constraint *a* shall be determined by applying Formula B-20.

Formula B-19

$$\text{O/R-t-S ACR}_{a,n} = \text{ACR}_{a,n} * \left[\frac{\text{FLOW}_{a,n,actual} - \text{FLOW}_{a,n,basecase} + \text{TotalRatingChange}_{a,n} * \text{OPFSignChange}_{a,n}}{\text{FLOW}_{a,n,actual} - \text{FLOW}_{a,n,basecase} + \text{ISORatingChange}_{a,n} * \text{OPFSignChange}_{a,n}} \right]$$

Where:

O/R-t-S $\text{ACR}_{a,n}$ = The amount of the O/R-t-S Auction Constraint Residual for stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*, as the case may be, for constraint *a*

$\text{TotalRatingChange}_{a,n}$ = The total change in the rating of constraint *a*, which shall be calculated as follows:

(a) For Reconfiguration Auction *n*, $\text{TotalRatingChange}_{a,n}$ shall be equal to (1) the rating limit, in MW-*p*, of constraint *a* in the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, minus (2) the rating limit, in MW-*p*, of constraint *a* applicable in Reconfiguration Auction *n*

(b) For stage 1 round *n* of a 6-month sub-auction, $\text{TotalRatingChange}_{a,n}$ 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 stage 1 round *n*

and the variable $\text{ACR}_{a,n}$ is as calculated pursuant to Formula B-17 or, if required, pursuant to Formula B-18, and each of the other variables are as defined in Formula B-17.

Formula B-20

$$U/D\ ACR_{a,n} = ACR_{a,n} * \left[\frac{-\left(TotalRatingChange_{a,n} - ISORatingChange_{a,n}\right) * OPFSignChange_{a,n}}{FLOW_{a,n,actual} - FLOW_{a,n,basecase} + ISORatingChange_{a,n} * OPFSignChange_{a,n}} \right]$$

Where,

$U/D\ ACR_{a,n}$ = The amount of the U/D Auction Constraint Residual for stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*, as the case may be, for constraint *a*

and the variable $ACR_{a,n}$ is as calculated pursuant to Formula B-17 or, if required, pursuant to Formula B-18, the variable $TotalRatingChange_{a,n}$ is defined as set forth in Formula B-19 and each of the other variables are defined as set forth in Formula B-17.

17.5.3.6.2 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 17.5.3.6.2. 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 17.5.3.6.2 is subject to being set equal to zero pursuant to Section 17.5.3.6.5.

17.5.3.6.2.1 Identification of Outages and Returns-to-Service Qualifying for Charges and Payments

For each stage 1 round of a 6-month sub-auction or 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 17.5.3.6.4, 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 17.5.3.6.2.2 or 17.5.3.6.2.3.

17.5.3.6.2.1.1 Definition of Qualifying Auction Outage

A "**Qualifying Auction Outage**" (which term shall apply to stage 1 round *n* of a 6-month sub-auction or 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 Part 17.5 of this Attachment B, "*o*" shall refer to a single Qualifying Auction Outage.

An "**Actual Qualifying Auction Outage**" (which term shall apply to stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*, as the case may be) shall be defined as a transmission facility that, for a given stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*, as the case may be:

(a) For Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed and was modeled as in-service in the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and

(ii) the facility exists but is not modeled as in-service for Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; or

(b) For stage 1 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 stage 1 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 Reconfiguration Auction *n*) shall be defined as a transmission facility that, for Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service in the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(ii) the facility existed but was not modeled as in-service in Reconfiguration Auction *n* as a result of an Auction Status Change or external event described in Section 17.5.3.6.4.3 in Reconfiguration Auction *n* for which responsibility was assigned pursuant to Section 17.5.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to 17.5.3.6.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service in the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*.

17.5.3.6.2.1.2 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 Part 17.5 of this Attachment B, "*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 Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service for the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and

(ii) the facility exists and is modeled as in-service in Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*.

Notwithstanding any other provision of this Part 17.5 of this Attachment B, a transmission facility returning to service for stage 1 round *n* of a 6-month sub-auction shall not be an Actual Qualifying Auction Return-to-Service for that stage 1 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 stage 1 round *n*.

A "**Deemed Qualifying Auction Return-to-Service**" shall be defined as a transmission facility that, for a given Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service in the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(ii) the facility existed but was not modeled as in-service in Reconfiguration Auction *n* as a result of an Auction Status Change or external event described in Section

17.5.3.6.4.3 in Reconfiguration Auction *n* for which responsibility was assigned pursuant to Section 17.5.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 17.5.3.6.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service for the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*.

17.5.3.6.2.2 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 17.5.3.6.2.2 describes the allocation of an O/R-t-S Auction Constraint Residual for a given stage 1 round of a 6-month sub-auction or Reconfiguration Auction, as the case may be, and a given constraint when only one Transmission Owner is responsible, as determined pursuant to Section 17.5.3.6.4, for all of the Qualifying Auction Outages and all of the Qualifying Auction Returns-to-Service for that stage 1 round of a 6-month sub-auction or Reconfiguration Auction that contribute to that constraint.

If the same Transmission Owner is responsible, as determined pursuant to Section 17.5.3.6.4, for all of the Qualifying Auction Outages *o* and Qualifying Auction Returns-to-Service *o* for stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* that contribute to constraint *a*, then the ISO shall allocate the O/R-t-S Auction Constraint Residual for that stage 1 round *n* of a 6-month sub-auction or 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.

17.5.3.6.2.3 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 17.5.3.6.2.3 describes the allocation of an O/R-t-S Auction Constraint Residual for a given stage 1 round of a 6-month sub-auction or Reconfiguration Auction, as the case may be, and a given constraint when more than one Transmission Owner is responsible, as determined pursuant to Section 17.5.3.6.4, for the Qualifying Auction Outages and the Qualifying Auction Returns-to-Service for that stage 1 round of a 6-month sub-auction or Reconfiguration Auction that contribute to that constraint.

If more than one Transmission Owner is responsible, as determined pursuant to Section 17.5.3.6.4, for the Qualifying Auction Outages and the Qualifying Auction Returns-to-Service for stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* that contribute to constraint *a*, the ISO shall allocate the O/R-t-S Auction Constraint Residual for constraint *a* for stage 1 round *n* of a 6-month sub-auction or for 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 stage 1 round *n* of a 6-month sub-auction or 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 stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* with an impact on the Energy flow across that constraint of 1 MW-*p* or more by applying Formula B-21, and then applying either Formula B-

22 or Formula B-23, as specified herein, to assess O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments.

<u>Formula B-21</u>

$$\text{O/R-t-SNetAuctionImpact}_{a,n} = \sum_{\text{for all } o \in O_n} \text{FlowImpact}_{a,n,o} * \text{ShadowPrice}_{a,n}$$

Where,

$\text{O/R-t-SNetAuctionImpact}_{a,n}$ = The net impact, in dollars, for stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*, as the case may be, on constraint *a* of all Qualifying Auction Outages and Qualifying Auction Returns-to-Service for stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* having an impact of more than 1 MW-*p* on Energy flow across constraint *a; provided, however,* O/R-t-S $\text{NetAuctionImpact}_{a,n}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula B-21

$\text{FlowImpact}_{a,n,o}$ = 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 Reconfiguration Auction *n* or stage 1 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 $\text{FlowImpact}_{a,n,o}$ calculated for the corresponding Deemed Qualifying Auction Return-to-Service as described in part (b) of this definition of $\text{FlowImpact}_{a,n,o}$, 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:

$\text{FlowImpact}_{a,n,o} = \text{BaseCaseFlow}_{a,n} - \text{One-OffFlow}_{a,n,o}$

Where,

$\text{BaseCaseFlow}_{a,n}$ = Either, as the case may be:

(i) for a Reconfiguration Auction, the Energy flow on constraint *a* resulting from a Power Flow using (1) the set of injections and withdrawals corresponding to the actual TCCs and Grandfathered Rights represented in the solution to the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n* (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction); (2) the phase angle regulator schedule determined in the Optimal Power Flow solution for the final round of the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and (3) the Transmission System model for the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; 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 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 schedule produced in the Optimal Power Flow used to calculate the Energy flow on constraint *a* for stage 1 round *n* of a 6-month sub-auction, as described in the definition of $FLOW_{a,n,basecase}$ in Formula B-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 stage 1 round *n* of a 6-month sub-auction or in 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 schedule 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 stage 1 round *n* of a 6-month sub-auction or in 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 schedule 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, FlowImpacta,n,o shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula B-21

O_n	=	The set of all Qualifying Auction Outages *o* and Qualifying Auction Returns-to-Service *o* in stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*
p	=	A one-month period for Reconfiguration Auction *n*, or a six-month period for stage 1 round *n* of a 6-month sub-auction

and the variable $ShadowPrice_{a,n}$ is defined as set forth in Formula B-17.

After calculating O/R-t-S $NetAuctionImpact_{a,n}$ pursuant to Formula B-21, the ISO shall determine whether O/R-t-S $NetAuctionImpact_{a,n}$ for constraint *a* in stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* has a different sign than O/R-t-S $ACR_{a,n}$ for constraint *a* in stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*. If the sign is different, the ISO shall (i) recalculate O/R-t-S $NetAuctionImpact_{a,n}$ pursuant to Formula B-21 after setting equal to zero each $FlowImpact_{a,n,o}$ for which $FlowImpact_{a,n,o}$ * $ShadowPrice_{a,n}$ has a different sign than O/R-t-S $ACR_{a,n}$, and then (ii) use this recalculated O/R-t-S $NetAuctionImpact_{a,n}$ and reset value of $FlowImpact_{a,n,o}$ to allocate O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments pursuant to Formula B-22 or Formula B-23, as specified below.

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 stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* as calculated using Formula B-21 (or recalculated pursuant to Formula B-21 using a reset value of $FlowImpact_{a,n,o}$ 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 $ACR_{a,n}$) for constraint *a* in stage 1 round *n* of a 6-month sub-auction or 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 B-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 stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* as calculated using Formula B-21 (or recalculated pursuant to Formula B-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 stage 1 round *n* of a 6-month sub-auction or 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 B-23.

Formula B-22

$$\text{O/R-t-S Allocation}_{a,t,n} = \left(\frac{\sum_{\substack{o \in O_n \\ \text{and } q=t}} \text{FlowImpact}_{a,n,o} * \text{Responsibility}_{n,q,o}}{\sum_{\text{for all } o \in O_n} \text{FlowImpact}_{a,n,o}} \right) * \text{O/R-t-S ACR}_{a,n}$$

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 Reconfiguration Auction *n* or stage 1 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 Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction

$\text{Responsibility}_{n,q,o}$ = 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 17.5.3.6.4.2 or 17.5.3.6.4.3) for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* in Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction, as determined pursuant to Section 17.5.3.6.4

and the variable O/R-t-S $\text{ACR}_{a,n}$ is defined as set forth in Formula B-19 and the variables $\text{FlowImpact}_{a,n,o}$ and O_n are defined as set forth in Formula B-21.

<u>Formula B-23</u>

$$\text{O/R-t-S Allocation}_{a,t,n} = \sum_{\substack{o \in O_n \\ \text{and } q=t}} \text{FlowImpact}_{a,n,o} * \text{ShadowPrice}_{a,n} * \text{Responsibility}_{n,q,o}$$

Where,

the variable $\text{ShadowPrice}_{a,n}$ is defined as set forth in Formula B-17, the variables O/R-t-S $\text{Allocation}_{a,t,n}$ and $\text{Responsibility}_{n,q,o}$ are defined as set forth in Formula B-22, and the variables $\text{FlowImpact}_{a,n,o}$ and O_n are defined as set forth in Formula B-21.

17.5.3.6.3 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 17.5.3.6.3. Each U/D Auction Revenue Shortfall Charge and each U/D Auction Revenue Surplus Payment allocated to a Transmission Owner pursuant to this Section 17.5.3.6.3 is subject to being set equal to zero pursuant to Section 17.5.3.6.5.

17.5.3.6.3.1 Identification of Upratings and Deratings Qualifying for Charges and Payments

For each constraint for each stage 1 round of a 6-month sub-auction or 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 17.5.3.6.4, 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 17.5.3.6.3.2.

17.5.3.6.3.1.1 Definition of Qualifying Auction Derating

A "**Qualifying Auction Derating**" (which term shall apply to stage 1 round *n* of a 6-month sub-auction or 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 Part 17.5 of this Attachment B, "*r*" shall refer to a single Qualifying Auction Derating.

An "**Actual Qualifying Auction Derating**" (which term shall apply to stage 1 round *n* of a 6-month sub-auction or 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 stage 1 round *n* or Reconfiguration Auction *n* meets each of the following requirements:

For Reconfiguration Auction *n*:

(i) the constraint has a lower rating in Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service 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 Reconfiguration Auction *n*;

(iii) the lower rating resulting from Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was not modeled in the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iv) this lower rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint was binding in Reconfiguration Auction *n*.

For stage 1 round *n* of a 6-month sub-auction:

(i) the constraint has a lower rating in stage 1 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 stage 1 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 stage 1 round *n* of the 6-month sub-auction; and

(iv) the constraint is binding in stage 1 round *n* of the 6-month sub-auction.

A "**Deemed Qualifying Auction Derating**" (which term shall apply to Reconfiguration Auction *n*) shall be defined as a change in the rating of a constraint that, for a given constraint *a* and a given Reconfiguration Auction *n* meets each of the following requirements:

(i) the constraint has a lower rating in Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service 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 Reconfiguration Auction *n*;

(iii) this lower rating resulting from Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was modeled in the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, but responsibility for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* resulting in the lower rating for Reconfiguration Auction *n* is assigned pursuant to Section 17.5.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 17.5.3.6.4) other than the Transmission Owner responsible for the lower rating in the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iv) this lower rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint is binding in Reconfiguration Auction *n*.

17.5.3.6.3.1.2 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 Part 17.5 of this Attachment B, "*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 Reconfiguration Auction *n*, as the case may be, meets each of the following requirements:

(i) the constraint has a higher rating for Reconfiguration Auction *n* than it would have absent an Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n*;

(ii) this higher rating resulting from Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was not modeled in the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iii) this higher rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(iv) the constraint is binding in Reconfiguration Auction *n*.

Notwithstanding any other provision of this Part 17.5 of this Attachment B, a transmission facility uprating for a stage 1 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 Reconfiguration Auction *n*, as the case may be, meets each of the following requirements:

(i) the constraint has a lower rating in Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service 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 Reconfiguration Auction *n*;

(iii) this lower rating resulting from Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was modeled in the last 6-month sub-auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, but responsibility for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* resulting in the lower rating for Reconfiguration Auction *n* is assigned pursuant to Section 17.5.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 17.5.3.6.4) other than the Transmission Owner responsible for the lower rating in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating in 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 Reconfiguration Auction *n*.

17.5.3.6.3.2 Allocation of U/D Auction Constraint Residuals

This Section 17.5.3.6.3.2 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 Reconfiguration Auction *n* or stage 1 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 stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* of all Qualifying Auction Deratings *r* and Qualifying

Auction Upratings *r* for constraint *a* in Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction pursuant to Formula B-24 and then applying either Formula B-25 or Formula B-26, as specified herein, to assess U/D Auction Revenue Shortfall Charges and U/D Auction Revenue Surplus Payments.

Formula B-24

$$\text{U/D NetAuctionImpact}_{a,n} = \left(\sum_{r \in R_{a,n}} \text{RatingChange}_{a,n,r} * \text{ShadowPrice}_{a,n} \right) * \text{OPFSignChange}_{a,n}$$

Where,

U/D NetAuctionImpact$_{a,n}$ = The net impact, in dollars, on constraint *a* in Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction of all Qualifying Auction Deratings or Qualifying Auction Upratings for constraint *a* in Reconfiguration Auction *n* or stage 1 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 B-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 Reconfiguration Auction *n* or stage 1 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 Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction, which in the case of 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 stage 1 round *n* of a 6-month sub-auction shall be as shown in the Centralized TCC Auction Interface Uprate/Derate Table in effect for stage 1 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 Reconfiguration Auction *n* or stage 1 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 Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction, which in the case of 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 stage 1 round n of a 6-month sub-auction shall be as shown in the Centralized TCC Auction Interface Uprate/Derate Table in effect for stage 1 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 B-24

$R_{a,n}$ = The set of all Qualifying Auction Deratings *r* or Qualifying Auction Upratings *r* for binding constraint *a* in Reconfiguration Auction *n* or stage 1 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 B-17.

After calculating U/D $\text{NetAuctionImpact}_{a,n}$ pursuant to Formula B-24, the ISO shall determine whether U/D $\text{NetAuctionImpact}_{a,n}$ for constraint *a* in stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n* has a different sign than U/D $\text{ACR}_{a,n}$ for constraint *a* in stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*. If the sign is different, the ISO shall (i) recalculate U/D $NetAuctionImpact_{a,n}$ pursuant to Formula B-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 B-25 or Formula B-26, as specified below.

If the absolute value of the net impact (U/D $NetAuctionImpact_{a,n}$) on constraint *a* for Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction of all Qualifying Auction Deratings or Qualifying Auction Upratings for constraint *a* in Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction as calculated using Formula B-24 (or recalculated pursuant to Formula B-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 Reconfiguration Auction *n* or stage 1 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 B-25. If the absolute value of the net impact (U/D $NetAuctionImpact_{a,n}$) on constraint *a* for Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction of all Qualifying Auction Deratings or Qualifying Auction Upratings for constraint *a* in Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction as calculated using Formula B-24 (or recalculated pursuant to Formula B-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 Reconfiguration Auction *n* or stage 1 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 B-26.

Formula B-25

$$\text{U/D Allocation}_{a,t,n} = \left(\frac{\sum_{\substack{r \in R_{a,n} \\ \text{and } q=t}} \text{RatingChange}_{a,n,r} * \text{Responsibility}_{n,q,r}}{\sum_{\text{for all } r \in R_{a,n}} \text{RatingChange}_{a,n,r}} \right) * \text{U/D ACR}_{a,n}$$

Where,

U/D $\text{Allocation}_{a,t,n}$ = 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 $\text{Allocation}_{a,t,n}$ is negative, then U/D $\text{Allocation}_{a,t,n}$ 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 Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction; or

(b) If U/D $\text{Allocation}_{a,t,n}$ is positive, then U/D $\text{Allocation}_{a,t,n}$ 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 Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction

$\text{Responsibility}_{n,q,r}$ = 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 17.5.3.6.4.2 or 17.5.3.6.4.3) for Qualifying Auction Derating *r* or Qualifying Auction Uprating *r* in Reconfiguration Auction *n* or stage 1 round *n* of a 6-month sub-auction, as determined pursuant to Section 17.5.3.6.4

and the variable U/D $ACR_{a,n}$ is defined as set forth in Formula B-20 and the variables $\text{RatingChange}_{a,n,r}$ and $R_{a,n}$ are defined as set forth in Formula B-24.

Formula B-26

$$\text{U/D Allocation}_{a,t,n} = \sum_{\substack{r \in R_{a,n} \\ \text{and } q=t}} \text{RatingChange}_{a,n,r} * \text{ShadowPrice}_{a,n} * \text{Responsibility}_{n,q,r}$$

Where,

the variables U/D $\text{Allocation}_{a,t,n}$ and $\text{Responsibility}_{n,q,r}$ are defined as set forth in Formula B-25, the variable $\text{ShadowPrice}_{a,n}$ is defined as set forth in Formula B-17, and the variables $\text{RatingChange}_{a,n,r}$ and $R_{a,n}$ are defined as set forth in Formula B-24.

17.5.3.6.4 Assigning Responsibility for Outages, Returns-to-Service, Deratings, and Upratings

17.5.3.6.4.1 General Rule for Assigning Responsibility; Presumption of Causation

Unless the special rules set forth in Sections 17.5.3.6.4.2 or 17.5.3.6.4.3 apply, a Transmission Owner shall for purposes of this Section 17.5.3.6 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 17.5.3.6.6.3) 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 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 17.5.3.6.4.2 or 17.5.3.6.4.3, 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 17.5.3.6.4.2 or Section 17.5.3.6.4.3; or (iii) FERC orders otherwise.

17.5.3.6.4.2 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 stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*. To do so, the ISO shall be treated as a Transmission Owner when allocating Auction Constraint Residuals pursuant to Section 17.5.3.6.2 and Section 17.5.3.6.3, 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 17.5.3.6.2 and Section 17.5.3.6.3; *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 17.5.3.6.4.2 shall ultimately be allocated to the Transmission Owners as Net Auction Revenues pursuant to Section 17.5.3.7.

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 6-month sub-auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction.

The ISO shall not direct that a transmission facility be modeled as in-service or out-of-service for purposes of 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 17.5.3.6.4.2.

17.5.3.6.4.3 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 stage 1 round *n* of a 6-month sub-auction or Reconfiguration Auction *n*. To do so, the ISO shall be treated as a Transmission Owner when allocating Auction Constraint Residuals pursuant to Section 17.5.3.6.2 and Section 17.5.3.6.3 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 17.5.3.6.4.3 shall ultimately be allocated to the Transmission Owners as Net Auction Revenues pursuant to Section 17.5.3.7.

17.5.3.6.5 Exceptions: Setting Charges and Payments to Zero

17.5.3.6.5.1 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 B-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 stage 1 round *n* of a 6-month sub-auction or in 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 B-27) for Transmission Owner *t* for all constraints for stage 1 round *n* of a 6-month sub-auction or 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 17.5.3.6.4) for any Qualifying Auction Returns-to-Service or Qualifying Auction Upratings in stage 1 round *n* of a 6-month sub-auction or in 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 17.5.3.6.4) for any Qualifying Auction Outages or Qualifying Auction Deratings in stage 1 round *n* of a 6-month sub-auction or in Reconfiguration Auction *n*, as the case may be; *provided, however,* the ISO shall not set equal to zero pursuant to this Section 17.5.3.6.5.1 any O/R-t-S $\text{ARSC}_{a,t,n}$, U/D $\text{ARSC}_{a,t,n}$, O/R-t-S $\text{ARSP}_{a,t,n}$, or U/D $\text{ARSP}_{a,t,n}$

arising from an ISO-Directed Auction Status Change or Deemed ISO-Directed Auction Status Change described in Section 17.5.3.6.4.2 or external events described in Section 17.5.3.6.4.3.

