Attachment III

2.1 Definitions - A

Actual Demand Reductions: Demand Reductions that are measured using a revenue-quality real-time meter.

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

Actual Energy Withdrawals: Energy withdrawals which are either: (1) measured with a revenue-quality real-time meter; (2) assessed (in the case of Load Serving Entities ("LSEs") serving retail customers where withdrawals are not measured by revenue-quality real-time meters) on the basis provided for in a Transmission Owner's retail access program; or (3) calculated (in the case of wholesale customers where withdrawals are not measured by revenue-quality real-time meters), until such time as revenue - quality real-time metering is available on a basis agreed upon by the unmetered wholesale customers.

Adjusted Actual Load: Actual Load adjusted to reflect: (i) Load relief measures such as voltage reduction and Load Shedding; (ii) Load reductions provided by ~~Demand Side Resources~~Aggregations; (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 Resources.

Adjusted DMGC: The value, in MW, of a BTM:NG Resource's capability in a Capability Period, as calculated pursuant to Section 5.12.6.1.1 of this Services Tariff.

Adjusted Host Load ("AHL"): The value, in MW, of a BTM:NG Resource's Load calculated pursuant to Section 5.12.6.1.2 of this Services Tariff for the purposes of determining the Resource's Capacity.

Adjusted Installed Capacity: The amount of Installed Capacity a Resource may offer taking into account the Resource's applicable Duration Adjustment Factor.

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

Access Transmission Tariff and set forth in a separate service schedule under the PJM Interconnection, L.L.C. Open Access Transmission Tariff.

Adverse Conditions: Those conditions of the natural or man-made environment that threaten the adequate reliability of the NYS Power System, including, but not limited to, thunderstorms, hurricanes, tornadoes, solar magnetic flares and terrorist activities.

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

Aggregation: A Resource, comprised of two or more individual Generators, Demand Side Resources, or Distributed Energy Resources, or one or more individual Demand Side Resources, at separate points of interconnection and that are grouped and dispatched as a single unit by the ISO, and for which Energy injections, withdrawals and Demand Reductions are modeled at a single Transmission Node. *See*, Services Tariff Sec. 4.1.10.

Aggregator: A Supplier that offers Capacity, Energy, and/or Ancillary Services for an Aggregation.

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 and Aggregations within a prescribed range in response to a change in system frequency, or tie-line loading, to maintain system frequency or scheduled interchange with other areas within predetermined limits.

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

Available Operating Capacity: For purposes of determining a Scarcity Reserve Requirement, the capability of all Suppliers that are eligible to provide Operating Reserves and have submitted Energy Bids in the Real-Time Market to provide Energy in greater than 30 minutes but less than or equal to 60 minutes; provided, however, that this value shall not include any quantity of Energy and Operating Reserves scheduled to be provided by all such Suppliers. The Available

Operating Capacity value (in MW) shall be calculated by the RTD software for each normal RTD run. For purposes of calculating a Scarcity Reserve Requirement in accordance with Section 15.4.6.2 of Rate Schedule 4 of this ISO Services Tariff, each RTD run shall utilize the value of Available Operating Capacity calculated during the immediately preceding normal RTD run and each RTC run shall utilize the value of Available Operating Capacity calculated during the most recently-completed normal RTD run prior to the RTC run.

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

Average Coincident Host Load ("ACHL"): The value calculated for a Capability Year in accordance with Section 5.12.6.1.2.1 of this Tariff. The ACHL shall account for weather normalization and Load growth.

Average Coincident Load ("ACL"): The value in each Capability Period calculated for each Special Case Resource, except those that are eligible to report a Provisional Average Coincident Load, that is equal to the average of the SCR's metered hourly Load that is supplied by the NYS Transmission System and/or the distribution system during the Capability Period SCR Load Zone Peak Hours applicable to such SCR, and computed and reported in accordance with Section 5.12.11.1.1 of this Services Tariff and ISO Procedures. Any Load supported by generation produced from a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter operating during the Capability Period SCR Load Zone Peak Hours may not be included in the SCR's metered Load values reported for the ACL.

~~**Average Coincident Load of an SCR Aggregation**: The value that is equal to the sum of the Average Coincident Loads and Provisional Average Coincident Loads for all Special Case Resources in an SCR Aggregation, assigned by the Responsible Interface Party to an SCR Aggregation in a single Load Zone, computed and reported monthly in accordance with Section 5.12.11.1.4 of this Services Tariff and ISO Procedures.~~

2.2 Definitions - B

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

Balance-of-Period Auction: As defined in the ISO OATT.

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

Basis Amount: The amount owed to the ISO for purchases of Energy and Ancillary Services excluding External Transactions in the Basis Month, after applying the Price Adjustment, as further adjusted by the ISO to reflect material changes in the extent of the Customer's participation in the ISO-administered Energy and Ancillary Services markets.

Basis Month: The month during the Prior Equivalent Capability Period in which the amount owed by the Customer for purchases of Energy and Ancillary Services excluding External Transactions, after applying the Price Adjustment, was greatest.

Beginning Energy Level: For Energy Storage Resources or Aggregations comprised entirely of Energy Storage Resources, the total amount of Energy stored by the Resource at the beginning of a market interval. ~~An Energy Storage Resource's~~The Beginning Energy Level shall be estimated for the Day-Ahead Market. An ISO-Managed Energy Storage Resource or ISO-Managed Aggregation comprised entirely of Energy Storage Resources shall submit an estimated Beginning Energy Level on each day that it submits a Day-Ahead Market Bid. The Beginning Energy Level shall be determined by 6-second telemetry data in real-time. If the ISO does not receive real-time telemetry from the Resource due to equipment failure or other reason, the ISO will use the last valid Energy Level value as modified to reflect subsequent schedules.

Behind-the-Meter Net Generation Resource ("BTM:NG Resource"): A facility within a defined electrical boundary comprised of a Generator and a Host Load located at a single point identifier (PTID), where the Generator routinely serves, and is assigned to, the Host Load and has excess generation capability after serving that Host Load. The Generator of the BTM:NG Resource must be electrically located in the NYCA, have a minimum nameplate rating of 2 MW and a minimum net injection to the NYS Transmission System or distribution system of 1 MW. The Host Load of the BTM:NG Resource must also have a minimum ACHL of 1 MW. A facility that otherwise meets these eligibility requirements, but either (i) is an Intermittent Power Resource or Energy Storage Resource, (ii) whose Host Load consists only of Station Power, or (iii) has made an election pursuant to Section 5.12.1.12, does not qualify to be a BTM:NG Resource. BTM:NG Resources cannot simultaneously participate as a BTM:NG Resource and in any ISO administered demand response programs.

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

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

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

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

Bidder: An entity that bids to purchase Unforced Capacity in an Installed Capacity auction.

Bidding Requirement: The credit requirement for bidding in certain ISO-administered auctions, calculated in accordance with Section 26.4.3 of Attachment K to this Services Tariff.

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

Billing Period: The period of time designated in Sections 7.2.2.1, 7.2.3.1, or 7.2.3.2 of this ISO Services Tariff over which the ISO will aggregate and settle a charge or a payment for services furnished under this ISO Services Tariff or the ISO OATT.

2.3 Definitions - C

Capability Period: Six-month periods which are established as follows: (i) from May 1 through October 31 of each year ("Summer Capability Period"); and (ii) from November 1 of each year through April 30 of the following year ("Winter Capability Period").

Capability Period Auction: An auction conducted no later than thirty (30) days prior to the start of each Capability Period in which Unforced Capacity may be purchased and sold in a six-month strip.

Capability Period SCR Load Zone Peak Hours: The top forty (40) coincident peak hours that, prior to the Summer 2014 Capability Period include hour beginning thirteen through hour beginning eighteen and beginning with the Summer 2014 Capability Period include hour beginning eleven through hour beginning nineteen. The Capability Period SCR Load Zone Peak Hours shall be determined by the NYISO from the Prior Equivalent Capability Period and shall be used by RIPs to report ACL values for the purpose of SCR enrollment. For a SCR enrolled with a Provisional ACL that requires verification data to be reported at the end of the Capability Period in which the SCR was enrolled, the Capability Period SCR Load Zone Peak Hours shall be determined from the Capability Period in which the SCR was enrolled. Such hours shall not include (i) hours in which Special Case Resources located in the specific Load Zone were called by the ISO to respond to a reliability event or test and (ii) hours for which the Emergency Demand Response Program resources were deployed by the ISO in each specific Load Zone. In addition, beginning with the Summer 2014 Capability Period, the NYISO shall not include, in descending rank order of NYCA Load up to a maximum of eight hours per Capability Period, a) the hour before the start time of a reliability event or performance test, in which SCRs located in the specific Load Zone were called by the ISO to respond to a reliability event or performance test, or b) the hour immediately following the end time of such reliability event or performance test.

Capability Year: A Summer Capability Period, followed by a Winter Capability Period (*i.e.*, May 1 through April 30).

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

Capacity Limited Resource: A Resource that is constrained in its ability to supply Energy above its Normal Upper Operating Limit by operational or plant configuration characteristics. Capacity Limited Resources must register their Capacity limiting characteristics with, and justify them to, the ISO consistent with ISO Procedures. Capacity Limited Resources may submit a schedule indicating that their Normal Upper Operating Limit is a function depending on one or more variables, such as temperature or pondage levels, in which case the Normal Upper Operating Limit applicable at any time shall be determined by reference to that schedule.

Capacity Reservation Cap: As defined in the ISO OATT.

CARL Data: Control Area Resource and Load ("CARL") data submitted by Control Area System Resources to the ISO.

Centralized Transmission Congestion Contracts ("TCC") Auction ("Auction"): As defined in the ISO OATT.

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

Commenced Repair: A determination by the ISO that a Market Participant with a Generator i) has decided to pursue the repair of its Generator, and based on the ISO's technical/engineering evaluation ii) has a Repair Plan for the Generator that is consistent with a Credible Repair Plan, and iii) has made appropriate progress in pursuing the repair of its Generator when measured against the milestones of a Credible Repair Plan.

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

Compensable Overgeneration: A quantity of Energy ~~injected~~ provided over a given RTD interval in which a Supplier has offered Energy that exceeds the Real-Time Scheduled Energy ~~Injection~~ established by the ISO for that Supplier and for which the Supplier may be paid pursuant to this Section and ISO Procedures.

For Suppliers not covered by other provisions of this Section and Intermittent Power Resources depending on wind as their fuel for which the ISO has imposed a Wind Output Limit in the given RTD interval, Compensable Overgeneration shall initially equal three percent (3%) of the Supplier's Normal Upper Operating Limit which may be modified by the ISO if necessary to maintain good Control Performance.

For a Generator or Aggregation:

(i) which is operating in Start-Up or Shutdown Periods, or Testing Periods; or

(ii) which is a Limited Control Run of River Hydro Resource that has offered its Energy to the ISO in a given interval not using the ISO-committed Flexible or Self-Committed Flexible bid mode; or

(iii) which is an Intermittent Power Resource that depends on solar energy or landfill gas for its fuel and has offered its Energy to the ISO in a given interval not using the ISO-committed Flexible or Self-Committed Flexible bid mode; or

(iv) which is an Intermittent Power Resource that depends on wind for its fuel, Compensable Overgeneration shall mean all Energy actually injected by the Generator or Aggregation that exceeds the Real-Time Scheduled Energy ~~Injection~~ established by the ISO for that Generator or Aggregation; provided however, this definition of Compensable Overgeneration shall not apply to an Intermittent Power Resource depending on wind as its fuel for any interval for which the ISO has imposed a Wind Output Limit. For a Generator or Aggregation operating in intervals when it has been designated as operating Out of Merit at the request of a Transmission Owner or the ISO, Compensable Overgeneration shall mean all Energy actually ~~injected~~ provided by the Generator or Aggregation that exceeds the Real-Time Scheduled Energy ~~Injection~~ up to the Energy level directed by the

Transmission Owner or the ISO.

For a Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, Compensable Overgeneration shall mean that quantity of Energy injected by the Generator, during the period when one of its grouped generating units is operating in a Start-Up or Shutdown Period, that exceeds the Real-Time Scheduled Energy ~~Injection~~ established by the ISO for that period, for that Generator, and for which the Generator may be paid pursuant to ISO Procedures.

Completed Application: An Application that satisfies all of the information and other requirements for service under the ISO Services Tariff.

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

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

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

Congestion Rent: As defined in the ISO OATT.

Congestion Rent Shortfall: As defined in the ISO OATT.

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

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

Control Area: An electric system or combination of electric power systems to which a common Automatic Generation Control scheme is applied in order to: (1) match, at all times, the power output of the Generators and Aggregations 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.

Credible Repair Plan: A Repair Plan that meets the requirements described in Section 5.18.1.4 of this Services Tariff and in ISO Procedures**.**

Credit Assessment: An assessment of a Customer's creditworthiness, conducted by the ISO in accordance with Section 26.5.3 of Attachment K to this Services Tariff.

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

CTS Enabled Interface: An External Interface at which the ISO has authorized the use of Coordinated Transaction Scheduling ("CTS") market rules and which includes a CTS Enabled Proxy Generator Bus for New York and a CTS Enabled Proxy Generator Bus for the neighboring Control Area.

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

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

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

CTS Sink Price: The price at a CTS Sink.

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

CTS Source Price: The price at a CTS Source.

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

~~**Curtailment Customer Aggregator:** A Curtailment Services Provider that produces real-time verified reductions in NYCA load of at least 100 kW through contracts with retail end-users. The procedure for qualifying as a Curtailment Customer Aggregator is set forth in ISO procedures.~~

~~**Curtailment Initiation Cost:** The fixed payment, separate from a variable Demand Reduction Bid, required by a qualified Demand Reduction Provider in order to cover the cost of reducing demand.~~

Curtailment Services Provider: A qualified entity that can produce real-time, verified reductions in NYCA Load of at least 100 kW in a single Load Zone, pursuant to the Emergency Demand Response Program and related ISO procedures. The procedure for qualifying as a Curtailment Services Provider is set forth in Section 3 below and in ISO Procedures.

Curtailment Services Provider Capacity: Capacity from a Demand Side Resource nominated by a Curtailment Services Provider for participation in the Emergency Demand Response Program.

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

2.4 Definitions - D

~~**DADRP Component:** The credit requirement for a Demand Reduction Provider to bid into the Day-Ahead Market, and a component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.~~

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

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

Day-Ahead Margin: That portion of Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for an hour that represents the difference between the Supplier's accepted Day-Ahead offer price and the Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for that hour.

Day-Ahead Margin Assurance Payment: A supplemental payment made to an eligible Supplier that buys out of a Day-Ahead Energy, Regulation Service, or Operating Reserves schedule such that an hourly balancing payment obligation offsets its Day-Ahead Margin. Rules for calculating these payments, and for determining Suppliers' eligibility to receive them, are **set** forth in Attachment J to this ISO Services Tariff.

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

Day-Ahead Reliability Unit: A Day-Ahead committed Resource which would not have been committed but for a request by a Transmission Owner to the ISO that the unit be committed in the Day-Ahead Market in order to meet the reliability needs of the Transmission Owner's local system or as the result of the ISO's analysis indicating the unit was needed in order to meet the reliability requirements of the NYCA.

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

Demand Reduction: A quantity of reduced electricity demand from a Demand Side Resource or a Distributed Energy Resource that is bid, produced, purchased or sold over a period of time and measured or calculated in Megawatt hours. ~~Demand Reductions offered by a Demand Side Resource as Energy in the LBMP Markets may only be offered in the Day-Ahead Market, and shall be offered only by a Demand Reduction Provider. The same Demand Reduction may not be offered by a Demand Reduction Provider and by a customer as Operating Reserves or Regulation Service.~~

~~**Demand Reduction Aggregator:** A Demand Reduction Provider, qualified pursuant to ISO Procedures, that bids Demand Side Resources of at least 1 MW through contracts with Demand Side Resources and is not a Load Serving Entity.~~

~~**Demand Reduction Incentive Payment:** A payment to Demand Reduction Providers that are scheduled to make Day-Ahead Demand Reductions. The payment shall be equal to the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction bus; and (b) the lesser of the actual hourly Demand Reduction or the Day-Ahead scheduled hourly Demand Reduction in MW.~~

~~**Demand Reduction Provider:** A Customer that is eligible, pursuant to the relevant ISO Procedures, to bid Demand Side Resources of at least 1 MW as Energy into the Day-Ahead Market. A Demand Reduction Provider can be (i) a Load Serving Entity or (ii) a Demand Reduction Aggregator.~~

~~**Demand Side Ancillary Service Program (DSASP):** An ISO program that allows qualified DSASP Resources to participate in the ISO's Day-Ahead and Real-Time Markets for Operating Reserves and Regulation Service in accordance with the ISO Services Tariff and ISO Procedures.~~

~~**Demand Side Ancillary Service Program Resource (DSASP Resource):** A Demand Side Resource or an aggregation of Demand Side Resources located in the NYCA with at least 1 MW of load reduction that is represented by a point identifier (PTID) and is assigned to a Load Zone or Subzone by the ISO and that is:~~

~~i. Capable of controlling demand in a responsive, measurable and verifiable manner within time limits prescribed by the ISO; and~~

~~ii. Qualified to participate in the ISO's Ancillary Services market as a Supplier of Operating Reserves or Regulation Service pursuant to the ISO Services Tariff and ISO Procedures.~~

~~**Demand Side Ancillary Service Program Provider (DSASP Provider):** A Customer that is eligible, pursuant to the ISO Tariff and ISO Procedures, to offer DSASP Resource(s) as Operating Reserves or Regulation Service in the Day-Ahead or Real-Time Market. A DSASP Provider is responsible for enrolling its DSASP Resource(s), and, when communicating directly with the ISO via telemetry, is responsible for dispatching its DSASP Resource(s).~~

Demand Side Resource: A Resource located in the NYCA that: (i) is capable of controlling demand by either curtailing its Load or by operating a Local Generator to reduce Load from the NYS Transmission System and/or the distribution system at the direction of the ISO, in a responsive, measurable and verifiable manner within time limits, and (ii) is qualified to participate in competitive Energy, Capacity, Operating Reserves or Regulation Service markets, or in the Emergency Demand Response Program pursuant to this ISO Services Tariff and the ISO Procedures.

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

Dependable Maximum Gross Capability ("DMGC"): The sustained maximum output of the Generator of a BTM:NG Resource, as demonstrated by the performance of a test or through actual operation in accordance with, and averaged over a continuous time period as defined in, ISO Procedures.

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

DER Aggregation: An Aggregation consisting of one or more Demand Side Resources, or two or more different Resource types, as described in Section 4.1.10 of the Services Tariff.

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

Direct Sale: As defined in the ISO OATT.

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

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

Dispute Resolution Administrator ("DRA"): An individual hired by the ISO to administer the Expedited Dispute Resolution Procedures in Section 5.17 of the ISO Services Tariff.

Distributed Energy Resource ("DER"): (i) a facility comprising two or more Resource types behind a single point of interconnection with an Injection Limit of 20 MW or less; or (ii) a Demand Side Resource; or (iii) a Generator with an Injection Limit of 20 MW or less, that is electrically located in the NYCA.

DMNC Test Period: The period within a Capability Period during which a Resource shall conduct a DMNC test, or a BTM:NG Resource shall conduct a DMGC test, if such a test is required. Such periods will be established pursuant to the ISO Procedures.

~~**DSASP Baseline MW**: The value of the Load level of a DSASP resource in the dispatch interval immediately preceding the interval with a non-zero Base Point Signal, where the status of the regulation flag is set to the off condition for either Operating Reserves or Regulation service.~~

~~**DSASP Component:** The credit requirement for a Demand Side Resource to offer Ancillary Services, and a component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.~~

Duration Adjustment Factor: The value of Installed Capacity, expressed as a percentage, for a Resource as specified in Section 5.12.14 of the ISO Services Tariff.

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

2.5 Definitions - E

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

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

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

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

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

Emergency Demand Response Program ("EDRP"): A program pursuant to which the ISO makes payments to Curtailment Service Providers that voluntarily take effective steps in real time, pursuant to ISO procedures, to reduce NYCA demand in Emergency conditions.

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

Emergency Upper Operating Limit (UOL_E): The upper operating limit that a Generator or an Aggregation, except for the Generator of a BTM:NG Resource, indicates it expects to be able to reach, or the upper operating limit that a BTM:NG Resource indicates it expects to be able to inject into the grid after serving its Host Load and subject to its Injection Limit, ~~or the maximum amount of demand that a Demand Side Resource expects to be able to reduce,~~ at the request of the ISO during extraordinary conditions. Each Resource shall specify a UOL_E in its bids that shall be equal to or greater than its stated Normal Upper Operating Limit.

Energy ("MWh"): A quantity of electricity that is bid, produced, purchased, consumed, sold, or transmitted over a period of time, and measured or calculated in megawatt hours. Demand Reductions by Demand Side Resources and Distributed Energy Resources are considered Energy.

Energy and Ancillary Services Component: A component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Energy Duration Limitation: for a Resource that is not capable of providing Energy for twenty-four hours each day, the number of consecutive hours per day that a Resource elects and is obligated, pursuant to Services Tariff Sections 5.12.1 and 5.12.7, to (i) schedule a Bilateral Transaction; (ii) Bid Energy in the Day-Ahead Market; or (iii) notify the ISO of any outages in the Day-Ahead Market as an Installed Capacity Supplier for the ICAP Equivalent of UCAP sold, as identified in Section 5.12.14 of the ISO Services Tariff.