Formula B-27

$$\text{NetAuctionAllocations}_{t,n} = \sum_{\text{for all a}} \text{O/R-t-S ARSC}_{a,t,n} + \text{U/D ARSC}_{a,t,n} + \text{O/R-t-S ARSP}_{a,t,n} + \text{U/D ARSP}_{a,t,n}$$

Where,

$\text{NetAuctionAllocations}_{t,n}$ = 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 stage 1 round *n* of a 6-month sub-auction or in Reconfiguration Auction *n*

$\text{O/R-t-S ARSC}_{a,t,n}$ = An O/R-t-S Auction Revenue Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in stage 1 round *n* of a 6-month sub-auction or in Reconfiguration Auction *n*, calculated pursuant to Section 17.5.3.6.2

$\text{U/D ARSC}_{a,t,n}$ = A U/D Auction Revenue Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in stage 1 round *n* of a 6-month sub-auction or in Reconfiguration Auction *n*, calculated pursuant to Section 17.5.3.6.3

$\text{O/R-t-S ARSP}_{a,t,n}$ = An O/R-t-S Auction Revenue Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in stage 1 round *n* of a 6-month sub-auction or in Reconfiguration Auction *n*, calculated pursuant to Section 17.5.3.6.2

$\text{U/D ARSP}_{a,t,n}$ = A U/D Auction Revenue Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in stage 1 round *n* of a 6-month sub-auction or in Reconfiguration Auction *n*, calculated pursuant to Section 17.5.3.6.3.

17.5.3.6.5.2 Zeroing Out of Charges and Payments Resulting from Formula Failure

Notwithstanding any other provision of this Part 17.5 of this Attachment B, 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 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 17.5.3.6, 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 17.5.3.6.5.2 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 17.5.3.6.5.2 in the same round of a Centralized TCC Auction or the same Reconfiguration Auction, as the case may be.

17.5.3.6.6 Information Requirements

17.5.3.6.6.1 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 period 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.

17.5.3.6.6.2 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.

17.5.3.6.6.3 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.

17.5.3.7 Allocation of Net Auction Revenue to Transmission Owners

In Centralized TCC Auction round *n* or in 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 Reconfiguration Auction; *provided, however*, where the Net Auction Revenue is negative for 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 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 Reconfiguration Auction *n* is calculated pursuant to Formula B-28.

Formula B-28

$$FFB_{t,n} = \left| \frac{\sum_{l \in L_{t,n}} FLOW_{l,n} - FLOW_{l,IC} \ * \ Price_{y,l} - Price_{x,l}}{\sum_{l \in L_n} FLOW_{l,n} - FLOW_{l,IC} \ * \ Price_{y,l} - Price_{x,l}} \right| * \ Share_{n,t,l}$$

Where,

$FFB_{t,n}$ =	The Facility Flow-Based Methodology coefficient for Transmission Owner *t* for Centralized TCC Auction round *n* or Reconfiguration Auction *n*, as the case may be
L_n =	The set of all transmission facilities modeled in the Transmission System model for round *n* or for 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 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 and Grandfathered Rights represented in the solution to round *n* or to 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 Reconfiguration Auction *n*, as the case may be, (ii) ETCNL not sold in prior Centralized TCC Auctions or through a Direct Sale, and (iii) Original Residual TCCs not sold in prior Centralized TCC Auctions 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 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 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 Reconfiguration Auction *n*

p = A one-month period for Reconfiguration Auction *n*, or the effective period of TCCs sold in round *n* for round *n*.

Calculation of Negative Net Auction Revenue Coefficient. The negative Net Auction Revenue coefficient for Transmission Owner t for Reconfiguration Auction n is calculated pursuant to Formula B-29.

Formula B-29

$$NNAR_{t,n} = \frac{\text{Original Residual}_{t,n} + ETCNL_{t,n} + NARs_{t,n} + GFR\&GFTCC_{t,n}}{\sum_{q \in T} \text{Original Residual}_{q,n} + ETCNL_{q,n} + NARs_{q,n} + GFR\&GFTCC_{q,n}}$$

Where,

$NNAR_{t,n}$ = The negative Net Auction Revenue coefficient for Transmission Owner *t* for Reconfiguration Auction *n*

$\text{Original Residual}_{q,n}$= The one-month portion of the revenue imputed to the Direct Sale or the sale in any Centralized TCC Auction sub-auction of Original Residual TCCs that are valid during the month corresponding to 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 stage 1 rounds of the 6-month sub-auction of the last Centralized TCC Auction held for TCCs valid during the month corresponding to 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 revenues the Transmission Owner has received as payment for the Direct Sale of ETCNL or for its ETCNL released in the Centralized TCC Auction sub-auctions held for TCCs valid for the month corresponding to Reconfiguration Auction *n*. Each one-month portion of the revenue for ETCNL released in such 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 to the ETCNL sold in the Centralized TCC Auction sub-auction.[1] 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 to that ETCNL in the stage 1 rounds of the 6-month sub-auction of the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*

$NARs_{q,n}$ = The one-month portion of the Net Auction Revenues the Transmission Owner has received in Centralized TCC Auction sub-auctions and Reconfiguration Auctions held for TCCs valid for the month corresponding to 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 17.5.3.7, divided by the duration in months of the TCCs sold in the Centralized TCC Auction sub-auction (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 B-27 (as adjusted for any charges or payments that are zeroed out) for Transmission Owner *q* for all stage 1 rounds *n* of a 6-month sub-auction for all Centralized TCC Auctions held for TCCs valid in the month corresponding to 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) $NetAuctionAllocations_{t,n}$ as calculated pursuant to Formula B-27 and as adjusted for any charges or payments that are zeroed out for Transmission Owner *q* for Reconfiguration Auction *n*

$GFR\&\ GFTCC_{q,n}$= The one-month portion of the imputed value of Grandfathered TCCs and Grandfathered Rights, valued at one-sixth of the market clearing price in the last Centralized TCC Auction held for TCCs valid during the month

		corresponding to Reconfiguration Auction *n*, provided that the Transmission Owner is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in the month corresponding to Reconfiguration Auction *n*
t	=	Transmission Owner *t*
T	=	The set of all Transmission Owners *q*.

Each Transmission Owner's share of Net Auction Revenues allocated pursuant to this Section 17.5.3.7 shall be incorporated into its TSC or NTAC, as the case may be.

18 Attachment C -Formulas For Determining Bid Production Cost Guarantee Payments

18.1 Supplemental Payments to Generators and Demand Resources

Three supplemental payments for Generators are described in this attachment: (i) Day-Ahead Bid Production Cost guarantees; (ii) Real-time Bid Production guarantees for all intervals except maximum generation pickups and large event reserve pickups; and (iii) Real-time Bid Production Cost guarantees for maximum generation pickups and large event reserve pickups. Generators shall be eligible for these payments under the circumstances described in Article 4 and Rate Schedule 15.4 of this ISO Services Tariff.

Demand Side Resources that are committed to provide non-synchronized Operating Reserves shall be treated the same as Generators with respect to the determination of supplemental payments. Demand Reduction Providers that provide Demand Reductions in the Day-Ahead Market shall be eligible for supplemental payments under Section 18.2, but not this Section 18.1. Demand Side Resources committed in the Day-Ahead market to provide synchronized Operating Reserves shall be eligible for supplemental payments under Section 18.4.1. Demand Side Resources committed in the real-time market to provide synchronized Operating Reserves or Regulation Service shall be eligible for supplemental payments under Section 18.4.2.

18.1.1 Day-Ahead Bid Production Cost Guarantee Formulas

Day-Ahead Bid Production Cost Guarantee =

$$\sum_{g\in G}\max\left[\sum_{h=1}^{24}\left(\begin{array}{l}\int_{MGH_{gh}^{DA}}^{EH_{gh}^{DA}} C_{gh}^{DA} + MGC_{gh}^{DA}\,MGH_{gh}^{DA} + SUC_{gh}^{DA}\,NSUH_{gh}^{DA} \\ - LBMP_{gh}^{DA}\,EH_{gh}^{DA} - NASR_{gh}^{DA}\end{array}\right),0\right]$$

Where:

G	=	set of Generators;
EH_{gh}^{DA}	=	Energy scheduled Day-Ahead to be produced by Generator g in hour h expressed in terms of MW;
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 MW;
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 $/MW;
SUC_{gh}^{DA}	=	Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, in hour h into the Day-Ahead Market expressed in terms of $/start;
$NSUH_{gh}^{DA}$	=	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 to operate in hour h 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 Bid to provide that amount of Regulation Service in that hour (unless the Bid exceeds the payments that Generator receives for providing Regulation Service that was committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead, in which case this component shall be zero); 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.

18.1.2 Real-Time Bid Production Guarantee Formulas for All Imports and Real-Time Bid Production Guarantee Formulas for All Intervals With No Maximum Generation Pickups or Large Event Reserve Pickups for All Other Generators

Real-Time Bid Production Cost Guarantee =

$$\sum_{g \in G} \max \left[\left[\left\{ \sum_{i=1}^{N} \left(\left(\begin{array}{l} \int_{EI_{gi}^{DA}}^{EI_{gi}^{RT}} C_{gi}^{RT} + MGC_{gi}^{RT} \left(MGI_{gi}^{RT} - MGI_{gi}^{DA} \right) \\ - LBMP_{gi}^{RT} \left(EI_{gi}^{RT} - EI_{gi}^{DA} \right) \end{array} \right) * \frac{s_i}{3600} - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA} \right) - RRAP_{gi} + RRAC_{gi} \right) + \sum_{j=1}^{L} SUC_{gj}^{RT} \left(NSUI_{gj}^{RT} - NSUI_{gj}^{DA} \right) \right\}, 0 \right] \right]$$

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 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;

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 \$/MW;

SUC_{gj}^{RT} = Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, for the hour that includes interval j into RTD expressed in terms of \$/start, except that SUC_{gj}^{RT} shall be deemed to be zero in the cases of (i) Self-Committed Fixed and Self-Committed Flexible Generators, (ii) 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 (iii) 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. Rules addressing the handling of Start-Up Bids submitted by Generators that are committed via SRE under particular factual circumstances are set forth below;

$NSUI_{gj}^{RT}$ = number of times Generator g started up in the hour that includes RTD interval j;

$NSUI_{gj}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in the hour that includes RTD interval j;

$LBMP_{gi}^{RT}$ = Real-Time LBMP at Generator g's bus in RTD interval i expressed in terms of $/MWh;

N = except for imports, the number of eligible RTD intervals in the day excluding intervals in which there are any maximum generation pickups or large event reserve pickups and the three RTD intervals following the termination of the large event reserve pickup or maximum generation pickup (which are addressed separately in subsection 18.1.3 below) and excluding any RTD intervals where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA}; *provided*, *however*, for imports, the variable N is the number of eligible RTD intervals in the day excluding any RTD intervals where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA};

L = all intervals in the day

EI_{gi}^{RT} = if $EOP_{ig} > AEI_{ig}$ then $\min(\max(AEI_{ig},RTSen_{ig}),EOP_{ig})$ and $\max(\min(AEI_{ig},RTSen_{ig}),EOP_{ig})$ otherwise

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 scheduled revenue paid to Generator g as a result of either having been committed Day-Ahead to operate in hour that includes RTD interval i or having operated in interval i 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 Bid(s) 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 (unless the Bid(s) exceeds the payments that Generator receives for providing Regulation Service, in which case this component shall be zero); (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 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 $.

Time periods including reserve pickups, and time periods following a reserve pickup in which the dispatch of a given Generator is constrained by its downward ramp rate, will not be included in the above calculation of supplemental payments for that Generator.

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). 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.

Supplemental payments to Generators that trip before completing their minimum run-time (for Generators that were not scheduled to run Day-Ahead) or before running for the number of hours they were scheduled to operate (for Generators scheduled to run Day-Ahead) may be reduced by the ISO, per ISO Procedures.

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.

18.1.3 Real-Time Bid Production Cost Guarantees for Intervals With Maximum Generation Pickups or Large Event Reserve Pickups

Real-Time Bid Production Cost Guarantee Payment =

$$\sum_{g \in G}\left[\sum_{i=1}^{M}\max\left(\begin{array}{l}\left(\begin{array}{l}\displaystyle\int_{EI_{gi}^{DA}}^{EI_{gi}^{RT}} C_{gi}^{RT} + MGC_{gi}^{RT}\left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right) \\ - LBMP_{gi}^{RT}\left(EI_{gi}^{RT} - EI_{gi}^{DA}\right)\end{array}\right) * \frac{s_i}{3600} \\ \\ -\left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}\end{array}, 0\right)\right]$$

where:

M = number of intervals in which there are maximum generation pickups or large event reserve pickups in the 24--hour day and the three RTD intervals following the termination of the large event reserve pickup or maximum generation pickup, 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};

The definition of all other variables is identical to those defined in Section 18.1.2 above.

18.2 Supplemental Payments for Curtailment Initiation Costs

A supplemental payment for Curtailment Initiation Costs shall be made when the Curtailment Initiation Cost Bid and the Demand Reduction Bid price offered by a Demand Reduction Provider for any Demand Reduction committed by the ISO in the Day-Ahead market over the [twenty-four (24) hour] day exceeds Day-Ahead LBMP revenue, provided however that Supplemental payments made to Demand Reduction Providers that fail to complete their scheduled reductions may be reduced by the ISO, pursuant to ISO Procedures.

18.3 Supplemental Payments for Special Case Resources

A supplemental payment for Minimum Payment Nominations shall be made when the Minimum Payment Nomination for any Special Case Resource committed by the ISO 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.

18.4 Supplemental Payments for Demand Side Resources providing Synchronized Operating Reserves

A. A supplemental payment to a Demand Side Resource with a synchronized Operating Reserves or Regulation Service schedule in the Day-Ahead Market shall be calculated by setting to zero all terms provided in Section 18.1.1 of this Attachment C, with which Day-Ahead supplemental payments are calculated, with the exception of the term $NASR_{gh}^{DA}$ which shall be calculated pursuant to its description.

B. A supplemental payment to a Demand Side Resource with a synchronized Operating Reserves schedule in the real-time Market shall be calculated by setting to zero all terms provided in Section 18.1.2 of this Attachment C, with which real-time supplemental payments are calculated, with the exception of the terms $NASR_{gi}^{DA}$ and $NASR_{gi}^{TOT}$, which shall be calculated pursuant to their descriptions.

Generators with start-up times of greater than twenty-four (24) hours will have their start-up cost Bids equally prorated over the course of each day included in their start-up period. Consequently, units whose start-ups are aborted will receive a prorated portion of those payments, based on the portion of the start-up sequence they have completed (e.g., if a unit 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 cost Bid).

19 Attachment D – Data Requirements For LBMP Bidders

Table 19.1 Data Requirements for Internal Generators for LBMP Bidders				
Data Item	**Cat.**	**Bid Parameters**	**Variability**	**Comments**
Company Name	G	--	Static Required	Parent organization.
Generator Name/No.	G	--	Static Required	
Generator Unit Code/ID	G	--	Static Required	Unique code which identifies the Generator to the ISO.
Bus	G	Bus No.	Static Required	Specific location of Generator within the NYCA.
Submitted By	G	Name	May vary Required	Organization submitting Bid. Multiple organization can be authorized to submit Bids with the ISO accepting the most recent. A single organization must be specified to receive invoices from the ISO.
DMNC (Summer & Winter)	P/G	MW	Static Required	Dependable Maximum Net Capability. Confirmed by test for Generator's with Installed Capacity contracts, or historical production data.
Power Factor	P/G	MW/MVA	Static Optional	Generator's tested Power Factor for producing Reactive Power (MVArs) at normal high operating limit MW output level, provided it is at least 90% of DMNC. This is required for Generators receiving Voltage Support Payments.
Installed Capacity Contracts	G	MW	May vary Required	Installed Capacity contracts in effect with LSEs within the NYCA. The ISO may limit maximum and/or minimum amounts of Installed Capacity by location due to reliability Constraints.
Normal Upper Operating Limit	C/D	MW	May change Required by hour for Day-Ahead	Maximum output of a Generator that could be expected in any hour of the following operating day. The ISO must be informed of a limit change that results in less Capability.
Emergency Upper Operating Limit	C/D	MW	May change Required by hour for Day-Ahead	Maximum output that a Generator's owner expects it can reach during extraordinary conditions. A Generator's Emergency Upper Operating Limit may be no less than its Normal Upper Operating Limit.
Normal Response Rate (NRR)	P/C/D	MW/min.	May vary Required	To be provided as an expected response rate. Generators may specify up to three NRRs. The minimum acceptable response rate is 1% of a Generator's gross output per minute.
Regulation Response Rate (RRR)	P/C/D	MW/Min.	Same as Optional NRR	To be provided as an expected response for Regulation Service. If RRR differs from NRR, the total expected response rate is restricted to the maximum of the two rates.
Emergency Response Rate (ERR)	P/C/D	MW/Min.	Same as NRR	To be provided as expected response for reserve pickups; A Generator's ERR must be greater than or equal to the capacity-weighted average of its NRRs.
Reactive Power Capability	P/G	Piecewise linear curve with MW as independent variable and +/- MVArs as dependent variable	Static Optional	Update as changed.
Physical Minimum Generation Limit	P/G	MW	Static Required	

Notes:

Internal Generators LBMP bidders are located within the NYCA.
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Static Data remains relatively constant over the lifetime of Bids but can be changed.
General Data may be provided electronically or by mail, but requires a confirmation or Pre-Qualification process by the ISO.
Some data will require substantiation by a test; actual data Bid may be subject to validation checking against Pre-Qualification data.
Optional = Required only when providing or bidding to provide the associated service.

Table 19.2 Data Requirements for Demand Side Resources				
Data Item	**Cat.**	**Bid Parameters**	**Variability**	**Comments**
Company Name		--	Static Required	Parent organization.
Generator Name/No.	G	--	Static Required	
Generator Unit Code/ID	G	--	Static Required	Unique code which identifies the Demand Side Resource to the ISO
Bus	G	Bus No.	Static Required	Specific location of Demand Side Resource within the NYCA
Submitted By	G	Name	May vary Required	Organization submitting Bid. Multiple organization can be authorized to submit Bids with the ISO accepting the most recent. A single organization must be specified to receive invoices from the ISO.
DMNC (Summer & Winter)	P/G	MW	Static Required	Specify maximum, megawatt Curtailment Bid.
Power Factor	P/G	MW/MVA	Static Optional	Values to be initialized pursuant to ISO requirements.
Installed Capacity Contracts	G	MW	May vary Required	Installed Capacity contracts in effect between Special Case Resources that are Demand Side Resources and LSEs within the NYCA. The ISO may limit maximum and/or minimum amounts of Installed Capacity by location due to reliability Constraints.
Normal Upper Operating Limit	C/D	MW	May vary Required by hour for Day-Ahead	Maximum output of a Demand Side Resource that could be expected in any hour of the following operating day. The ISO must be informed of a limit change that results in less Capability.
Emergency Upper Operating Limit	C/D	MW	May vary Required by hour for Day-Ahead	Maximum output that a Demand Side Resource expects to be able to reach during extraordinary conditions. A Demand Side Resource's Emergency Upper Operating Limit may be no lower than its Normal Upper Operating Limit.
Normal Response Rate (NRR)	P/C/D	MW/min.	May vary Required	To be provided as an expected response rate for RTD. Demand Side Resources may specify up to three NRRs. The minimum acceptable response rate is 1% of the quantity of Demand Reductions that the Demand Side Resource produces per minute.
Emergency Response Rate (ERR)	P/C/D	MW/Min.	Same as NRR	To be provided as expected response for reserve pickups. A Demand Side Resource's ERR must be greater than or equal to the capacity-weighted average of its NRRs.
Physical Minimum Demand Reduction Limit	P/G	MW	Static Required	

Notes:
Demand Side Resource LBMP bidders are located within the NYCA.
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Static Data remains relatively constant over the lifetime of Bids but can be changed.
General Data may be provided electronically or by mail, but requires a confirmation or Pre-Qualification process by the ISO.
Some data will require substantiation by a test; actual data Bid may be subject to validation checking against Pre-Qualification data.
Optional = Required only when providing or bidding to provide the associated service.

Table 19.3 Data Requirements for External Generators

Data Item	Cat.	Bid Parameters	Variability	Comments
Company Name	G	--	Static Required	Parent organization.
Generator Name/No.	G	--	Static Required	
Generator Unit Code/ID	G	--	Static Required	Unique code which identifies the Generator to the ISO.
Submitted By	G	Name	May vary Required	Organization submitting Bid. Multiple organizations can be authorized to submit Bids with the ISO accepting the most recent. A single organization must be specified to receive invoices from the ISO.
Dependable Maximum Net Capability	P/G	MW	Static Required	Confirmed by test for Generators with Installed Capacity contracts.
Installed Capacity Contracts	P/G	MW	Variable (not within a Bid) Optional	Installed Capacity contracts in effect with LSEs within the NYCA. The ISO may limit maximum and/or minimum amounts of Installed Capacity by location due to reliability Constraints.
Normal Upper Operating Limit	C/D	MW	May change by hour for Day-Ahead Required	Maximum output of a Generator that could be expected in any hour of the following operating day. The ISO must be informed of a limit change that results in less Capability.
Emergency Upper Operating Limit	C/D	MW	May vary Required by hour for Day-Ahead	Maximum output that a Generator's owner expects it can reach during extraordinary conditions. A Generator's Emergency Upper Operating Limit may be no lower than its Normal Upper Operating Limit.
Physical Minimum Generation Limit	P/G	MW	Static Required	

Notes:

External Generators LBMP bidders are located outside the NYCA.
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Static Data remains relatively constant over the lifetime of Bids but can be changed.
General Data may be provided electronically or by mail, but requires a confirmation or Pre-Qualification process by the ISO.
Some data will require substantiation by a test; actual data Bid may be subject to validation checking against Pre-Qualification data.
Optional = Required only when providing or bidding to provide the associated service.

Table 19.4 Data Requirements for Generator Commitment Bids				
Data Item	**Cat.**	**Bid Parameters**	**Variability**	**Comments**
Startup Time	C/B	Hours: Minutes **or** Piecewise linear curve with Hours Off-Line as independent variable and Hours to Start as dependent variable	May be changed for any Day-Ahead or Real-Time Commitment Required	Length of time needed to startup an off-line Generator, synchronize it to the power grid and stabilize at minimum.
Startup Bid Price	C/B	$$ to Start specified hourly **or** Piecewise linear curve with hours off-line as an independent variable and $ to Start as a dependent variable	May be changed hourly for any Day-Ahead Commitment. May only be lowered in the Real-Time Commitment in any hour in which the Generator has a Day-Ahead schedule. Required	
Minimum Run Time	C/B	Hours:Minutes	May be changed for any Day-Ahead Commitment but may not be changed once a Generator is online. May be changed in Real-Time if the Generator is not currently online. Required	Duration of time that a Generator must run once started before it can subsequently be decommitted. Minimum Run Time cannot be honored past the end of the Dispatch Day. The longest Minimum Run Time allowed for Generators that are economically committed by RTC or RTD in the Real-Time Market shall be one hour, unless the Generator is a Real-Time Minimum Run Qualified Gas Turbine. For Real-Time Minimum Run Qualified Gas Turbines, the Minimum Run Time that shall be assigned by RTC for economic commitment shall be two hours.
Minimum Down Time	C/B	Hours:Minutes	May be changed for any Day-Ahead or Real-Time Commitment Required	Duration of time that a Generator must remain off-line following decommission before it can be re-started. SCUC shall honor Minimum Down Time within a twenty four hour Dispatch Day. RTC will honor Minimum Down Times in the Real-Time Market unless the Generator has a Day-Ahead Schedule for any portion of the RTC optimization period.
Maximum Number of Startups per Day	C/B	No	Static Required	RTC will monitor but will not honor this parameter.
Notes: Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity. Static Data remains relatively constant over the lifetime of bids but can be changed.				