Energy Level: The amount of Energy stored in an Energy Storage Resource or in an Aggregation comprised entirely of Energy Storage Resources.

Energy Level Management: The method by which an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources controls the amount of Energy stored in the Resource(s). Energy Storage Resources and Aggregations comprised entirely of Energy Storage Resources may choose to be Self-Managed or ISO-Managed in their Bid.

Energy Limited Resource: Capacity resources, not including BTM:NG Resources, that, due to environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis, but are able to operate for at least four consecutive hours each day. If an Energy Limited Resource requires Energy to recharge or refill, it is also a Withdrawal-Eligible Generator. Energy Limited Resources must register their Energy limiting characteristics with, and justify them to, the ISO consistent with ISO Procedures. Resources that meet the qualifications to be an Energy Limited Resource, and choose to participate in the wholesale market as an Energy Limited Resource, are not subject to the rules applicable to Energy Storage Resources.

Energy Storage Resource ("ESR"): Generators that receive Energy from the grid at a specified location, and are capable of storing that Energy, for later injection back onto the grid at the same location. Resources that cannot inject Energy onto the grid cannot be Energy Storage Resources. In order to qualify for wholesale market participation, Energy Storage Resources must be able to inject at a rate of at least 0.1 MW for a period of at least one hour. Energy Storage Resources are Withdrawal-Eligible Generators.

Equivalent Demand Forced Outage Rate: The portion of time a unit is in demand, but is unavailable due to forced outages.

Equivalency Rating: A rating determined by the ISO, at a Customer's request, based on the ISO's financial evaluation of an Unrated Customer that shall serve as the starting point of the

ISO's determination of an amount of Unsecured Credit to be granted to the Customer, if any, as provided in Table K-1 of Attachment K to this Services Tariff.

ETA Agent: As defined in the ISO OATT.

ETCNL TCC: As defined in the ISO OATT.

Excess Amount: The difference, if any, between the dollar amounts charged to purchasers of Unforced Capacity in an ISO–administered Unforced Capacity auction and the dollar amounts paid to sellers of Unforced Capacity in that ISO–administered Installed Capacity auction.

Excess Congestion Rents: As defined in the ISO OATT.

Existing Transmission Capacity for Native Load ("ETCNL"): As defined in the ISO OATT.

Existing Transmission Agreement ("ETA"): As defined in the ISO OATT.

Expected EDRP/SCR MW: The aggregate Load reduction (in MW) expected to be realized from EDRP and/or SCRs during the real-time intervals that the ISO has called upon EDRP and/or SCRs to provide Load reduction in a Scarcity Reserve Region, as determined based on the ISO's calculation of the historical performance of EDRP and SCRs. There will be separate values for voluntary and mandatory Load reductions. When determining the historical performance of SCRs, provision of Load reduction shall be deemed mandatory if the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of this ISO Services Tariff as it relates to the SCRs in the applicable Load Zone, otherwise provision of such Load reduction shall be deemed voluntary. When determining the historical performance of the EDRP, provision of Load reduction by EDRP shall be deemed voluntary.

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

Expedited Dispute Resolution Procedures: The dispute resolution procedures applicable to disputes arising out of the Installed Capacity provisions of this ISO Services Tariff (as set forth in Section 5.17) and the Customer settlements provisions of this ISO Services Tariff (as set forth in Section 7.4.3).

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

Export Credit Requirement: A component of the External Transaction Component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

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

External-to-ROS Deliverability Rights ("EDRs"): Rights, as measured in MW, associated with incremental transfer capability (i) on a new or existing Scheduled Line over an External Interface, with a terminus in Rest of State, and (ii) that has CRIS obtained pursuant to Attachment S of the OATT. When combined with qualified Unforced Capacity which is located in an External Control Area either by contract or ownership, and which is deliverable to the NYCA Interface with Rest of State over which it created the incremental transfer capability, EDRs allow such Unforced Capacity to be offered into the ISO-Administered Market.

External Transaction Component: A component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

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

2.9 Definitions - I

ICAP Demand Curve: A series of prices which decline until reaching zero as the amount of Installed Capacity increases.

ICAP Demand Curve Reset Filing Year: A calendar year in which the ISO files ICAP Demand Curves, in accordance with Section 5.14.1.2.1.11 or Section 5.14.1.2.2.4.11.

ICAP Ineligible Forced Outage: The outage state of a Market Participant's Generator after: i) the expiration or termination of its Forced Outage pursuant to the provisions in Section 5.18.1.6 of this Services Tariff, which Forced Outage started on or after May 1, 2015; ii) the Market Participant voluntarily reclassified its Forced Outage pursuant to the provisions in Section 5.18.2.1 of this Services Tariff, which Forced Outage started on or after May 1, 2015; or iii) substantial actions have been taken, such as dismantling or disabling essential equipment, which actions are inconsistent with an intention to return the Generator to operation and the Energy market. A Generator in an ICAP Ineligible Forced Outage is subject to the return-to-service provisions in Section 5.18.4 of this Services Tariff and is ineligible to participate in the Installed Capacity market.

ICAP Spot Market Auction: An auction conducted pursuant to Section 5.14.1.1 of this Tariff to procure and set LSE Unforced Capacity Obligations for the subsequent Obligation Procurement Period, pursuant to the Demand Curves applicable to each respective LSE and the supply that is offered.

Import Constrained Locality: New York City and the G-J Locality.

Import Credit Requirement: A component of the External Transaction Component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Import Curtailment Guarantee Payment: A payment made in accordance with Section 4.5.2.2 and Attachment J of this ISO Services Tariff to compensate a Supplier whose Import is Curtailed by the ISO.

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

Imputed LBMP Revenue: Revenue developed for calculating a Generator, Aggregation or Import Bid Production Cost guarantee, for any interval, which equals the product of (i) the Bilateral Transaction scheduled MW in the Day-Ahead Market or real-time market, as appropriate, from the Generator bus or Proxy Generator Bus, as appropriate, for the interval, (ii) the LBMP, in units of $/MWh, either Day-Ahead or real-time as appropriate, at the Generator or Proxy Generator Bus for that interval and (iii) the length of the interval, in units of hours.

Inactive Reserves: The outage state in which a Market Participant's Generator is unavailable to produce Energy for a limited period of time not to exceed six months, for reasons that are not equipment related, which state does not meet the criteria to be classified as any other outage pursuant to the provisions of this Services Tariff or of ISO Procedures. A Generator in Inactive Reserves is ineligible to participate in the Installed Capacity market.

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

In-City: Located electrically within the New York City Locality (LBMP Load Zone J).

Incremental Average Coincident Load ("Incremental ACL"): Beginning with the Summer 2014 Capability Period, the amount of qualifying Load that may be added to the Average Coincident Load of a Special Case Resource. In order to qualify to use Incremental ACL the SCR must enroll with an ACL and report an increase in the Load of the facility that is supplied by the NYS Transmission System and/or distribution system that meets or exceeds the SCR Load Change Reporting Threshold in accordance with this Services Tariff. The Incremental ACL reported in a Capability Period cannot exceed one-hundred percent (100%) of the ACL that has been calculated for the SCR when it first enrolls in the Capability Period. For resources reporting an Incremental ACL, the Net Average Coincident Load shall equal the enrolled ACL plus the reported Incremental ACL less any applicable SCR Change of Status. Each resource for which a RIP reports an Incremental ACL is subject to verification subsequent to the Capability Period pursuant to reporting requirements and calculations using the SCR's metered Load values provided in Section 5.12.11.1.5 of this Services Tariff and ISO Procedures.

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

Incremental TCC: As defined in the ISO OATT.

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

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

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

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

Indicative NCZ Locational Minimum Installed Capacity Requirement: The amount of capacity that must be electrically located within a New Capacity Zone, or possess an approved Unforced Capacity Deliverability Right, in order to ensure that sufficient Energy and Capacity are available in that NCZ and that appropriate reliability criteria are met.

Injection Limit: The maximum injection of ~~a~~ BTM:NG Resources and Distributed Energy Resources, in MW, into the NYS Transmission System or distribution system at the BTM:NG Resource's Point of Injection or Distributed Energy Resource's point of interconnection. The Injection Limit for a BTM:NG Resource must be at least 1 MW.

Installed Capacity ("ICAP"): External or Internal Capacity, in increments of 100 kW, that is made-available pursuant to Tariff requirements and ISO Procedures.

Installed Capacity Equivalent: The Resource capability that corresponds to its Unforced Capacity, calculated in accordance with ISO Procedures.

Installed Capacity Marketer: An entity which has signed this Tariff and which purchases Unforced Capacity from qualified Installed Capacity Suppliers, or from LSEs with excess Unforced Capacity, either bilaterally or through an ISO-administered auction. Installed Capacity Marketers that purchase Unforced Capacity through an ISO-administered auction may only resell Unforced Capacity purchased in such auctions in the NYCA.

Installed Capacity Supplier: An Energy Limited Resource, Generator, Aggregation, Installed Capacity Marketer, Responsible Interface Party, Intermittent Power Resource, Limited Control Run of River Hydro Resource, municipally-owned generation, BTM:NG Resource, System Resource or Control Area System Resource that satisfies the ISO's qualification requirements for supplying Unforced Capacity to the NYCA.

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

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

Interface MW - Mile Methodology: As defined in the ISO OATT.

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

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

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

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

Investment Grade Customer: A Customer that meets the criteria set forth in Section 26.3 of Attachment K to this Services Tariff.

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

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

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

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator ~~or Demand Side Resource~~ or Aggregation comprised entirely of Energy Storage Resources follows Base Point Signals and is committed by the ISO. ~~A~~ BTM:NG Resources and Aggregations that are not entirely comprised of Energy Storage Resources ~~is~~ are not permitted to utilize the ISO-Committed Flexible bidding mode.

ISO-Managed Energy Level: A Bid parameter which when selected indicates that an Energy Storage Resource's, or an Aggregation comprised entirely of Energy Storage Resources, Energy Level constraints will be directly accounted for in the optimization. See Section 4.2.1.3.4 of this Services Tariff.

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, the ISO/NYSRC Agreement, and the Operating Agreements.

ISO Services Tariff (the "Tariff"): The ISO Market Administration and Control Area Services Tariff.

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

ISP UCAP MW: The quantity of Unforced Capacity determined by the ISO in accordance with Section 5.14.1.1 of this Services Tariff.

2.13 Definitions - M

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

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

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

Market-Clearing Price: The price determined in an Installed Capacity auction for each ISO-defined Locality, the remainder of the NYCA and each adjacent External Control Area for which all offers to sell and bids to purchase Unforced Capacity are in equilibrium.

Market Mitigation and Analysis Department: A department, internal to the ISO, that is responsible for participating in the ISO's administration of its Tariffs. The Market Mitigation and Analysis Department's duties are described in Section 30.3 of the Market Monitoring Plan that is set forth in Attachment O to this Services Tariff.

Market Monitoring Unit: "Market Monitoring Unit" shall have the same meaning in this ISO Services Tariff as it has in the Market Monitoring Plan that is set forth in Attachment O to this Services Tariff.

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

Market Problem: An issue which requires notification to Market Participants, the Commission and the Market Monitoring Unit pursuant to Section 3.5.1 of this Services Tariff. It includes market design flaws, software implementation and modeling anomalies or errors, market data anomalies or errors, and economic inefficiencies that have a material effect on the ISO-administered markets or transmission service. The term does not include erroneous Energy or Ancillary Services prices (which are managed through procedures outlined in Attachment E to the Services Tariff) or erroneous customer settlements.

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

MCZ Import Constrained Locality: A Mitigated Capacity Zone that is also an Import Constrained Locality.

Member Systems: The eight Transmission Owners that comprised the membership of the New York Power Pool, which are: (1) Central Hudson Gas & Electric Corporation, (2) Consolidated Edison Company of New York, Inc., (3) New York State Electric & Gas Corporation, (4) Niagara Mohawk Power Corporation d/b/a National Grid, (5) Orange and Rockland Utilities, Inc., (6) Rochester Gas and Electric Corporation, (7) the Power Authority of the State of New York, and (8) Long Island Lighting Company d/b/a Long Island Power Authority.

Meter Services Entity ("MSE"): An entity registered with the ISO and authorized to provide metering and meter data services, as applicable, to an Aggregator, Responsible Interface Party or Curtailment Service Provider.

Minimum Generation Bid: A two-parameter Bid that identifies the minimum operating level a Supplier requires to operate a Generator, and the payment a Supplier requires to operate its Generator at that level~~, or the minimum quantity of Demand Reduction a Demand Side Resource requires to provide Demand Reduction and the payment the Supplier requires to provide that level of Demand Reduction~~. If the Supplier is a BTM:NG Resource, LESR, ~~or an~~ Energy Storage Resource, or an Aggregation, it shall not submit a Minimum Generation Bid.

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

Minimum Payment Nomination: An offer, submitted by a Responsible Interface Party, in dollars per Megawatt-hour and not to exceed $500 per Megawatt-hour, to reduce Load equal to the Installed Capacity Equivalent of the amount of Unforced Capacity a Special Case Resource is supplying to the NYCA.

Mitigated Capacity Zone: New York City and any Locality added to the definition of "Locality" accepted by the Commission on or after March 31, 2013.

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

Monthly Auction: An auction administered by the ISO pursuant to Section 5.13.3 of the ISO Services Tariff.

Monthly Average Coincident Load ("Monthly ACL"): Beginning with the Summer 2014 Capability Period, the Load value calculated for each month during a Capability Period applicable to a Special Case Resource with a reported Incremental Average Coincident Load. The Monthly ACL is an average of the SCR's metered hourly Load that is supplied by the NYS Transmission System and/or the distribution system and reported for the Monthly SCR Load Zone Peak Hours applicable to such SCR. The calculation and verification data reporting requirements are provided in Section 5.12.11.1.5 of this Services Tariff and ISO Procedures. Any Load supported by generation produced from a Local Generator, other behind-the-meter generator, or other supply source located behind the meter operating during the Monthly SCR Zone Load Peak Hours may not be included in the metered Load values reported for the Monthly ACL.

Monthly Net Benefit ~~Offer Floor~~Threshold: The price, in $/MWh, determined by the ISO pursuant to Section ~~4.2.1.9~~4.5.7.1 of the ISO Services Tariff and ISO Procedures~~, below which offers submitted by Demand Reduction Providers shall not be evaluated in the ISO's Security Constrained Unit Commitment~~.

Monthly SCR Load Zone Peak Hours: Beginning with the Summer 2014 Capability Period, the top forty (40) coincident peak hours for each month within a Capability Period that include hour beginning eleven through hour beginning nineteen as identified by the ISO for each Load Zone; provided, however, that such hours shall not include (i) hours in which Special Case Resources located in the specific Load Zone were called by the ISO to respond to a reliability event or test, (ii) hours for which the Emergency Demand Response Program resources were deployed by the ISO in each specific Load Zone and (iii) in descending rank order of NYCA Load up to a maximum of eight hours per month, a) the hour before the start time of a reliability event or performance test, in which SCRs located in the specific Load Zone were called by the ISO to respond to a reliability event or performance test, or b) the hour immediately following the end time of such reliability event or performance test.

Mothball Outage: The outage state in which a Market Participant's Generator is voluntarily removed from service on or after May 1, 2015, with applicable prior notice, for reasons not related to equipment failure. A Generator in Mothball Outage is subject to the return-to-service provisions in Section 5.18.4 of this Services Tariff and is ineligible to participate in the Installed Capacity market.

2.14 Definitions - N

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

NCZ Locational Minimum Installed Capacity Requirement: The amount of Capacity that must be electrically located within an NCZ, or possess an approved Unforced Capacity Deliverability Right, designed to ensure that sufficient Energy and Capacity are available in that NCZ and that appropriate reliability criteria are met.

NCZ Study Capability Period: The Summer Capability Period that begins five years from May 1 in a calendar year including an NCZ Study Start Date.

NCZ Study Start Date: September 1 or the next business day thereafter in the calendar year prior to an ICAP Demand Curve Reset Filing Year.

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

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

Net Auction Revenue: As defined in the ISO OATT.

Net Average Coincident Load ("Net ACL"): The effective Average Coincident Load calculated and used by the ISO for a Special Case Resource during a specific month in which a SCR Change of Status was reported for the resource or, beginning with the Summer 2014 Capability Period, an Incremental Average Coincident Load was reported for the resource.

Net Benefits Test: The monthly calculations performed by the ISO in accordance with Section 4.~~2.1.9~~5.7.1 of the ISO Services Tariff and ISO Procedures to determine the Monthly Net Benefit ~~Offer Floor~~Threshold, the ~~threshold~~ price at which the ~~dispatch of d~~Demand ~~response resources~~ Reductions meet~~s~~ the test required by Commission Order 745.

Net Congestion Rent: As defined in the ISO OATT.

Net Installed Capacity ("Net-ICAP"): ~~-~~The amount of Installed Capacity that a BTM:NG Resource has demonstrated (in accordance with ISO Procedures) it is capable of supplying in accordance with Section 5.12.6.1 of this Tariff, used to determine its Net Unforced Capacity.

Net Unforced Capacity ("Net-UCAP"): ~~-~~The amount of Unforced Capacity a BTM:NG Resource can offer in the ISO's Installed Capacity market.

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

New Capacity Zone ("NCZ"): -A single Load Zone or group of Load Zones that is proposed as a new Locality, and for which the ISO shall establish a Demand Curve.

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

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

New York Power Pool ("NYPP"): An organization established by agreement (the "New York Power Pool Agreement") made as of July 21, 1966, and amended as of July 16, 1991, by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the Power Authority of the State of New York. LIPA became a Member of the NYPP on May 28, 1998 as a result of the acquisition of the Long Island Lighting Company by the Long Island Power Authority.

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

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

New York State Reliability Council ("NYSRC"): An organization established by agreement among the Member Systems to promote and maintain the reliability of the NYS Power System.

New York State Reliability Council Agreement ("NYSRC Agreement"): The agreement which established the NYSRC.

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

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

Non-Competitive Proxy Generator Bus. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff., as set forth in Section 4.4.2.2 of the MST

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

Non-Investment Grade Customer: A Customer that does not meet the criteria necessary to be an Investment Grade Customer, as set forth in Section 26.3 of Attachment K to this Services Tariff.

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

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

Normal Upper Operating Limit (UOL_N): The upper operating limit that a Generator or Aggregation, except for the Generator of a BTM:NG Resource, indicates it expects to be able to reach, or the upper operating limit a BTM:NG Resource indicates it expects to be able to inject into the grid after serving its Host Load and subject to its Injection Limit, ~~or the maximum amount of demand that a Demand Side Resource expects to be able to reduce,~~ during normal conditions. Each Resource will specify its UOL_N in its Bids which shall be reduced when the Resource requests that the ISO derate its Capacity or the ISO derates the Resource's Capacity. A Normal Upper Operating Limit may be submitted as a function depending on one or more variables, such as temperature or pondage levels, in which case the Normal Upper Operating Limit applicable at any time shall be determined by reference to that schedule. Bids for Self-Managed Energy Storage Resources or Aggregations containing Energy Storage Resources may include a negative UOL_N when the Resource bids to withdraw Energy from the grid. The UOL_N for ISO-Managed Energy Storage Resources shall not be lower than 0 MW.

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

Notice of Intent to Return: -The notice a Supplier with a Generator that is in a Mothball Outage or ICAP Ineligible Forced Outage provides to the ISO, pursuant to ISO Procedures, that gives the date by which it intends to return to the Energy market, which proposed return date shall be no later than the expiration date of the Generator's Mothball Outage or ICAP Ineligible Forced Outage.

NPCC: The Northeast Power Coordinating Council.

NRC: The Nuclear Regulatory Commission or any successor thereto.

NYCA Installed Reserve Margin: The ratio of the amount of additional Installed Capacity required by the NYSRC in order for the NYCA to meet NPCC reliability criteria to the forecasted NYCA upcoming Capability Year peak Load, expressed as a decimal.

NYCA Minimum Installed Capacity Requirement: The requirement established for each Capability Year by multiplying the NYCA peak Load forecasted by the ISO by the quantity one plus the NYCA Installed Reserve Margin.

NYCA Minimum Unforced Capacity Requirement: The Unforced Capacity equivalent of the NYCA Minimum Installed Capacity Requirement.

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

NYPA Tax-Exempt Bonds: Obligations of the New York Power Authority, the interest on which is not included in gross income under the Internal Revenue Code.

2.15 Definitions - O

Obligation Procurement Period: The period of time for which LSEs shall be required to satisfy their Unforced Capacity requirements. Starting with the 2001-2002 Winter Capability Period, Obligation Procurement Periods shall be one calendar month in duration and shall begin on the first day of each calendar month.

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

Offeror: An entity that offers to sell Unforced Capacity in an auction.

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

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

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

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

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

Operating Data: Pursuant to Section 5.12.5 of this Tariff, Operating Data shall mean GADS Data, data equivalent to GADS Data, CARL Data, metered Load data, or actual system failure occurrences data, all as described in the ISO Procedures.

Operating Requirement: The amount calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

Operating Reserves : Capacity that is available to ~~supply~~ provide Energy ~~or reduce demand~~ and that meets ~~the~~ all applicable requirements of the ISO, NERC, NPCC and New York State Reliability Council. 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~~ and Aggregations that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff, 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. Generators utilizing inverter-based energy storage technology and that otherwise meet the eligibility criteria set forth in this ISO Services Tariff may provide Spinning Reserves. Spinning Reserves may not be provided ~~a Demand Side Resource that facilitates demand reduction using a Local Generator, unless that Local Generator utilizes inverter-based energy storage technology, or~~ by Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit, or Aggregations comprised of one or more (i) generating units (unless each of the generating units use inverter-based energy storage technology) or (ii) Demand Side Resources where at least one Demand Side Resource facilitates its Demand Reduction using a Local Generator (unless the Local Generator(s) use inverter-based energy storage technology);

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

(3) 30-Minute Reserve: Synchronized Operating Reserves provided by Generators and Aggregations, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit~~, and Demand Side Resources that do not facilitate demand reduction using Local Generators, or that facilitate demand reduction using a Local Generator utilizing inverter-based energy storage technology~~ or Aggregations that are comprised of one or more (i) generating units (unless each of the generating units use inverter-based energy storage technology) or (ii) Demand Side Resource(s) where at least one Demand Side Resource facilitates its Demand Reduction using a Local Generator (unless the Local Generator(s) use inverter-based energy storage technology); or non-synchronized Operating Reserves provided by Generators, Aggregations, or Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit~~, or Demand Side Resources~~ that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can respond to instructions to change their output level within thirty (30) minutes, including starting and synchronizing to the NYS Power System.

Operating Reserve Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Operating Reserves meeting a particular Operating Reserve requirement corresponding to each possible quantity of Resources that the ISO's software may schedule to meet that requirement.

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

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

Optimal Power Flow ("OPF"): -As defined in the ISO OATT.

Order Nos. 888 et seq.: The Final Rule entitled Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, issued by the Commission on April 24, 1996, in Docket Nos. RM95-8-000 and RM94-7-001, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles January 1991 - June 1996] ¶ 31,036 (1996) ("Order No. 888"), on reh'g, III FERC Stats. & Regs. ¶ 31,048 (1997) ("Order No. 888-A"), on reh'g, 81 FERC ¶ 61,248 (1997) ("Order No. 888-B"), order on reh'g, 82 FERC ¶ 61,046 (1998) ("Order No. 888-C")).

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

Original Residual TCC: As defined in the ISO OATT.

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

2.18 Definitions - R

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

RCRR TCC: -As defined in the ISO OATT.

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

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

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

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

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

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

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

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

Real-Time Minimum Run Qualified Gas Turbine: One or more gas turbines, offered in the Real-Time Market, which, because of their physical operating characteristics, may qualify for a minimum run time of two hours in the Real-Time Market. Characteristics that qualify gas turbines for this treatment are established by ISO Procedures and include using waste heat from the gas turbine-generated electricity to make steam for the generation of additional electricity via a steam turbine.

Real-Time Scheduled Energy: The quantity of Energy that a Supplier is directed to ~~inject or withdraw~~provide in real-time by the ISO. Injections and Demand Reductions are indicated by positive Base Point Signals and withdrawals are indicated by negative Base Point Signals. Unless otherwise directed by the ISO, Dispatchable Supplier's Real-Time Scheduled Energy is equal to its RTD Base Point Signal, or, if it is providing Regulation Service, to its AGC Base Point Signal, and an ISO-Committed Fixed or Self-Committed Fixed Supplier's Real-Time Scheduled Energy is equal to its bid output level in real-time.

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

Reconfiguration Auction: As defined in the ISO OATT.

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

Reference Month: For purposes of the Net Benefits Test, the calendar month that is twelve months prior to the Study Month.

Regulation Capacity: The Energy ~~or Demand Reduction~~ capability, measured in MW, that a Regulation Service provider offers and/or which it is scheduled to provide for Regulation Service.

Regulation Capacity Market Price: The price for Regulation Capacity determined by the ISO pursuant to section 15.3 of this Services Tariff.

Regulation Capacity Response Rate: -The Regulation Capacity a Resource is capable of providing over five minutes, measured in MW/minute which shall not exceed the lowest normal energy response rate provided for the Resource and which must be sufficient to permit that Resource to provide the Regulation Capacity (in MW) offered within a five-minute RTD interval. Reference to a Regulation response rate shall be a reference to the Regulation Capacity Response Rate.

Regulation Movement: -The absolute value of the change in Energy ~~or Demand Reduction~~ over a six second interval, measured in MW, that a Regulation Service provider is instructed to deliver for the purpose of providing Regulation Service.

Regulation Movement Market Price: -The price for Regulation Movement as determined by the ISO pursuant to section 15.3 of this Services Tariff.

Regulation Movement Multiplier: -A factor with the value of thirteen (13), used with the Regulation Movement Bids, to schedule Regulation Service providers in both the Day-Ahead and Real-Time Energy markets. The ISO calculates the Regulation Movement Multiplier based on the historical relationship between the number of MW of Regulation Capacity that the ISO seeks to maintain in each hour and the number of Regulation Movement MW instructed by AGC in each hour.

Regulation Movement Response Rate: -The amount of Regulation Movement a Regulation Service provider is capable of delivering in six seconds which shall not be less than, but can be equal to or greater than, the Regulation Capacity Response Rate equivalent.

Regulation Service: -The Ancillary Service defined by the Commission as “frequency regulation” and that is instructed as Regulation Capacity in the Day-Ahead Market and as Regulation Capacity and Regulation Movement in the Real-Time Market as is further described in Section 15.3 of the Services Tariff. Day-Ahead and Real-Time Bids to provide Regulation Service shall include a Bid for Regulation Capacity and a Bid for Regulation Movement. The Regulation Service requirement or target level shall be for MW of Regulation Capacity.

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

Regulation Revenue Adjustment Charge (“RRAC”): -A charge that will be assessed against certain ~~Generators~~ Regulation Service Providers 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~~ Regulation Service Providers that are providing Regulation Service under Section 15.3.6 of Rate Schedule 3 to this ISO Services Tariff.

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

Repair Plan: -A work plan, set of actions, and time frame for such actions, that is necessary to repair a Generator and return it to service as described in Section 5.18.1 of this Services Tariff**.**

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

~~**Reserve Performance Index**: An index created by the ISO for the purpose of calculating the Day-Ahead Margin Assurance Payment pursuant to Attachment J of this Services Tariff made to Demand Side Resources scheduled to provide Operating Reserves in the Day-Ahead Market.~~

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

Residual Capacity Reservation Right ("RCRR"): -As defined in the ISO OATT.

Residual Transmission Capacity: -As defined in the ISO OATT.

Resource: -An Aggregation, or an Energy Limited Resource, Energy Storage Resource, Limited Energy Storage Resource, Generator, Installed Capacity Marketer, Special Case Resource, Intermittent Power Resource, Limited Control Run of River Hydro Resource, municipally-owned generation, System Resource, BTM:NG Resource, Demand Side Resource or Control Area System Resource that is not participating in an Aggregation.

Resource with Energy Duration Limitation: A Resource that is not capable of supplying its ICAP equivalent of UCAP sold in each hour of the day due to a run-time limitation, such as an Energy storage limitation or permit restriction, and has elected an Energy Duration Limitation as specified in Section 5.12.14 of the ISO Services Tariff.

Responsible Interface Party ("RIP"): -A Customer that is authorized by the ISO to be the Installed Capacity Supplier for one or more Special Case Resources and that agrees to certain notification and other requirements as set forth in this Services Tariff and in the ISO Procedures.

Rest of State: -The set of all non-Locality NYCA LBMP Load Zones. As of the 2014/2015 Capability Year, Rest of State includes all NYCA LBMP Load Zones other than LBMP Load Zones G, H, I, J and K.

Retired: -A Generator that has permanently ceased operating on or after May 1, 2015 either: i) pursuant to applicable notice; or ii) as a result of the expiration of its Mothball Outage or of its ICAP Ineligible Forced Outage.

RMR Agreement: ~~s~~Shall have the meaning specified in Section 1.18 of the ISO's Open Access Transmission Tariff.

RMR Avoidable Costs: ~~s~~Shall have the meaning specified in Section 1.18 of the ISO's Open Access Transmission Tariff.

RMR Generator: ~~s~~Shall have the meaning specified in Section 1.18 of the ISO's Open Access Transmission Tariff.

Rolling RTC:~~-~~ The RTC run that is used to schedule a given 15-minute External Transaction. The Rolling RTC may be an RTC00, RTC15, RTC30 or RTC45 run.

Roundtrip Efficiency: ~~-~~The ratio of energy injections to energy withdrawals for an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources.

2.19 Definitions - S

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

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

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

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

Scheduled Energy Injections: As defined in the ISO OATT.

Scheduled Energy Withdrawals: As defined in the ISO OATT.

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

SCR Aggregation: One or more Special Case Resources registered by the Responsible Interface Party at a single PTID, with the Load of each Special Case Resource electrically located within the same single Load Zone and the total of all Loads at the PTID greater than or equal to 0.1 MW.

SCR Change of Load: A decrease in the Load of the SCR that meets the criteria of a Qualified Change of Load Condition and the SCR Load Change Reporting Threshold in accordance with this Services Tariff and results in a total Load reduction, within the range of hours that corresponds with the Capability Period SCR Load Zone Peak Hours, and the total Load reduction persists for more than seven (7) and less than or equal to sixty (60) continuous days from the first date of the reduction of the Load.

SCR Change of Status: The decrease to be treated as an adjustment to the applicable Average Coincident Load of a Special Case Resource when the SCR meets the criteria of a Qualified Change of Status Condition and the SCR Load Change Reporting Threshold in accordance with this Services Tariff and results in a total Load reduction, within the range of hours that corresponds with the Capability Period SCR Load Zone Peak Hours, and the total Load reduction persists for more than sixty (60) continuous days from the first date of the reduction of the Load.

SCR Load Change Reporting Threshold: -For a Special Case Resource with an applicable ACL greater than or equal to 500 kW, a reduction or increase in total Load not attributable to fluctuations in Load due to weather as described in ISO Procedures, that is equal to or greater than (i) thirty (30) percent of the applicable ACL for any month within the Capability Period, or (ii) five (5) MW in the NYC Locality or ten(10) MW if in any other Load Zone; whichever is less. For SCRs that elect to enroll with an Incremental ACL and do not increase the eligible Installed Capacity associated with the SCR, the RIP may enroll the SCR with a lower percentage change to its total Load increase as specified in Section 5.12.11.1.5 of this Services Tariff.

SCUC: Security Constrained Unit Commitment, described in Section 4.2.4 of this ISO Services Tariff.

Secondary Holder: As defined in the ISO OATT.

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

Secondary Market: As defined in the ISO OATT.

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

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

Self-Managed Energy Level: A Bid parameter which when selected indicates that an Energy Storage Resource's, or Aggregation comprised entirely of Energy Storage Resources, Energy Level constraints will not be directly accounted for in the optimization. See Sections 4.2.1.3.4 and 4.4.2.1 of this Services Tariff.

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. The Shut-Down Period shall be set to zero for a BTM:NG Resource, an Energy Storage Resource, and an Aggregation.

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

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

Special Case Resource ("SCR"): Demand Side Resources whose Load is capable of being interrupted upon demand at the direction of the ISO, and/or Demand Side Resources that have a Local Generator, which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System or the distribution system at the direction of the ISO. Special Case Resources are subject to special rules, set forth in Section 5.12.11.1 of this ISO Services Tariff and related ISO Procedures, in order to facilitate their participation in the Installed Capacity market as Installed Capacity Suppliers.

Special Case Resource Capacity: The Installed Capacity Equivalent of the Unforced Capacity which has been sold by a Special Case Resource in the Installed Capacity market during the current Capability Period.

Start-Up Period: An ISO approved period of time immediately following synchronization to the Bulk power system, which has been designated by a Customer and bid into the Real-Time Market, during which unstable operation prevents the unit from accurately following its base points. The Start-Up Period shall be set to zero for a BTM:NG Resource and Energy Storage Resource~~s~~ and an Aggregation.

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 Limited Energy Storage Resources and Energy Storage Resources when that Energy is stored for later injection back to the grid; ~~or~~ (iii) provided during a Black Start restoration by Generators that provide Black Start Capability Service; or (iv) used by a Resource in a DER Aggregation.

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

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

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

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

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

Study Month: The calendar month for which the ISO calculates the Monthly Net Benefit Offer Floor, in accordance with Section 4.2.1.9 of the ISO Services Tariff and ISO Procedures.

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

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

Supplemental Resource Evaluation ("SRE"): A determination of (i) the least cost selection of additional Generators or Aggregations, 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) the least cost selection of additional Generators, which are to be committed to meet forecast Load and reserve requirements over the six-day period that follows the Dispatch Day. An Aggregation or ESR is expected to be available in real-time and capable of injecting Energy at its full capability for all of the SRE commitment hours it receives.

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

4.1 Market Services - General Rules

4.1.1 Overview

Market Services include all services and functions performed by the ISO under this Tariff related to the sale and purchase of Energy, Capacity or Demand Reductions, and the payment to Suppliers who provide Ancillary Services in the ISO Administered Markets.

4.1.2 Independent System Operator Authority

The ISO shall provide all Market Services in accordance with the terms of the ISO Services Tariff and the ISO Related Agreements. The ISO shall be the sole point of Application for all Market Services provided in the NYCA. Each Market Participant that sells or purchases Energy, including ~~Demand Side Resources,~~ Special Case Resources and Emergency Demand Response Program participants, sells or purchases Capacity, or provides Ancillary Services in the ISO Administered Markets utilizes Market Services and must take service as a Customer under this Tariff and enter into a Service Agreement under the Tariff, as set forth in Attachment A; each entity that withdraws Energy to supply Load within the NYCA or provides Installed Capacity to an LSE serving Load within the NYCA utilizes the Control Area Services provided by the ISO and benefits from the reliability achieved as a result of ISO Control Area Services, must take service as a Customer under this Tariff and enter into a Service Agreement under this Tariff, as set forth in Attachment A; and each entity that has its virtual bids accepted and thereby engages in Virtual Transactions and each entity that purchases Transmission Congestion Contracts, excluding Transmission Congestion Contracts that are created prior to January 1, 2010, utilizes Market Services and must take service as a Customer under this Tariff and enter into a Services Agreement under this Tariff, as set forth in Attachment A. Each Customer that utilizes Market Services also utilizes Transmission Service and shall obtain Transmission Service under the ISO OATT.

4.1.3 Informational and Reporting Requirements

4.1.3.1 The ISO shall operate and maintain an OASIS, including a Bid/Post System that will facilitate the posting of Bids to supply Energy~~,~~ and 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~~,~~ and Ancillary Services ~~and Demand Reductions~~. The Bid/Post System will be used to post schedules for Bilateral Transactions. The ISO will provide historical data regarding Energy and Capacity market clearing prices in addition to Congestion Costs on a publicly accessible portion of its OASIS.

4.1.3.2 Zonal Uplift Report. The ISO shall post on a publicly accessible portion of its website, in machine-readable format, a report on total daily uplift dollars paid to (a) Generators and Demand Side Resources located in Load Zones H, I and J collectively, (b) Generators and Demand Side Resources located in each of the other NYCA Load Zones, and (c) Suppliers scheduling Imports at a Proxy Generator Bus, no more than 20 calendar days after the conclusion of each month. The report shall be updated at the time the Resource-Specific Uplift Report is posted, and again approximately 120 days after an initial invoice was issued for a month, to incorporate updated information. The report shall provide the uplift paid for each month, by day and by billing category.

Costs that the ISO will report as uplift include: (1) Day-Ahead and real-time Bid Production Cost guarantee payments to Generators and to Demand Side Resource aggregations; (2) Day-Ahead Bid Production Cost guarantee payments to Suppliers that schedule Imports; (3) Day-Ahead Margin Assurance Payments; (4) cost recovery for units responding to Local Reliability Rules addressing loss of Generator gas supply; (5) Import Curtailment Guarantee Payments to Suppliers that schedule Imports in real-time; and (6) Lost Opportunity Cost payments to Suppliers of Voltage Support Service.

4.1.3.3 Resource-Specific Uplift Report. The ISO shall post on a publicly accessible portion of its website, in machine-readable format, a report on total uplift paid to Generators, Demand Side Ancillary Service Program Resources, Day-Ahead Demand Response Program resources or aggregations, and to Special Case Resource aggregations**,** on a monthly basis. The report shall provide the total uplift payment across all uplift categories paid to each Generator or aggregation of Demand Side Resources. The report shall be posted no more than 90 calendar days after the conclusion of each month and shall be updated approximately 120 days after an initial invoice was issued for the month, to incorporate updated information.

4.1.3.4 Operator-Initiated Commitment Report. The ISO shall post on a publicly accessible portion of its website, in machine-readable format, commitments made after the Day-Ahead Market for a reason other than minimizing the total production cost of serving load.

For each reported commitment, the ISO shall provide the following information:

(a) commitment size: provide both the resource's UOL_N and the quantity of MW committed;

(b) location: the Load Zone in which the resource is located;

(c) commitment reason: (i) system-wide capacity need, or (ii) constraint management, or (iii) voltage support; and

(d) commitment start time.

Operator-initiated commitments are ordinarily posted in real-time as they occur. All operator-initiated commitments for a calendar month will be available no more than 30 days after the conclusion of that month. Operator-initiated commitment postings may later be updated to improve accuracy.

4.1.4 Scheduling Prerequisites

Pursuant to ISO Procedures, each Transaction offered in the Energy, Installed Capacity, Ancillary Services or Transmission Congestion Contract market shall be subject to a minimum size of one (1) megawatt (“MW”); provided however, the minimum size of each Transaction offered in the Energy, Installed Capacity or Ancillary Services market on behalf of Energy Storage Resources and Aggregations shall be one tenth (0.1) of one MW. Regulation Service may be offered in tenths of a MW. Pursuant to ISO Procedures, Special Case Resources may offer a minimum of 100 kW of Unforced Capacity in the Installed Capacity Market. ~~Each~~ Transactions ~~above~~ that exceed one (1) megawatt may be scheduled in tenths of a megawatt provided, however, that Bilateral Transactions and External Transactions in the LBMP Market must always be bid and scheduled in increments of one (1) megawatt.

4.1.5 Communication Requirements for Market Services

Customers and Transmission Customers shall utilize Internet service providers to access the ISO’s OASIS and bid/post system. Customers shall arrange for and maintain all communications facilities for the purpose of communication of commercial data to the ISO.

Each Customer shall be the customer of record for the telecommunications facilities and services its uses and shall assume all duties and responsibilities associated with the procurement, installation and maintenance of the subject equipment and software.

4.1.6 Customer Responsibilities

All purchasers in the Day-Ahead or Real-Time Markets who withdraw Energy within the NYCA to serve Load, or at an NYCA Interconnection with another Control Area must obtain Transmission Service under the ISO OATT. All Customers requesting service under the ISO Services Tariff to engage in Virtual Transactions must obtain Transmission Service under the ISO OATT.

All LSEs serving Load in the NYCA must comply with the Installed Capacity requirements set forth in Article 5 of this ISO Services Tariff.

All Customers taking service under the ISO Services Tariff must pay the Market Administration and Control Area Services Charge, as specified in Rate Schedule 1 of this ISO Services Tariff.

A Supplier with a Generator or ~~Demand Side Resource~~ Aggregation with a real time physical operating problem that makes it impossible for it to operate in the bidding mode in which it was scheduled shall notify the NYISO.

4.1.7 Customer Compliance with Laws, Regulations and Orders

All Customers shall comply with all applicable federal, state and local laws, regulations and orders, including orders from the ISO.

4.1.7.1 Violations of FERC's orders, rules and regulations also violate this Section 4.1.7 of the ISO Services Tariff. In particular, if FERC or a court of competent jurisdiction determines there has been a violation of FERC's regulations related to electric energy market manipulation (see 18 C.F.R. Section 1c.2, or any successor provision thereto), such violation is also a violation of this ISO Services Tariff if such violation affects or is related to the ISO Administered Markets.

4.1.7.2 If the ISO becomes aware that a Customer may be engaging in, or might have engaged in, electric energy market manipulation, it shall promptly inform its Market Monitoring Unit.

4.1.7.3 This Section 4.1.7 of the ISO Services Tariff does not independently empower the ISO or its Market Monitoring Unit to impose penalties for, or to provide a remedy for, violations of FERC's prohibition against electric energy market manipulation, or for other violations of the ISO's Tariffs.

4.1.8 Commitment for Reliability

Suppliers with generating units committed by the ISO for service to ensure NYCA reliability or local system reliability, ~~except for Behind-the-Meter Net Generation Resources and Energy Storage Resources~~that are eligible to submit start-up and minimum generation Bids, will recover startup and minimum generation costs that were not bid, that were not known before the close of the Real-Time Scheduling Window, and that were not recovered in the Dispatch Day, provided however, eligibility to recover such additional costs shall not be available for megawatts scheduled Day-Ahead. Payment for such costs shall be determined, as if bid, pursuant to the provisions of Attachment C of this Tariff. Energy Storage Resources, Aggregations that include Withdrawal-Eligible Generator(s), and Behind-the-Meter Net Generation Resources dispatched by the ISO for service to ensure NYCA reliability or local system reliability will recover incremental energy costs that were not bid, that were not known before the close of the Real-Time Scheduling Window, and that were not recovered in the Dispatch Day, provided however, eligibility to recover such additional costs shall not be available for megawatts scheduled Day-Ahead. Payments for securing NYCA reliability and local system reliability shall be recovered by the ISO in accordance with Rate Schedule 1 of the ISO OATT.