Table 19.5 Data Requirements for Demand Side Resource Commitment Bids				
Data Item	**Cat.**	**Bid Parameters**	**Variability**	**Comments**
Startup Time	C/B	Hours: Minutes	May be changed for any Day-Ahead or Real-Time Commitment Required	ISO will provide assumed value.
Startup Bid Price	C/B	$$ to Start specified hourly	May be changed hourly for any Day-Ahead Commitment and, for any Real-Time Commitment in an hour in which the Demand Side Resource does not have a Day-Ahead schedule. Required	The Curtailment Initiation Cost should be entered here
Minimum Run Time	C/B	Hours:Minutes	May be changed for any Day-Ahead or Real-Time Commitment; may not be changed once Resource is on-line Required	Duration of time that the Demand Side Resource must reduce its demand once started before it can subsequently be decommitted. Minimum Run Time cannot be for more than 8 hours and cannot be honored past the end of the Dispatch Day.
Minimum Down Time	C/B	Hours:Minutes	May be changed for any Day-Ahead or Real-Time Commitment Required.	Duration of time that the Demand Side Resource must remain off-line following decommission before it can be re-started. SCUC shall honor Minimum Down Time within a twenty four hour Dispatch Day. RTC will honor Minimum Down Times in the Real-Time Market unless the Demand Side Resource has a Day-Ahead Schedule for any portion of RTC's optimization period.
Maximum Number of Startups per Day	C/B	No	Static (but may be changed in Real-Time Bids.) Required	RTC will monitor but will not honor this parameter.

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Static Data remains relatively constant over the lifetime of bids but can be changed.

Table 19.6 Data Requirements for Generator Energy Bids

Data Item	Cat.	Bid Parameters	Variability	Comments
Minimum Generation Energy Block and Bid Price	C/B	MW and $/hour	May vary by hour.	Must be provided for commitment. Gas turbine units that fully load on startup can use this form or bid in lieu of a Dispatchable Energy Bid, but will set LBMP when economic.
Dispatchable Energy Bids	C/B	No. of steps $/MWh, and MWs of each step	May vary by hour.	Bids may consist of up to eleven constant cost incremental Energy steps. The cost of each step must exceed the cost of the preceding step.
Dispatch Status	C/B	ISO-Committed Flexible, ISO-Committed Fixed, Self-Committed Flexible, or Self-Committed Fixed	May vary. ISO-Committed Flexible or Self-Committed Flexible Resources that are scheduled Day-Ahead may not be ISO-Committed Fixed in real-time, unless a physical operating problem makes it impossible for them to be flexible.	ISO-Committed Fixed Generators are eligible to receive a Day-Ahead schedule on request.

<u>Notes</u>:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.

Table 19.7 Data Requirements for Demand Side Resource Reduction Bids				
Data Item	**Cat.**	**Bid Parameters**	**Variability**	**Comments**
Minimum Generation Energy Block and Bid Price	C/B	MW and $/hour	May vary by hour.	Enter Demand Side Resources' minimum reduction and Bid price. Must be provided for commitment.
Dispatchable Energy Bids	C/B	No. of steps $/MWh, and MWs of each step	May vary by hour.	Bids may consist of up to eleven constant cost incremental Energy steps. The cost of each step must exceed the cost of the preceding step.
Bidding Mode	C/B	ISO-Committed Fixed if participating in DADRP. ISO-Committed Flexible if providing non-synchronized reserves in real-time (to the extent that ISO's software can support such participation.)	May vary by hour.	
Notes: Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.				

Table 19.8 Data Requirements for Generator Regulation Service Bids				
Data Item	**Cat.**	**Bid Parameters**	**Variability**	**Comments**
Regulation Capacity Availability Bid	C/B	Table D-4 is required MW	May vary by hour Required	Generator must be able to respond to AGC Base Point Signals from the ISO. The Regulation Capacity Availability Bid along with the submitted Regulation Response Rate (from Table 19.1) represent the maximum response range in MW and change Rate in MW/Min.
Regulation Capacity Price Bid	C/B	$/MW	May vary by hour Required	

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Regulation Service Bids made for the Day-Ahead Market which are accepted are binding for the next 24 hour operating day.
Regulation Service not scheduled for use by the ISO may be marketed by the bidder providing no other terms or forward contracts are violated.
Unscheduled Regulation Service may be bid into the Real-Time Market, and may have a different Bid price than the Day-Ahead Bid.
Optional = Required only when providing or bidding to provide the associated service.

Table 19.9 Data Requirements for Operating Reserve Bids

Data Item	Cat.	Bid Parameters	Variability	Comments
Spinning Reserve Bid	C/B/D	Same as in Table D-4 Day-Ahead only $/MW Availability Price Bid	Required Day-Ahead, may vary hourly Real-Time Availability Bids will not be accepted. All Generators accepted to provide Energy will be treated as offering Reserves at a price of $0/MW.	MW available is not separately bid but is a function of the bidder's ERR and UOL. If no Day-Ahead Availability price is bid, the relevant Day-Ahead Bid shall be rejected in its entirety (without prejudice to its being resubmitted in a timely manner).
10-Minute Non-Synchronized Reserve Bid	C/B/D	Day-Ahead only $/MW Availability Price Bid	Required Day-Ahead, may vary hourly. Real-Time Availability Bids will not be accepted. All Generators accepted to provide Energy will be treated as offering Reserves at a price of $0/MW.	MW available is not separately Bid but is a function of the Bidder's UOL. If no Day-Ahead Availability price is bid, the relevant Day-Ahead Bid shall be rejected in its entirety (without prejudice to its being resubmitted in a timely manner).
30-Minute Operating Reserve Spinning or Non-Synchronized	C/B/D	Day-Ahead only $/MW Availability Price Bid	Required Day-Ahead, may vary hourly. Real-Time Availability Bids will not be accepted. All Generators and Demand Side Resources accepted to provide Energy will be treated as offering Reserves at a price of $0/MW.	MW available is not separately Bid but is a function of the Bidder's ERR if synchronized, and its UOL. If no Day-Ahead Availability price is bid, the relevant Day-Ahead Bid shall be rejected in its entirety (without prejudice to its being resubmitted in a timely manner).

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Operating Reserve Bids made for the Day-Ahead Market which are accepted are binding for the next 24 hour operating day.
Operating Reserves not scheduled for use by the ISO may be marketed by the bidder providing no other terms or forward contracts are violated.
Optional = Required only when providing or bidding to provide the associated service.

Table 19.10 Data Requirements for Virtual Transaction Bids to Purchase Energy				
Data Item	**Cat.**	**Bid Parameters**	**Variability**	**Comments**
Company Name	G	--	Static	LSE, Energy Service Co. or other Transmission/Distribution Co. providing Load forecast.
Point of Withdrawal (Sink) Location	G	For Internal Loads: LBMP Zone or Zone and Bus **or** For External Loads: Control Area or Control Area and Proxy Bus	Static	
Submitted By	G	Name	May Vary	Organization submitting Bid.
Energy Forecast	C/B/D	MWh/hr	Variable by Hour	Total Estimate for Bid and non-Bid Load; ISO will rely on *its* own composite Load forecast as a reliability commitment to ensure that all Load is served. May be updated after DAM and/or Real Time to indicate adjusted Load served
Energy Commit Bid	C/B/D	MW that will be committed for Day-Ahead Forward Contract	Variable by hour	Bidding is limited to the Day-Ahead Market.
Price Capped Energy Block Bids	C/B/D	No. of Blocks, MW/Block, and $/MW/Block	Variable by hour	Bidding is limited to the Day-Ahead Market.

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Energy Bids made for the Day-Ahead Market which are accepted are binding for the next 24 hour operating day.

Table 19.11 Data Requirements for Virtual Transaction Bids to Supply Energy

Data Item	Cat.	Bid Parameters	Variability	Comments
Company Name	G	--	Static	LSE, Energy Service Co. or other Transmission/Distribution Co. providing Load forecast.
Point of Injection (Source) Location	G	LBMP Zone	Static	
Submitted By	G	Name	May Vary	Organization submitting Bid.
Price Capped Energy Block Bids	C/B/D	No. of Blocks, MW/Block, and $/MW/Block	Variable by hour	Bidding is limited to the Day-Ahead Market.

Notes:
Cat. = Data Categories: **G** = General; **P** = Pre-Qualification; **C** = Commitment; **B** = Balancing; **D** = Dispatch; **I** = Installed Capacity.
Energy Bids made for the Day-Ahead Market which are accepted are binding for the next 24 hour operating day.

20 Attachment E - Procedures for Reserving and Correcting Erroneous Energy and Ancillary Services Prices

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. These provisions shall control the reservation and correction of Energy and Ancillary Services prices that are posted on OASIS and used in ISO settlements.

20.1 Market Clearing Price Errors Requiring Correction

To be determined in accordance with the ISO tariffs, an Energy and Ancillary Service clearing price must be: (i) calculated correctly according to the relevant provision(s) of the ISO tariffs and (ii) based on the appropriate price-setting resource (*i.e.*, the marginal resource, except as otherwise provided by the ISO tariffs).

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 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 Commitment or Real-Time Dispatch 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);

(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 - Temporary Bid Caps

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 Cap" shall mean the maximum Bid Price that may be submitted in connection with certain Bids, as specified in Sections 21.5 and 21.6 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 Sections 21.5 and 21.6 below.

21.4 Expiration Date

Attachment F shall remain in effect until a Northeastern RTO is in place and operating pursuant to market rules established pursuant to the Commission's RTO market design and market structure rulemaking.

21.5 Establishment of Temporary Bid Caps

During the period that Attachment F is in effect, the Bid Cap for all Bids referenced in Section 21.6.1 below shall be $1,000/MWh. If a Bid exceeds an applicable Bid Cap, the Bid shall be automatically rejected by the ISO. In addition, any Bid for a date during the effectiveness of this Attachment F that is submitted prior to the incorporation of Bid Cap logic into the ISO software that exceeds an applicable Bid Cap will be rejected, and the bidding entity will be required to submit a new Bid that conforms to the Bid Cap.

21.6 Applicability of Temporary Bid Caps

21.6.1 The Bid Cap established in Section 21.5 shall apply to Day-Ahead and real-time Energy Bids, Minimum Generation Bids, Decremental Bids, Price Cap Load Bids, and real-time Sink Price Cap Bids, as applicable, except with respect to the bid pricing rules for Sink Price Cap Bids and Decremental Bids submitted for External Transactions and Wheels Through at Proxy Generator Buses that are set forth in Section 17.3.2 of Attachment B to this ISO Services Tariff. But for this exception, all Suppliers and Demand Side Resources, whether External or Internal to the NYCA, shall be subject to a Bid Cap for all Bids specified herein.

21.6.2. The Bid Cap shall not apply to Ancillary Services Bids, Start-Up Bids or to any other Bid that is not specified in Section 21.6.1. 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 (until its expiration twelve months after July 8, 2003) of Attachment H to this ISO Services Tariff.

21.6.3 Bid Caps 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 shall become effective on May 1, 2001. At the end of each Capability Period, the ISO will review the Emergency Demand Response Program's performance 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 become Customers solely for the purpose of participating in the Emergency Demand Response Program, must become Limited Customers. The requirements for becoming a Limited Customer are set forth in the ISO Procedures.

Customers and Limited Customers seeking to become Curtailment Service Providers must: (i) comply with the registration requirements set forth in the ISO Procedures; and (ii) as discussed in 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 activation 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. Curtailment Services Providers must also comply with the metering requirements set forth below in Section 22.8, and in the 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. Curtailment Service Providers are free to participate in other demand response programs, to the extent that those programs allow, except as noted in Section 22.5 below, provided, however that the NYISO 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 by another Curtailment Service Provider.

22.5 ISO Activation Of The Emergency Demand Response Program

The ISO shall have discretion to activate the Emergency Demand Response Program in response to: (i) a Real-Time Locational or statewide Operating Reserve shortage or an ISO peak forecast of a locational or system-wide Operating Reserve shortage; (ii) an ISO declared Major Emergency State; or (iii) in response to a request for assistance from a Transmission Owner for Load relief purposes or as a result of a Local Reliability Rule. In the event that the NYISO instructs Special Case Resources to reduce their consumption of Energy, the ISO may activate the Emergency Demand Response Program. The ISO may use its discretion to call on the Emergency Demand Response Program to relieve NYCA or Zonal Emergencies and may call on the performance of fewer than all participants in the Emergency Demand Response Program within Load Zone J in accordance with ISO Procedures when responding to the request for assistance from the Transmission Owner.

22.6 Notification Of Curtailment Service Providers

The ISO shall attempt, whenever possible, to provide Curtailment Service Providers with day-ahead notice that it may activate the Emergency Demand Response Program. Providing day-ahead notice of possible activation does not commit the ISO to activate the Emergency Demand Response Program or to make payments. The ISO shall provide Curtailment Service Providers with at least two hours' notice of its activation of the Emergency Demand Response Program. The notice shall specify the time at which the ISO requests that demand reductions begin and shall, whenever possible, specify when the need for demand reductions will end. The ISO may call Curtailment Services Providers to provide Load reduction as soon as possible in the event of a Real-Time Locational or statewide Operating Reserve shortage, emergency, or in response to a Transmission Owner request for assistance for Load relief purposes or as a result of a Local Reliability Rule.

Curtailment Service Providers shall designate a contact person to receive the ISO's notification.

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 demand when the Emergency Demand Response Program is activated. Participation in the Emergency Demand Response Program shall not expand or reduce a Local Generator's rights and obligations to buy or sell Energy into the wholesale Energy market. Special Case Resources that have not sold their capacity for the month shall be temporarily transferred to the Emergency Demand Response Program for such month until such time as their capacity is sold.

22.8 Metering

Curtailment Service Providers shall provide sufficient hourly interval metering data, pursuant to ISO procedures, to allow verification of their demand reduction performance.

22.9 Verification

Curtailment Service Providers shall verify their demand reduction performance by providing interval metering data to the ISO within 75 days of their performance in the Emergency Demand Response Program. If a Curtailment Service Provider fails to provide the data within the 75 day period the ISO shall refuse to pay for that Curtailment Service Provider's claimed demand reductions. All load reduction data are subject to audit by the NYISO. 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 cause a verified reduction in demand in response to the activation of the Emergency Demand Response Program provided the Curtailment Service Provider provides evidence of such reductions within 75 days of the demand reduction performance. If the ISO activates the Emergency Demand Response Program, each Curtailment Service Provider that caused a verified reduction in demand shall be paid for demand reduced for the duration of the ISO activation of the Demand Response Program or four hours, whichever is greater.

If the ISO activates the Emergency Demand Response Program for more than four hours, each Curtailment Service Provider shall be paid the higher of $500/MWh, or the zonal Real-Time LBMP per MWh, of demand reduced, starting with the hour specified by the ISO as the starting time of the activation, or, in the event that the ISO specified that the demand reduction begin as soon as possible, starting with the hour that the Curtailment Service Provider began its response.

If the ISO activates the Emergency Demand Reduction Program for four hours or less, each Curtailment Service Provider shall be paid as if the Emergency Demand Response Program had been activated for four hours. Each Curtailment Service Provider that reduces demand shall be paid the higher of $500/MWh or the zonal Real-Time LBMP per MWh, of demand reduced, for the duration of the ISO activation of the Emergency Demand Response Program or two hours whichever is greater, starting with the hour specified by the ISO as the starting time of the activation, or, in the event that the ISO specified that the demand reduction begin as soon as possible, starting with the hour that the Curtailment Service Provider began its response. Each Curtailment Service Provider shall be paid the zonal Real-Time LBMP per MWh of demand reduced for the remainder of the four hour minimum payment period, provided that a verified demand reduction was effectuated by the time specified in the ISO’s notice.

22.11 Cost Allocation

In the event that the ISO activates the Emergency Demand Response Program in response to a statewide Emergency, a Real-Time statewide Operating Reserve Shortage or peak forecast of a statewide Operating Reserve shortage, payments made to Curtailment Service Providers shall be recovered from all Transmission Customers on a statewide basis. The ISO shall calculate, and the Transmission Customer shall pay, the monthly charge equal to the product of (A) payments made to Curtailment Service Providers and (B) the ratio of (i) the customer's billing units for the month to (ii) the sum of all billing units during that month. Billing units shall be based on the Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA, and hourly Energy schedules for all Wheel Throughs and Exports. To the extent that the ISO activates the Emergency Demand Response Program in response to an Emergency or a Real-Time Locational Operating Reserve shortage or a peak forecast of an Operating Reserve shortage in a particular zone or zones, including Load relief or to meet a Local Reliability Rule within a Zone as requested by a Transmission Owner, the billing units for such charges will be based on the Actual Energy Withdrawals the affected zone(s) during the hours in which the Emergency Demand Response Program was activated.

LSEs shall also be required to pay the monthly charges calculated above for the Transmission Customers which the LSE serves as retail access customers.

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 ~~it~~ 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, **"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 an In-City 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

iv) all persons or Entities with which such person or Entity has any form of agreement under which such person or Entity has retained or has conferred rights of Control of 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.

~~For purposes of §Section 23.4.5 of this Attachment H, "Attributable ICAP" shall mean ICAP from an In-City Installed Capacity~~ Supplier ~~that an entity has rights to use in fulfillment of its Installed Capacity obligation, or to which the entity has rights of ownership or Control, or as to which it has any other form of significant financial obligation.~~

"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 ~~either (a)~~ the ability to determine the quantity or price of offers to supply Unforced Capacity from an In-City Installed Capacity Supplier submitted into an ICAP Spot Market Auction~~, or (b) a right to revenue or other financial benefits from such Unforced Capacity~~.

"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.

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 the New York City Locality, net of costs that would have been incurred as a result of the foregone sale if it had taken place.

“Initial Decision Period” shall have the meaning specified in Attachment S of the ISO’s Open Access Transmission Tariff.

“Interconnection Customer” shall have the meaning specified in Attachment Z of the ISO’s Open Access Transmission Tariff.

“Interconnection Facilities Study Agreement” shall have the meaning specified in 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 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.

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.

“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, “Net Buyer” shall mean an entity that, together with its Affiliates, has a total LSE Unforced Capacity Obligation relating to In-City Load that is greater than the total amount of Attributable ICAP of the entity and its Affiliates.~~

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 the New York City Locality, net of the likely projected annual Energy and Ancillary Services revenues of such unit, as determined in connection with establishing the Demand Curve for the New York City Locality 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.

For purposes of Section 23.4.5 of this Attachment H, **"Offer Floor"** for an In-City Installed Capacity Supplier that is not a Special Case Resource shall mean the lesser of a numerical value equal to 75% of the Net CONE translated into a seasonally adjusted monthly UCAP value, or a numerical value determined as specified in Section 23.4.5.7.3, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate, or for an In-City Installed Capacity Supplier that is a Special Case Resource shall mean a numerical value determined as specified in Section 23.4.5.7.5.

For purposes of Section 23.4.5 of this Attachment H, **"Pivotal Supplier"** shall mean a Market Party that, together with any of its Affiliated~~s~~ 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 Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction.

"Project Cost Allocation" shall have the meaning specified in 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 Attachment S of the ISO's Open Access Transmission Tariff.

"Subsequent Decision Period" shall have the meaning specified in 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 the New York City Locality in excess of the Locational Minimum Installed Capacity Requirement for the New York City Locality.

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 the New York City Locality 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 the New York City Locality including embedded costs of transmission service, in either case net of likely projected annual Energy and Ancillary Services revenues, as determined by the ISO, translated into a seasonally adjusted monthly UCAP value using an appropriate class outage rate.

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 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.

Filed March 20, 2008 to comply with order of the Federal Energy Regulatory Commission, Docket No. EL07-39-000, issued March 7, 2008, 122 FERC ¶ 61,211 (2008). Proposed effective date: March 27, 2008.

Filed May 6, 2008 to comply with order of the Federal Energy Regulatory Commission, Docket No. EL07-39-000, issued March 7, 2008, 122 FERC ¶ 61,211 (2008). Proposed effective date: November 1, 2008.

Filed October 30, 2008 to comply with order of the Federal Energy Regulatory Commission, Docket Nos. EL07-39-002, ER08-695-000, and -001, issued September 30, 2008, 124 FERC ¶ 61,301 (2008). Proposed effective date: November 1, 2008.

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 into the area in which the Generator or generation is located has a Shadow Price greater than zero, 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 into the area in which the generation is located has a Shadow Price greater than zero, 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 generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the ISO as may be appropriate that an outage was forced.

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 a 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 Energy and Minimum Generation Bids: A 300 percent increase or an increase of $100 per MWh, whichever is lower; provided, however, that 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: 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.

23.3.1.2.1.3 Start-up costs 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: 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 into the area in which a Generator is located has a Shadow Price greater than zero, the lower of the thresholds specified for areas that are not Constrained Areas or a threshold determined in accordance with the following formula:

$$\text{Threshold} = \frac{2\,\% * \text{Average Price} * 8760}{\text{Constrained Hours}}$$

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 zero 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 zero 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 costs 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.

23.3.1.3 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 – 23.3.1.4.5 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 previous 90 days, adjusted for changes in fuel prices. 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, and (ii) 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 The mean of the LBMP at the Generator's location during the lowest-priced 25 percent of the hours that the Generator was dispatched over the previous 90 days, adjusted for changes in fuel prices. 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 via Supplemental Resource Evaluation or was Out-of-Merit Generation, from its development of that Generator's LBMP-based reference levels, and (iii) 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 Bid is intended to reflect the Generator's marginal costs. The ISO's determination of a Generator's marginal costs shall include an assessment of the Generator's incremental operating costs in accordance with the following formula, and 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:

((heat rate * fuel costs) + (emissions rate * emissions allowance price) + other variable operating and maintenance costs)).

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, 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 Energy Bids for New Capacity for the three year period following commencement of its commercial operation 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 peak LBMPs over the twelve months prior to the commencement of operation of the New Capacity in the 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 paragraph shall apply only to net additions of capacity during the applicable three year 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 start times, adjusted for changes in fuel prices;

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 by the bidding Generator to achieve its specified minimum operating level from an offline state, including, where appropriate, costs incurred to meet minimum run time and minimum downtime requirements, 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; or

23.3.1.4.4.3 The methods specified in Section 23.3.1.4.2.

23.3.1.4.5 Notwithstanding the foregoing provisions, the reference level for 10-Minute Non-Synchronized reserves shall be the lower of (i) the amount determined in accordance with the provisions of Section 23.3.1.4.1.1, or (ii) $2.52.