External Installed Capacity Suppliers that respond to an SRE request are eligible to recover the ISO-verified costs they incur to respond to the SRE request to the extent such costs exceed the ISO-verified market revenues the External Installed Capacity Supplier receives. It is the obligation of the External Installed Capacity Supplier to demonstrate its costs and revenues to the ISO's satisfaction. In verifying the costs of External Installed Capacity Suppliers that respond to an SRE, the ISO will consider the incremental net costs the Market Party incurred to respond to the SRE. Recoverable costs could include, but are not limited to, incremental costs of generating to supply Energy using the requested Installed Capacity, and the incremental costs incurred by the Market Party to transmit Energy from the External Installed Capacity Supplier's resource to the NYCA, including the opportunity cost associated with lost expected revenue. However, losses resulting from the difference in External Transaction settlement prices between an External Control Area and the NYCA will only be recoverable if and to the extent the following conditions are satisfied: (a) the losses are demonstrated to be reasonably related to responding to the SRE request; and (b)(i) a counterflow Export from the NYCA offered by the Market Party at the External Interface where the Capacity delivery obligation applies is not scheduled due to NYCA reliability concerns or is curtailed to address NYCA reliability concerns, or (ii) no opportunity exists to schedule a counterflow Export from the NYCA at the External Interface where the Capacity delivery obligation applies. Payments for securing NYCA reliability and local system reliability shall be recovered by the ISO as *DisputeResolutionCosts* in accordance with Section 6.1.13 of Rate Schedule 1 of the ISO OATT.

Re-dispatching costs incurred as a result of reductions in Transfer Capability caused by Storm Watch ("Storm Watch Costs") shall be aggregated and recovered on a monthly basis by the ISO exclusively from Transmission Customers in Load Zone J. The ISO shall calculate Storm Watch Costs by multiplying the real-time Shadow Price of any binding constraint associated with a Storm Watch, by the higher of (a) zero; or (b) the scheduled Day-Ahead flow across the constraint minus the actual real-time flow across the constraint.

4.1.9 Cost Recovery for Units Responding to Local Reliability Rules Addressing Loss of Generator Gas Supply

4.1.9.1 Eligibility for Cost Recovery

Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rule addressing the Loss of Generator Gas Supply for Generators located in New York City or the Local Reliability Rule addressing the Loss of Generator Gas Supply for Generators located on Long Island, as being required either to burn an alternate fuel at designated minimum levels, or to activate their auto-swap capability, based on forecast Load levels in Load Zones J and K (for purposes of this Section 4.1.9, "Eligible Units"), shall be eligible to recover costs associated with burning the required alternate fuel when one of the specified Local Reliability Rules is invoked. For purposes of this Section 4.1.9, the periods of time in which the Eligible Unit burns the alternate fuel only because one of the Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island has been invoked, including that period of time required for an Eligible Unit to move into and out of compliance with a Local Reliability Rule addressing the Loss of Generator Gas Supply, shall be referred to as the "Eligibility Period."

4.1.9.1.1 Obligation to Test Automatic Fuel Swap Capability and Eligibility to Recover Costs of Performing Fuel Swap Tests

Combined cycle Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rules addressing the Loss of Generator Gas Supply for Generators located in New York City, which have the ability to automatically swap from natural gas to a liquid fuel source in the event of the sudden interruption of gas fuel supply or loss of gas pressure or the unavailability of gas supply to the Generator, shall:

(a) develop test procedures that are consistent with the requirements of the applicable Local Reliability Rule and ISO Procedures; and

(b) successfully test to demonstrate that the designated combined cycle units are able to automatically swap from natural gas to a liquid fuel source each Capability Period.

The requirement to perform a test each Capability Period can be met by performing a real-time automatic fuel swap, if that fuel swap was successful and occurred during the relevant Capability Period. The scheduling of a test to demonstrate that a designated combined cycle unit is able to automatically swap from natural gas to a liquid fuel source in real-time operations shall be coordinated with the ISO and with the Transmission Owner in whose subzone the Generator is located, consistent with ISO Procedures.

The period during which combined cycle Eligible Units are performing scheduled automatic fuel swap testing, including that period of time required for an Eligible Unit to move into and out of compliance with a Local Reliability Rule addressing the Loss of Generator Gas Supply, is an "Eligibility Period."

4.1.9.2 Variable Operating Cost Recovery

For Eligibility Periods, Eligible Units burning an alternate fuel that would not have been burned but for Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island being invoked and Eligible Units burning an alternate fuel because they activated their auto-swap capability and experienced a swap to the alternate fuel that would not have occurred but for the operation of the auto-swap capability in accordance with the implementation of the Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island shall recover costs that vary with the amount of alternate fuel burned ("variable operating costs") if: (i) such costs are not reflected in the reference level for that Eligible Unit for the hours included in the Eligibility Period, pursuant to ISO Procedures, and (ii) the hour is one for which the commodity cost of the alternate fuel including taxes and emission allowance costs is greater than the commodity cost for natural gas, including taxes and emission allowance costs, as determined by the ISO. These relative commodity cost determinations shall use the same indices used by the ISO to establish daily Reference Levels. Variable operating costs shall include the commodity cost, associated taxes and emission allowance costs, of the required alternate fuel burned during an Eligibility Period pursuant to Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island. The owner or bidder of an Eligible Unit shall notify the ISO when variable operating costs change due to a change in tax rates.

4.1.9.3 Additional Cost Recovery

An Eligible Unit that seeks to recover costs incurred in connection with its compliance with Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island, in addition to the commodity cost, associated taxes and emission allowance cost recovery specified in Section 4.1.9.2, shall negotiate an Implementation Agreement with the ISO. The Eligible Unit and the ISO shall consult with and consider the input of the New York State Public Service Commission, and the Transmission Owner designated by the applicable Local Reliability Rule addressing the loss of gas supply for Generators located in New York City or on Long Island. Such Implementation Agreements shall specify, among other terms and conditions, the facilities (or portions of facilities) used to meet obligations under the Local Reliability Rule addressing the loss of gas supply for Generators located in New York City or on Long Island. The Implementation Agreement shall indicate the rate to be charged during the period of the Implementation Agreement to recover such additional costs.

The Implementation Agreement may also include costs in addition to commodity cost, associated taxes and emission allowance costs of the alternate fuel incurred in connection with compliance with Local Reliability Rules addressing the loss of gas supply for Generators located in New York City or on Long Island that vary with the amount of alternate fuel burned because a Local Reliability Rule addressing the loss of gas supply was invoked. These variable costs shall be paid pursuant to Section 4.1.9.2 as variable operating costs so as to not duplicate payments.

Each such Implementation Agreement shall have a duration of one or more Capability Periods and shall commence at the beginning of a Capability Period unless another date is approved by the Commission. If the Eligible Unit and the ISO reach agreement on the terms and conditions of the Implementation Agreement, the ISO shall file it with the Commission for its review and acceptance.

In the event that the Eligible Unit and the ISO have not come to an agreement six months prior to the beginning of the Capability Period that the Implementation Agreement is intended to govern, then either one of them may request the assistance of the Commission's Dispute

Resolution Service. If the Dispute Resolution Service agrees to provide its assistance the Eligible Unit and the ISO shall participate in whatever dispute resolution process the Dispute Resolution Service may recommend. The Commission's Dispute Resolution Service may include other stakeholders to the extent confidentiality protections are in place. If, however, there is no agreement four months prior to the beginning of the relevant Capability Period then the Eligible Unit and the ISO may each file an unexecuted Implementation Agreement for the Commission's review and acceptance.

In the event that any provisions of this Section 4.1.9 are modified prior to the termination date of any Commission-accepted Implementation Agreement, such Implementation Agreement will remain in full force and effect until it expires in accordance with its contractual terms and conditions.

Rules for establishing Eligibility Periods shall be specified in ISO Procedures.

4.1.9.4 Billing

Payments made by the ISO to the Eligible Unit to pay variable operating costs and to pay the rate established by the Implementation Agreement pursuant to this Section 4.1.9 shall be in addition to any LBMP, Ancillary Service or other revenues received as a result of the Eligible Unit's Day-Ahead or Real-Time dispatch for that day. Payment by the ISO of variable operating costs pursuant to Section 4.1.9.2 shall be based on the Eligibility Period, quantity of alternate fuel burned, and relative costs of alternate fuel compared to natural gas. Payment by the ISO of the rate established in the Implementation Agreement for costs incurred other than variable operating costs shall be made as part of the ISO billing cycle regardless of which Local Reliability Rule addressing the loss of gas supply an alternate fuel is burned pursuant to, and regardless of the relative cost of the alternate fuel compared to natural gas reflected in reference levels.

4.1.9.5 Other Provisions

The ISO shall make available for the Transmission Owner in whose subzone the Generator is located: (i) the identity of Generators determined by the ISO to be eligible to recover the costs associated with burning the required alternate fuel pursuant to the provisions of this Section 4.1.9; (ii) the start and stop hours for each claimed Eligibility Period and (iii) the amount of alternate fuel for which the Generator has sought to recover variable operating costs.

4.1.10 Supplier Aggregations

Suppliers may aggregate individual Resources electrically located in the NYCA to provide Energy, Capacity and Ancillary Services. Demand Side Resources participating in the Emergency Demand Response Program and Aggregations of Special Case Resources shall follow the rules set forth in Services Tariff Sections 22 (Att. G) and 5.12.11, respectively. Each Aggregation shall be offered as a single unit and all bidding and offer obligations under the ISO Tariffs apply to the Aggregation, or to the Aggregator, where appropriate, not to the individual Resources that comprise the Aggregation. An Aggregation that offers a combination of Energy injections, Energy withdrawals and/or Demand Reduction must be able to offer at least 100 kW of each.

Each Aggregation must meet the minimum eligibility and performance requirements to participate in the ISO Administered Markets. Unless otherwise noted, Resources within an Aggregation are not individually required to meet the minimum eligibility and performance requirements to participate in the ISO Administered Markets. Generators with PURPA contracts, Limited Control Run of River Resources, Behind-the-Meter Net Generation

Resources, Municipally-owned Generation, System Resources and Control Area System Resources are ineligible to participate in an Aggregation. One Aggregation cannot participate in another Aggregation, however, the individual Resources within an Aggregation may switch to a new Aggregation in accordance with Services Tariff Section 4.1.10.3.

4.1.10.1 Aggregation Composition

Aggregations must contain at least two Resources, except that a single Demand Side Resource may participate as a single-Resource Aggregation. The maximum physical injection capability for a Resource participating in an Aggregation is 20 MW. Resources with a nameplate capability greater than 20 MW may participate in an Aggregation if the ISO determines sufficient physical protection and control schemes exist to limit the injection capability of the Resource to 20 MW or less. There is no maximum Demand Reduction capability for Demand Side Resources participating in an -Aggregation.

Aggregations may be comprised of a single Resource type or multiple Resource types. Except as otherwise provided in the ISO Tariffs and the ISO Procedures, Aggregations that are comprised of a single Resource type shall follow the rules associated with that Resource type (*e.g.*, an Aggregation of Energy Storage Resources shall follow the rules applicable to Energy Storage Resources). Aggregated (i) Intermittent Power Resources, (ii) Energy Limited Resources, (iii) Capacity Limited Resources, or (iv) Limited Energy Storage Resources shall constitute a single Resource type Aggregation only when the individual Resources in the Aggregation have the same Intermittent, energy limiting, or capacity limiting characteristic (*e.g.*, an Aggregation of only solar Resources, or an Aggregation of only pumped storage Resources). Provided, however, that Aggregations with multiple, different types of Intermittent Power

Resources, Energy Limited Resources, Capacity Limited Resources, and Limited Energy Storage Resources shall follow the rules associated with DER Aggregations.

Aggregations that are comprised of more than one Resource type, and Aggregations comprised of only Demand Side Resources shall follow the rules associated with DER Aggregations.

Aggregations that include at least one Withdrawal-Eligible Generator may submit Bids to withdraw Energy. For the purpose of measuring Aggregation compliance with Base Point Signals, Aggregations that include at least one Withdrawal-Eligible Generator will be measured based on their net performance; that is, Energy injections and Demand Reductions will be reduced by Energy withdrawals.

Aggregators shall not offer any Resource as part of an Aggregation that is participating in the ISO Administered Markets in a different Aggregation or as an individual Resource.

4.1.10.2 Aggregation Electrical Location

The ISO shall establish a set of Transmission Nodes in the New York Control Area at which individual Resources may aggregate. Each Transmission Node shall be identified in the ISO Procedures. The ISO shall consult with the appropriate Member System prior to identifying a Transmission Node in accordance with ISO Procedures. Aggregators shall identify, after consultation with the interconnecting utility, the Transmission Node for each Aggregation. All Resources in an Aggregation must be electrically located in the New York Control Area, and electrically connected to the same ISO-identified Transmission Node. Multiple Aggregators may each enroll one or more Aggregations at a Transmission Node.

The ISO may modify the set of Transmission Nodes from time to time due to- conditions on the New York State Transmission System and the underlying distribution systems changing over time. The ISO shall also review and update (if needed) the identified Transmission Nodes on an annual basis, and will post a notice of any changes to the identified Transmission Nodes at least ninety (90) days prior to the beginning of the Capability Year. Changes to the set of Transmission Nodes shall take effect on the first day of the Capability Year. Aggregators shall certify, in accordance with ISO Procedures, that Aggregations affected by changes to Transmission Nodes meet all requirements of this Section pursuant to ISO Procedures.

4.1.10.3 Resources Changing Aggregations

Subject to the requirement that all of the Resources in an Aggregation must be electrically connected to the same ISO-identified Transmission Node, an individual Resource may leave its current Aggregation and/or join a new Aggregation to be effective at the start of a calendar month, but must provide at least thirty (30) calendar days notice of its intent to change Aggregations. Registration of Resources that leave or join an Aggregation shall be completed in accordance with ISO Procedures. The ISO must approve all Resource registrations before the Resource is allowed to participate in an Aggregation.

Additional rules for Resources changing Aggregations, that participate in the ICAP market are located in Services Tariff Section 5.12.13.1.

4.1.10.4 Aggregation Metering

Each Aggregation must meet the applicable metering standards identified in the ISO's Tariffs and in ISO Procedures. Aggregators may choose to have an ISO-authorized Meter Services Entity or the applicable Member System provide Aggregation metering services for wholesale market participation. *See* Services Tariff § 13.

Real-time telemetry data and revenue-quality meter data shall be submitted for each Aggregation. Real-time telemetry for DER Aggregations shall consist of three parts: (i) the net of Energy injections and Energy withdrawals by Withdrawal Eligible Generators, (ii) Demand Reductions; and (iii) the sum of both (i) and (ii). Revenue-quality meter data for each DER Aggregation shall consist of three parts: (i) Energy injections; (ii) Energy withdrawals by Withdrawal-Eligible Generators; and (iii) Demand Reductions. Aggregations of other Resource types shall submit meter data in accordance with Services Tariff Section 13 and the ISO Procedures.

4.1.10.5 Qualification Requirements for Aggregators

Aggregators must be Customers. Aggregators must (i) comply with the registration requirements set forth in Services Tariff Section 9, and the ISO Procedures; (ii) designate one or more contact persons to receive ISO communications; and (iii) comply with the metering requirements set forth in Services Tariff Section 13 and the associated ISO Procedures.

4.1.11 Dual Participation

Effective May 1, 2020, Generators, Demand Side Resources, and Distributed Energy Resources electrically located in the NYCA may simultaneously participate in the ISO Administered Markets and in programs or markets operated to meet the needs of distribution systems located in the NYCA. Generators, Demand Side Resources, and Distributed Energy Resources engaged in dual participation must meet all applicable rules and obligations set forth in the ISO Tariffs.

Generators, Demand Side Resources, and Distributed Energy Resources operating to meet an obligation outside of the ISO Administered Markets must Bid in a manner that ensures they will be dispatched by the ISO for the market intervals consistent with the manner in which the Resource operates to meet such obligation(s). The ISO and Transmission Owners shall coordinate scheduling and dispatch for all Generators, Demand Side Resources, and Distributed

Energy Resources engaged in Dual Participation in accordance with ISO Procedures. The ISO has the authority to determine schedules for these resources.

4.2 Day-Ahead Markets and Schedules

4.2.1 Day-Ahead Load Forecasts, Bids and Bilateral Schedules

4.2.1.1 General Customer Forecasting and Bidding Requirements

Subject to the two earlier submission deadlines set forth below, by 5 a.m. on the day prior to the Dispatch Day: (i) All LSEs serving Load in the NYCA shall provide the ISO with Load forecasts for the Dispatch Day and the day after the Dispatch Day; and (ii) Customers and Transmission Customers submitting Bids in the Day-Ahead Market shall provide the ISO, consistent with ISO Procedures:

a. Bids to supply Energy, including Bids to supply Energy in Virtual Transactions;

b. Bids to supply Ancillary Services;

c. Requests for Bilateral Transaction schedules;

d. Bids to purchase Energy, including Bids to purchase Energy in Virtual Transactions and Bids to withdraw Energy by Withdrawal-Eligible Generators; and

e. ~~Demand Reduction Bids; and~~

~~f.~~ For Behind-the-Meter Net Generation Resources, the forecasted Host Load for each hour of the Dispatch Day.

By 4:50 a.m. on the day prior to the Dispatch Day, all Customers or Transmission Customers shall submit Bids for External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line.

By 4:45 a.m. on the day prior to the Dispatch Day, all Customers or Transmission Customers shall submit Bids that include revised fuel type or fuel price information to the ISO's Market Information System.

In general, the information provided to the ISO shall include the following:

4.2.1.2 Load Forecasts

The Load forecast shall indicate the predicted level of Load in MW by Point of Withdrawal for each hour.

4.2.1.3 Bids by Suppliers Using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed Bid Modes to Supply Energy and/or Ancillary Services

4.2.1.3.1 General Rules

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes shall identify the Capacity, in MW, available for commitment in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Supplier will voluntarily enter into dispatch commitments. If the Supplier elects to participate in the Day-Ahead Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not consist solely of Station Power) at a single PTID, it can only participate in the Day-Ahead Market as a Behind-the-Meter Net Generation Resource. If the Supplier is a Behind-the-Meter Net Generation Resource, the ISO shall only consider price-MW pairs in excess of the forecasted Host Load for the Resource.

A Supplier's Day-Ahead Bids for an Energy Storage Resource to withdraw Energy and to inject Energy shall be submitted as a single, continuous, bid curve representing the Capacity, in MW, available for commitment in the Day-Ahead Market for each hour of the Dispatch Day, and shall indicate whether the Resource's Energy Level will be ISO- or Self-Managed. An Energy Storage Resource may not change its Energy Level Management election within the Day-Ahead Market evaluation period (i.e., within a single day).

A Supplier's Day-Ahead Market Self-Committed Flexible Bid for a DER Aggregation may include Energy withdrawals if the DER Aggregation includes at least one Withdrawal-Eligible Generator. A Supplier's hourly Day-Ahead Bids for a DER Aggregation to withdraw Energy and to supply Energy shall be submitted as a single, continuous bid curve representing the Capacity, in MW, available for each hour of the Dispatch Day. When the Energy Bid for a DER Aggregation includes both Energy supply and Energy withdrawal by a Withdrawal-Eligible Generator that is a component of the Aggregation, each point of the DER Aggregation's Bid curve shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

If the Supplier using the ISO-Committed Flexible or Self-Committed Flexible bid mode is eligible to provide Regulation Service or Operating Reserves under Rate Schedules 3 and 4 respectively of this ISO Services Tariff, the Supplier's Bid may specify the quantity of Regulation Capacity it is making available and shall specify an emergency response rate that determines the quantity of Operating Reserves that it is capable of providing. Offers to provide Regulation Service and Operating Reserves must comply with the rules set forth in Rate Schedules 3 and 4 of this ISO Services Tariff. If a Supplier that is eligible to provide Operating Reserves does not submit a Day-Ahead Availability Bid for Operating Reserves, its Day-Ahead Bid shall be rejected in its entirety. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit, or an Aggregation containing at least one generating unit (unless all of the generating unit(s) use inverter-based energy storage technology) that is dispatched as a single aggregate unit at a single PTID is not qualified to provide Regulation Service or Spinning Reserves. Aggregations may only qualify to offer the Ancillary Services that all individual Resources in the Aggregation are qualified to provide. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new Bid is timely. ~~See Section 4.2.1.9 for bidding requirements for Demand Side Resources offering Energy in the Day-Ahead Market.~~

Suppliers ~~other than Demand Side Resources~~ entering a Bid into the Day-Ahead Market may also enter Day-Ahead Bids for each of the next nine (9) Dispatch Days. If not subsequently modified or withdrawn, these offers for subsequent Dispatch Days may be used by the ISO as offers from these Suppliers in the Day-Ahead Market for these subsequent Dispatch Days. For Suppliers that are providing Unforced Capacity in the ISO-administered ICAP Market for the month in which the Dispatch Day and the nine-day advance bidding period are encompassed, the ISO may enter the eighth day offer as the Bid for that Supplier's ninth day, if there is, otherwise no ninth–day Bid.

4.2.1.3.2 Bid Parameters

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes may identify-variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, and other parameters described in ISO Procedures. ~~Day-Ahead Bids from Demand Side Resources offering Operating Reserves or Regulation Service shall be ISO-Committed Flexible and shall have an Energy Bid price no lower than the Monthly Net Benefit Offer Floor.~~ Day-Ahead offers by Intermittent Power Resources that depend on wind as their fuel shall be ISO-Committed Flexible and shall include a Minimum Generation Bid of zero megawatts and zero costs and a Start-Up Bid of zero cost.

Day-Ahead Bids by ISO-Committed Fixed and ISO-Committed Flexible Generators, other than bids from Intermittent Power Resources that depend on wind as their fuel, shall also include Minimum Generation Bids and hourly Start-Up Bids. Bids shall specify whether a Supplier is offering to be ISO-Committed Fixed, ISO-Committed Flexible, Self-Committed Fixed, or Self-Committed Flexible.

4.2.1.3.3 Upper Operating Limits, Lower Operating Limits, and Response Rates

All Bids to supply Energy and Ancillary Services must specify a UOL_N and a UOL_E for each hour. A Resource's UOL_E may not be lower than its UOL_N. Bids from Withdrawal-Eligible Generators, and Aggregations containing at least one Withdrawal-Eligible Generator, shall also specify the Generator's Lower Operating Limit for each hour.

Bids from Suppliers for Generators and Aggregations supplying Energy and Ancillary Services must specify a normal response rate and may provide up to three normal response rates provided the minimum normal response rate may be no less than one percent (1%) of the Generator's or Aggregation's Operating Capacity per minute. All Bids from Suppliers for Generators and Aggregations supplying Energy and Ancillary Services must also specify an emergency response rate which shall be equal to or greater than the maximum normal response rate of the Generator or Aggregation.

~~Bids from Suppliers offering Operating Reserves or Regulation Service from Demand Side Resources must specify a normal response rate and an emergency response rate provided that the emergency response rate may not be lower than the normal response rate. For Demand Side Resources the minimum acceptable response rate is one percent (1%) of the quantity of Demand Reduction the Demand Side Resource produces per minute.~~

4.2.1.3.4 Additional Parameters for Energy Storage Resources and Aggregations Comprised only of Energy Storage Resources

In addition to the parameters that Suppliers submit for Energy Storage Resources because they are Generators, specific parameters may apply to some Bids for Energy Storage Resources. Consistent with the ISO Procedures, Bids from Suppliers for Energy Storage Resources supplying Energy and Ancillary Services may be required to specify whether the Energy Level will be ISO-Managed or Self-Managed, the Beginning Energy Level, the Energy Storage Resource's Roundtrip Efficiency. An Energy Storage Resource must also specify its Upper and Lower Storage Limits.

The Day-Ahead Schedule for Energy Storage Resources with ISO-Managed Energy Levels will reflect the Resource's Energy Level constraints, including the Beginning Energy Level, the Upper and Lower Storage Limits, and the Resource's Roundtrip Efficiency. An Energy Storage Resource that self-manages its Energy Level is obligated to submit Bids that are consistent with its Energy Level constraints, and the Day-Ahead optimization will not honor the above-identified Energy Level constraints.

The rules in this section 4.2.1.3.4 shall also apply to Aggregations comprised entirely of Energy Storage Resources.

4.2.1.4 Offers to Supply Energy from Self-Committed Fixed Generators and Aggregations

Self-Committed Fixed Generators and Aggregations shall provide the ISO with a schedule of their expected Energy output and withdrawals (when applicable) for each hour. Self-Committed Fixed Generators and Aggregations are responsible for ensuring that any hourly changes in output are consistent with their response rates. Self-Committed Fixed Generators and Aggregations shall also submit UOL_{NS}, UOL_{ES} and variable Energy Bids for possible use by the

ISO in the event that RTD-CAM initiates a maximum generation pickup, as described in Section 4.4.3 of this ISO Services Tariff.

A Supplier may submit a Day-Ahead Market Self-Committed Fixed Bid for a DER Aggregation to withdraw Energy if the DER Aggregation includes at least one Withdrawal-Eligible Generator. When a Self-Committed Fixed Bid for a DER Aggregation reflects both Energy supply and Energy withdrawals by a Withdrawal-Eligible Generator that is a component of the Aggregation, the DER Aggregation's Bid shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

4.2.1.5 Bids to Supply Energy in Virtual Transactions

Customers submitting Bids to supply Energy in Virtual Transactions shall identify the Energy, in MW, available in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Customer will voluntarily make it available.

4.2.1.6 Bids to Purchase Energy in Virtual Transactions

Customers submitting bids to purchase Energy in Virtual Transactions shall identify the Energy, in MW, to be purchased in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Customer will voluntarily purchase it.

4.2.1.7 Bilateral Transactions

Transmission Customers requesting Bilateral Transaction schedules shall identify hourly Transaction quantities (in MW) by Point of Injection and Point of Withdrawal, minimum run times associated with Firm Point-to-Point Transmission Service, if any, and shall provide other information (as described in ISO Procedures). The source of a Bilateral Transaction at the Point of Interconnection shall not be a DER Aggregation containing one or more Demand Side Resources.

4.2.1.8 Bids to Purchase LBMP Energy in the Day-Ahead Market

Each purchaser shall submit Bids indicating the hourly quantity of Energy, in MW, that it will purchase from the Day-Ahead Market for each hour of the following Dispatch Day. These Bids shall indicate the quantities to be purchased by Point of Withdrawal. The Bids may identify prices at which the purchaser will voluntarily enter into the Transaction.

~~4.2.1.9 Day-Ahead Bids from Demand Reduction Providers and DSASP Providers to Supply Energy from Demand Reductions~~

~~Demand Reduction Providers and DSASP Providers offering Energy from Demand Side Resources shall submit Bids: (i) identifying the amount of Demand Reduction, in MWs in accordance with Section 4.1.4, that is available for commitment in the Day-Ahead Market (for every hour of the dispatch day) and (ii) identifying the prices at which the Demand Reduction Provider or DSASP Provider will voluntarily enter into dispatch commitments to reduce demand; provided, however, the price at which the Demand Reduction Provider or DSASP Provider will voluntarily enter into dispatch commitments to reduce demand shall be no lower than the Monthly Net Benefit Offer Floor, as determined in accordance with this section. The Bids will identify the minimum period of time that the Demand Reduction Provider or DSASP Provider is willing to reduce demand, however the minimum period may not be less than one hour. The Bid may separately identify the Demand Reduction Provider's Curtailment Initiation Cost. Demand Reduction Bids from Demand Reduction Providers that are not accepted in the Day-Ahead Market shall expire at the close of the Day-Ahead Market.~~

~~The ISO shall perform the Net Benefits Test and post on its web site the Monthly Net Benefit Offer Floor for each month by the 15th of the preceding month in accordance with ISO Procedures. The Net Benefits Test shall establish the threshold price below which the dispatch of Energy from Demand Side Resources is not cost-effective. The Net Benefits Test shall consist of the following steps: (1) the ISO shall compile hourly supply curves for the Reference Month; (2) the ISO shall develop the average supply curve for the Study Month by updating the Reference Month supply curves for retirements and new entrants, and adjusting offers for changes in fuel prices; (3) the ISO shall apply an appropriate mathematical formula to smooth the average supply curve; and (4) the ISO shall evaluate the smoothed average supply curve to determine the Monthly Net Benefit Floor for the Study Month. The ISO shall apply the Monthly Net Benefit Offer Floor, as so calculated, to Bids submitted by Demand Response Providers for all hours in the Study Month.~~

~~The ISO shall promptly post corrections, where necessary, to the Monthly Net Benefit Offer Floor. Corrections shall only apply to errors in conducting the calculations described above and/or in posting the properly calculated Monthly Net Benefit Offer Floor. Corrections shall not include recalculations based on changes in gas prices as set forth above. The ISO shall not use any correction to the Monthly Net Benefit Offer Floor to determine revised Day-Ahead Market clearing prices for periods prior to the imposition of the correction.~~

4.2.2 ISO Responsibility to Establish a Statewide Load Forecast

By 8 a.m., or as soon thereafter as is reasonably possible, the ISO will develop and publish its statewide Load forecast on the OASIS. The ISO will use this forecast to perform the SCUC for the Dispatch Day.

4.2.3 Security Constrained Unit Commitment ("SCUC")

Subject to ISO Procedures and Good Utility Practice, the ISO will develop a SCUC schedule over the Dispatch Day using a computer algorithm which simultaneously minimizes the total Bid Production Cost of: (i) supplying ~~power~~ Energy ~~or Demand Reductions~~ to satisfy accepted purchasers' Bids to buy Energy from the Day-Ahead Market; (ii) providing sufficient Ancillary Services to support Energy purchased from the Day-Ahead Market consistent with the Regulation Service Demand curve and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively of this ISO Services Tariff; (iii) committing sufficient Capacity to meet the ISO's Load forecast and provide associated Ancillary Services; and (iv) meeting Bilateral Transaction schedules submitted Day-Ahead excluding schedules of Bilateral Transactions with Trading Hubs as their POWs. ~~The computer algorithm shall consider whether accepting Demand Reduction Bids will reduce the total Bid Production Cost.~~

The ISO shall compute all NYCA Interface Transfer Capabilities prior to scheduling Transmission Service Day-Ahead. The ISO shall run the SCUC utilizing the computed Transfer Capabilities, submitted Firm Point-to-Point Transmission Service requests, Load forecasts, and submitted Incremental Energy Bids, Decremental Bids and Sink Price Cap Bids.

The schedule will include commitment of sufficient Generators and/or ~~Demand Side Resources~~ Aggregations to provide for the safe and reliable operation of the NYS Power System. SCUC will treat Behind-the-Meter Net Generation Resources, ~~and~~ Energy Storage Resources, and Aggregations as already being committed and available to be scheduled. Pursuant to ISO Procedures, the ISO may schedule any Resource to run above its UOL_N up to the level of its UOL_E. In cases in which the sum of all Bilateral Schedules, excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load within the NYCA in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of

Load, the ISO will commit Resources in addition to the Operating Reserves it normally maintains to enable it to respond to contingencies. The purpose of these additional resources is to ensure that sufficient Capacity is available to the ISO in real-time to enable it to meet its Load forecast (including associated Ancillary Services). In considering which additional Resources to schedule to meet the ISO's Load forecast, the ISO will evaluate unscheduled Imports, and will not schedule those Transactions if its evaluation determines the cost of those Transactions would effectively exceed a Bid Price cap in the hours in which the Energy provided by those Transactions is required. In addition to all Reliability Rules, the ISO shall consider the following information when developing the SCUC schedule: (i) Load forecasts; (ii) Ancillary Service requirements as determined by the ISO given the Regulation Service Demand Curve and Operating Reserve Demand Curves referenced above; (iii) Bilateral Transaction schedules excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs; (iv) price Bids and operating Constraints submitted for Generators or for ~~Demand Side Resources~~Aggregations; (v) price Bids for Ancillary Services; (vi) Decremental Bids and Sink Price Cap Bids for External Transactions; and (vii) Bids to purchase or sell Energy from or to the Day-Ahead Market. External Transactions with minimum run times greater than one hour will only be scheduled at the requested Bid for the full minimum run time. External Transactions with identical Bids and minimum run times greater than one hour will not be prorated. The SCUC schedule shall list the hourly injections and withdrawals for: (a) each Customer whose Bid the ISO accepts for the Dispatch Day; and (b) each Bilateral Transaction scheduled Day-Ahead excluding Bilateral Transactions with Trading Hubs as their POWs.

In the development of its SCUC schedule, the ISO may commit and decommit Generators and ~~Demand Side Resources~~Aggregations, based upon any flexible Bids, including

Minimum Generation Bids, Start-Up Bids, Curtailment Initiation Cost Bids, Energy, and Incremental Energy Bids and Decremental Bids received by the ISO provided however that~~: (a) the ISO shall commit zero megawatts of Energy for Demand Side Resources committed to provide Operating Reserves and Regulation Service; and (b)~~ for Behind-the-Meter Net Generation Resources, the ISO will consider for dispatch only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

The ISO will select the least cost mix of Ancillary Services and Energy from Suppliers, ~~Demand Side Resources,~~ and Customers submitting Virtual Transactions bids. The ISO may substitute higher quality Ancillary Services (*i.e.*, shorter response time) for lower quality Ancillary Services when doing so would result in an overall least bid cost solution. For example, 10-Minute Non-Synchronized Reserve may be substituted for 30-Minute Reserve if doing so would reduce the total bid cost of providing Energy and Ancillary Services.

4.2.3.1 Reliability Forecast for the Dispatch Day

At the request of a Transmission Owner to meet the reliability of its local system, the ISO may incorporate into the ISO's Security Constrained Unit Commitment constraints specified by the Transmission Owner.

A Transmission Owner may request commitment of certain Generators for a Dispatch Day if it determines that certain Generators are needed to meet the reliability of its local system. Such request shall be made before the Day-Ahead Market for that Dispatch Day has closed if the Transmission Owner knows of the need to commit certain Generators before the Day-Ahead Market close. The ISO may commit one or more Generator(s) in the Day-Ahead Market for a Dispatch Day if it determines that the Generator(s) are needed to meet NYCA reliability requirements.

A Transmission Owner may request commitment of additional Generators and/or Aggregations 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~~Resources.

All Generator and/or Aggregation commitments made in the Day-Ahead Market pursuant to this Section 4.2.3.1 shall be posted on the ISO website following the close of the Day-Ahead Market, in accordance with ISO procedures. In addition, the ISO shall post on its website a non-binding, advisory notification of a request, or any modifications thereto, made pursuant to this Section 4.2.3.1 in the Day-Ahead Market by a Transmission Owner to commit a Generator and/or Aggregation 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. The postings described here may be included with the operator-initiated commitment report that the ISO posts in accordance with Section 4.1.3.4 of this Services Tariff.

After the Day-Ahead schedule is published, the ISO shall evaluate any events, including, but not limited to, the loss of significant Generators, Aggregations, or transmission facilities that may cause the Day-Ahead schedules to be inadequate to meet the Load or reliability requirements for the Dispatch Day.

In order to meet Load or reliability requirements in response to such changed conditions the ISO may: (i) commit additional Resources, beyond those committed Day-Ahead, using a SRE and considering (a) Bids submitted to the ISO that were not previously accepted but were designated by the bidder as continuing to be available; or (b) new Bids from all Suppliers, including neighboring systems; or (ii) take the following actions: (a) after providing notice, require all Resources to run above their UOL_Ns, up to the level of their UOL_Es (pursuant to ISO Procedures) and/or raise the UOL_Ns of Capacity Limited Resources and Energy Limited Resources to their UOL_E levels, or (b) cancel or reschedule transmission facility maintenance outages when possible. Actions taken by the ISO in performing supplemental commitments will not change any financial commitments that resulted from the Day-Ahead Market.

4.2.4 Reliability Forecast for the Six Days Following the Dispatch Day

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the ISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven (7)-day period that begins with the next Dispatch Day. The ISO will perform a Supplemental Resource Evaluation ("SRE") for days two (2) through seven (7) of the commitment cycle. If it is determined that a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) is needed for reliability, the ISO shall accept a Bid from the Generator and the Generator will begin its start-up sequence. During each day of the start-up sequence, the ISO will perform an SRE to determine if long start-up time Generators will still be needed as previously forecasted. If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start-up sequence.

The ISO will commit to long start-up time Generators to preserve reliability. However, the ISO will not commit resources with long start-up times to reduce the cost of meeting Loads that it expects to occur in days following the next Dispatch Day.

A Supplier that bids on behalf of a long start-up time Generator, including one that is committed and whose start is subsequently aborted by the ISO as described in this Section 4.2.4, may be eligible for a Bid Production Cost Guarantee pursuant to the provisions of Section 4.6.6 and Attachment C of this ISO Services Tariff. The costs of such a Bid Production Cost guarantee will be recovered by the ISO under Rate Schedule 1 of the ISO OATT.

The ISO shall perform the SRE as follows: (1) The ISO shall develop a forecast of daily system peak Load for days two (2) through seven (7) in this seven (7)-day period and add the appropriate reserve margin; (2) the ISO shall then forecast its available Generators for the day in question by summing the Operating Capacity for all Generators currently in operation that are available for the commitment cycle, the Operating Capacity of all other Generators capable of starting on subsequent days to be available on the day in question, and an estimate of the net Imports from External Bilateral Transactions; (3) if the forecasted peak Load plus reserves exceeds the ISO's forecast of available Generators for the day in question, then the ISO shall commit additional Generators capable of starting prior to the day in question (*e.g.*, start-up period of two (2) days when looking at day three (3)) to assure system reliability; (4) in choosing among Generators with comparable start-up periods, the ISO shall schedule Generators to minimize Minimum Generation Bid and Start-Up Bid costs of meeting forecasted peak Load plus Ancillary Services consistent with the Reliability Rules; (5) in determining the appropriate reserve margin for days two (2) through seven (7), the ISO will supplement the normal reserve requirements to allow for forced outages of the short start-up period units (*e.g.*, gas turbines) assumed to be operating at maximum output in the unit commitment analysis for reliability.

Energy Bids are binding for day one (1) only for units in operation or with start-up periods less than one (1) day. Minimum Generation Bids for Generators with start-up periods greater than one (1) day will be binding only for units that are committed by the ISO and only for the first day in which those units could produce Energy given their start-up periods. For example, Minimum Generation Bids for a Generator with a start-up period of two (2) days would be binding only for day three (3) because, if that unit begins to start up at any time during day one (1), it would begin to produce Energy forty-eight (48) hours later on day three (3). Similarly, the Minimum Generation Bids for a Generator with a start-up period of three (3) days would be binding only for day four (4).

4.2.5 Post the Day-Ahead Schedule

By 11 a.m. on the day prior to the Dispatch Day, the ISO shall close the Day-Ahead scheduling process and post on the Bid/Post System the Day-Ahead schedule for each entity that submits a Bid or Bilateral Transaction schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the statewide aggregate resources (Day-Ahead Energy schedules and total operating capability forecast), Day-Ahead scheduled Load, forecast Load for each Load Zone, and the Day-Ahead LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone in each hour of the upcoming Dispatch Day. The ISO shall conduct the Day-Ahead Settlement based upon the Day-Ahead schedule determined in accordance with this section and Attachment B to this Services Tariff. The ISO will provide the Transmission Owner with the Load forecast (for seven (7) days) as well as the ISO security evaluation data to enable local area reliability to be assessed.

4.2.6 Day-Ahead LBMP Market Settlements

The ISO shall calculate the Day-Ahead LBMPs for each Load Zone and at each Generator bus and ~~Demand Reduction Bus~~ Transmission Node as described in Attachment B. Each Supplier that bids a Generator or Aggregation into the ISO Day-Ahead Market and is scheduled in the SCUC to sell or purchase Energy in the Day-Ahead Market will be settled at the product of: (a) the Day-Ahead hourly LBMP at the applicable Generator bus or Transmission Node; and (b) the hourly Energy schedule. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to sell Energy into the Day-Ahead LBMP Market will be settled at the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. ~~For each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in SCUC to provide Energy from the Demand Reduction, the LSE providing Energy service to the Demand Side Resource that accounts for the Demand Reduction shall be settled at the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction Bus; and (b) the hourly demand reduction scheduled Day-Ahead (in MW). In addition, each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in the SCUC to provide Energy through Demand Reduction shall receive a Demand Reduction Incentive Payment from the ISO equal to the product of: (a) the Day-Ahead hourly LBMP at the Demand Reduction bus; and (b) the lesser of the verified actual hourly Demand Reduction or the scheduled hourly Demand Reduction (in MW).~~ Each Customer that bids into the Day-Ahead Market, including each Customer that submits a Bid for a Virtual Transaction, and has a schedule accepted by the ISO to purchase Energy in the Day-Ahead Market will pay the product of: (a) the Day-Ahead hourly Zonal LBMP at each Point of Withdrawal; and (b) the scheduled Energy at each Point of Withdrawal. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to buy Energy from the Day-Ahead LBMP Market will pay the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. Each Customer that submits a Virtual Transaction bid into the ISO Day-Ahead Market and has a schedule accepted by the ISO to sell Energy in a Load Zone in the Day-Ahead Market will receive a payment equal to the product of (a) the Day-Ahead hourly zonal LBMP for that Load Zone; and (b) the hourly scheduled Energy for the Customer in that Load Zone. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POI and has its schedule accepted by the ISO will pay the product of: (a) the Day-Ahead hourly zonal LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POW and has its schedule accepted by the ISO will be paid the product of: (a) the Day-Ahead hourly zonal LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

The ISO shall publish the Day-Ahead Settlement Load Zone LBMPs for each hour in the Dispatch Day.

4.4 Real-Time Markets and Schedules

4.4.1 Real-Time Commitment ("RTC")

4.4.1.1 Overview

RTC will make binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of Resources that can respond in ten minutes) and thirty minutes (in the case of Resources that can respond in thirty minutes) after the scheduled posting time of each RTC run, will provide advisory commitment information for the remainder of the two and a half hour optimization period, and will produce binding schedules for External Transactions to begin at the start of each quarter hour. RTC will treat Behind-the-Meter Net Generation Resources ~~and~~ Energy Storage Resources, and Aggregations as already being committed and available to be scheduled. RTC will co-optimize to solve simultaneously for all Load, Operating Reserves and Regulation Service and to minimize the total as-bid production costs over its optimization timeframe. RTC will consider SCUC's Resource commitment for the day, load forecasts that RTC itself will produce each quarter hour, binding transmission constraints, and all Real-Time Bids and Bid parameters submitted pursuant to Section 4.4.1.2 below.