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 guarantee payments to a Market Party 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 30.4.6.2.3 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 30.4.6.2.4 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, including a Demand Side Resource participating in the Operating Reserves or Regulation Service Markets, that would be subject to mitigation or other information available to the ISO that the conduct and associated price or guarantee payments 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 guarantee payments to a Market Party for a day.

23.3.3 Consultation with a Market Party

23.3.3.1 Consultation Process

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. 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. 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. Upon request, the ISO shall also consult with a Market Party with respect to the information and analysis used to determine reference levels under Section 23.3.1.4

for that Market Party. 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 should be changed, revised reference levels shall be determined by the ISO, reviewed by the Market Monitoring Unit and, following the ISO's consideration of the Market Monitoring Unit's recommendation, communicated to the Market Party, and implemented by the ISO as soon as practicable. 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.

23.3.3.2 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 real-time guarantee payment mitigation 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 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 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 Market Parties that want to consult with the ISO regarding real-time guarantee payment impact test results 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").

23.3.3.3.1.3.1 Consultation Requests must be received by the ISO's customer relations department within 15 business days after the ISO posts new or revised real-time guarantee payment impact test settlement results for the relevant market day. Consultation Requests received outside the 15 business day period shall be rejected by the ISO.

23.3.3.3.1.3.2 The ISO may send more than one notice informing a Market Party of the same instance of real-time guarantee payment mitigation. Notices that identify real-time guarantee payment impact test 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.

23.3.3.3.1.3.3 If consultation was timely requested and completed addressing a particular set of real-time guarantee payment impact test results, a Market Party may not again request consultation regarding the same real-time guarantee payment impact test results unless revised real-time guarantee payment impact test settlement results, that are not due to the previously completed consultation and that change the dollar impact of real-time guarantee payment mitigation, are posted.

23.3.3.3.1.4 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 to determine the real-time guarantee payment impact test results 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 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 to determine the real-time guarantee payment impact test results 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.

23.3.3.3.1.6 Following the submission of a Consultation Request that satisfies the timing and bid identification requirements of Section 23.3.3.3.1.3, above, consultation shall be performed in accordance with Section 23.3.3.1 of these Mitigation Measures, as supplemented by the following rules:

23.3.3.3.1.6.1 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 real-time guarantee payment 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.

23.3.3.3.1.6.2 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 50 business days after the new or revised real-time guarantee payment impact test settlement results for the relevant market day were posted. 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 after the new or revised real-time guarantee payment impact test settlement results for the relevant market day were posted, 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 30.4.6.2.6 of Attachment O.

23.3.3.3.1.6.3 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.

23.3.3.3.1.7 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 Test

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, may contact the ISO within 15 business days after new or revised impact test settlement results are posted to request that the reference levels used to perform the conduct and impact tests for real-time guarantee payment 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 gas balancing penalties;

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 23.3.3.3.1.6.2 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 for the affected day. Only the reference levels used to perform real-time guarantee payment mitigation 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 conduct and impact tests using reference levels that reflect the verifiable costs that the Generator incurred and shall apply real-time guarantee payment mitigation if the Generator's bids fail conduct and impact 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

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.

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 for a bid submitted for an Electric Facility. The default bid shall establish a maximum or minimum value for one or more components of the submitted bid, 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 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.

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 procedures shall not be applied to hydroelectric resources or External Generators. In addition, except as specified below the following shall not be mitigated on an automated basis: (i) bids by a Market Party or its Affiliates that together have bidding control over 50 MW or less of capacity; or (ii) bids by a Market Party or its Affiliates that together have bidding control over 50 MW or more of capacity if the bids by such entities that meet the applicable conduct test for mitigation are for an amount of capacity that totals 50 MW or less. The foregoing exemptions shall be reduced or discontinued for any Market Party or its Affiliates determined by the ISO, after consulting with the Market Party as specified in Section 23.3.3, to be submitting bids that constitute economic withholding that has a significant effect on prices or guarantee payments. The foregoing exemptions shall not apply to mitigation imposed pursuant to Sections 23.3.1.2.2 and 23.3.2.1.3 of this Attachment H.

23.4.2.2.5.2 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.

23.4.2.2.5.3 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.

23.4.2.2.5.4 The posting of the Day-Ahead schedule may be delayed if necessary for the completion of automated mitigation procedures.

23.4.2.2.5.5 Bids not mitigated under automated procedures shall remain subject to mitigation by other procedures specified herein as may be appropriate.

23.4.2.2.5.6 The role of automated mitigation measures in the determination of market clearing prices are described in Section 17.1.1.5 of Attachment B of the ISO Services Tariff and Section 16.1.1.5 of Attachment J of the ISO OATT.

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.

23.4.3.3 Base Penalty Amount

23.4.3.3.1 Except for financial penalties determined pursuant to Section 23.4.3.3.2, 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 LBMP.

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 LBMP" shall mean: (i) for a seller, the LBMP at the generator bus of the withheld resource; 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 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 The exclusive means for the resolution of disputes arising from or relating to the imposition of a sanction under this Section 23.4.3 shall be the dispute resolution provisions of Attachment O and this Attachment H. 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 the amount of any unpaid penalty from the date of the infraction giving rise to the penalty to the date of payment. The exclusive remedy for the 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.

23.4.4.2.2 The ISO shall compute the average hourly deviation between day-ahead and real-time zone prices, measured as: $(\text{Zone Price}_{\text{real time}} / \text{Zone Price}_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling eight week period or such other period determined by the ISO to be appropriate to achieve the purpose of this mitigation measure.

23.4.4.2.3 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.

23.4.4.2.4 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 ~~Capability~~Capacity Market Mitigation Measures

23.4.5.1 If and to the extent that sufficient installed ~~capability~~capacity is not under a contractual obligation to be available to serve load in New York and if physical or economic withholding of installed ~~capability~~capacity would be likely to result in a material change in the price for installed ~~capability~~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 ~~Addendum~~Attachment H, in accordance with the procedures and requirements for amending the Plan, to implement appropriate mitigation measures for installed ~~capability~~capacity markets.

23.4.5.2 Offers to sell~~Sales or resales of Unforced Capacity from the In-City Generators specified below~~ 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.~~at prices not higher than $112.95 per kW-year, the translated equivalent value of the $105 per kW-year price cap for Installed Capacity for the specified Generators approved by the Commission. *Consolidated Edison Company of New York, Inc.*, 84 FERC ¶ 61,287 (1998). The specified Generators are: Arthur Kill Units 2 and 3, the Arthur Kill Gas Turbine, the Astoria Gas Turbines, Ravenswood Units 1, 2 and 3, the Ravenswood Gas Turbines, Astoria Units 3, 4 and 5, the Gowanus Gas Turbines, the Narrows Gas Turbines, the East River Generating Station, and the Waterside Generating Station.~~

~~In the event an In-City mitigated Generator, as specified above, fails to comply with the Unforced Capacity auction offer requirements in section 5.13.1 of the Services Tariff, the mitigated Generator will be required to pay to the ISO an amount equal to the ISO Capacity Deficiency Charge for such period times its rated capacity at the time of the divestiture. The ISO will distribute this deficiency charge among the proper In-City LSEs under procedures determined by the ISO and stakeholders.~~

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~~: (a)~~ 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 it has been~~and (b) shall not be~~ exported to an External Control Area or sold to meet Installed Capacity requirements outside the New York City Locality in a transaction that does not constitute physical withholding under the standards specified below~~unless the New York City Locational Minimum Unforced Capacity Requirement has been met~~.

23.4.5.4.1 An export to an External Control Area or sale to meet an Installed Capacity requirement outside the New York City Locali~~l~~ty of Mitigated UCAP (either of the foregoing being referred to as "External Sale UCAP") may be subject to audit and review by the ISO to assess whether such action constituted physical withholding of UCAP from the New York City Locality. External Sale UCAP shall be deemed to have been physically withheld ~~if the price~~on the basis of a comparison of the net revenues from UCAP sales that would have been earned by the sale in the New York City Locality of External Sale UCAP. The comparison shall be made for the period for which Installed Capacity is committed (the "Comparison Period")~~, net of costs that would not have been incurred but for the export or sale of External Sale UCAP, in~~ in each of the shortest term organized capacity markets (the "External Reconfiguration Markets") for the area and during the period in which the Mitigated UCAP ~~has been~~ was exported or sold. External Sale ICAP shall be deemed to have been withheld from the New York City Locality 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 New York City Locality by buying out of its external capacity obligation through participation in an External Reconfiguration Market; and (2) the net revenues over the Comparison Period from sale in the New York City Locality of the External Sale UCAP that could have been made available for sale in that Locality would have been greater by 5% or more than the net UCAP revenues from that portion of the External Sale UCAP over the Comparison Period. ~~that is most proximate in time to an ICAP Spot Market Auction for the New York City Locality in which the External Sale UCAP was not sold, when adjusted to a comparable basis is five percent or more below the price, net of any costs that would have been incurred because of the comparable internal sale, in such ICAP Spot Market Auction.~~

23.4.5.4.2 If Mitigated UCAP is not offered or sold as specified ~~in the foregoing sentence~~above, and if the failure to offer or the sale of External Sale UCAP causes or contributes to an increase in UCAP prices in the New York City Locality of ~~five~~15 percent or more, provided such increase is at least $2.~~5~~00/kilowatt-month, the Responsible Market Party for such Installed Capacity Supplier shall be required to pay to the ISO an amount equal to 1.5 times the lesser of (A) the difference between the average Market-Clearing Price for the New York City Locality in the ICAP Spot Market Auctions for the relevant Comparison Period with and without the inclusion of the Export Sale UCAP in those auctions, or (B) the difference between such average price and the clearing price in the External Reconfiguration Market for the relevant Comparison Period, times the total of (1) the amount of Mitigated UCAP not offered or sold as specified above, and (2) all other megawatts of Unforced Capacity in the New York City Locality under common Control with such Mitigated 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 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~~, *in consultation with its independent Market Advisor*,~~ a projection of ICAP Spot Auction clearing prices for the New York City Locality over the Comparison Period for the External Reconfiguration Market. Prior to completing its projection of ICAP Spot Auction clearing prices for the New York City Locality 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 External UCAP Sales that would exceed the net revenues that would have been realized from sale of the External UCAP Sales capacity in the New York City Locality 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 30.4.6.2.7 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. The presumption of Control from ownership can be rebutted by either: (1) the sale of Unforced Capacity from the Installed Capacity Supplier in a Capability Period Auction or a Monthly Auction, or (2) demonstrating to the reasonable satisfaction of the ISO~~, *in consultation with the Market Advisor*, and without any right to revenues or other financial benefits from such Unforced Capacity that would enable the seller to benefit from an increase in the Market-Clearing Price in the New York City Locality~~;provided, however, that if the presumption has not been rebutted, and if two or more Market Parties each have rights or obligations~~ or incentives~~ with respect to Unforced Capacity ~~offers, sales or revenues~~ 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 30.4.6.2.8 of Attachment O.

23.4.5.6 Any proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier from the In-City 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 the New York City Locality subsequent to such action. 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. If the ISO determines that the proposal or decision constitutes physical withholding, and would increase Market-Clearing Prices in one or more ICAP Spot Market Auctions for the New York City Locality by five percent or more, provided such increase is at least $.50/kilowatt-month, for each such violation of the above requirements the Market Participant shall be assessed an amount up to 1.5 times the market clearing price in the ICAP Spot Market Auction for each month during which Installed Capacity was withheld, times the total of (1) the number of megawatts withheld in each month and (2) all other megawatts of Installed Capacity in the New York City Locality under common Control with such withheld megawatts. The requirement to pay such amounts shall continue until the Market Party demonstrates that the removal from service, retirement or de-rate is justified by economic considerations other than the effect of such action on Market-Clearing Prices in the ICAP Spot Market Auctions for the New York City Locality. The ISO will distribute any amount recovered in accordance with the foregoing provisions among the LSEs serving Loads in regions affected by the withholding in accordance with ISO Procedures.

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.

23.4.5.7 Unless exempt as specified below, offers to supply Unforced Capacity in an ICAP Spot Market Auction from an In-City Installed Capacity Supplier shall equal or exceed the applicable Offer Floor. The Offer Floors shall apply to offers for Unforced Capacity from the Installed Capacity Supplier, if it is not a Special Case Resource, for each of the six Capability Periods starting with the Capability Period for which the Installed Capacity Supplier first offers to supply UCAP ("Initial Capability Period"), or the period of years if longer determined by (1) the initial DMNC value of the Installed Capacity Supplier plus the amount of Surplus Capacity at the time the Installed Capacity Supplier first offers to supply UCAP, divided by (2) the average annual growth in MW of the Locational Minimum Installed Capacity Requirement for the New York City Locality over the six Capability Periods preceding the Initial Capability Period. If the foregoing calculation extends mitigation to part of a Capability Period, the entire Capability Period shall be subject an Offer Floor. The initial DMNC value of the Installed Capacity Supplier shall be determined as specified in the ISO's tariffs and ISO Procedures.

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 In-City Load unless such Unforced Capacity is obtained through participation in an ICAP Spot Market Auction.

23.4.5.7.2 An Installed Capacity Supplier shall be exempt from an Offer Floor if: (a) any ICAP Spot Market Auction price for the two Capability Periods beginning with the first Capability Period for any part of which the Installed Capacity Supplier is reasonably anticipated to offer to supply UCAP (the "Starting Capability Period") is projected by the ISO to be higher, with the inclusion of the Installed Capacity Supplier, than the highest Offer Floor based on Net CONE that would be applicable to such supplier in such Capability Periods, or (b) 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 to be higher, with the inclusion of the Installed Capacity Supplier, than the reasonably anticipated Unit Net CONE of the Installed Capacity Supplier. The Developer or Interconnection Customer may request the ISO to make such determinations upon execution of all necessary Interconnection Facilities Study Agreements for the Installed Capacity Supplier. If relating to the exemption specified in (ii)(b) above, such a request shall include all data available to the requesting entity relating to the reasonably anticipated Unit Net CONE. The ISO~~, *in consultation with the Market Advisor*,~~ shall provide the requesting entity with the relevant price projections, the Offer Floors specified in (ii)(a) above, and the ISO's determination, if applicable, of the reasonably anticipated Unit Net CONE less the costs to be determined in the Project Cost Allocation or Revised Project Cost Allocation, as applicable, not later than the commencement of the Initial Decision Period for the Interconnection Facilities Study to which the Interconnection Facilities Study Agreement applies, provided that all information reasonably necessary to determine the Installed Capacity Supplier's Unit Net CONE has been delivered to the ISO not later than 60 days prior to the commencement of the Initial Decision Period. When evaluating a request by a Developer or Interconnection Customer 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 ISO shall provide revised price projections to a requesting entity proceeding to a Subsequent Decision Period not later than the ISO's issuance of a Revised Project Cost Allocation. The ISO shall inform the requesting entity whether the exemption specified in (b) above is applicable as soon as practicable after completion of the relevant Project Cost Allocation or Revised Project Cost Allocation, in accordance with methods and procedures specified in ISO Procedures. 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.

23.4.5.7.3 If an Installed Capacity Supplier demonstrates to the reasonable satisfaction of the ISO~~, *in consultation with the Market Advisor*,~~ that its Unit Net CONE is less than any Offer Floor that would otherwise be applicable to the Installed Capacity Supplier, then its Offer Floor shall be reduced to a numerical value equal to its Unit Net CONE.

23.4.5.7.4 Net CONE for the first two years after the last year covered by the most recent Demand Curves approved by the Commission shall be increased by the escalation factor approved by the Commission for such Demand Curves.

23.4.5.7.5 An In-City Installed Capacity Supplier ~~shall be exempt from an Offer Floor if it~~ that is a Special Case Resource shall be subject to an Offer Floor for (A) its initial offer to supply Installed Capacity, and (B) its initial offer to supply

Installed Capacity following a period of one year or more in which it did not offer to supply Installed Capacity. Responsible Interface Parties shall identify to the ISO any Special Case Resource that is subject to an Offer Floor, in accordance with ISO Procedures. The Special Case Resource shall continue to be subject to an Offer Floor for the following 11 months, for a total for 12 months. 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. 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. 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 an decrease in UCAP prices in the New York City Locality 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 New York City Locality in the ICAP Spot Auction for which the offers exceeding 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.

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.

~~vi) An Offer Floor shall only be applicable to Attributable ICAP of Net Buyer. An entity that has an LSE Unforced Capacity Obligation relating to InCity Load ("In City LSE") shall, not less often than every six months, or upon obtaining any rights or ovligations in~~

~~Attributable ICAP, produce to the NYISO, to the extent not previously produced, and certify that is has produced, (1) all documents, in whatever form, relating to any rights or obligations of use, ownership or Control, or to any financial obligation, that it or any of its Affiliated Entities may have relating to any Installed Capacity from an In-City Installed Capacity Supplier, and (2) documents sufficient to identify any Affiliated Entity that is an In-City LSE, and the LSE Unforced Capacity Obligation for In-City Load of each such Affiliated Entity. An In-City LSE shall be presumed to be a Net Buyer unless the documents produced to the NYISO show that the entity does not meet the definition of "Net Buyer" specified in §Section23.2.1 of this Attachment H.~~

23.4.5.7.6 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.

23.4.5.8 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.

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.

23.4.6.2.2 The ISO shall compute the average hourly deviation between day-ahead and real-time zone prices, measured as: $(\text{Zone Price}_{\text{real time}} / \text{Zone Price}_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four week period or such other period determined by the ISO to be appropriate to achieve the purpose of this mitigation measure.

23.4.6.2.3 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, 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 Duration of Mitigation Measures

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.

Filed March 20, 2008 to comply with order of the Federal Energy Regulatory Commission, Docket No. EL07-39-000, issued March 7, 2008, 122 FERC ¶ 61,211 (2008). Proposed effective date: March 27, 2008.

Filed May 6, 2008 to comply with order of the Federal Energy Regulatory Commission, Docket No. EL07-39-000, issued March 7, 2008, 122 FERC ¶ 61,211 (2008). Proposed effective date: November 1, 2008.

Filed October 30, 2008 to comply with order of the Federal Energy Regulatory Commission, Docket Nos. EL07-39-002, ER08-695-000, and -001, issued September 30, 2008, 124 FERC ¶ 61,301 (2008). Proposed effective date: November 1, 2008.

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. 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.

23.5.3.3 In addition, In-City generators must bid zero ($0) for the availability portion of Day-Ahead Spinning Reserves Bids. The implementation of this mitigation measure will have no effect on the ability of a Generator located in New York City to recover the market-clearing price established by the ISO for the sale of Spinning Reserves.

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.

23.5.5 Redetermination of 10-Minute Non-Synchronized Reserves Prices

The following provisions shall be in effect for a period of twelve months from July 8, 2003: (i) if any 10-Minute Non-Synchronized Reserves prices are determined by the ISO, with the concurrence of the ISO Market Advisor, to reflect a significant abuse of market power, the ISO shall so notify the Market Parties within 24 hours of the initial posting of such prices (such prices being hereinafter referred to as "flagged prices"); (ii) the ISO shall determine, with the concurrence of the Market Advisor, within five business days of such notification whether a filing seeking the reimposition of a bid cap or some other market power mitigation measure for 10-Minute Non-Synchronized Reserves is warranted, and if such a filing is not warranted the ISO shall notify the Market Parties that the flagged prices are final, subject to price correction procedures for other reasons if applicable; and (iii) if the ISO determines, with the concurrence of the Market Advisor, that a filing seeking reimposition of a bid cap or some other market power mitigation measure for 10-Minute Non-Synchronized Reserves is appropriate, such filing will request authorization from the Commission to redetermine the flagged prices in accordance with such bid cap or other mitigation measure as may be approved by the Commission.

23.6 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 seek a determination in accordance with the dispute resolution provisions of the New York Independent System Operator Agreement 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.

23.7 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

25.1 General Rule

If an eligible Supplier 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. Day-Ahead Margin Assurance Payments payable to Limited Energy Storage Resources shall be determined pursuant to Section 25.6 of this Attachment J.

25.2 Eligibility for Receiving Day-Ahead Margin Assurance Payments

The following categories of Suppliers shall be eligible to receive Day-Ahead Margin Assurance Payments provided however, that intermittent Power Resources depending on wind as their fuel shall not be eligible for Day-Ahead Margin Assurance Payments: (i) all Self-Committed Flexible and ISO-Committed Flexible Generators that are online and dispatched by RTD; (ii) Demand Side Resources committed to provide Operating Reserves or Regulation Service; (iii) any Supplier 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 Supplier 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 a total margin for the dispatch day that is less than its Day-Ahead margin as a result of an ISO-approved real-time reduction in scheduled output from its Day-Ahead schedule for Energy limited reasons.

No Day-Ahead Margin Assurance Payment shall be paid a Generator, otherwise eligible for a Day-Ahead Margin Assurance Payment, in hours in which the NYISO has increased the Generator'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.