4.4.1.2 Bids and Other Requests

After the Day-Ahead schedule is published and before the close of the Real-Time Scheduling Window for each hour, Customers may submit Real-Time Bids into the Real-Time Market for real-time evaluation by providing all information required to permit real-time evaluation pursuant to ISO Procedures. If the Supplier elects to participate in the Real-Time Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not exclusively consist of Station Power) at a single PTID, it can only participate in the Real-Time Market as a Behind-the-Meter Net Generation Resource. If a Behind-the-Meter Net Generation Resource submits Bids into the Real-Time Market for real-time evaluation, such Bids shall provide the forecasted Host Load for each hour for which Bids are submitted.

An Energy Storage Resource shall indicate in its Real-Time Bids whether its Energy Level will be ISO- or Self-Managed. An Energy Storage Resource that elects to Self-Manage its Energy Level shall be responsible for managing its Energy Level through its Bids. An Energy Storage Resource, including an Energy Storage Resource that received a Day-Ahead Schedule, may change its Energy Level Management election for each operating hour in the Real-Time Market day.

A Supplier's Real-Time Market Self-Committed Flexible Bid for a DER Aggregation may include Energy withdrawals if the DER Aggregation includes at least one Withdrawal-Eligible Generator. A Supplier's Real-Time Market Bids for a DER Aggregation to withdraw Energy and to supply Energy shall be submitted in a single, continuous bid curve representing the Capacity, in MW, available. When the Energy Bid for the DER Aggregation includes both Energy supply and Energy withdrawal by a Withdrawal-Eligible Generator that is a component of the Aggregation, each point of the DER Aggregation's Bid curve shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

A Supplier may submit a Real-Time Market Self-Committed Fixed Bid for a DER Aggregation to withdraw Energy if the DER Aggregation includes at least one Withdrawal-Eligible Generator. When a Self-Committed Fixed Bid for a DER Aggregation reflects both Energy supply and Energy withdrawals by a Withdrawal-Eligible Generator that is a component of the Aggregation, the DER Aggregation's Bid shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying. However, if the Monthly Net Benefit Threshold price is less than the LBMP, Demand Side Resources shall not be permitted to net Energy withdrawals of Withdrawal-Eligible Generators in the DER Aggregation.

4.4.1.2.1 Real-Time Bids to Supply or Withdraw Energy and Supply Ancillary Services, other than External Transactions

Intermittent Power Resources and Aggregations that depend solely on wind as their fuel submitting new or revised offers to supply Energy shall bid as ISO-Committed Flexible and shall submit a Minimum Generation Bid of zero MW and zero cost and a Start-Up Bid at zero cost. Eligible Customers may submit new or revised Bids to supply or withdraw Energy, and to supply Operating Reserves and/or Regulation Service. Customers that submit such Bids may specify different Bid parameters in real-time than they did Day-Ahead. Incremental Energy Bids, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, and/or Start-Up Bids may be submitted by Suppliers bidding Resources using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the Incremental Energy Bids or Start-Up Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids or Start-Up Bids where appropriate, if not otherwise prohibited pursuant to other provisions of the tariff. Minimum Generation Bids or Regulation Service Bids for any hour in which such Resources received a Day-Ahead Energy schedule or a Regulation Service schedule, as appropriate, may not exceed the Minimum Generation Bids or Regulation Service Bids, as appropriate, submitted for those Resources in the Day-Ahead Market. Additionally, Real-Time Minimum Run Qualified Gas Turbine Customers shall not increase their previously submitted Real-Time Incremental Energy Bids, Minimum Generation Bids, or

Start-Up Bids within 135 minutes of the dispatch hour. Bids to supply Energy or Ancillary Services shall be subject to the rules set forth in Section 4.2.1 of this ISO Services Tariff. For Behind-the-Meter Net Generation Resources, the ISO will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

Suppliers bidding on behalf of Generators or Aggregations (except Aggregations comprised of only Intermittent Power Resource) that did not receive a Day-Ahead schedule for a given hour may offer their Generators or Aggregations, for those hours, using the ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed bid mode or, with ISO approval, the ISO-Committed Fixed bid modes in real-time. For Behind-the-Meter Net Generation Resources, the ISO will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit. ~~Suppliers bidding on behalf of Demand Side Resources that did not receive a Day-Ahead schedule to provide Operating Reserves or Regulation Service for a given hour may offer to provide Operating Reserves or Regulation Service using the ISO-Committed Flexible bid mode for that hour in the Real-Time Market provided, however, that the Demand Side Resource shall have an Energy price Bid no lower than the Monthly Net Benefit Offer Floor.~~ A Supplier bidding on behalf of a Generator or Aggregation that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator or Aggregation for the Real-Time Market for that hour provided, however, that Generators or Aggregations 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 or Aggregations 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~~ Generators and Aggregations 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 ISO. Additionally, if the Host Load of a Behind-the-Meter Net Generation Resource is greater in real-time than was forecasted Day-Ahead such that it cannot meet its Day-Ahead schedule, it must notify the ISO.

Generators and Aggregations ~~and Demand Side Resources~~ may not submit separate Operating Reserves Availability Bids in real-time and will instead automatically be assigned a real-time Operating Reserves Availability Bid of zero for the amount of Operating Reserves they are capable of providing in light of their response rate (as determined under Rate Schedule 4).

4.4.1.2.2 Real-Time Bids Associated with Internal and External Bilateral Transactions

Customers may use Real-Time Bids to seek to modify Bilateral Transactions that were previously scheduled Day-Ahead or propose new Bilateral Transactions, including External Transactions, for economic evaluation by RTC, provided however, that Bilateral Transactions with Trading Hubs as their POWs that were previously scheduled Day-Ahead may not be modified. Bids associated with Internal Bilateral Transactions shall be subject to the rules set forth above in Section 4.2.1.7.

Except as provided in this section, External Transaction Bids may not vary over the course of an hour. Each such Bid must offer to import, export or wheel the same amount of Energy at the same price at each point in time within that hour. At Variably Scheduled Proxy Generator Buses the ISO shall permit the submission of Bids to import or export Energy that vary the amount of Energy, and vary the price, for each quarter hour evaluation period.

The ISO may vary External Transaction Schedules at Proxy Generator Buses that are authorized to schedule transactions on an intra-hour basis if the party submitting the Bid for such a Transaction elects to permit variable scheduling. The ISO may also vary External Transaction Schedules at CTS Enabled Proxy Generator Buses. External Transaction Bids submitted to import Energy from, or export Energy to Proxy Generator Buses that are authorized to schedule transactions on either an intra-hour or hourly basis shall indicate whether the ISO may vary schedules associated with those Bids within each hour. Transmission Customers scheduling External Bilateral Transactions shall also be subject to the provisions of Section 16, Attachment J of the ISO OATT.

4.4.1.2.3 Self-Commitment Requests

Self-Committed Flexible Resources must provide the ISO with schedules of their expected minimum operating points in quarter hour increments. Self-Committed Fixed Resources must provide their expected actual operating points in quarter hour increments or, with ISO approval, bid as an ISO-Committed Fixed Generator.

4.4.1.2.4 ISO-Committed Fixed

The ability to use the ISO-Committed Fixed bidding mode in the Real-Time Market shall be subject to ISO approval pursuant to procedures, which shall be published by the ISO. Generators that have exclusively used the Self-Committed Fixed or ISO-Committed Fixed bid modes in the Day-Ahead Market or that do not have the communications systems, operational control mechanisms or hardware to be able to respond to five-minute dispatch basepoints are eligible to bid using the ISO-Committed Fixed bid mode in the Real-Time Market. Real-Time Bids by Generators using the ISO-Committed Fixed bid mode in the Real-Time Market shall provide variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, Minimum Generation Bids, hourly Start-Up Bids and other information pursuant to ISO Procedures.

RTC shall schedule ISO-Committed Fixed Generators.

4.4.1.3 External Transaction Scheduling

RTC15 will schedule External Transactions on an hourly basis as part of its development of a co-optimized least-bid cost Real-Time Commitment. For External Transactions that are scheduled on a 15 minute basis, the amount of Energy scheduled to be imported, exported or wheeled in association with that External Transaction may change on the quarter hour. All RTC runs will schedule intra-hour External Transactions on a 15 minute basis at Variably Scheduled Proxy Generator Buses. RTC will alert the ISO when it appears that scheduled External Transactions need to be reduced for reliability reasons but will not automatically Curtail them. Curtailment decisions will be made by the ISO, guided by the information that RTC provides, pursuant to the rules established by Attachment B of this ISO Services Tariff and the ISO Procedures. External Bilateral Transaction schedules are also governed by the provisions of Section 16, Attachment J of the OATT.

4.4.1.4 Posting Commitment/De-Commitment and External Transaction Scheduling Decisions

Except as specifically noted in Section 4.4.2, 4.4.3 and 4.4.4 of this ISO Services Tariff, RTC will make all Resource commitment and de-commitment decisions. RTC will make all economic commitment/de-commitment decisions based upon available offers assuming Suppliers internal to the NYCA have a minimum run time of at least 15 minutes, but not longer than one hour; provided however, Real-Time Minimum Run Qualified Gas Turbines shall be assumed to have a two-hour minimum run time. For Behind-the-Meter Net Generation

Resources, RTC will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

RTC will produce advisory commitment information and advisory real-time prices. RTC will make decisions and post information in a series of fifteen-minute "runs" which are described below.

RTC_{15} will begin at the start of the first hour of the RTC co-optimization period and will post its commitment, de-commitment, and External Transaction scheduling decisions no later than fifteen minutes after the start of that hour. During the RTC_{15} run, RTC will:

(i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their scheduled dispatch levels by that time;

(ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at their scheduled dispatch levels by that time;

(iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time;

(iv) Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information;

(v) Schedule economic hourly External Transactions for the next hour;

(vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;

(vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and

(viii) Schedule ISO-Committed Fixed Resources.

All subsequent RTC runs in the hour, *i.e.*, RTC_{30}, RTC_{45}, and RTC_{00} will begin executing at fifteen minutes before their designated posting times (for example, RTC_{30} will begin in the fifteenth minute of the hour), and will take the following steps:

(i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at that time;

(ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at that time;

(iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected at that time;

(iv) Issue advisory commitment, de-commitment, and dispatching guidance for the period from thirty minutes in the future until the end of the RTC co-optimization period;

(v) Either reaffirm that the External Transactions scheduled by previous RTC runs should continue to flow in the next hour, or inform the ISO that External Transactions may need to be reduced;

(vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;

(vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and

(viii) Schedule ISO-Committed Fixed Resources.

4.4.1.5 External Transaction Settlements

Settlements for External Transactions in the LBMP Market are described in Sections 4.2.6 and 4.5 of this ISO Services Tariff. Settlements for External Bilateral Transactions are also described in Section 16, Attachment J and Rate Schedules 7 and 8 of the OATT.

The calculation of Real-Time LBMPs at Proxy Generator Buses and CTS Enabled Interfaces is described in Section 17, Attachment B to this ISO Services Tariff.

4.4.2 Real-Time Dispatch

4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and ~~Demand Side Resources~~Aggregations, produce schedules for intra-hour External

Transactions at Dynamically Scheduled Proxy Generator Buses, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Real-Time Market Prices for Regulation

Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions, except as specifically provided in Section 4.4.2.4 below. In each interval, Real-Time Dispatch will review the Beginning Energy Level of each Energy Storage Resource~~'s~~ and of each Aggregation comprised only of Energy Storage Resources~~Beginning Energy Level in each interval~~. Real-Time Dispatch will attempt to prevent dispatching a Self-Managed Energy Storage Resource or Aggregation composed only of Energy Storage Resources in a manner that would be infeasible based on its Beginning Energy Level. Instead, Real-Time dispatch will reduce the Upper Operating Limit or increase the Lower Operating Limit, as appropriate, to an achievable value for the Energy Storage Resource~~'s~~ or Aggregation composed only of Energy Storage Resources~~Upper Operating Limit or increase its Lower Operating Limit, as appropriate, to an achievable value~~. An Energy Storage Resource's Beginning Energy Level will be used to ensure that Operating Reserves scheduled from the Resource can be sustained for one hour if the Operating Reserves are converted to Energy. Each Real-Time Dispatch run will co-optimize to solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon (which may be fifty, fifty-five, or sixty minutes long depending on where the run falls in the hour.) In addition to producing a binding schedule for the next five minutes, each Real-Time Dispatch run will produce advisory schedules for the remaining four time steps of its bid-optimization horizon (which may be five, ten, or fifteen minutes long depending on where the run falls in the hour). An advisory schedule may become binding in the absence of a subsequent Real-Time Dispatch run. RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

4.4.2.2 External Transaction Scheduling

All RTD runs will schedule External Transactions on a 5 minute basis at Dynamically Scheduled Proxy Generator Buses. For External Transactions that are scheduled on a 5 minute basis, the amount of Energy scheduled to be imported, exported or wheeled in association with that External Transaction may change every 5 minutes. External Bilateral Transaction Schedules are also governed by the provisions of Attachment J of the OATT.

4.4.2.3 Calculating Real-Time Market LBMPs and Advisory Prices

RTD shall calculate *ex ante* Real-Time LBMPs at each Generator bus, Transmission Node, and for each Load Zone in each RTD cycle, in accordance with the procedures set forth in Attachment B to this ISO Services Tariff. RTD will also calculate and post advisory Real-Time LBMPs for the next four quarter hours in accordance with the procedures set forth in Attachment B.

4.4.2.4 Real-Time Pricing Rules for Scheduling Ten Minute Resources

RTD may commit and dispatch, for pricing purposes, Resources capable of starting and meeting Minimum Generation Levels within ten minutes ("eligible Resources") when necessary to meet load. Eligible Resources committed and dispatched by RTD for pricing purposes may be physically started through normal ISO operating processes. In the RTD cycle in which RTD commits and dispatches an eligible Resource, RTD will consider the Resource's start-up and incremental energy costs and will assume the Resource has a zero downward response rate for purposes of calculating *ex ante* Real-Time LBMPs pursuant to Section 17, Attachment B to this ISO Services Tariff.

~~4.4.2.5 Converting to Demand Reduction, Special Case Resource Capacity scheduled as Operating Reserves, Regulation or Energy in the Real-Time Market~~

~~The ISO shall convert to Demand Reductions, in hours in which the ISO requests that Responsible Interface Parties notify their Special Case Resources to reduce their demand pursuant to ISO Procedures, any Operating Reserves, Regulation Service or Energy scheduled in the Day-Ahead Market from Demand Side Resources that are also providing Special Case Resource Capacity. The ISO shall settle the Demand Reduction provided by that portion of the Special Case Resource Capacity that was scheduled Day-Ahead as Operating Reserves, Regulation Service or Energy as being provided by a Supplier of Operating Reserves, Regulation Service or Energy as appropriate. The ISO shall settle any remaining Demand Reductions provided beyond Capacity that was scheduled Day-Ahead as Ancillary Services or Energy as being provided by a Special Case Resource, provided such Demand Reduction is otherwise payable as a reduction by a Special Case Resource.~~

~~Operating Reserves or Regulation Service scheduled Day-Ahead and converted to Energy in real-time pursuant to this Section 4.4.2.4, will be eligible for a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.~~

~~Special Case Resource Capacity that has been scheduled in the Day-Ahead Market to provide Operating Reserves, Regulation Service or Energy and that has been instructed as a Special Case Resource to reduce demand shall be considered, for the purpose of determining a Scarcity Reserve Requirement pursuant to Rate Schedule 4 of this ISO Services Tariff, to be a Special Case Resource.~~

~~The ISO shall not accept offers of Operating Reserves or Regulation Service in the Real-Time Market from Demand Side Resources that are also providing Special Case Resource Capacity for any hour in which the ISO has requested Special Case Resources to reduce demand.~~

~~4.4.2.6 Converting to Demand Reduction Curtailment Services Provider Capacity scheduled as Operating Reserves, Regulation or Energy in the Real-Time Market~~

~~The ISO shall convert to Demand Reductions, in hours in which the ISO requests Demand Reductions from the Emergency Demand Response Program pursuant to ISO Procedures, any Operating Reserves, Regulation Service or Energy scheduled in the Day-Ahead Market by Demand Side Resources that are also providing Curtailment Services Provider Capacity. The ISO shall settle the Demand Reduction provided by that portion of the Curtailment Services Provider Capacity that was scheduled Day-Ahead as Operating Reserves, Regulation Service or Energy as being provided by a Supplier of Operating Reserves, Regulation Service or Energy as appropriate. The ISO shall settle Demand Reductions provided beyond Capacity that was scheduled Day-Ahead as ancillary services or Energy as being provided by a Curtailment Services Provider.~~

~~Operating Reserves or Regulation Service scheduled Day-Ahead and converted to Energy in real-time pursuant to this Section 4.4.2.5, will be eligible for a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.~~

~~Curtailment Services Provider Capacity that has been scheduled in the Day-Ahead Market as Operating Reserves, Regulation Service or Energy and that has been instructed to reduce demand shall be considered, for the purpose of determining a Scarcity Reserve Requirement pursuant to Rate Schedule 4 of this ISO Services Tariff, to be a Emergency Demand Response Program Resource.~~

~~The ISO shall not accept offers of Operating Reserves and Regulation Service in the Real-Time Market from Demand Side Resources that are also providing Curtailment Services Provider Capacity for any hour in which the ISO has requested participants in the Emergency Demand Response Program pursuant to ISO Procedures to reduce demand.~~

4.4.2.~~7~~5 Post the Real-Time Schedule

Subsequent to the close of the Real-Time Scheduling Window, the ISO shall post the real-time schedule for each entity that submits a Bid or Bilateral Transaction schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer, Transmission Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the real-time Load for each Load Zone, and the Real-Time LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone for each hour of the Dispatch Day. The ISO shall conduct the real-time settlement based upon the real-time schedule determined in accordance with this Section.

4.4.3 Real-Time Dispatch - Corrective Action Mode

When the ISO needs to respond to system conditions that were not anticipated by RTC or the regular Real-Time Dispatch, *e.g.*, the unexpected loss of a major Generator or Transmission line, it will activate the specialized RTD-CAM program. RTD-CAM runs will be nominally either five or ten minutes long, as is described below. Unlike the Real-Time Dispatch, RTD-CAM will have the ability to commit certain Resources, and schedule intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses. When RTD-CAM is activated, the ISO will have discretion to implement various measures to restore normal operating conditions. These RTD-CAM measures are described below.

The ISO shall have discretion to determine which specific RTD-CAM mode should be activated in particular situations. In addition, RTD-CAM may require Resources to run above their UOL_Ns, up to the level of their UOL_Es as is described in the ISO Procedures. Self-

Committed Fixed Resources will not be expected to move in response to RTD-CAM Base Point Signals except when a maximum generation pickup is activated.

Except as expressly noted in this section, RTD-CAM will dispatch the system in the same manner as the normal Real-Time Dispatch.

4.4.3.1 RTD-CAM Modes

4.4.3.1.1 Reserve Pickup

The ISO will enter this RTD-CAM mode when necessary to re-establish schedules when large area control errors occur. When in this mode, RTD-CAM will send 10-minute Base Point Signals and produce schedules for the next ten minutes. RTD-CAM may also commit, or if necessary de-commit, Resources capable of starting or stopping within 10-minutes. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements and Scarcity Reserve Requirements, but will set all Regulation Service schedules to zero. If Resources are committed or de-committed in this RTD-CAM mode the schedules for them will be passed to RTC and the Real-Time Dispatch for their next execution.

The ISO will have discretion to classify a reserve pickup as a "large event" or a "small event." In a small event the ISO will have discretion to reduce Base Point Signals in order to reduce transmission line loadings. The ISO will not have this discretion in large events. The distinction also has significance with respect to a Supplier's eligibility to receive Bid Production Cost guarantee payment in accordance with Section 4.6.6 and Attachment C of this ISO Services Tariff.

4.4.3.1.2 Maximum Generation Pickup

The ISO will enter this RTD-CAM mode when an Emergency makes it necessary to maximize Energy production in one or more location(s), i.e., Long Island, New York City, Southeastern New York, East of Central East and/or NYCA-wide. RTD-CAM will produce schedules directing all Generators and Aggregations located in a targeted location to increase production at their emergency response rate up to their UOL_E level and to stay at that level until instructed otherwise. Security constraints will be obeyed to the extent possible. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements and Scarcity Reserve Requirements, but will set all Regulation Service schedules to zero.

4.4.3.1.3 Base Points ASAP -- No Commitments

The ISO will enter this RTD-CAM mode when changed circumstances make it necessary to issue an updated set of Base Point Signals. Examples of changed circumstances that could necessitate taking this step include correcting line, contingency, or transfer overloads and/or voltage problems caused by unexpected system events. When operating in this mode, RTD-CAM will produce schedules and Base Point Signals for the next five minutes but will only redispatch Generators and Aggregations that are capable of responding within five minutes. RTD-CAM will not commit or de-commit Resources in this mode.

4.4.3.1.4 Base Points ASAP -- Commit As Needed

This operating mode is identical to Base Points ASAP – No Commitments, except that it also allows the ISO to commit Generators that are capable of starting within 10 minutes when doing so is necessary to respond to changed system conditions.

4.4.3.1.5 Re-Sequencing Mode

When the ISO is ready to de-activate RTD-CAM, it will often need to transition back to normal Real-Time Dispatch operation. In this mode, RTD-CAM will calculate normal five-minute Base Point Signals and establish five minute schedules. Unlike the normal RTD-Dispatch, however, RTD-CAM will only look ahead 10-minutes. RTD-CAM re-sequencing will terminate as soon as the normal Real-Time Dispatch software is reactivated and is ready to produce Base Point signals for its entire optimization period.

4.4.3.2 Calculating Real-Time LBMPs

When RTD-CAM is activated, RTD shall calculate *ex ante* Real-Time LBMPs at each Generator bus, Transmission Node, and for each Load Zone in accordance with the procedures set forth in Section 17, Attachment B of this ISO Services Tariff.

4.4.4 Identifying the Pricing and Scheduling Rules That Apply to External Transactions

LBMPs will be determined and External Transactions will be scheduled at external Proxy Generator Buses consistent with the table below.

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	Non-Competitive	CTS Enabled Proxy Generator Bus		Scheduling Frequencies		
					Requires CTS Bids	Permits CTS Bids	Hourly Scheduled	Variably Scheduled	Dynamically Scheduled (Not Presently Available)
Hydro Quebec									
HQ_GEN_IMPORT	323601			✓			✓	✓	
HQ_LOAD_EXPORT	355639			✓			✓	✓	
HQ_GEN_CEDARS_PROXY	323590	Dennison Scheduled Line		✓			✓		
HQ_LOAD_CEDARS_PROXY	355586	Dennison Scheduled Line		✓			✓		
HQ_GEN_WHEEL	23651			✓			✓		
HQ_LOAD_WHEEL	55856			✓			✓		
PJM									
PJM_GEN_KEYSTONE	24065					✓	✓* (See Notes)	✓	
PJM_LOAD_KEYSTONE	55857					✓	✓* (See Notes)	✓	
PJM_GEN_NEPTUNE_PROXY	323594	Neptune Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_LOAD_NEPTUNE_PROXY	355615	Neptune Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_GEN_VFT_PROXY	323633	Linden VFT Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_LOAD_VFT_PROXY	355723	Linden VFT Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_HTP_GEN	323702	HTP Scheduled Line	✓			✓	✓* (See Notes)	✓	

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	Non-Competitive	CTS Enabled Proxy Generator Bus		Scheduling Frequencies		
					Requires CTS Bids	Permits CTS Bids	Hourly Scheduled	Variably Scheduled	Dynamically Scheduled (Not Presently Available)
HUDSONTP_345KV_HTP_LOAD	355839	HTP Scheduled Line	✓			✓	✓* (See Notes)	✓	
ISO New England									
N.E._GEN_SANDY_POND	24062				✓		✓** (See Notes)	✓	
NE_LOAD_SANDY_PD	55858				✓		✓** (See Notes)	✓	
NPX_GEN_CSC	323557	Cross Sound Scheduled Line	✓				✓		
NPX_LOAD_CSC	355535	Cross Sound Scheduled Line	✓				✓		
NPX_GEN_1385_PROXY	323591	Northport Norwalk Scheduled Line					✓		
NPX_LOAD_1385_PROXY	355589	Northport Norwalk Scheduled Line					✓		
Ontario									
O.H._GEN_BRUCE	24063						✓		
OH_LOAD_BRUCE	55859						✓		

Notes:

* At specifically identified Proxy Generator Buses ("* See Notes"), only Wheels Through (the NYCA) are scheduled on an hourly basis.

** At specifically identified Proxy Generator Buses ("** See Notes"), only wheels through the NYCA or a neighboring Control Area are scheduled on an hourly basis.

Pricing rules for Proxy Generator Buses are set forth in Section 17 of the Services Tariff.

The ISO may offer a more frequent scheduling option at a Proxy Generator Bus identified on the table. The ISO shall inform its Market Participants of the availability of such an option by providing notice at least two weeks in advance of the implementation of any such change. At the same time, the ISO shall update the above table to reflect the change in scheduling options by submitting a compliance filing in FERC Docket No. ER11-2547. Unless FERC acts on the ISO's compliance filing, the ISO shall effectuate the change in scheduling capability on the date it proposed in its compliance filing. The addition of new Proxy Generator Buses to the table, or changing the pricing rules that apply at a Proxy Generator Bus, may not be accomplished by submitting a compliance filing in Docket No. ER11-2547. The ISO may revert to establishing hourly Import and Export schedules using all available External Transaction Bids at a Proxy Generator Bus that is identified as a Dynamically or Variably Scheduled Proxy Generator Bus when the ISO or a neighboring Balancing Authority is not able to implement schedules as expected, or when necessary to ensure or preserve system reliability. When it reverts to hourly Import and Export schedules at a Dynamically or Variably Scheduled Proxy Generator Bus, the ISO shall apply the pricing rules for a corresponding Proxy Generator Bus that is not Dynamically Scheduled or Variably Scheduled. The ISO may cease evaluating CTS Interface Bids at CTS Enabled Proxy Generator Buses when the ISO or a neighboring Balancing Authority is not able to implement schedules as expected, or when necessary to ensure or preserve system reliability.

4.5 Real-Time Market Settlements

Transmission Customers and Customers taking service under this ISO Services Tariff or the ISO OATT, shall be subject to the Real-Time Market Settlement. All withdrawals, ~~and~~ injections and Demand Reductions not scheduled on a Day-Ahead basis, including Real-Time deviations from any Day-Ahead External Transaction schedules, shall be subject to the Real-Time Market Settlement. Transmission Customers not taking service under this Tariff shall be subject to balancing charges as provided for under the ISO OATT. Settlements with Suppliers scheduling service from External Suppliers to the LBMP Market or to External Loads from the LBMP Market will be based upon scheduled withdrawals or injections. Real-Time Market Settlements for ~~injections~~ Energy provided by Resources supplying Regulation Service or Operating Reserves shall follow the rules which are described in Rate Schedules 15.3 and 15.4, respectively.

For the purposes of this section, the scheduled output of each of the following Generators in each RTD interval in which it has offered Energy shall retroactively be set equal to its actual output in that RTD interval:

(i) Generators, except for the Generator of a Behind-the-Meter Net Generation Resource and Generators in an Aggregation, providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999 who have not provided telemetering to their local TO and historically have not been eligible to participate in the NYPP market, which will continue to be treated as TO Load modifiers under the ISO-administered markets;

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 523 MW of such units.

This procedure shall not apply to Behind-the-Meter Net Generation Resources, Aggregations or a Generator for those hours it has used the ISO-Committed Flexible or Self-Committed Flexible bid mode.

In Sections 4.5.1, 4.5.2, 4.5.3, and 4.5.4 of this Tariff, references to "scheduled" Energy injections and withdrawals shall encompass injections, including Demand Reductions, and withdrawals that are scheduled Day-Ahead, unless otherwise noted, as well as injections and withdrawals that occur in connection with real-time Bilateral Transactions. In Sections 4.5.2 and 4.5.3 of this Tariff, references to Energy Withdrawals and Energy Injections shall not include Energy Withdrawals or Energy Injections in Virtual Transactions, or Energy Withdrawals or Energy Injections at Trading Hubs. Generators, including Limited Energy Storage Resources and Aggregations, that are providing Regulation Service shall not be subject to the real-time Energy market settlement provisions set forth in this Section, but shall instead be subject to the Energy settlement rules set forth in Rate Schedule 15.3 of this ISO Services Tariff.

4.5.1 Settlement 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.

4.5.2 Real-Time Market Settlements for Energy ~~Injections or When Actual Demand Reductions are Less Than Scheduled Demand Reductions~~

4.5.2.1 General Rules for Suppliers

A Supplier, which is not a DER Aggregation, shall pay or be paid for Energy imbalance to account for differences between Actual Energy Injections, compensable Demand Reductions, real-time Energy schedules and Day-Ahead Energy schedules.

A DER Aggregation shall pay or be paid for Energy imbalance based on the (1) Actual Energy Injections, real-time Energy schedules, Day-Ahead Energy schedules, and (2) all compensable Demand Reductions eligible for payment at the applicable LBMP pursuant to Services Tariff Section 4.5.7.

A Generator or Aggregation that is not following Base Point Signals shall not be compensated for Energy in excess of its Real-Time Scheduled Energy injection if its applicable upper operating limit has been reduced below its bid-in upper operating limit by the ISO in order to reconcile the ISO's dispatch with the Generator or Aggregation's actual output, or to address reliability concerns.

If the Energy provided by a Supplier over an RTD interval is less than the Supplier's Day-Ahead Energy schedule, and if the Supplier reduced the Energy it provides 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.

4.5.2.1.1 Supplier Payments when LBMP is Positive

When the LBMP calculated in that RTD interval at the applicable Generator or Aggregation's bus is positive, the Supplier payment shall be calculated as follows:

Supplier payment for Energy injections and withdrawals = ((MIN(AE_{iu},RTS_{iu}) – DAS_{hu}) $* LBMP_{iu}^{RT}) * \frac{S_i}{3600}$

Where:

AE_{iu} = (1) average Actual Energy Injection by Supplier *u* in interval *i* expressed in terms of MW; or (2) average Actual Energy Withdrawal by an Energy Storage Resource *u* or Aggregation *u* that includes Energy Storage Resource(s)in interval *i* expressed in terms of MW;

RTS_{iu} = (1) real-time Energy scheduled ~~for injection~~ by Supplier *u* in interval *i* plus Compensable Overgeneration; or (2) real-time Energy scheduled for withdrawal by Energy Storage Resource *u* or Aggregation *u* that includes Withdrawal-Eligible Generator(s) in interval *i* plus 3% of the absolute value of the Energy Storage Resource's or Aggregation's Lower Operating Limit; or (3) average Actual Energy Withdrawal by an Energy Storage Resource *u* or Aggregation *u* that includes Withdrawal-Eligible Generator(s) in interval *i* when it has been designated as operating Out-of-Merit to withdraw at the request of a Transmission Owner or the ISO;

DAS_{hu} = Day-Ahead Energy schedule for Supplier *u* in hour *h* containing interval *i*;

$LBMP_{iu}^{RT}$ = real-time price of Energy at the location of Supplier *u* in interval *i*;

S_i = number of seconds in RTD interval *i*;

Supplier payment for Demand Reductions =

(MIN(ADR_{iu} , MAX($RTS_{iu} - AE_{iu}$, 0)) $* LBMP_{iu}^{RT}) * \frac{S_i}{3600}$

Where:

ADR_{iu} = average Actual Demand Reduction that ~~are~~ is eligible for Energy payments pursuant to Services Tariff Section 4.5.7 by Supplier *u* in interval *i*, ~~this~~ the ADR_{iu} term will be set to zero if the Actual Demand Reduction is not eligible for Energy payments pursuant to Services Tariff Section 4.5.7;

The remaining variables are defined above in this Section 4.5.2.1.1.

4.5.2.1.2 Supplier Payments when LBMP is negative, during a large event reserve pickup, during a maximum generation pickup, or during a Transmission Owner initiated reserve pickup

When: (1) the LBMP calculated in that RTD interval at the applicable Generator or Aggregation bus is negative; or (2) the ISO initiates a large event reserve pickup or a maximum generation pickup under RTD-CAM that applies to the Load Zone where the Generator or Aggregation is located; or (3) a Transmission Owner initiates a reserve pickup in accordance with a Reliability Rule, including a Local Reliability Rule, then the Supplier payment shall be calculated as follows:

Supplier ~~P~~payment for Energy injections and withdrawals = $((AE_{iu} - DAS_{hu}) * LBMP_{iu}^{RT}) * \frac{S_i}{3600}$

Where:

The variables are defined above in this Section 4.5.2.1.~~.~~1

Supplier payment for Demand Reductions = $ADR_{iu} * LBMP_{iu}^{RT} * \frac{S_i}{3600}$

Where:

ADR_{iu} = average Actual Demand Reduction by Supplier *u* in interval *i*;

The remaining variables are defined above in Section 4.5.2.1.1.

~~A Generator that is not following Base Point Signals shall not be compensated for Energy in excess of its Real-Time Scheduled Energy injection if its applicable upper operating limit has~~

~~been reduced below its bid-in upper operating limit by the ISO in order to reconcile the ISO's dispatch with the Generator's actual output, or to address reliability concerns.~~

~~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.~~

4.5.2.1.3 Supplier Payments for Imports

Suppliers scheduling Imports shall pay or be paid for Energy imbalance to account for differences between real-time Energy schedules and Day-Ahead Energy schedules. For an Import to the LBMP Market that is only scheduled in the Real-Time Market, or to the extent it is scheduled to supply additional or less Energy to the LBMP Market in real-time than it was scheduled to supply Day-Ahead, the Supplier payment shall be calculated as follows:

Supplier ~~P~~payment for Imports = $((RTS_{iup} - DAS_{hup}) * LBMP_{ip}^{RT}) * \frac{S_i}{3600}$

Where:

RTS_{iup} = real-time Energy scheduled for injection by Supplier *u* in interval *i* at Proxy Generator Bus *p*;

DAS_{hup} = Day-Ahead Energy schedule for Supplier *u* in hour *h* containing interval *i* at Proxy Generator Bus *p*;

$LBMP_{ip}^{RT}$ = real-time price of Energy at the Point of Receipt *p* (*i.e.*, the Proxy Generator Bus) in interval *i*;

S_i = number of seconds in RTD interval *i*;

4.5.2.2 Failed Transactions

If an Energy injection scheduled by RTC at a Proxy Generator Bus fails in the ISO's checkout process and 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 will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy injection at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy injection from the amount of the Import scheduled by RTC; multiplied by (ii) the greater of the Real-Time Market Congestion Component of the LBMP in the relevant interval, or zero.

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this section and the Financial Impact Charge described below in Section 4.5.3.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 1 of this ISO Services Tariff. In the event that the Energy injections for an Import scheduled by RTC or RTD, at a Proxy Generator Bus is Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible to receive an Import Curtailment Guarantee Payment for its curtailed Import pursuant to Attachment J of this ISO Services Tariff.

4.5.2.3 Capacity Limited Resources and Energy Limited Resources

For any hour in which: (i) a Capacity Limited Resource or an Aggregation comprised entirely of Capacity Limited Resources 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 or Aggregation comprised entirely of Capacity Limited Resources requests a reduction for Capacity limitation reasons; and (iv) the ISO reduces the Capacity Limited Resource's or the Aggregation comprised entirely of Capacity Limited Resources 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 or Aggregation comprised entirely of Capacity Limited Resources for that hour for its Day-Ahead Market obligations above its Capacity limited upper operating limit shall be equal to the product of: (a) the Real-Time price for Energy, Operating Reserve Service and Regulation Capacity; and (b) the Capacity Limited Resource's or the Aggregation comprised entirely of Capacity Limited Resources 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 or the Aggregation comprised entirely of Capacity Limited Resources Day-Ahead obligation above its Capacity limited upper operating limit is balanced as described above, any real-time variation from its obligation pursuant to its Capacity limited schedules shall be settled pursuant to the methodology set forth in Section 4.5.2.1.

For any day in which: (i) an Energy Limited Resource or an Aggregation comprised entirely of Capacity Limited Resources is scheduled to supply Energy, Operating Reserves or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in Normal Upper Operating Limit; (iii) the Energy Limited Resource or the Aggregation comprised entirely of Capacity Limited Resources requests a reduction for Energy limitation reasons; and (iv) the ISO reduces the Energy Limited Resource's Day-Ahead Emergency Upper Operating Limit to a limit no lower than the Normal Upper Operating Limit; the Resource may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

4.5.2.4 Demand Reductions

When the verified actual Demand Reduction over an hour from a Demand Reduction Provider that is also the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled for that hour, that-LSE shall pay a Demand Reduction imbalance charge consisting of the product of: (a) the greater of the Day-Ahead LBMP or the Real-Time LBMP for that hour and (b) the difference between the scheduled Demand Reduction and the verified actual Demand Reduction in that hour.

When the verified actual Demand Reduction over an hour from a Demand Reduction Provider that is not the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled over that hour, then (1) the LSE providing Energy service to the Demand Reduction Provider's Demand Side Resource(s) shall pay a Demand Reduction imbalance charge equal to the product of (a) the Day-Ahead LBMP calculated for that hour for the applicable Load bus and (b) the difference between the scheduled Demand Reduction and the verified actual Demand Reduction at that bus in that hour, and (2) the Demand Reduction Provider will pay an amount equal to (a) the product of (i) the higher of the Day-Ahead LBMP or the Real-Time LBMP calculated for that hour for the applicable Load bus, and (ii) the difference between the scheduled Demand Reduction and the verified actual Demand Reduction at that bus in that hour, and (b) minus the amount paid by the

LSE providing service to the Demand Reduction Provider's Demand Side Resource(s) under (1), above.

4.5.3 Real-Time Market Settlements for Energy Withdrawals Other Than in Virtual Transactions

4.5.3.1 General Rules

A Customer (other than a Generator that is eligible to withdraw Energy) shall pay or be paid for Energy imbalance to account for differences between Actual Energy Withdrawals over an RTD interval and its Energy withdrawals scheduled Day-Ahead. The ISO shall charge the Customer as follows for each applicable Load Zone:

$$\text{Customer Charge} = ((AEW_{icz} - DAS_{hcz}) * LBMP_{iz}^{RT}) * \frac{S_i}{3600}$$

Where:

AEW_{icz}	=	Actual Energy Withdrawal by Customer *c* in Load Zone *z* in interval *i*;
DAS_{hcz}	=	Day-Ahead scheduled Energy withdrawals by Customer *c* in Load Zone *z* in hour *h* containing interval *i*;
$LBMP_{iz}^{RT}$	=	real-time price of Energy for Load Zone *z* in interval *i*;
S_i	=	number of seconds in RTD interval i;

~~A Customer LSE providing Energy service to a Demand Reduction Provider's Demand Side Resource in a Load Zone shall be charged the product of: (a) the Real-Time hourly LBMP for that Load Zone; and (b) the actual Demand Reduction at the Demand Reduction Bus in that Load Zone.~~

If the Generator of a Behind-the-Meter Net Generation Resource is not able to serve the Resource's Host Load at any time, any resulting Actual Energy Withdrawals that serve the Host

Load will be charged to the Load Serving Entity responsible for serving the Behind-the-Meter Net Generation Resource.

4.5.3.1.1 Customer Settlements for Exports

Customers scheduling Exports shall pay or be paid for Energy imbalance to account for differences between real-time Energy schedules and Day-Ahead Energy schedules. For an Export from the LBMP Market that is only scheduled in the Real-Time Market, or to the extent it is scheduled to withdraw additional or less Energy from the LBMP Market in real-time than it was scheduled to withdraw Day-Ahead, the ISO shall charge the Customer as follows:

Customer Charge for Exports $= ((RTS_{iup} - DAS_{hup}) * LBMP_{ip}^{RT}) * \frac{S_i}{3600}$

Where:

RTS_{iup}	=	real-time Energy scheduled for withdrawal by Customer *u* in interval *i* at Proxy Generator Bus *p*;
DAS_{hup}	=	Day-Ahead Energy schedule for Customer *u* in hour *h* containing interval *i* at Proxy Generator Bus *p*;
$LBMP_{ip}^{RT}$	=	real-time price of Energy at the Point of Delivery *p* (*i.e.*, the Proxy Generator Bus) in interval *i*;
S_i	=	number of seconds in RTD interval i;

4.5.3.2 Failed Transactions

If an Energy withdrawal at a Proxy Generator Bus scheduled by RTC fails in the ISO's checkout process and 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 will determine whether the Transaction associated with a withdrawal failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy withdrawal at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy withdrawal from the amount of the Export scheduled by RTC; multiplied by (ii) the product of negative one and the lesser of the Real-Time Market Congestion Component of the LBMP in the relevant interval, or zero.

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this subsection and the Financial Impact Charge described above in Section 4.5.2.2.

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.

4.5.4 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: (a) 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.

4.5.5 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.

4.5.6 Settlement for Trading Hub Energy Owner when POW is a Trading Hub

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Real-Time Market with a Trading Hub as its POW and has its schedule accepted by the ISO will be paid the product of: (a) the hourly integrated Real-Time LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

4.5.7 Settlement for Demand Reductions

4.5.7.1 Monthly Net Benefits Test

The ISO shall perform the Net Benefits Test and post on its web site the Monthly Net Benefit Threshold for each month by the 15th of the preceding month in accordance with ISO Procedures. The Net Benefits Test shall establish the threshold price below which the dispatch of Energy from Demand Side Resources is not cost-effective. The Net Benefits Test shall consist of the following steps: (1) the ISO shall compile hourly supply curves for the Reference Month; (2) the ISO shall develop the average supply curve for the Study Month by updating the Reference Month supply curves for retirements and new entrants, and adjusting offers for changes in fuel prices; (3) the ISO shall apply an appropriate mathematical formula to smooth the average supply curve; and (4) the ISO shall evaluate the smoothed average supply curve to determine the Monthly Net Benefit Floor for the Study Month.