25.3 Calculation of Day-Ahead Margin Assurance Payments

25.3.1

Day-Ahead Margin Assurance Payments for Generators shall be determined by applying the following equations to each individual Generator using the terms as defined in subsection 25.3.3:

$$DMAP_{hu} = \max\left(0, \sum_{i \in h} CDMAP_{iu}\right) \text{where:}$$

$$CDMAP_{iu} = CDMAPen_{iu} + \sum_{p} CDMAPres_{iup} + CDMAPreg_{iu},$$

If the Supplier's real-time Energy schedule is lower than its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = \left\{ \begin{matrix} (DASen_{hu} - LL_{iu}) \times RTPen_{iu} \\ - \int_{LL_{iu}}^{DASen_{hu}} DABen_{hu} \end{matrix} \right\} * \frac{Seconds_i}{3600},$$

If the Supplier's real-time Energy schedule is greater than or equal to its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = MIN\left(\left\{ \begin{matrix} (DASen_{hu} - UL_{iu}) \times RTPen_{iu} \\ + \int_{DASen_{hu}}^{UL_{iu}} RTBen_{iu} \end{matrix} \right\} * \frac{Seconds_i}{3600}, 0 \right)$$

If the Supplier's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup} \right) \times \left(RTPres_{iup} - DABres_{hup} \right) \right] * \frac{Seconds_i}{3600}$$

If the Supplier'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:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup} \right) \times \left(RTPres_{iup} \right) \right] * \frac{Seconds_i}{3600}$$

If the Supplier's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu} \right) \times \left(RTPreg_{iu} - DABreg_{hu} \right) \right] * \frac{Seconds_i}{3600}$$

If the Supplier's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu} \right) \times MAX\left(\left(RTPreg_{iu} - RTBreg_{iu} \right), 0 \right) \right] * \frac{Seconds_i}{3600} .$$

25.3.2

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 subsection 25.3.3:

$$DMAP_{hu} = \max\left(0, \sum_{i \in h} CDMAP_{iu} \right) \text{where:}$$

$$CDMAP_{iu} = \sum_{p} CDMAPres_{iup} + CDMAPreg_{iu} ,$$

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:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup} \right) \times \left(RTPres_{iup} - DABres_{hup} \right) \right] * RPIiu * \frac{Seconds_i}{3600}$$

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:

$$CDMAPres_{iup} = \left(DASres_{hup} - RTSres_{iup}\right) \times \left(RTPres_{iup}\right) * RPI_{iu} * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left(DASreg_{hu} - RTSreg_{iu}\right) \times \left(RTPreg_{iu} - DABreg_{hu}\right) * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left(DASreg_{hu} - RTSreg_{iu}\right) \times MAX\left(\left(RTPreg_{iu} - RTBreg_{iu}\right), 0\right) * \frac{Seconds_i}{3600}.$$

25.3.3 Terms used in this Attachment J:

h is the hour that includes interval *i*;

DMAPhu	=	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 curve for Supplier *u* in hour *h*;
$DABreg_{hu}$	=	Day-Ahead Availability Bid for Regulation Service 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 Availability Bid for Regulation Service for Supplier *u* in interval *i*.
$RTBen_{iu}$	=	Real-time Energy bid curve 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 Service 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*;
LL_{iu}	=	max ($RTSen_{iu}$, min(AEI_{iu},EOP_{iu})), but not more than $DASen_{hu}$ if $RTSen_{iu} < EOP_{iu}$ and min ($RTSen_{iu}$, max(AEI_{iu},EOP_{iu})), but not more than $DASen_{hu}$ otherwise;
UL_{iu}	=	min ($RTSen_{iu}$, max(AEI_{iu},EOP_{iu})) but not less than $DASen_{hu}$if $RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}$ and max ($RTSen_{iu}$, min(AEI_{iu},EOP_{iu})) but not less than $DASen_{hu}$ otherwise;
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*
RPIiu		= the Reserves Performance Index in interval i for Demand Side Resource u. The Reserves Performance Index is calculated pursuant to Section 15.4.3.6 of Rate Schedule 4 of this Services Tariff.
K_{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 which shall initially be set at 1.0 for LESRs.

25.3.4 Other Provisions

The AGC Base Point Signal for a Supplier that is not providing Regulation Service during a given RTD interval shall be initialized by either: (i) the Supplier's last AGC Base Point Signal from the prior RTD interval; or (ii) the Supplier's actual metered generation or calculated

Demand Reduction at the time new RTD Base Point Signals are received by the ISO's AGC software, whichever is closer to the Supplier's new RTD Base Point Signal. AGC Base Point Signals for a Supplier that is not providing Regulation Service will ramp evenly over the course of the RTD interval starting at the initialized AGC Base Point Signal and ending at the level of its new RTD Base Point Signal. AGC Base Point Signals for Suppliers providing Regulation Service during a given RTD interval are determined based on the ISO's need to minimize the NYCA area control error.

25.4 Exception for Generators Lagging Behind RTD Base Point Signals

An otherwise eligible Generator that does not respond to, or that lags behind, the ISO's RTD Base Point Signals in a given interval, as determined below, shall not be eligible for Day-Ahead Margin Assurance Payments for that interval. If such a 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:

$REDtot_{iu}$ = $\max(DASen_{hu} + DASreg_{hu} + \Sigma_p DASres_{hup} - RTUOL_{iu},0)$

$POTREDen_{iu}$ = $\max(DASen_{hu} – RTSen_{iu}, 0)$

$POTREDreg_{iu}$ = $\max(DASreg_{hu} – RTSreg_{iu}, 0)$

$POTREDres_{iup}$ = $\max(DASres_{hup} – RTSres_{iup}, 0)$

$REDen_{iu}$ = $((POTREDen_{iu}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$

$REDreg_{iu}$ = $((POTREDreg_{iu}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$

$REDres_{iup}$ = $((POTREDres_{iup}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$

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 in interval;

All other variables are as defined above.

25.6 Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources

A. 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 subsection 25.3.3, provided however, DAMAP 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 to account for the Energy storage capacity of such Resource and the NYISO is not pursuing LESR Energy Management for such Resource for such interval, pursuant to ISO Procedures:

If the Supplier's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu} \right) * \left(RTPreg_{iu} - DABreg_{hu} \right) \right] * K_{pr} * \frac{Seconds_i}{3600}$$

If the Supplier's real-time Regulation Service schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu} \right) \times MAX\left(RTPreg_{iu} - RTBreg_{iu}, 0 \right) \right] * \frac{Seconds_i}{3600}$$

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 Reporting Requirements

26.1.1 All Customers. All Customers shall be required to comply with the reporting requirements in this Section 26.1.1

26.1.1.1 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.

26.1.1.2 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.

26.1.1.3 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.

26.1.1.4 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 (e) restatement of prior financial statements.

26.1.1.5 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.

26.1.2 Customers Requesting Unsecured Credit

In addition to the reporting requirements in Section 26.1.1., 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 26.1.2.

26.1.2.1 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 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.

26.1.2.2 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.

26.1.2.3 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.

26.1.2.4 Government Entities

Notwithstanding Section 26.1.2.1 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.

26.2 Investment Grade Customers

26.2.1 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.

26.2.2 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 26.2.1 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.

26.2.3 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.

26.3 Operating Requirement and Bidding Requirement

26.3.1 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 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 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.

26.3.2 Calculation of Operating Requirement

The Operating Requirement shall be equal to the sum of (i) the Energy and Ancillary Services Component; (ii) the UCAP Component; (iii) the TCC Component; (iv) the WTSC Component; (v) the Virtual Transaction Component; (vi) the DADRP Component; and (vii) the DSASP Component where:

26.3.2.1 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:

Basis Amount for Energy and Ancillary Services x 50 Days in Basis Month

- or -

$$\frac{\text{Total Charges Incurred for Energy and Ancillary Services for Previous Ten (10) Days}}{10} \times 50$$

(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 W-1, the greater of either:

Basis Amount for Energy and Ancillary Services x 3 Days in Basis Month

or-

$$\frac{\text{Total Charges Incurred for Energy and Ancillary Services for Previous Ten (10) Days} \times 3}{10}$$

(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 x 720 x 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.

26.3.2.2 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.

26.3.2.3 TCC Component

The TCC Component shall be equal to the greater of either:

(a) The sum of the amounts calculated in accordance with the appropriate per TCC term-based formula listed below for TCC purchases less the amounts calculated in accordance with the appropriate per TCC term-based formula listed below for TCC sales:

for two-year TCCs:

(1) upon initial award of a two-year TCC until completion of the final round of the current one-year TCC auction:

2 x the amount calculated in accordance with the one-year TCC formula listed below

where:

Pijt = auction 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; *provided, however*, in the event there is no price for a one-year TCC with the same POI and POW combination as the two-year TCC, then "Pijt" shall equal a proxy price, assigned by the NYISO, for a one-year TCC with like characteristics. For Centralized TCC Auctions conducted before May 1, 2010, the "auction price of a one-year TCC in the final round of the one-year Sub-Auction" means the auction price of a one-year TCC in the final Stage 1 round of the one-year TCC auction.

(2) upon completion of the final round of the current one-year Sub-Auction until commencement of year two of a two-year TCC:

2 x the amount calculated in accordance with the one-year TCC formula listed below

where:

Pijt = auction price of a one-year TCC in the final round of the current one-year TCC auction with the same POI and POW combination as the two-year TCC

(3) upon commencement of year two of a two-year TCC:

1 x the amount calculated in accordance with the one-year TCC formula listed below

where:

Pijt = auction 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.

for one-year TCCs, representing a 5% probability curve:

$$+1.909\sqrt{e^{10.9729+.6514(\ln(|P_{ijt}|+e))+.6633*Zone\ J}}-.9696\ P_{ijt}$$

for six-month TCCs, representing a 3% probability curve:

$$+2.565\sqrt{e^{11.6866+.4749(\ln(|p_{ijt}|+e))+.4856*Zone\ J-.0373\ Summer}}-.8166\ P_{ijt}$$

for one-month TCCs, representing a 3% probability curve:

$$+2.221\sqrt{e^{11.2682+0.3221(\ln(|p_{ijt}|+e))+1.3734*ZoneJ+2.001*ZoneK+Month}}-.8152\ P_{ijt}$$

where:

Pijt = auction 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

Month	= the following values:	
January	=	0
February	=	-0.0201
March	=	0.1065
April	=	-0.3747
May	=	0.8181
June	=	0.2835
July	=	0.5201
August	=	0.7221
September	=	0.242
October	=	0.32
November	=	-0.7681
December	=	-0.3836

Provided, however, for purposes of determining the credit holding requirement for a Fixed Price TCC, the auction price shall be replaced by the fixed price associated with that Fixed Price TCC, as determined in Section 19.2.1 of Attachment M of the OATT.

- or -

(b) 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:

$$\sum_{n \in N} \left\{ \frac{NAPn}{90} \times RDn \right\}$$

where:

NAP = the net amount of Congestion Rents (positive or negative) 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; and

N = the set of TCCs held by the Primary Holder.

26.3.2.4 WTSC Component

The WTSC Component shall be equal to the greater of either:

$$\frac{\text{Greatest Amount Owed for WTSC During Any Single Month in the Prior Equivalent Capability Period}}{\text{Days in Month}} \times 50$$

- or –

$$\frac{\text{Total Charges Incurred for WTSC Based Upon the Most Recent Monthly Data Provided by the Transmission Owner}}{\text{Days in Month}} \times 50$$

26.3.2.5 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 = $\sum (VSG_{MWh} \times VSG_{CS})$

VLCR = $\sum (VLG_{MWh} \times VLG_{CS})$

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

26.3.2.6 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.

26.3.2.7 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 97^{th} 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 97^{th} 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

26.3.3 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 an upcoming ISO-administered TCC auction, which shall account for all positive bids to purchase TCCs and the absolute value 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) (2 x $/MW for one-year TCCs) per MW for two-year TCCs, (b) $1,500 per MW for one-year TCCs, (c) $2,000 per MW for six-month TCCs, and (d) $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 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 maximum amount that the Customer may be required to pay for UCAP in the auction.

26.4 Unsecured Credit

A Customer may use Unsecured Credit to satisfy any part of its Operating Requirement or Bidding Requirement other than any credit requirement for bidding on or holding TCCs incurred on or after November 12, 2009. Notwithstanding the preceding sentence, a Customer may use Unsecured Credit to satisfy its credit requirement for holding Fixed Price TCCs obtained pursuant to Section 19.2.1 of Attachment M to the OATT.

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.

26.4.1 Eligibility

A Customer may be eligible to receive Unsecured Credit if the Customer (i) (a) is an Investment Grade Customer, or (b) is an Unrated Customer that is deemed an Investment Grade Customer pursuant to an Equivalency Rating, and (ii) (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 Section 26.4.3.2 just provide evidence satisfactory to the ISO of such payment history.

26.4.2 Market Concentration Cap

A Customer's Unsecured Credit shall not exceed one hundred and fifty million dollars ($150M) unless the Customer: (i) is an Investment Grade Customer, (ii) provides evidence to the

ISO, in a form satisfactory to the ISO in its sole discretion, that the Customer has a legal right to recover its costs for supplying Energy, Ancillary Services, and Capacity to end-users, and (iii) uses its Unsecured Credit to meet its Native Load Credit Requirements only. For NYPA, Native Load Customers include all wholesale and retail power customers for which NYPA is under contract to provide electric service. A Customer that satisfies all of the conditions in clauses (i), (ii) and (iii) of this Section 26.4.2 may receive Unsecured Credit in excess of one hundred and fifty million dollars ($150M) but the Customer's Unsecured Credit shall not exceed two hundred and fifty million dollars ($250M). Once Market Participants approve the indexing methodology for adjusting these dollar limits, then the indexing methodology will be set forth in ISO Procedures and these dollar limits will be adjusted annually in accordance with that methodology.

26.4.3 Determination of Unsecured Credit

26.4.3.1 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 26.4.3.6 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.

26.4.3.2 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%

26.4.3.3 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 26.4.3.1 and 26.4.3.2 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

	Score Bucket	**1**	**2**	**3**	**4**	**5**
Prior Credit Assessment Score Bucket	**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

26.4.3.4 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 26.4.3.1 and 26.4.3.2 of this Attachment K.

26.4.3.5 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.

26.4.3.6 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. Once Market Participants approve the indexing methodology for adjusting this dollar limit, then the indexing methodology will be set forth in ISO Procedures and this dollar limit will be adjusted annually in accordance with that methodology. 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 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.

(c) At its request, a Public Power Entity that (1) is an Investment Grade Customer, (2) fulfills the additional reporting requirements set forth below, and (3) uses its Unsecured Credit to meet its Native Load Credit Requirement only, may qualify for Unsecured Credit, without regard to its Tangible Net Worth or Credit Assessment, equal to the lesser of (x) sixty million dollars ($60M), or (y) its Native Load Credit Requirement. Once Market Participants approve the indexing methodology for adjusting this dollar limit, then the indexing methodology will be set forth in ISO Procedures and this dollar limit will be adjusted annually in accordance with that methodology.

To fulfill the additional reporting requirements, a Public Power Entity must submit either (1) quarterly financial statements within 60 days of quarter-end that have been certified for accuracy by a senior officer, or (2) if quarterly financial statements are not typically prepared, then (a) a copy of the current year adopted budget prior to the start of the of the Customer's fiscal year that has been certified for accuracy by a senior officer, and (b) within sixty (60) days of quarter-end, a statement from a senior officer certifying that actual costs have not exceeded budgeted costs by greater than 10%.

26.4.4 Affiliate Guarantors

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.

26.4.5 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.

26.5 Additional Security

A Customer shall be required to provide collateral to support its obligations to the ISO to (i) satisfy any credit requirement for bidding on or holding TCCs incurred on or after November 12, 2009, and (ii) to the extent that its Operating Requirement exceeds the total of its Unsecured Credit and any existing collateral by more than $10,000. The ISO shall also not accept an Affiliate guarantee to satisfy any credit requirement for bidding on or holding TCCs incurred on or after November 12, 2009. Notwithstanding the preceding sentences, a Customer may use Unsecured Credit to satisfy its credit requirement for holding Fixed Price TCCs obtained pursuant to Section 17.1.1.2 of Attachment B to this Services Tariff or Section 16.1.1.2 of Attachment J to the OATT.

26.5.1 Acceptable Collateral

26.5.1.1 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.

26.5.1.2 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 with a minimum "A" rating from Standard & Poor's, Fitch, Moody's, or Dominion. A Customer's failure to provide a source of 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 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 draw upon the full value of the letter of credit.

26.5.1.3 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 secure its obligations to the ISO 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 in the full amount of the Affiliate guarantee.

26.5.1.4 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 a source of collateral in an amount sufficient to secure its obligations to the ISO fifty (50) days prior to the termination of a surety bond, 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 of the full value of the surety bond.

26.5.1.5 Netting of Amounts Receivable

Upon written notice to the ISO, 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 monthly payment to the Customer and that will be payable to the Customer in the following regular monthly payment, provided that any such payment to the Customer may be adjusted by the ISO as necessary to correct for any error in this determination.

26.5.2 Cash Collateral Investment Alternatives

26.5.2.1 Investment Alternatives

A Customer may elect to deposit some or all of its cash collateral it has posted with the ISO to satisfy its Operating Requirement into one or both of two bond funds: a short-term bond fund ("Short-Term Bond Fund") and an intermediate-term bond fund ("Intermediate-Term Bond Fund") (each a "Bond Fund"). A Customer's election shall be in writing and shall not be changed more than twice each year.

26.5.2.2 Additional Premium

A Customer electing to deposit cash collateral into a Bond Fund shall be required to also deposit a premium above the base amount of cash collateral to protect against fluctuations in the value of the Bond Fund. A 5% premium shall be required for investments in the Short-Term Bond Fund. A 10% premium shall be required for investments in the Intermediate-Term Bond Fund.

26.5.2.3 ISO Monitoring

The ISO shall monitor the value of the Bond Funds at least once each week. If at any time the value of the Customer's account in a Bond Fund reduces by an amount equal to fifty percent (50%) of the premium required for participation in that Bond Fund, or more, the ISO shall provide the Customer with a notice requesting additional cash collateral to restore the required balance in the Bond Fund. If a Customer fails to provide the additional collateral by 4:00 p.m. on the business day following the NYISO's notice requesting additional cash collateral, the ISO may immediately liquidate the Customer's Bond Fund deposit and transfer the balance to a standard cash collateral deposit account.

26.5.2.4 Example

Assume a Customer has an Operating Requirement of $300 and elects to place $100 in the standard cash collateral deposit account; $100 in the Short-Term Bond Fund; and $100 in the Intermediate-Term Bond Fund. As such, the Customer would be required to place $100 in the standard cash collateral deposit account. The Customer would be required to place $100 plus $5 (the 5% required premium) for a total of $105 to participate in the Short-Term Bond Fund. The Customer would be required to place $100 plus $10 (the 10% required premium) for a total of $110 to participate in the Intermediate-Term Bond Fund. Assume further that upon the ISO monitoring, it discovers that the value of the Customer's Short-Term Bond Fund decreased to $102.50 while the value of the Intermediate-Term Bond Fund remained unchanged. The ISO would then notify the Customer to provide an additional $2.50 of collateral such that the 5% premium would be met for the Short-Term Bond Fund. If the Customer failed to timely provide the additional collateral, the ISO may then liquidate the $102.50 balance in the Short-Term Bond Fund and place it in a standard cash collateral deposit account. The Intermediate-Term Bond Fund would remain unaffected.

26.5.3 Pay-down Agreement

In lieu of providing any collateral or additional collateral otherwise required by the ISO's creditworthiness requirements, a Customer may execute a pay-down agreement with the ISO pursuant to which the Customer shall, upon written demand by the ISO, pay down the amount by which its Operating Requirement, as calculated pursuant to Article 26.3 of this Attachment K, exceeds the amount of its Unsecured Credit and any existing collateral. The ISO shall accept payment from a Customer at any time, but such payment shall eliminate the Customer's collateral requirements only if the payment is made pursuant to a pay-down agreement.

26.5.4 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.

26.6 Additional Financial Assurance Policies for Virtual Transactions

26.6.1 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.

26.6.2 Suspension

If, at any time during the regular monthly billing cycle, 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 during the regular monthly billing cycle, 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.

26.7 Additional Financial Assurance Policies for Demand Side Resources Offering Ancillary Services

26.7.1 Suspension

(i) If, at any time during the regular monthly billing cycle, 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 during the regular monthly billing cycle, 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.

26.8 Additional Financial Assurance Policies for Wholesale Transmission Service Charges

26.8.1 Application of Security

In the event a Transmission Owner declares a certain WTSC overdue and satisfies the requirements specified in Section 26.8.2 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.

26.8.2 Prerequisites to NYISO Action

The following conditions must be fully satisfied before the NYISO takes action to address a WTSC nonpayment:

26.8.2.1 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;

26.8.2.2 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;

26.8.2.3 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

26.8.2.4 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 26.8.3 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).

26.8.3 NYISO Action

On the first business day after the ISO has received the notice that satisfies the requirements listed in Section 26.8.2.4 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.

26.8.4 Transmission Owner Indemnification to the NYISO

As a prerequisite for ISO action listed in Section 26.8.3 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.

26.9 Retention of a Withdrawing Customer's Collateral

To the extent that a Customer's credit requirements are met with a cash deposit or a letter of credit, the ISO shall retain a portion of that collateral upon the Customer's withdrawal from the ISO-Administered Markets to secure any remaining financial obligations, including true-up payments or other invoice adjustments. The amount retained by the ISO shall be determined according to the following formula:

RCC = (AFA x F) + (ASA x S)

where:

RCC	=	Retained Customer Collateral. The amount of a Customer's cash deposit or letter of credit to be retained following the Customer's withdrawal from the NYISO-administered markets.
AFA	=	Average adjustment to the Customer's initial invoices in its four-month true-ups calculated over the prior six months.
F	=	Number of four-month true-ups remaining until all of the Customer's monthly invoices are finalized by the ISO.
ASA	=	Average adjustment to the Customer's initial invoices in its six-month true-ups calculated over the prior six months.
S	=	Number of six-month true-ups remaining until all of the Customer's monthly invoices are finalized by the ISO.

26.10 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.

Table K-1 Tangible Net Worth Credit Matrix

<table>
<tr><th colspan="4">Customer
Rating</th><th>Starting Point for Determining
Unsecured Credit</th></tr>
<tr><td colspan="2">Senior Long-term Unsecured
Debt Rating</td><td colspan="2">Issuer Rating or
Equivalency Rating</td><td rowspan="2">(% of Tangible Net Worth)</td></tr>
<tr><td>S&P, Fitch,
and Dominion</td><td>Moody's</td><td>S&P, Fitch,
Dominion, and
NYISO</td><td>Moody's</td></tr>
<tr><td>A+
or higher</td><td>A1
or higher</td><td>AA-
or higher</td><td>Aa3
or higher</td><td>7.5%</td></tr>
<tr><td>A</td><td>A2</td><td>A+</td><td>A1</td><td>6.5%</td></tr>
<tr><td>A-</td><td>A3</td><td>A</td><td>A2</td><td>5.0%</td></tr>
<tr><td>BBB+</td><td>Baa1</td><td>A-</td><td>A3</td><td>4.0%</td></tr>
<tr><td>BBB</td><td>Baa2</td><td>BBB+</td><td>Baa1</td><td>2.5%</td></tr>
<tr><td>BBB-</td><td>Baa3</td><td>BBB</td><td>Baa2</td><td>1.5%</td></tr>
<tr><td>BB+
or lower</td><td>Ba1
or lower</td><td>BBB-
or lower</td><td>Baa3
or lower</td><td>0%</td></tr>
</table>

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 26.3.2.1 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 next calendar 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 monthly settlements shall not reduce or offset the Prepayment Amount.

3. Manner of Payment. Customer shall make each Prepayment not later than 4:00 P.M. EST on the first business day of the week by wire transfer 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 Monthly 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

monthly 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 Attachment M-1 – Operating Protocol For The Implementation Of Commission Opinion No. 476 - (DOCKET NO. EL02-23-000 (Phase II))

28.1.1 This "Operating Protocol" establishes procedures for the planning, operation, control, and scheduling of energy by the New York Independent System Operator, Inc. (NYISO), PJM Interconnection, LLC (PJM), Consolidated Edison Company of New York (ConEd) and Public Service Electric and Gas Company (PSE&G) (collectively, the "parties"), pursuant to contracts dated May 22, 1975 (as amended May 9, 1978) and May 8, 1978 between ConEd and PSE&G. The 1975 contract is referred to herein as the 400 MW contract and the 1978 contract is referred to as the 600 MW contract. The two contracts are referred to collectively as the "600/400 MW contracts."

28.1.2 This Operating Protocol shall be used by the NYISO and PJM in preparing to operate, and operating in real-time, to the hourly flow of energy between them pursuant to the 600/400 MW contracts as established by this Operating Protocol.

28.1.3 During system emergencies, the appropriate emergency procedures of the NYISO and PJM, if necessary, shall take priority over the provisions of this Operating Protocol. The NYISO and PJM dispatchers shall have the authority to implement their respective emergency procedures in whatever order is required to ensure overall system reliability. Without limiting the foregoing, the order of load relief measures and contract reductions when there is an emergency on the PJM system will be:

- Reduction of the 400 MW contract[27]
- Calling of Active Load Management

[27] If ConEd converts the 400 MW contract to firm transmission service (by purchasing PJM firm transmission service, with a credit for payments ConEd has made to PSE&G for non-firm transmission service), then the 400 MW contract will be treated in the same manner as the 600 MW contract.

- Voltage reduction
- Reduction of the 600 MW contract[28]
- Load shedding

In addition, if PJM declares an emergency condition that arises from outages on the PSE&G system the NYISO and PJM may agree to deliver up to 400 MW to Goethals for re-delivery to Hudson via the NYISO's system. Such emergency re-deliveries shall not be considered in the calculation of the Real-Time Market Desired Flow under Appendices 1 and 3 of this Operating Protocol.

28.1.4 All aspects of this Operating Protocol are subject to the dispute resolution procedures of PJM and the NYISO.

28.1.5 Because the procedures in this Operating Protocol are new, the parties will review all aspects of this Operating Protocol on a periodic basis, initially monthly and, after a six month period, annually, to determine if modifications are required to effectuate the Commission's Opinion No. 476 in Docket No. EL02-23-000 (Phase II).

28.1.6 All aspects of this Operating Protocol are subject to, and this Operating Protocol may need to be revised or extinguished in order to accommodate, the outcome of ongoing Commission and Federal court proceedings addressing FERC Docket No. EL02-23, including all sub-dockets thereof. This Operating Protocol implements the directives set forth in the Commission Opinion No. 476 without resolving issues that are still pending before the Commission or that have been appealed to the Federal courts.

---

[28] The 600 MW contract shall be reduced in the same manner as all other firm transactions in PJM.

28.1.7 Attached and included as part of this Operating Protocol are the following appendices:

Appendix 1	Process Flow
Appendix 2	Transmission Constraints and Outages Associated with the Contracts
Appendix 3	The Day-Ahead Market and Real-Time Market Desired Flow Calculation
Appendix 4	Market Monitoring Procedures and Information Sharing Procedures
Appendix 5	Impairments Impacting Delivery
Appendix 6	Operation of the PARs
Appendix 7	Distribution of Flows Associated with Implementation of Day-Ahead and Real-Time Market Desired Flows
Appendix 8	References
Appendix 9	Comparison of Contracts
Appendix 10	Definitions

Appendix 1- Process Flow

Two Day-ahead Actions:

1. PJM shall post constraint forecast information indicating if there is the potential for off-cost operations, two days prior to the operating day by 9 pm. (http://oasis.pjm.com/inform.html - sample at Figure 1 in Appendix 8) or a comparable website.
2. PJM shall analyze transmission and generation outages in accordance with Appendix 2B to determine if the 600/400 MW contract flow is expected to be feasible under a security constrained dispatch in PJM. If any portion of the flow is not expected to be feasible under a security-constrained dispatch, PJM will determine what portion of the flow is expected to be feasible and post that information on the PJM OASIS. This advance notification is not binding on any party.
3. The NYISO shall post transmission outages on its OASIS, or a comparable website, to identify outages that impact the transfer capability of the ISO Secured Transmission System.[29]

Day Ahead Scheduling:

4. ConEd shall submit a contract election (NY-DAE) in the NYISO's Day-Ahead Market for the 600/400 MW contracts prior to 5:00 a.m.
5. The NYISO shall establish New York (aggregate ABC interface and aggregate JK interface) Desired Flow (NYDF) schedules for NYISO Day Ahead Market using the NY-DAE identified in (4).
6. The NYISO shall establish the distribution of flows for the NYISO DAM in accordance with Appendix 7.
7. The NYISO shall run the New York Day Ahead Market with NYDF schedules determined in (5 and 6).
8. The NYISO shall post DAM results by the deadline established in its market rules (currently prior to 11:00 a.m.). The NYISO shall provide NYDF schedules and post nodal prices for the JK (Ramapo), BC (Farragut) and A (Goethals) pricing points on the NYISO OASIS, or a comparable website. (http://www.nyiso.com/oasis/index.html - sample at Figure 2 in Appendix 8).
9. ConEd shall submit a contract election (PJM-DAE) in the PJM Day Ahead Market prior to 12 noon:
    a) ConEd shall submit a contract election for the 600 MW contract.

---

[29] The ISO Secured Transmission System is defined in the NYISO's Transmission and Dispatching Operations Manual.
See <http://www.nyiso.com/services/documents/manuals/pdf/oper_manuals/trans_disp.pdf>.

b) ConEd shall submit a contract election for the 400 MW contract. For the 400 MW contract, ConEd shall specify whether it is willing to pay congestion (WPC) under the following options:[30]

i) ConEd is not willing to pay congestion for any portion of the 400 MW

ii) ConEd willing to pay congestion up to $25

iii) ConEd willing to pay congestion with no redispatch cost limit

10. PJM shall establish the PJM (aggregate ABC interface and aggregate JK interface) Desired Flow (PJMDF) schedules for PJM Day Ahead Market using PJM-DAE identified in (9).

11. PJM shall establish the distribution of flows for the PJM DAM in accordance with Appendix 7.

12. PJM shall run the PJM Day Ahead Market with the PJMDF schedules determined in (11). The amount of the PJM-DAE which clears will become the PJM Day Ahead Schedule amount (PJM-DAS). The PJM-DAS may be reduced from the PJM-DAE based on ConEd's WPC specification or infeasibility under the PJM security-constrained dispatch.

13. PJM Day Ahead results shall be posted by the deadline established in PJM's market rules (currently at 4:00 p.m.), and shall identify the PJM-DAS. The PJM posting will include nodal prices for the JK (Waldwick), BC (Hudson) and A (Linden) pricing points, or a comparable website. (https://esuite.pjm.com/mui/index.htm - sample at Figure 3 in Appendix 8.)

If there is congestion in the PJM Day Ahead Market:

14. If there is congestion in PJM that affects the portion of the wheel that is associated with the 600 MW contract, PJM shall re-dispatch and PSE&G shall pay for re-dispatch. PSE&G shall be provided Fixed Transmission Rights (FTRs) in an amount equal to the PJM-DAS.

15. If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch.[31] ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[32]

---

[30] ConEd may submit a series of bids totaling up to 400 MW that employ several or all of the pricing options described in (9).

[31] Settlements will be based on the differences in prices between the JK and ABC pricing points.

[32] If ConEd converts the 400 MW contract to firm transmission service (by purchasing PJM firm transmission service**,** with a credit for payments ConEd has made to PSE&G for non-firm transmission service), then ConEd congestion credits instead will be determined in the same manner as the credits provided to all other PJM firm transmission customers.

In Day Operations:

16. Aggregate ABC and aggregate JK Real-Time Market Desired Flow (RTMDF) calculations shall be made in real time, continuous throughout the operating day, by the NYISO and PJM.

17. The desired distribution of flows on the A, B, C, J, and K lines for the in-day markets shall be established by PJM and the NYISO in accordance with Appendix 7.

18. If neither PJM nor the NYISO are off-cost, or if both are off-cost, aggregate actual ABC interface flows shall be within +/- 100 MW of the aggregate RTMDF for the ABC interface and aggregate actual JK interface flows shall be within +/- 100 MW of the aggregate RTMDF for the JK interface.

19. ConEd shall have the option to request a modification in the Real-Time Market from its Day Ahead Market election (NY_DAE and PJM_DAE) for each hour.[33]

    a) ConEd must request a Real-Time election (RTE) modification through NYISO at least 75 minutes prior to the dispatch hour (or a shorter notice period that is agreed upon by the NYISO and PJM.).
    b) The NYISO shall notify PJM of the RTE.
    c) ConEd shall settle with PJM for balancing market costs for deviations between PJM-DAS and RTE. Con Ed shall settle with the NYISO for balancing market costs for deviations between NY-DAE and RTE.

    Note - Actions identified in steps 18 and 19 that are taken will be logged, and PSE&G and ConEd will be notified of PAR moves related to these steps.

If there is In-Day congestion:

20. If PJM is off-cost or is expected to go off-cost for two or more consecutive hours in maintaining the RTMDF, and the NYISO is not off-cost, then PJM and NYISO shall consult with each other and shall redirect up to 300 MW (in a mutually agreed upon amount and in mutually agreed upon increments) from the PJM system onto the NYISO system; provided, however, that PJM and the NYISO verify that allowing actual aggregate interface flows to deviate from the RTMDF will not result in violation of applicable PJM or NYISO reliability criteria. The process of modifying actual interface flows in incremental adjustments will continue until

    a) PJM is no longer off-cost, or
    b) The NYISO is about to go off-cost (i.e., the NYISO expects that it will have to redispatch in response to transmission constraints in order to maintain the RTMDF), or
    c) 300 MW have been redirected.

21. If the NYISO is off-cost or expected to go off-cost for two or more consecutive hours in

[33] At all times, however, the ConEd election under the 600/400 MW contracts must be the same in PJM and NYISO in In-Day Operations. Absent an in-day change in the election by ConEd, the ConEd Real-Time election shall be the PJM-DAS.

maintaining the RTMDF, and PJM is not off-cost, then PJM and the NYISO shall consult with each other and shall redirect up to 300 MW (in a mutually agreed upon amount and in mutually agreed upon increments) from the NYISO system onto the PJM system; provided, however, that PJM and NYISO verify that allowing actual aggregate interface flows to deviate from the RTMDF will not result in violation of applicable PJM or NYISO reliability criteria. The process of modifying actual interface flows in incremental adjustments will continue until

a) The NYISO is no longer off-cost, or
b) PJM is about to go off-cost (i.e., PJM expects that it will have to redispatch in response to transmission constraints in order to maintain the RTMDF), or
c) 300 MW have been redirected.

Appendix 2 - Transmission Constraints and Outages Associated with the Contracts

A. Constraints

The following transmission constraints are identified as potential constraints that may result in off-cost operation due to transfers associated with the 600/400 MW contracts. The constraints included in this listing should be considered representative of the kinds of constraints that may exist within PJM or the NYISO. If such transmission constraints are limiting, then the affected ISO/RTO may be subject to off-cost operation due to transfers associated with the 600/400 MW contracts. Other constraints, not listed here, may arise that could cause either ISO/RTO to operate off-cost. This list may be revised by NYISO/PJM to reflect system changes or security monitoring technique changes in their respective Control Areas.

NYISO

- UPNY-Con Ed Interface
- Dunwoodie- South Interface
- Dunwoodie-Rainey 345kV
- Rainey-Farragut 345kV
- Sprainbrook-W49th Street 345kV
- W49th Street-Farragut 345kV
- Ramapo-Ladentown 345kV
- Ramapo-Buchanan 345kV
- Buchanan-Millwood 345kV
- Buchanan-Eastview 345kV
- Millwood-Eastview 345kV
- Eastview-Sprainbrook 345kV
- East Fishkill-Pleasantville 345kV
- Pleasantville-Dunwoodie 345kV
- Pleasant Valley-East Fishkill 345kV
- Linden – Goethals 230 kV A-2253 Par
- Farragut - Hudson 345kV B-3402 Par
- Farragut - Hudson 345 kV C-3403 Par
- Waldwick - South Mahwah 345 kV K-3411
- Waldwick - South Mahwah 345 kV J-3410

PJM

- ATHENIA 230 KV ATHENIA 220-2 XFORMER

- ATHENIA 230 KV ATHENIA 220-1 XFORMER
- BAYWAY 138 KV BAYWAY Z-1352
- BRANCHBU 500 KV BRANCHBU 500-1 XFORMER
- BRANCHBU 500 KV BRANCHBU 500-2 XFORMER
- DEANS 500 KV DEANS 500-1 XFORMER
- DEANS 500 KV DEANS 500-2 XFORMER
- DEANS 500 KV DEANS 500-3 XFORMER
- HUDSON 230 KV HUDSON HUDSON2 XFORMER
- INTERFACE EAST
- ATHENIA-ERUTHERF S-1345 138 KV
- BAYONNE-MARION L-1338 138 KV
- BAYONNE-PVSC I-1335 138 KV
- BERGEN-ERUTHERF R-1344 138 KV
- BERGEN-HOMESTEA F-1306 138 KV
- BRUNSWIC-EDISON H-1360 138 KV
- EDISON-MEADOWRD Q-1317 138 KV
- EDISON-MEADOWRD R-1318 138 KV
- LINDEN-NORTHAV T-1346 138 KV
- PLAINSBU-TRENTON D-1330 138 KV
- ADAMS-BENNETTS X-2224-3 230 KV
- ATHENIA-CLIF PS K-2263 230 KV
- ATHENIA-SADDLEBR Q-2217 230 KV
- BERGEN-HOBOKEN R-2270 230 KV
- BERGEN-LEONIA T-2272 230 KV
- BRANCHBU-FLAGTOWN C-2203 230 KV
- BRANCHBU-READINGT M-2265 230 KV
- CEDARGRO-CLIF PS K-2263-3 230 KV
- CEDARGRO-ROSELAND B-2228 230 KV
- CEDARGRO-ROSELAND F-2206 230 KV
- GOETHALS-LINDEN A-2253 230 KV
- GREYSTON-PORTLAND S1007 230 KV
- HAWTHORN-HINCHMAN N-2266 230 KV
- HILLSDAL-NEWMILFR V-2222 230 KV
- HILLSDAL-NEWMILFR V-2222 230 KV
- HOBOKEN-NEWP PS R-2270 230 KV
- LEONIA-NEWMILFR T-2272 230 KV
- ROSELAND-WHIPPANY A-941 230 K
- BRANCHBU-RAMAPO 5018 500 KV
- GOETHALS-LINDEN 230 KV A-2253 PAR or Circuit
- HUDSON - FARRAGUT 345 KV B-3402 PAR or Circuit
- HUDSON - FARRAGUT 345 KV C-3403 PAR or Circuit
- WALDWICK - FAIRLAWN 230 KV O-2267 PAR or Circuit
- WALDWICK - HAWTHORNE 230 KV E-2257 PAR or Circuit
- WALDWICK - HILLSDALE 230 KV F-2258 PAR or Circuit

- WALDWICK - SOUTH MAHWAH 345 KV K-3411
- WALDWICK - SOUTH MAHWAH 345 KV J-3410

B. Outages

The NYISO and PJM will identify critical outages that may impact redispatch costs incurred for the delivery of energy, under the 600/400 MW contracts. Identified outages may have the following consequences:

The outage of any A, B, C, J, or K facility will result in the NY-DAE, PJM-DAE, and/or RTE (as appropriate) being limited to a value no greater than the remaining thermal capability of the most limiting of the ABC interface or the JK interface. The remaining thermal capability of either the ABC interface or the JK interface may be limited by other facilities directly in series with the A, B, C, J, or K lines.

1. 600 MW Contract - It is not anticipated that one primary facility outage will preclude PJM from providing redispatch for the 600 MW contract. However, combinations of two or more outages of the facilities, listed below, could preclude PJM from accommodating all or part of the 600 MW delivery, even with redispatch. In this case, PJM will provide notification to NYISO.
2. 400 MW Contract - The outage of one or more of the facilities in the following list, may impact redispatch costs regarding, or the delivery of all or portions of the 400 MW contract:

Branchburg-Ramapo 500 kV 5018
South Mahwah-Waldwick J 345 kV J-3410/69
South Mahwah-Waldwick K 345 kV K-3411/70
Hudson-Farragut B-3402
Hudson-Farragut C-3403
Linden-Goethals 230 kV A-2253
Athenia-NJT Meadows -Essex-Hudson 230 kV C-2281-P-2216-A-2227
New Milford-Leonia-Bergen-Penhorn-Hudson 230 kV T-2272-X-2250
Waldwick-Hillsdale-New Milford 230 kV F-2258-V-2222
Waldwick- Fairlawn 230 kV O-2267
Waldwick-Hawthorne-Hinchman's Ave-Cedar Grove 230 kV E-2257 – N-2266 – M-2239 – L-2238
Roseland-Cedar Grove-Clifton-Athenia B 230 kV B-2228
Roseland-Cedar Grove-Clifton-Athenia K 230 kV F-2206 – K-2263
Linden-Bayway 230 kV H-2234

Linden-Minue Street R 230 kV R-2218
Linden-Minue Street G 230 kV G-2207
Roseland-Whippany A-941
Branchburg-Readington-Roseland M-2265 - U-2221
Roseland-Montville-Newton-Kittatinny E-2203 – N-2214 - T-2298
Deans – Aldene W-2249

In addition, the forced or maintenance outage of one or more of the following generators may impact redispatch costs regarding, or the delivery of all or portions of the 400 MW contract provided that any such maintenance outage is approved by PJM. Otherwise, each of these generators will be considered to be available to support the 600/400 MW contracts under a security constrained dispatch in PJM's Day-Ahead and Real-Time Markets.

Hudson #1
Hudson #2
Bergen #1
Bergen #2
Linden #1
Linden #5, 6, 7, & 8

PJM will provide notification[34] of all outages by posting these outages (transmission only) on the PJM OASIS (http://oasis.pjm.com/inform.html). At a minimum, PJM will identify critical scheduled outages by the first day of the month prior to the month of the start of the outage.

NYISO will provide notification of all outages by posting these outages (transmission only) on the NYISO OASIS (http://www.nyiso.com/oasis/index.html). NYISO will identify critical scheduled outages by the first day of the month prior to the month of the start of the outage.

PJM and the NYISO will review and revise, as necessary, the list of primary and secondary facilities contained in this Appendix 2 on an annual basis.

---

[34] PJM can also provide the option of automated email outage notification through the PJM eDart tool.

Appendix 3 - The Day-Ahead Market and Real-Time Market Desired Flow Calculation

The following shall be the formula for calculating Day-Ahead Market (DAM) and Real-Time Market (RTM) desired flows:

$NYDF_{ABC}$ = [NY-DAE] + [A]*[PJM-NYISO DAM Schedule] + [B] *[OH-NYISO DAM Schedule] + [C] *[West-PJM DAM Schedule] + [D]*[DAM Lake Erie Circulation]

$NYDF_{JK}$ = [NY-DAE] - [A]*[PJM-NYISO DAM Schedule] - [B] *[OH-NYISO DAM Schedule] - [C] *[West-PJM DAM Schedule] - [D]*[DAM Lake Erie Circulation]

$PJMDF_{ABC}$ = [PJM-DAE] + [A]*[PJM-NYISO DAM Schedule] + [B] *[OH-NYISO DAM Schedule] + [C] *[West-PJM DAM Schedule] + [D]* DAM Lake Erie Circulation]

$PJMDF_{JK}$ = [PJM-DAE] - [A]*[PJM-NYISO DAM Schedule] - [B] *[OH-NYISO DAM Schedule] - [C] *[West-PJM DAM Schedule] - [D]*[DAM Lake Erie Circulation]

RTMDFABC = [RTE] + [A]*[PJM-NYISO RTM Schedule] + [B] *[OH-NYISO RTM Schedule]
+ [C] *[West-PJM RTM Schedule] + [D]*[RTM Lake Erie Circulation]

RTMDFJK = [RTE] - [A]*[PJM-NYISO RTM Schedule] - [B] *[OH-NYISO RTM Schedule]
- [C] *[West-PJM RTM Schedule] - [D]*[RTM Lake Erie Circulation]

A	13 %	Adjustment for NYISO-PJM Schedule
B	0 %	Adjustment for OH-NYISO Schedule
C	0 %	Adjustment for West-PJM Schedules
D	0 %	Adjustment for Lake Erie Circulation

Other impacts will be part of the real time bandwidth operation – not the desired flow calculation. These impacts will be reviewed by PJM and the NYISO on an annual basis.

The above distribution factors (A, B, C, D) will be used in the calculation unless otherwise agreed by PJM and the NYISO based upon operating analysis conducted in response to major topology changes or outages referenced in Appendix 2. Such modifications will be posted by PJM and the NYISO.

Appendix 4 - Market Monitoring and Information Sharing Procedures

A. General Principles

The NYISO and PJM and their Market Monitoring Units shall, to the extent compatible with their respective tariffs and with any other market monitoring procedures that they have filed with the Commission:

1. Conduct such investigations as may be necessary to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the 600/400 MW contracts;
2. Conduct investigations that go into the region of the other ISO jointly with the NYISO, PJM and both Market Monitoring Units;
3. Inform each other of any such investigations; and
4. Share information related to such investigations, as necessary to conduct joint investigations, subject to the requirements of Section C, below.

The responsibilities of the Market Monitoring Unit that are addressed in Section A of Appendix 4 to the Operating Protocol for the Implementation of Commission Opinion No. 476 (Appendix M-1 to the ISO Services Tariff) are also addressed in Section 30.4.6.5.2 of Attachment O.

B. Information Regarding Transactions Associated with the 600/400 MW Contracts

1. General Information

a. The NYISO and PJM Market Monitoring Units shall have made available to them by their respective ISOs the Day-Ahead and Real-Time elections made by ConEd in both Control Areas under this protocol.

b. The NYISO and PJM Market Monitoring Units shall have available to them such data on transmission conditions in both the Day-Ahead and Real-Time markets in both PJM and NYISO, as is publicly available and posted on the ISOs' internet sites.

2. Information Available upon Request

a. On a case-by-case basis, as documented in writing as being necessary to an investigation or to determine if an investigation is necessary or appropriate, the NYISO and PJM shall make available to each other, and to each of their Market Monitoring Units, generator outages and deratings in both the Day-Ahead and Real-Time markets.

b. On a case-by-case basis, as documented in writing as being necessary to an investigation or to determine if an investigation is necessary or appropriate, the NYISO and PJM shall make available to each other, and to each of the Market Monitoring Units, the specific FTRs or TCCs in the PSE&G zone or the ConEd Transmission District, respectively, held by ConEd, PSE&G, and any of their affiliates.

3. Information Needed To Conduct a Joint Investigation

The sharing of information that is necessary or appropriate to facilitate a joint investigation by the PJM and NYISO, and/or by their Market Monitoring Units shall be governed by the terms and conditions of the ISOs' respective tariffs, operating agreements, and other procedures that they have filed with the Commission, and shall be subject to the limitations in Section C, below.

C. Protection of Confidential Information

1. This Appendix does not present an independent basis for, and shall not be construed to authorize or require the disclosure of, confidential, proprietary or privileged information that the NYISO or PJM are otherwise prohibited from disclosing under applicable laws, regulations, tariffs, or other market monitoring procedures that they have filed with the Commission.

2. The NYISO's or its Market Monitoring Unit's disclosure of "Protected Information" to PJM, or to its Market Monitoring Unit are subject to the provisions of Section 30.6.6 of Attachment O. PJM's, or its Market Monitoring Unit's disclosure of "confidential information" to the NYISO, or to its Market Monitoring Unit, is subject to the provisions of Section 18.17.5 of the PJM Operating Agreement.

3. If the NYISO or PJM, or either of their Market Monitoring Units receive~~s~~ a demand for the disclosure of confidential information that it received under this Appendix 4, it shall notify the other so that the other will have an opportunity to take any legal steps required to protect the information.

Appendix 5 - Impairments Impacting Delivery

The procedures for identifying and remedying impairments shall be handled on a planning basis. The impairment process is not directly applicable to DAM or RT operations under the 600/400 MW contracts.

EXISTING IMPAIRMENTS

- PJM and the NYISO are not aware of any existing impairments that would preclude provision of transmission service under the 600 MW contract. There should not be any impairment on the 400 MW contract based on available redispatch options.

NOTIFICATION PROCEDURES

- ConEd and PSE&G shall notify the NYISO and PJM respectively under their existing ISO/RTO interconnection procedures when interconnecting new generation facilities to their transmission systems.

PROCEDURES FOR DETERMINATION OF FUTURE IMPAIRMENTS

- The procedures to be used by the NYISO and PJM for the determination of future impairments shall be in accordance with:
    - The PJM Regional Transmission Expansion Planning Process;
    - The NYISO Comprehensive Reliability Planning Process; and
    - The Northeast ISO/RTO Planning Coordination Protocol executed by PJM, the NYISO and ISO-New England Inc.
- The Northeast ISO/RTO Planning Coordination Protocol contains provisions for the coordination of interconnection requests received by one ISO/RTO that have the potential to cause impacts on an adjacent ISO/RTO to include the handling of firm transmission service.
- The Northeast ISO/RTO Planning Coordination Protocol has provisions for notification, development of screening procedures, and coordination of the study process between the ISO/RTOs.
- The Northeast ISO/RTO Planning Coordination Protocol also provides that all analyses performed to evaluate cross-border impacts on the system facilities of one of the ISOs/RTOs will be based on the criteria, guidelines, procedures or standards applicable to those facilities.
- Future planning studies by the ISOs/RTOs shall include 1,000 MW[35] of firm delivery from the NYISO at Waldwick and 1,000 MW of re-delivery from PJM at

[35] 1,000 MW will also be included in the FTR simultaneous feasibility analysis.

the Hudson and Linden interface independent of the amount of off-cost operation that is required to meet reliability criteria. For PJM load deliverability planning studies, which simulate a capacity emergency situation, the system shall be planned to include 1,000 MW of firm delivery from the NYISO at Waldwick and 600 MW of re-delivery from PJM at the Hudson and Linden interface.

Nothing in this Operating Protocol shall modify any planning-related obligations of ConEd or PSE&G set forth in the 600/400 MW contracts.

Appendix 6 – Operation of the PARs

General

This procedure outlines the steps taken to coordinate tap changes on the PARs in order to control power flow on selected transmission lines between New York and New Jersey. The facilities are used to provide transmission service and to satisfy the 600/400 MW contracts, other third party uses, and to provide emergency assistance as required. These tie-lines are part of the interconnection between the PJM and NYISO. These PAR operations will be coordinated with the operation of other PAR facilities including the 5018 PARs. The 5018 PAR will be operated taking into account this Operating Protocol. The ties are controlled by PARs at the following locations:

- Waldwick (F-2258, E-2257, O-2267)
- Goethals (A-2253)
- Farragut (C-3403, B-3402)

This appendix addresses the operation of the PARs at Waldwick, Goethals, and Farragut as these primarily impact the delivery associated with the 600/400 MW contracts between PSE&G and ConEd.

PJM and the NYISO will work together to maintain reliable system operation, and to implement the RTMDF within the bandwidths established by this Operating Protocol while endeavoring to minimize the tap changes necessary to implement these contracts.

RTMDF calculations will be made for the 'ABC Interface', and the 'JK Interface'. Desired line flow calculations will be made for A, B, and C lines (initial assumption is balanced each 1/3 of the ABC Interface), and for the J and K lines (initial assumption is balanced each ½ of the JK Interface).

Normal Operations

The desired flow calculation process is a coordinated effort between PJM and the NYISO. PJM and the NYISO have the responsibility to direct the operation of the PARs to ensure compliance with the requirements of the Operating Protocol. However, one of the objectives of this procedure is to minimize the movement of PARs while implementing the requirements of the 600/400 MW contracts. PJM and the NYISO will employ a +/- 100 MW bandwidth at each of the ABC and JK Interfaces to ensure that actual flows are maintained at acceptable levels.

PJM and the NYISO have operational control of the PARs and direct the operation of the PARs, while PSE&G and ConEd have physical control of the PARs. The ConEd dispatcher sets the PAR taps at Goethals and Farragut at the direction of the NYISO. The PSE&G dispatchers set the PAR taps at Waldwick at the direction of PJM.

Tap movements shall be limited to 400 per month based on 20 operations (per PAR) in a 24-hour period. If, in attempting to maintain the desired bandwidth, tap movements exceed these limits, then the bandwidth shall be increased in 50 MW increments until the tap movements no longer exceed 20 per day, unless PJM and the NYISO agree otherwise.

Emergency Operations

If an emergency condition exists in either the NYISO or PJM, the NYISO dispatcher or PJM dispatcher may request that the ties between New York and New Jersey be adjusted to assist directing power flows in the respective areas to alleviate the emergency situation. The taps on the PARs at Waldwick, Goethals, and Farragut may be moved either in tandem or individually as needed to mitigate the emergency condition. Responding to emergency conditions in either the NYISO or PJM overrides any requirements of this Operating Protocol and the appendices hereto.

PAR Movement Scenarios

Case 1 — Aggregate actual flow on the JK interface (at Waldwick) or the ABC interface (at Farragut and Goethals) is higher or lower than RTMDF, but within the bandwidth.

No action taken. Flows will continue to be monitored, but action will only be taken if the flows get above or below the bandwidth.

Case 2 — Aggregate actual flow on the JK interface (at Waldwick) or the ABC interface (at Farragut and Goethals) is higher or lower than the RTMDF, and outside the bandwidth.

PJM and the NYISO will coordinate the following procedures:

- PJM shall determine the Waldwick PAR tap change(s) that change the aggregate actual flow to be within the bandwidth, considering the impact that the proposed tap changes have on the NYISO. If the PJM analysis indicates that the tap changes can be made without causing an actual or contingency constraint in the NYISO that would result in NYISO off-cost operation, PJM will inform the NYISO of the proposed PAR moves, obtain the NYISO's concurrence, and direct PSE&G to implement the PAR tap changes.

- The NYISO shall determine the Farragut and Goethals PAR tap change(s) that change the aggregate actual flow to be within the bandwidth, considering the impact that the proposed tap changes have on PJM. If the NYISO analysis indicates that the tap changes can be made without an actual or contingency constraint in PJM that would result in PJM off-cost operation, the NYISO will inform PJM of the proposed PAR moves, obtain PJM concurrence, and direct ConEd to implement the PAR tap changes.

- If PJM is off-cost or expected to go off-cost in maintaining the RTMDF and the NYISO is not off-cost, then PJM/NYISO shall agree to allow actual aggregate interface flows to deviate from the RTMDF in order to re-direct up to 300 MW from the PJM system onto the NYISO system. The process of modifying actual interface flows in incremental adjustments will continue until 1) PJM is no longer off-cost; or 2) the NYISO is about to go off-cost (i.e., the NYISO expects that it will have to redispatch in response to transmission constraints in order to maintain the RTMDF).

- If the NYISO is off-cost or expected to go off-cost and PJM is not off-cost in maintaining the RTMDF, then PJM/NYISO shall agree to allow actual aggregate interface flows to deviate from the RTMDF in order to re-direct up to 300 MW from the NYISO system onto the PJM system. The process of modifying actual interface flows in incremental adjustments will continue until 1) NYISO is no longer off-cost; or 2) PJM is about to go off-cost (i.e., PJM expects that it will have to redispatch in response to transmission constraints in order to maintain the RTMDF).

- If the ABC actual interface flows cannot be maintained within the interface desired flow range due to the following system conditions: (1) insufficient PAR angle capability resulting from any of the A, B, C, J, or K PARs being at their maximum tap setting, and (2) PJM's inability to redispatch in response to transmission constraints to support ABC deliveries to New York, then PJM and the NYISO shall consider using other available facilities, including the other PARs, to create flow capability to permit the necessary tap changes to bring the actual flow within the tolerances of the desired flow calculation, provided that this can be done without creating additional redispatch costs in either the NYISO or PJM. If after such actions have been taken, including the use of other facilities, and ABC/JK actual interface flows still cannot be maintained within the interface desired flow range, then an adjustment to the desired flow calculation (a desired flow offset, with the amount agreed to by PJM and the NYISO) shall be made such that both the ABC and JK actual interface flows are within +/- 100 MW of the ABC and JK interface RTMDF respectively.

- If the JK actual interface flows cannot be maintained within the interface desired flow range due to the following system conditions: (1) insufficient PAR angle capability resulting from any of the A, B, C, J, or K PARs being at their maximum tap setting, and (2) the NYISO's inability to re-dispatch in response to transmission constraints to support JK deliveries to PJM then PJM and NYISO shall consider using other available facilities, including the other PARs to create flow capability to permit the necessary tap changes to bring the actual flow within the tolerances of the desired flow calculation, provided that this can be done without creating additional redispatch costs in either the NYISO or PJM. If after such actions have been taken, including the use of other facilities, and ABC/JK actual interface flows still cannot be maintained within the interface desired flow range, then an adjustment to the desired flow calculation (a desired flow offset, with the amount agreed to by PJM and NYISO) shall be made such that both the ABC and JK actual interface flows are within +/- 100 MW of the ABC and JK interface RTMDF respectively.

Case 3 — If PJM or NYISO analysis reveals that future system conditions (within the next several hours)may reasonably be expected to require that a PAR will need to change by more than 3 taps in order to remain within the bandwidth, then PJM and NYISO shall consider pre-positioning the system to address these future conditions. Both PJM and the NYISO must agree to any decision to re-position the taps to address expected future conditions.

PJM and the NYISO will coordinate with each other and may mutually agree to position the respective PARs on each system to be within two tap changes in anticipation of changes to RTMDF for the next several hours to ensure that the PARs are positioned such that they are able to meet the anticipated RTMDF.

Appendix 7 – Distribution of Flows Associated with Implementation of Day-Ahead and Real Time Market Desired Flows

In general, the ability to maintain the ABC / JK actual interface flows at their corresponding ABC/JK Day-Ahead and Real Time Market Desired Flow (RTMDF) values should not be impacted by individual line flow constraints. The Operating Protocol will ordinarily be considered satisfied if the ABC/JK actual interface flows are each equal to the desired flow values plus or minus the 100 MW bandwidth.

The initial estimate of individual line flow distribution for the ABC / JK interfaces shall be based on an equal flow assumption among the lines comprising the interface. Under outage conditions of the A, B, C, J, or K lines, the initial estimate of individual line flow distribution shall be based on an assumption that flows should be equalized among those remaining lines comprising the interface. Further, the ISOs shall adjust (from RTMDF) the flow distribution for ABC (move flow from the A line to the B and C lines) upon the NYISO's request, provided that the adjustment shall not exceed 125 MW if PJM is off-cost or is expected to be off-cost. Con Ed shall not be responsible for balancing charges resulting from changes in the individual line flow distribution between the PJM Day-Ahead and Real-Time Markets.

For example:

If the ABC interface RTMDF is 900 MW, then the initial estimate of line flow on A is 1/3 * 900=300 MW, B is 1/3 * 900=300 MW, and C is 1/3 * 900=300 MW.

If the J, K interface RTMDF is 900 MW, then the initial estimate of line flow on J is 1/2 * 900=450 MW, K is 1/2 * 900=450 MW.

However, if the ABC/JK actual interface flows cannot be maintained within the 100 MW bandwidth of desired flows due to the following system conditions: 1) insufficient PAR angle capability and an inability to redispatch in response to transmission constraints in PJM; or 2) upon implementing a NYISO request to adjust the distribution of flow on the A line (move flow from the A line to the B and C lines) in excess of 125 MW as described above, then the actual ABC and/or JK interface flow shall be adjusted to be as close as feasible to the interface desired flow values for each of the JK and ABC interfaces.

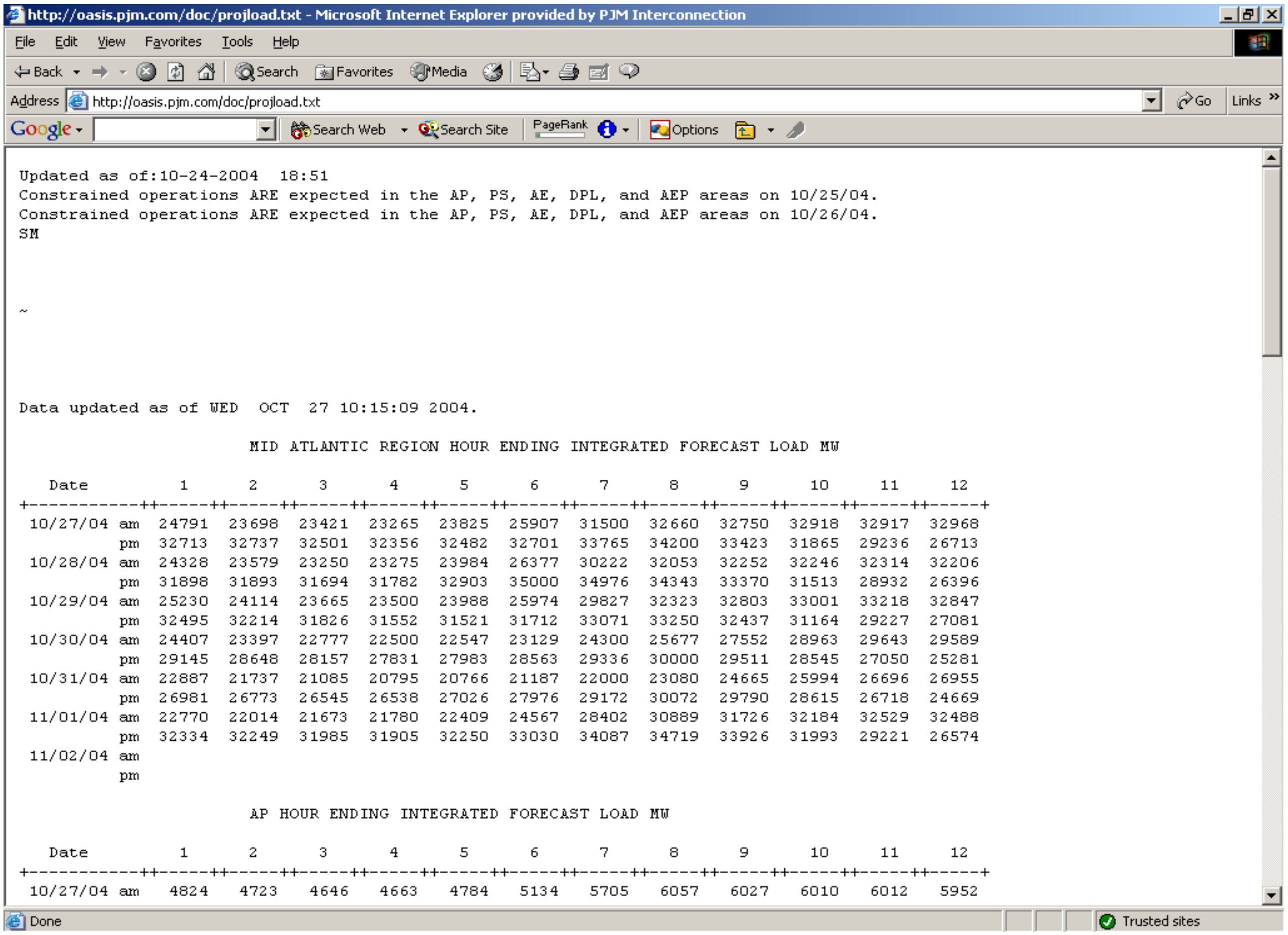
For example:

Assume the ABC interface RTMDF = 900 MW, then the initial estimate of line flow on A is 1/3* 900=300 MW, B is 1/3 * 900=300 MW, and C is 1/3 * 900=300 MW.

Further assume that the NYISO requests that the distribution of flow over the A line be limited to 100 MW, then the resulting system conditions are an actual ABC interface flow of 825 MW with individual PAR flows of A=100 MW, B=362.5 MW, C=362.5 MW.

In this example, the actual ABC interface flow is as close as feasible to the ABC RTMDF assuming off-cost operation in the PJM area and the NYISO request that the distribution of flow over the A line be limited to 100 MW, which is in excess of the 125 MW distribution adjustment (300 MW-100 MW = 200 MW). PJM and the NYISO's obligations under this Operating Protocol will be deemed to be satisfied even though the ABC/JK actual interface flows are not equal to the RTMDF plus or minus the 100 MW bandwidth.

Appendix 8 – References



http://oasis.pjm.com/doc/projload.txt - Microsoft Internet Explorer provided by PJM Interconnection

Updated as of:10-24-2004 18:51
Constrained operations ARE expected in the AP, PS, AE, DPL, and AEP areas on 10/25/04.
Constrained operations ARE expected in the AP, PS, AE, DPL, and AEP areas on 10/26/04.
SM

~

Data updated as of WED OCT 27 10:15:09 2004.

MID ATLANTIC REGION HOUR ENDING INTEGRATED FORECAST LOAD MW

Date		1	2	3	4	5	6	7	8	9	10	11	12
10/27/04	am	24791	23698	23421	23265	23825	25907	31500	32660	32750	32918	32917	32968
	pm	32713	32737	32501	32356	32482	32701	33765	34200	33423	31865	29236	26713
10/28/04	am	24328	23579	23250	23275	23984	26377	30222	32053	32252	32246	32314	32206
	pm	31898	31893	31694	31782	32903	35000	34976	34343	33370	31513	28932	26396
10/29/04	am	25230	24114	23665	23500	23988	25974	29827	32323	32803	33001	33218	32847
	pm	32495	32214	31826	31552	31521	31712	33071	33250	32437	31164	29227	27081
10/30/04	am	24407	23397	22777	22500	22547	23129	24300	25677	27552	28963	29643	29589
	pm	29145	28648	28157	27831	27983	28563	29336	30000	29511	28545	27050	25281
10/31/04	am	22887	21737	21085	20795	20766	21187	22000	23080	24665	25994	26696	26955
	pm	26981	26773	26545	26538	27026	27976	29172	30072	29790	28615	26718	24669
11/01/04	am	22770	22014	21673	21780	22409	24567	28402	30889	31726	32184	32529	32488
	pm	32334	32249	31985	31905	32250	33030	34087	34719	33926	31993	29221	26574
11/02/04	am												
	pm												

AP HOUR ENDING INTEGRATED FORECAST LOAD MW

Date		1	2	3	4	5	6	7	8	9	10	11	12
10/27/04	am	4824	4723	4646	4663	4784	5134	5705	6057	6027	6010	6012	5952

Figure 1 - PJM Constraints

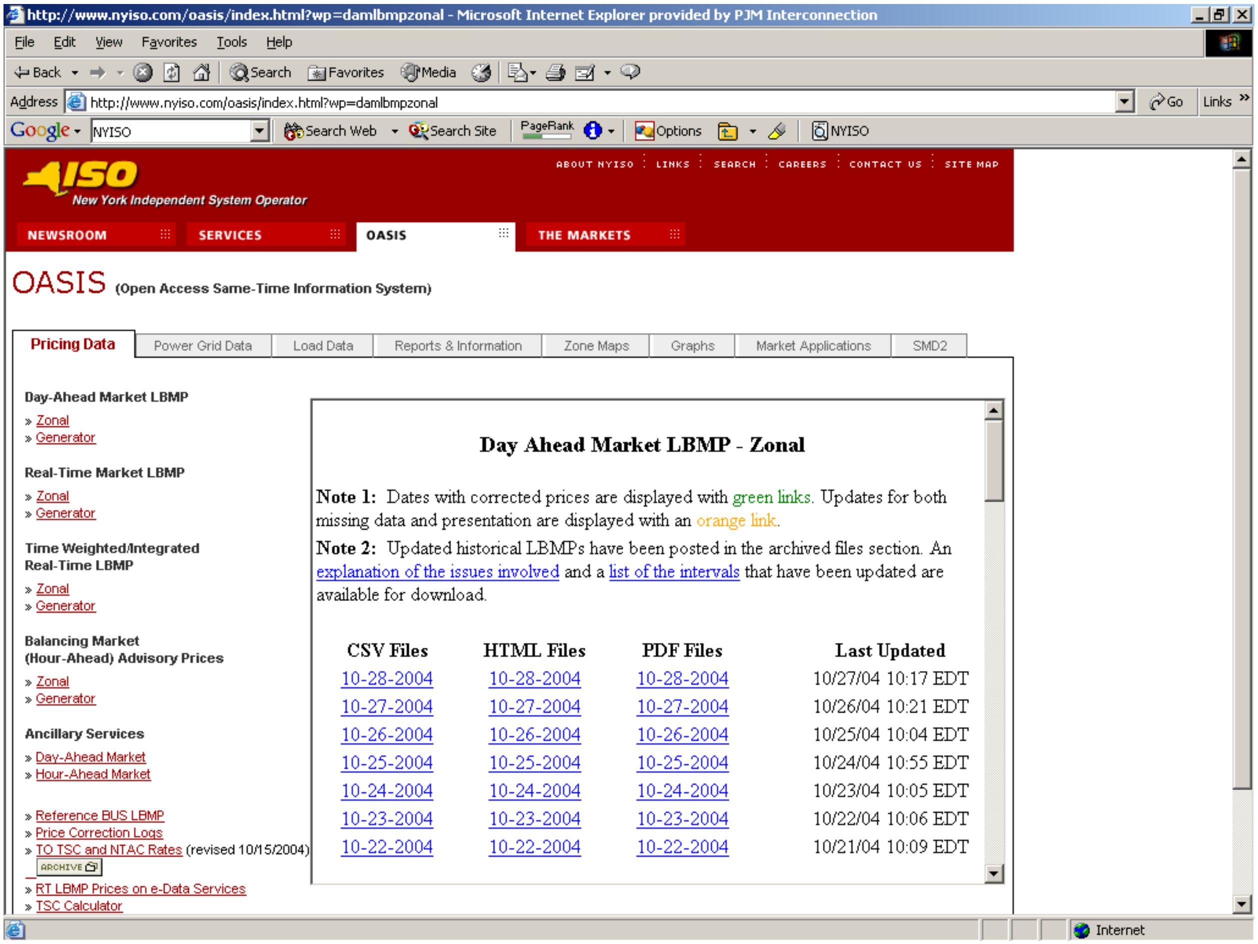


Figure 2 - NYISO Day Ahead Results

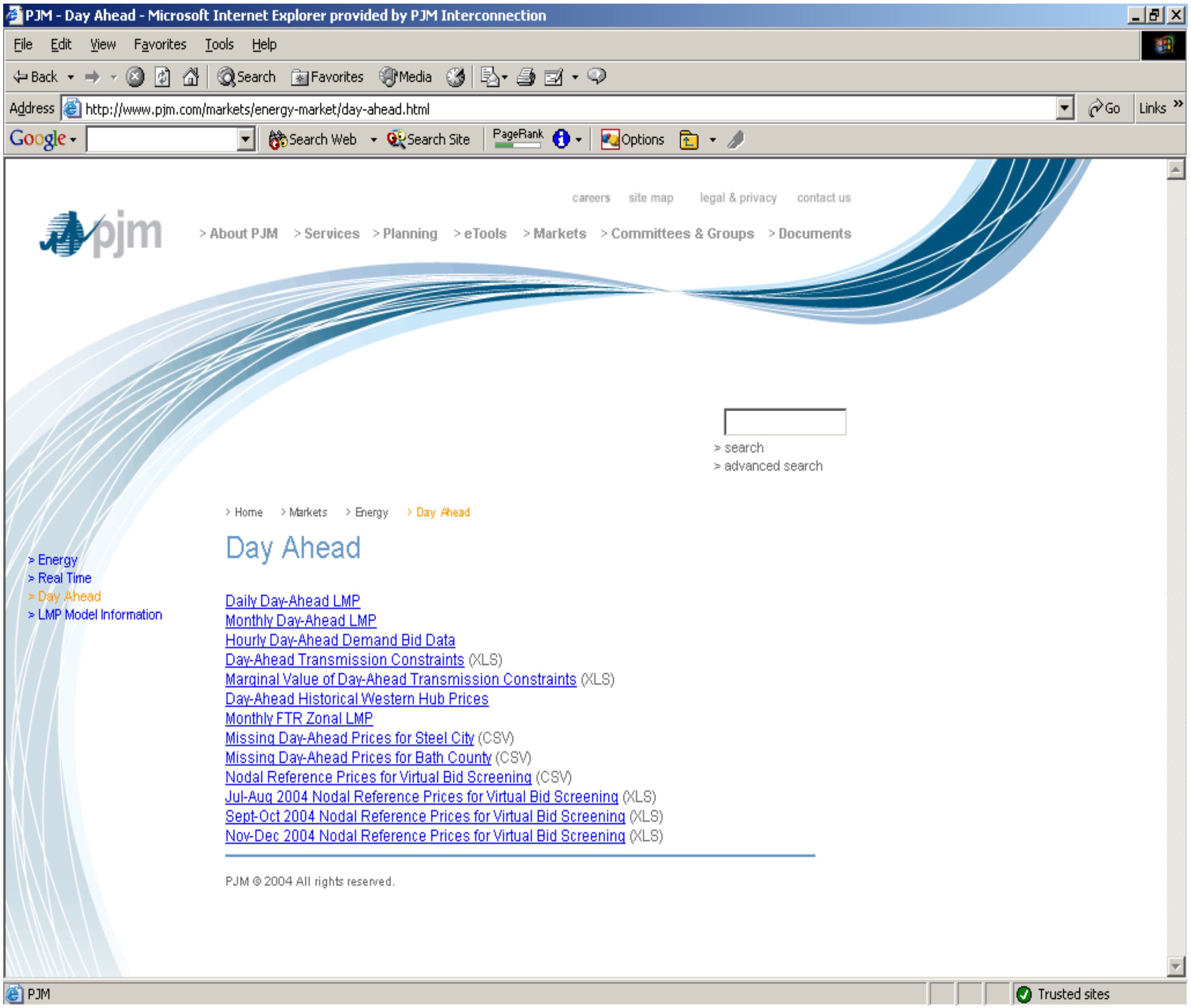


Figure 3 - PJM Day Ahead Market Results

Appendix 9 – Comparison of Contracts

	Delivery Priority	PJM Redispatch Required	Day Ahead Market Submittal	Day Ahead Market Congestion Charges	FTRs	Real Time Contract Schedule	Balancing Market Settlements
600 MW Contract	Firm	PJM redispatch required.	ConEd may submit up to 600 MW as DA Market transaction (fixed hourly MW schedule of up to 600 MW each hour)	PSEG pays DA Market congestion costs for amount of 600 MW contract scheduled in DA Market. Congestion charge = (LMPABC - LMPJK) * DA MW	PSEG receives up to 600 MW FTR with source of JK and sink of ABC. (hourly FTR MW level will equal hourly DA MW scheduled on 600 MW contract)	ConEd may request RT election which deviates from DA election.	ConEd receives/pays real time LMP /LBMP differential between JK and ABC for real-time MW amount scheduled below/above MW amount cleared in Day Ahead Market in both PJM and NY.
400 MW Contract	If ConEd is willing to pay congestion (WPC) then contract priority is above all other WPC transactions but below firm. If not then same priority as non-firm, non-WPC. If ConEd converts to firm transmission service then the contract shall be treated as firm.	PJM redispatch required to the extent that ConEd is willing to pay congestion (less credits back to ConEd.)	ConEd may submit up to 400 MW as DA Market transaction (fixed hourly MW amount of up to 400 MW each hour and/or 'WPC' of up to $25)	ConEd pays DA Market congestion costs for amount of 400 MW contract cleared in the DA Market. Congestion charge = (LMPABC - LMPJK) * DA MW	No FTRs Allocated. lConEd receives credit for DA congestion charges paid . The manner in which credits are alloted depends on whether ConEd converts the 400 MW contract to firm service	ConEd may request RT election which deviates from DA election.	ConEd receives/pays real time LMP/LBMP differential between JK and ABC for real-time MW amount scheduled below/above MW amount cleared in Day Ahead Market in bith PJM and NY.

Appendix 10 – Definitions

1. Off cost – the weighted LMP of JK is less than the weighted LMP of ABC by more than $5 and/or the weighted nodal pricing of Ramapo is less than the weighted nodal pricing of the aggregate of Farragut and Goethals by more than $5 (with a reasonable expectation of the appropriate cost differential continuing for at least two consecutive hours).
2. New York ISO Day Ahead Election (NY-DAE) - election by ConEd – submitted in the NYISO Day-Ahead Market prior to 5 a.m.
3. NY Desired Flow (NYDF) – desired flow calculation by NYISO based on NY-DAE for input to NYISO Day Ahead Market.
4. PJM Day Ahead Market Election (PJM-DAE) - election by the ConEd – submitted in the PJM Day Ahead Market prior to 12 noon.
5. Willing To Pay Congestion (WPC) – an election made by ConEd based on willingness to pay congestion costs.
6. PJM Desired Flow (PJMDF) – desired flow calculation by PJM based on PJM-DAE for input to PJM Day Ahead Market.
7. ConEd Real-Time election (RTE) – option by ConEd to request Real-Time Market modification from its Day Ahead Market election.
8. Real-Time Market Desired Flow (RTMDF) – Desired flow for real time operations.
9. Impairments – Conditions determined during the NYISO's and PJM's respective planning analyses that will cause implementation of the 600/400 MW contracts to result in violations of established reliability criteria.
10. Active Load Management (ALM) - Active Load Management is end-use customer load which can be interrupted at the request of PJM. Such PJM request is considered an Emergency action and is implemented prior to a voltage reduction.
11. Pricing points – aggregate nodal points for the ABC interface and JK interface at the respective locations in both PJM and NYISO regions. These points will be defined and posted.

29 Attachment N – External Transactions at The Proxy Generator Buses Associated With The Cross-Sound Scheduled Line, Neptune Scheduled Line, and Linden VFT 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, and the Linden VFT 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, or the Linden VFT Scheduled Line, the provisions of this Attachment N shall prevail.

29.2 Transmission Reservations on the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line

Customers scheduling External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT 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.

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, or the Linden VFT 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, or the Linden VFT 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, or the Linden VFT 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, and the Linden VFT 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, or the Linden VFT 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, or the Linden VFT 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, or the Linden VFT 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 or the Linden VFT 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.

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 it the ISO deems appropriate to the effective implementation of Attachment O, subject to the management oversight of the Chief Executive Officer. 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.

30.3.4 Accountability

The MMA shall act at the direction of the Chief Executive Officer, who shall be accountable for the ISO's implementation of Attachment O.

The Chief Executive Officer shall ensure that the MMA has adequate employees, funding and other resources, access to required information, and the cooperation of the 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 Article 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 deadline, or to take any other action, required of Developers under Attachments S, X, or Z to the ISO OATT that subjects a Developer to a possible loss of queue position;

30.4.5.3.2.2 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;

30.4.5.3.2.3 failure to provide wind forecasting information that results in a sanction under Section 5.8.1 of the ISO Services Tariff;

30.4.5.3.2.4 failure to provide Installed Capacity related information or operating data under Articles 5.12.1, 5.12.3, or 5.12.5 of the ISO Services Tariff that triggers sanctions under Article 5.12.12 of the ISO Services Tariff;

30.4.5.3.2.5 failure to comply with the scheduling, bidding, and notification requirements under Articles 5.12.1 or 5.12.7 of the ISO Services Tariff that trigger sanctions under Article 5.12.12 of the ISO Services Tariff;

30.4.5.3.2.6 other actions or failures to act that trigger sanctions under Article 5.12.12 of the ISO Services Tariff, including, but not limited to, failures by:

30.4.5.3.2.6.1 Installed Capacity Suppliers 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 Installed Capacity, or afford the same Curtailment priority that it affords its own Control Area Load to: (a) provide Installed Capacity related information required for certification as an Installed Capacity Resource as established in the ISO Procedures; and (b) comply with scheduling, bidding, or notification requirements for certification as an Installed Capacity Supplier established in the ISO Procedures.

30.4.5.3.2.6.2 Transmission Owners to provide information required by Article 5.11.3 of the ISO Services Tariff;

30.4.5.3.2.7 shortfalls by Installed Capacity Suppliers and External Installed Capacity Suppliers that trigger sanctions under Article 5.14.2 of the ISO Services Tariff;

30.4.5.3.2.8 Voltage Support Service performance that results in the imposition of charges under Rate Schedule 2 to the ISO Services Tariff;

30.4.5.3.2.9 Regulation Service performance that results in the imposition of penalties under Section 15.3.8 of Rate Schedule 3 to the ISO Services Tariff (in the event that such penalties are re-instituted by the ISO);

30.4.5.3.2.10 performance that results in the imposition of Persistent Undergeneration charges under Rate Schedule 3-A to the ISO Services Tariff;

30.4.5.3.2.11 Black Start performance that results in reduction or forfeitures of payments under Rate Schedule 5 to the ISO Services Tariff;

30.4.5.3.2.12 conduct that results in a sanction under Section 23.4.3 of the Market Mitigation Measures, including, but not limited to: (i) where a Market Party, or its Affiliate, engages in physical withholding, including providing the ISO false information regarding the derating or outage of an electric facility; (ii) where a Market Party, or its Affiliate, fails to follow the ISOs dispatch instructions in real-time, resulting in a different output level than expected had the dispatch instruction been followed, where such conduct has caused a material increase in one or more prices or guarantee payments in an ISO administered market;

(iii) where a Market Party makes unjustifiable changes to one or more operating parameters of a Generator that reduce its ability to provide Energy or Ancillary Services; and

(iv) a Load Serving Entity that has been subjected to a "Load Bid Measure" Penalty Level payment in accordance with Section .23.4.4 of the Market Mitigation Measures;

30.4.5.3.2.13 conduct that results in the ISO's use of the "Load Bid Measure" set forth in Section .23.4.4 of the Market Mitigation Measures;

30.4.5.3.2.14 actions or failures to act by Installed Capacity Suppliers and Responsible Interface Parties that trigger sanctions under Section 23.4.5.4, 23.4.4.6, or 23.4.5.7 of the Market Mitigation Measures;

30.4.5.3.2.15 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;

30.4.5.3.2.16 failure of a Market Party to comply with the ISO's creditworthiness requirements for customers, including, but not limited to, failure to:

(i) comply with a demand for additional credit support, (ii) cure a default in another independent system operator/regional transmission organization market; (iii) prepay for charges in accordance with the terms of a prepayment agreement; (iv) comply with the ISO's creditworthiness reporting requirements; and (v) provide sufficient credit support to cover bid submissions.

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 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.

30.4.6.2.4 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.

30.4.6.2.5 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. A preliminary determination by the ISO 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. Upon request, the ISO shall also consult with a Market Party 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. 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 should be changed, revised reference levels shall be determined by the ISO, reviewed by the Market Monitoring Unit and, following the ISO's consideration of the Market Monitoring Unit's recommendation, communicated to the Market Party, and implemented by the ISO as soon as practicable. *See* Market Mitigation Measures Section 23.3.3.1.

30.4.6.2.6 With regard to a Market Party's request for consultation that satisfies the requirements of Sections 23.3.3.3.1.3 and 23.3.3.3.1.6 of the Market Mitigation Measures, and consistent with the duties assigned to the ISO in Section 23.3.3.3.1.6.1 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 23.3.3.3.1.6.1 and 23.3.3.3.1.6.2.

30.4.6.2.7 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 the New York City Locality over the Comparison Period for the External Reconfiguration Market. Prior to completing its projection of ICAP Spot Auction clearing prices for the New York City Locality 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.

30.4.6.2.8 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.

30.4.6.2.9 Any proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier from the In-City 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 the New York City Locality subsequent to such action. 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.

30.4.6.2.10 When evaluating a request by a Developer or Interconnection Customer 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 and cost calculations. *See* Market Mitigation Measures Section 23.4.5.7.

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 Section 5.14.1.2.5.

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

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. *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.

30.4.6.5.2 Responsibilities under Appendix 4 to the Operating Protocol for the Implementation of Commission Opinion No. 476 (the "Operating Protocol")

The ISO and PJM and their Market Monitoring Units shall, to the extent compatible with their respective tariffs and with any other market monitoring procedures that they have filed with the Commission:

30.4.6.5.2.1 Conduct such investigations as may be necessary to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the 600/400 MW contracts;

30.4.6.5.2.2 Conduct investigations that go into the region of the other ISO jointly with the ISO, PJM and both Market Monitoring Units;

30.4.6.5.2.3 Inform each other of any such investigations; and

30.4.6.5.2.4 Share information related to such investigations, as necessary to conduct joint investigations, subject to the requirements of Section C of Appendix 4 to the Operating Protocol and Section 30.6.6 of Attachment O.

See Section A of Appendix 4 to Attachment M-1 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 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 16.1.4 of Attachment J to the ISO OATT.

30.4.6.8.2 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 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 31.2.6.2 of Attachment Y to the ISO OATT.

30.4.6.8.4 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.

30.4.6.9 Market Monitoring Unit responsibilities set forth in other documents that have been formally filed with the Commission.

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 Chief Executive Officer, 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 Chief Executive Officer or 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 Going-Forward Costs – All data or information not specifically identified above that 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.

30.6.2.2.6 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 New York Independent System Operator Agreement, or if the foregoing is not applicable to the party from which the information has been requested the dispute resolution provisions of the New York ISO Tariffs, if applicable, to determine the ISO's right to obtain the requested information. The parties shall submit any such determination to binding arbitration, or other form of binding resolution, and shall seek expedited resolution, in accordance with the applicable dispute resolution procedures. If the entity from which the data or other information has been requested is not subject to either of the foregoing dispute resolution procedures and does not voluntarily agree to the use of either or a comparable dispute resolution procedure, the ISO may initiate such judicial or regulatory proceedings to compel the production of the requested information as may be available and deemed appropriate.

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 SO 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. Except as may be required by subpoena or other compulsory process, 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 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 disclosure. 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.

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, ~~Other State Commission,~~ 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 Until such time as the ISO is able to develop with its stakeholders and FERC accepts appropriate confidentiality protections (*See* Order 719 at PP. 448, 459), the Market Monitoring Unit shall not provide Protected Information in response to a request under this Section 30.6.5.5 of Attachment O, except where the party designating the requested information as Protected Information has consented in writing to its disclosure.

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.~~4~~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 PJM Interconnection LLC to Comply with FERC Opinion No. 476

30.6.6.1 Subject to the requirements of Section 30.6.6.2, the ISO and the Market Monitoring Unit may release Protected Information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the Protected Information of any Market Participant regarding generation and/or transmission facilities located within the ConEd Transmission District (see "CARL Data" Section 2.3 of the ISO's Open Access Transmission Tariff) to PJM Interconnection LLC ("PJM") and the PJM Market Monitoring Unit ("PJM Market Monitor") to the limited extent that the

ISO or the ISO's Market Monitoring Unit determines necessary to carry out the responsibilities of the Market Monitoring Units of PJM Interconnection LLC ("PJM") and the ISO under FERC Opinion No. 476 (*see Consolidated Edison Company v. Public Service Electric and Gas Company, et al*., 108 FERC ¶ 61,120 at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

30.6.6.2 The ISO and the Market Monitoring Unit may release a Market Participant's Protected Information pursuant to Section 30.6.6.1 to PJM and/or the PJM Market Monitor only if the entity receiving the Protected Information is subject to obligations limiting the disclosure of such Protected Information that are equivalent to or greater than the limitations on disclosure specified in Section 30.6.4 of Attachment O. Information received from PJM or the PJM Market Monitor under Section 30.6.6.1 that is designated as Protected Information shall be protected from disclosure in accordance with Section 30.6.4 of Attachment O by the ISO and by its Market Monitoring Unit.

30.6.7 Sharing Confidential, Transmission System and Protected Information with ISO New England Inc. and PJM

30.6.7.1 Subject to the terms, requirements and conditions set forth below, the ISO is authorized to exchange Protected Information (including, but not limited to, information that is confidential, proprietary, commercially valuable or competitively sensitive or is a trade secret, and that has been designated as such in writing by the party supplying the information to the ISO or by the ISO) that is related to External Transactions at the Proxy Generator Buses representing the electrical interfaces between the NYCA and New England, with ISO New England Inc. ("ISO-NE") for the specific and limited purposes of: (i) identifying and preventing the actual or intended gaming of the market rules set forth in the New York and/or New England (NEPOOL and ISO-NE) tariffs, procedures and technical documents, and/or (ii) identifying and preventing the actual or intended exercise of market power in New York or in New England; and

30.6.7.2 to exchange Protected Information (including, but not limited to, information that is confidential, proprietary, commercially valuable or competitively sensitive or is a trade secret, and that has been designated as such in writing by the party supplying the information to the ISO or by the ISO) that is related to External Transactions at the Proxy Generator Buses representing the electrical interfaces between the NYCA and the PJM Control Area, with PJM for the specific and limited purposes of: (i) identifying and preventing the actual or intended gaming of the market rules set forth in the New York and/or PJM tariffs, procedures and technical documents, and/or (ii) identifying and preventing the actual or intended exercise of market power in New York or in PJM.

30.6.7.3 Prior to disclosing any Protected Information, the ISO shall ensure that ISO-NE or PJM (as appropriate) will provide protections for Protected Information that are the substantial equivalent of those required by Attachment O, and that are the substantial equivalent of the protections that are required by Section 12.4 of the ISO's OATT Attachment F Code of Conduct for Confidential Information. In particular, ISO-NE and PJM shall be required to provide the following protections, and the ISO and its Market Monitoring Unit are authorized to provide reciprocal protections for Protected Information that is provided by ISO-NE or PJM:

30.6.7.3.1 ISO-NE or PJM (as appropriate) shall be subject to a legally enforceable obligation to treat as confidential, in accordance with all applicable tariffs and rules (including, but not limited to, their FERC Code of Conduct and the FERC Standards of Conduct), all information that is designated in writing by the ISO as being Protected Information, except where such information would not be subject to protection under the ISO's Code of Conduct OATT Attachment F) or this Attachment O. ISO-NE's or PJM's legally enforceable obligation to treat Protected Information provided by the ISO as confidential shall be of a continuing nature, and shall survive the rescission, termination or expiration of any applicable tariffs, rules, Code of Conduct and/or Standards of Conduct;

30.6.7.3.2 ISO-NE or PJM (as appropriate) shall possess reciprocal legal authority to provide Protected Information to the ISO;

30.6.7.3.3 ISO-NE or PJM (as appropriate) shall notice the ISO of all requests from courts or regulatory entities for access to Protected Information provided by the ISO and shall provide all reasonable assistance requested by the ISO to prevent disclosure of such information. Upon receipt of notice from ISO-NE or PJM, the ISO shall inform the party or parties that are the source or subject of the Protected Information and, in conjunction with ISO-NE or PJM, shall undertake reasonable efforts to ensure that the source(s) or subject(s) of the information are provided an opportunity to participate in defending the information from disclosure;

30.6.7.3.4 if required to release Protected Information to a court or regulatory body, ISO-NE or PJM (as appropriate) shall take measures to ensure that it receives notice of any requests from third parties for access to such data and shall notice the ISO of any such requests. Upon receipt of notice from ISO-NE or PJM, the ISO shall inform the party or parties that are the source or subject of the Protected Information and, in conjunction with ISO-NE or PJM, shall undertake reasonable efforts to ensure that the source(s) or subject(s) of the information are provided an opportunity to participate in defending the information from disclosure;

30.6.7.3.5 if required to release Protected Information to a court or regulatory body, ISO-NE or PJM (as appropriate) shall seek appropriate protective relief to limit the disclosure to the greatest extent possible; and

30.6.7.3.6 ISO-NE or PJM shall return or destroy Protected Information received from the ISO when the issue underlying ISO-NE's or PJM's inquiry has been resolved.

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 Chief Executive Officer 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 Chief Executive Officer 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. 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 Chief Executive Officer, 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 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.

30.10.5 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 Chief Executive Officer 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, disputes as to the implementation of or compliance with Attachment O shall be subject to the dispute resolution procedures of the New York Independent System Operator Agreement.

30.13 Effective Date

Attachment O shall be effective as of the date it is accepted for filing by the FERC.