The ISO shall promptly post corrections, where necessary, to the Monthly Net Benefit Threshold. Corrections shall only apply to errors in conducting the calculations described above and/or in posting the properly calculated Monthly Net Benefit Threshold. Corrections shall not include recalculations based on changes in gas prices.

4.5.7.2 Settlement Eligibility for Demand Reductions

A DER Aggregation may offer into the Day-Ahead Market or Real-Time Market below the Monthly Net Benefit Threshold. However, when a DER Aggregation receives a real-time Energy schedule, and the Real-Time LBMP calculated in that RTD interval for the applicable Transmission Node is less than the Monthly Net Benefit Threshold price, Demand Reductions by the DER Aggregation shall not be eligible for Energy payments, Day Ahead Margin Assurance Payments or Bid Production Cost guarantee payments otherwise available under this Services Tariff. Provided, however, if the DER Aggregation is dispatched by the ISO or Transmission Owner to meet NYCA or local system reliability, the Demand Reductions shall be eligible for Energy payments. The DER Aggregation may also be eligible for Day Ahead Margin Assurance Payments pursuant to Attachment J of this ISO Services Tariff and Bid Production Cost guarantee payments pursuant to Attachment C of this ISO Services Tariff.

4.5.~~7~~8 Performance Tracking

The ISO shall use a Performance Tracking System to compute the difference between the Energy actually supplied and the Energy scheduled by the ISO for all Suppliers located within the NYCA and shall use it to measure compliance with criteria associated with the provision of Energy and Ancillary Services as set forth in the ISO Procedures. The Performance Tracking System shall also be used to report metrics for Loads.

4.6 Payments

4.6.1 Payments to Suppliers of Regulation Service

Suppliers of Regulation Service shall receive a payment that is calculated pursuant to Rate Schedule 15.3 of this ISO Services Tariff

4.6.2 Payments to Suppliers of Reactive Supply and Voltage Support Service ("Voltage Support Service")

Suppliers of Voltage Support Service shall receive a Voltage Support Service payment in accordance with the criteria and formula in Rate Schedule 15.2.

4.6.3 Payments to Suppliers for Operating Reserves

Suppliers of each type of Operating Reserve will receive payments for each MW of Operating Reserve that they provide, as requested by the ISO, pursuant to Rate Schedule 15.4.

Additionally, Generators and Aggregations providing Operating Reserves shall receive a payment for Energy injections when the ISO requests Energy under a reserve activation. The Energy payment shall be calculated as the product of: (a) the Energy provided; and (b) the Real-Time Market LBMP.

4.6.4 Payments to Generators for Black Start Capability

Black Start Capability providers shall receive a payment for Black Start Capability as set forth in Rate Schedule 15.5.

4.6.5 Day-Ahead Margin Assurance Payments

A Supplier that is scheduled in the Day-Ahead Market to provide Energy, Regulation Service, or Operating Reserves may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

4.6.6 Bid Production Cost Guarantee Payments

4.6.6.1 Day-Ahead BPCG for Generators

The ISO shall determine if a Supplier eligible under Section 18.2.1 of Attachment C of this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment will not recover its Day-Ahead Regulation Capacity Bid, Operating Reserves Bid, or its Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid for Energy scheduled in the Day-Ahead Market, including Energy provided by the capacity scheduled for Regulation Service, through Day-Ahead LBMP revenue, Day-Ahead Imputed LBMP Revenue and net Day-Ahead Ancillary Services revenues for Voltage Support Service, Regulation Service, and synchronized Operating Reserves. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Generator. On the basis of such determination (and subject to any mitigation that may apply) the ISO shall pay a Day-Ahead BPCG to the Supplier pursuant to Section 18.2 of Attachment C to this ISO Services Tariff.

4.6.6.2 Day-Ahead BPCG for Imports

The ISO shall determine if a Supplier supplying an Import and eligible under Section 18.3.1 of Attachment C of this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment will not recover its Day-Ahead Decremental Bid through Day-Ahead LBMP revenue and Day-Ahead Imputed LBMP Revenue. Such determination shall be made for an entire Day-Ahead Market day and such determination shall be made separately for each Import transaction. On the basis of such determination, the ISO shall pay a Day-Ahead Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.3 of Attachment C of this ISO Services Tariff.

4.6.6.3 Real-Time BPCG for Generators in RTD Intervals Other than Supplemental Event Intervals

The ISO shall determine if a Supplier eligible under Section 18.4.1 of Attachment C of this ISO Services Tariff for a real-time Bid Production Cost guarantee payment will not recover its real-time Regulation Capacity Bid, Regulation Movement Bid, Operating Reserves Bid, or its Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid for Energy that was not scheduled in the Day-Ahead Market, including Energy provided by the capacity scheduled for Regulation Service, through real-time LBMP revenue, real-time Imputed LBMP Revenue and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and synchronized Operating Reserves. Such determination shall be made for an entire Dispatch Day (except for Supplemental Event Intervals). Such determination shall be made separately for each Generator. On the basis of such determination, and subject to any mitigation that may apply, the ISO shall pay a real-time Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.4 of Attachment C to this ISO Services Tariff and, as applicable, Section 15.3.

Suppliers bidding on behalf of Resources that were not committed by the ISO to operate in a given Dispatch Day, but which continue to operate due to minimum run time Constraints, shall not receive such a supplemental payment.

4.6.6.4 BPCG for Generators for Supplemental Event Intervals

The ISO shall determine if a Supplier eligible under Section 18.5.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for a Supplemental Event Interval will not recover its real-time Regulation Capacity Bid, Regulation Movement Bid, Operating Reserves Bid, or its Minimum Generation Bid and Incremental Energy Bid for Energy that was not scheduled Day-Ahead, including Energy provided by the capacity scheduled for

Regulation Service, through real-time LBMP revenue, real-time Imputed LBMP Revenue and net real-time Ancillary Services revenues for Voltage Support Service, Regulation Service, and Operating Reserves in that interval. Such determination shall be made separately for each Supplemental Event Interval, and such determination shall be made separately for each Generator. On the basis of such determination, the ISO shall pay a Bid Production Cost guarantee payment to the Supplier for a Supplemental Event Interval pursuant to Section 18.5 of Attachment C of this ISO Services Tariff.

4.6.6.5 Real-Time BPCG for External Transactions

External Transactions are not eligible to receive Bid Production Cost guarantee payments in the Real-Time Market pursuant to Section 18.6 of Attachment C of this ISO Services Tariff.

4.6.6.6 BPCG for Long Start-Up Time Generators Whose Starts Are Aborted by the ISO Prior to their Dispatch

The ISO shall pay a Supplier eligible under Section 18.7.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) whose start is aborted by the ISO prior to its dispatch for that portion of its Start-Up Bid that corresponds to that portion of its start-up sequence that it completed prior to being aborted. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each long start-up time Generator. On the basis of such determination, the ISO shall pay a Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.7 of Attachment C of this ISO Services Tariff.

~~**4.6.6.7 BPCG for Demand Reduction in the Day-Ahead Market**~~

~~The ISO shall determine if a Demand Reduction Provider eligible under Section 18.8.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for Demand Reduction in the Day-Ahead Market will not recover its Day-Ahead Curtailment Initiation Cost and its Day-Ahead Demand Reduction Bid through Day-Ahead LBMP revenues. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall pay a Bid Production Cost guarantee payment to the Demand Reduction Provider pursuant to Section 18.8 of Attachment C of this ISO Services Tariff.~~

4.6.6.~~8~~7 BPCG for Special Case Resources

The ISO shall determine if a Supplier eligible under Section 18.9.1 of Attachment C of this ISO Services Tariff for a Bid Production Cost guarantee payment for a Special Case Resource will not recover its Minimum Payment Nomination through real-time LBMP revenues. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each Special Case Resource. On the basis of such determination, the ISO shall make a Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.9 of Attachment C of this ISO Services Tariff.

~~**4.6.6.9 Day-Ahead BPCG for Demand Side Resources Scheduled to Provide Synchronized Operating Reserves and/ or Regulation Service**~~

~~The ISO shall determine if a Supplier that bids Demand Side Resources committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service in the Day-Ahead Market will not recover its Day-Ahead synchronized Operating Reserves Bid to provide the amount of synchronized Operating Reserves that it was scheduled to provide, and/or its Day-~~

~~Ahead Regulation Capacity Bid to provide the amount of Regulation Capacity that it was scheduled to provide. Such supplier shall be eligible under Section 18.10.1 of Attachment C to this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall make a Bid Production Cost guarantee payment to the Customer pursuant to Section 18.10 of Attachment C of this ISO Services Tariff.~~

~~4.6.6.10 Real-Time BPCG for Demand Side Resources Scheduled to Provide Synchronized Operating Reserves and/ or Regulation Service~~

~~The ISO shall determine if a Supplier that bids Demand Side Resources committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service will not recover its real-time synchronized Operating Reserves Bid to provide the amount of synchronized Operating Reserves that it was scheduled to provide, and/or its real-time Regulation Capacity and Regulation Bids to provide Regulation Service. Such Supplier shall be eligible under Section 18.11.1 of Attachment C to this ISO Services Tariff for a real-time Bid Production Cost guarantee payment. Such determination shall be made for an entire Dispatch Day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall make a Bid Production Cost guarantee payment to the Customer pursuant to Section 18.11 of Attachment C of this ISO Services Tariff.~~

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 or be part of an Aggregation that is qualified as an Installed Capacity Supplier, Generators, ~~and~~ controllable transmission projects electrically located in the NYCA, ~~and~~ transmission projects with associated incremental transfer capability, and Distributed Energy Resources that have the ability to inject Energy must have obtained Capacity Resource Interconnection Service ("CRIS") pursuant to the applicable provisions of Attachment S to the ISO OATT and have entered service: controllable transmission projects must also have obtained Unforced Capacity Deliverability Rights and transmission projects with associated incremental transfer capability must also have obtained External-to-ROS Deliverability Rights. Even if a Resources~~Generator~~ has otherwise satisfied the requirements to participate in the ISO's Installed Capacity market, a Resources~~Generator~~ in Inactive Reserves, an ICAP Ineligible Forced Outage, a Mothball Outage, or that is Retired is ineligible to participate in the ISO's Installed Capacity market. A Resources~~Generator~~ that elects to participate in the ICAP Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not consist solely of Station Power) at a single PTID ~~can~~may only participate in the Installed Capacity market as a Behind-the-Meter Net Generation Resource. In order to participate as part of an Aggregation or as an Energy Storage Resource, such a resource may not participate with the Behind-The-Meter Net Generation configuration.

In addition, to qualify as an Installed Capacity Supplier in the NYCA, Energy Limited Resources, Generators, Installed Capacity Marketers, Intermittent Power Resources, Behind-the-Meter Net Generation Resources, Limited Control Run-of-River Hydro Resources and System

Resources rated 1 MW or greater, other than External System Resources and Control Area System Resources which have agreed to certain Curtailment conditions as set forth in the third to last paragraph of Section 5.12.1 below, Responsible Interface Parties, existing municipally-owned generation, Energy Limited Resources, and Intermittent Power Resources, to the extent those entities are subject to the requirements of Section 5.12.11 of this Tariff, Aggregations with a capacity rating of 0.1 MW or greater, and Energy Storage Resources with a nameplate capacity rating that allows a minimum injection to the NYS Transmission System or distribution system of 0.1 MW or greater shall:

5.12.1.1 provide information reasonably requested by the ISO including the name and location of Resources~~Generators~~, and System Resources;

5.12.1.2 in accordance with the ISO Procedures, perform DMNC or DMGC tests and submit the results to the ISO, or provide to the ISO appropriate historical production data;

5.12.1.3 abide by the ISO Generator maintenance coordination procedures;

5.12.1.4 provide the expected return date from any outages (including partial outages) to the ISO;

5.12.1.5 in accordance with the ISO Procedures,

5.12.1.5.1 provide documentation demonstrating that it will not use the same Unforced Capacity for more than one (1) buyer at the same time, and

5.12.1.5.2 in the event that the Installed Capacity Supplier supplies more Unforced Capacity than it is qualified to supply in any specific month (*i.e.*, is short on Capacity), documentation that it has procured sufficient Unforced Capacity to cover this shortfall.

5.12.1.6 except for Installed Capacity Marketers and Intermittent Power Resources that depend upon wind or solar as their fuel or Aggregations that are comprised of Intermittent Power Resources that depend on the same type of fuel, with that fuel being wind or solar, Bid into the Day-Ahead Market, unless the Energy Limited Resource, Generator, Aggregation, 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. Resources~~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 Resources~~Generator~~ to exceed its upper operating limit are described in the ISO Procedures;

5.12.1.7 provide Operating Data in accordance with Section 5.12.5 of this Tariff;

5.12.1.8 provide notice to the ISO of any proposed transfers of deliverability rights to be carried out pursuant to Sections 25.9.4 - 25.9.6 of Attachment S to the ISO OATT, on the Class Year Start Date if a request to transfer CRIS at a different location, and upon the submission of the request if it is a request to transfer CRIS at the same location;

5.12.1.9 comply with the ISO Procedures;

5.12.1.10 when the ISO issues a Supplemental Resource Evaluation request (an SRE), NYCA Resources must Bid into the in-day market unless (and only to the extent) 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.

If an External Installed Capacity Supplier is a Generator, or if an External Generator is associated with an Unforced Capacity sale using UDRs or EDRs, then except to the extent such a Generator is unable to Bid in response to the SRE request due to an outage as defined in the ISO Procedures, due to physical operating limitations affecting the Generator, or due to other operational issues that are outside the Installed Capacity Supplier's control, as determined by the ISO, it must take all of the following actions for each hour of an SRE request (a) Bid an Import to the NYCA in a MW quantity equal to the lesser of (i) the ICAP equivalent of the UCAP sold, or (ii) the maximum MW the Generator is able to produce, at the approved Proxy Generator Bus, at the applicable minimum Bid Price, and (b) ensure that the External Generator is operating and is available to provide all of the MW that were Bid to be imported into the NYCA, up to the ICAP equivalent of the UCAP sold, for the entire duration of the SRE request, and (c) obtain all reservations and transmission service necessary to deliver all of the MW that were Bid to be imported into the NYCA or to a Locality from the Generator, up to the ICAP equivalent of the UCAP sold from the External Generator, at the approved Proxy Generator Bus.

If the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, is not able to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Generator or EDR to the NYCA, or if a UDR to the

Locality, for every hour of an SRE request then, except to the extent already addressed by a declared outage, the Generator shall provide to the ISO an explanation of the reasons for its failure or inability to perform, including evidence demonstrating any physical operating limitations or other operational issues that prevented the Generator from Importing the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Generator to the NYCA. To the extent the ISO determines that the information and supporting evidence provided demonstrates that the failure or inability to deliver occurred for reasons outside the control of the External Installed Capacity Supplier or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, then the deficiency charge set forth in Section 5.12.12.2 below that applies solely to violations of this Section 5.12.1.10, shall not be assessed.

If an External Installed Capacity Supplier is a Control Area System Resource then, except to the extent it is unable to Bid in response to the SRE request due to an outage as defined in the ISO Procedures or due to operational issues that are outside the Installed Capacity Supplier's control, it must take all of the following actions for each hour of an SRE request (x) Bid an Import in a MW quantity equal to the ICAP equivalent of the UCAP sold, at the approved Proxy Generator Bus, at the applicable minimum Bid Price, and (y) obtain all reservations and transmission service necessary to deliver the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA at the approved Proxy Generator Bus.

If the External Installed Capacity Supplier that is a Control Area System Resource is not able to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA for every hour of an SRE request then, except to the extent already addressed by a declared outage, the External Installed Capacity Supplier shall provide to the ISO an explanation of the reasons for its failure or inability to perform, including evidence demonstrating any operational issues that prevented the External ICAP Supplier from Importing the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA. To the extent the ISO determines that the information and supporting evidence provided demonstrates that the failure or inability to deliver occurred for reasons outside the External Installed Capacity Supplier's control, then the deficiency charge set forth in Section 5.12.12.2 below that applies solely to violations of this Section 5.12.1.10, shall not be assessed. A Control Area System Resource must demonstrate that transmission outage(s) prevented delivery of all available Resources in order for the ISO to determine that the Control Area System Resource's failure to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold occurred for a reason that was outside the External Installed Capacity Supplier's control.

When an External Installed Capacity Supplier that is responding to an ISO SRE request Bids its Import at a Non-Competitive Proxy Generator Bus, its obligation to Bid an Import at the applicable minimum Bid Price includes the obligation to ensure that neither the External Installed Capacity Supplier nor any of its Affiliates are offering other Imports at an equivalent or greater economic priority at the Non-Competitive Proxy Generator Bus.

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 or Agreegation is unable to meet its commitment because of an outage as defined in the ISO Procedures), except for the Resources~~Generators~~ described in Subsections 5.12.1.11.1, 5.12.1.11.2 and 5.12.1.11.3 below;

5.12.1.11.1 Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchasers do not control the operation of the supply source but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999, who have not provided telemetering to their local TO and historically have not been eligible to participate in the NYPP market, which will continue to be treated as TO Load modifiers under the ISO-administered markets;

5.12.1.11.2 Existing topping turbine Generators and extraction turbine Generators producing Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators used in replacing or repowering steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 523 MW of such units; and

5.12.1.11.3 Resources~~Units~~ that have demonstrated to the ISO that they are subject to environmental, contractual or other legal or physical requirements that would otherwise preclude them from providing 10-Minute NSR;~~.~~

5.12.1.12 A Resource that was determined by the ISO to be qualified as a Behind-the-Meter Net Generation Resource and for which Net Unforced Capacity was calculated by the ISO for a Capability Year can annually, by written notice received by the NYISO prior to August 1, elect not to participate in the ISO Administered Markets as a Behind-the-Meter Net Generation Resource. Such notice shall be in accordance with ISO Procedures. A Resource that makes such an election cannot participate as a Behind-the-Meter Net Generation Resource for the entire Capability Year for which it made the election, but can, however, prior to August 1 of any subsequent Capability Year, provide all required information in order to seek to re-qualify as a Behind-the-Meter Net Generation Resource.

5.12.1.13 For Energy Storage Resources, or Aggregations comprised entirely of Energy Storage Resources, elect the ISO-Managed Energy Level bidding parameter for each Day-Ahead Market Bid.

5.12.1.14 Energy Limited Resources, Energy Storage Resources, Aggregations comprised entirely of Energy Storage Resources, DER Aggregations, and Aggregations that are Energy Limited Resources must elect an Energy Duration Limitation that corresponds to a Duration Adjustment Factor, as described in Section 5.12.14 below, and validate the Energy Duration Limitation pursuant to Section 5.12.1.2 above. An Installed Capacity Supplier may elect any Energy Duration Limitation that it can demonstrate pursuant to Section 5.12.1.2.

The ISO shall inform each potential Installed Capacity Supplier that the ISO must receive and approve DMNC or DMGC data, as applicable of its approved DMNC or DMGC ratings for the Summer Capability Period and the Winter Capability Period in accordance with the ISO Procedures.

Requirements to qualify as Installed Capacity Suppliers for External System Resources and Control Area System Resources located in External Control Areas that have agreed not to Curtail the Energy associated with such Installed Capacity or to afford it the same Curtailment priority that it affords its own Control Area Load shall be established in the ISO Procedures.

External Installed Capacity not associated with UDRs, including capacity associated with External CRIS Rights, EDRs, Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual, the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT, Import Rights, and External System Resources, is only qualified to satisfy a NYCA Minimum Unforced Capacity Requirement and is not eligible to satisfy a Locational Minimum Installed Capacity Requirement.

Not later than 30 days prior to each ICAP Spot Market Auction, each Market Participant that may make offers to sell Unforced Capacity in such auction shall submit information to the ISO, in accordance with ISO Procedures and in the format specified by the ISO that identifies each Affiliated Entity, as that term is defined in Section 23.2.1 of Attachment H of the Services Tariff, of the Market Party or with which the Market Party is an Affiliated Entity. The names of entities that are Affiliated Entities shall not be treated as Confidential Information, but such treatment may be requested for the existence of an Affiliated Entity relationship. The information submitted to the ISO shall identify the nature of the Affiliated Entity relationship by the applicable category specified in the definition of “Affiliated Entity” in Section 23.2.1 of Attachment H of the Services Tariff.

5.12.2 Additional Provisions Applicable to External Installed Capacity Suppliers

Terms in this Section 5.12.2 not defined in the Services Tariff have the meaning set forth in the OATT.

5.12.2.1 Provisions Addressing the Applicable External Control Area

External Generators, External System Resources, and Control Area System Resources qualify as Installed Capacity Suppliers if they demonstrate to the satisfaction of the NYISO that the Installed Capacity Equivalent of their Unforced Capacity is deliverable to the NYCA; 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; in the case of an EDR, to the NYCA interface over which it creates increased transfer capability; and 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, EDRs 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, EDRs, 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, EDRs, or External CRIS Rights will be evaluated annually as a part of the process that sets import rights for the upcoming Capability Year, to determine the amount of External Installed Capacity that can be imported to the New York Control Area across any individual External Interface and across all of those External Interfaces, taken together. The External Installed Capacity deliverability test will be performed using the ISO's forecast, for the upcoming Capability Year, of New York Control Area CRIS resources, transmission facilities, and load. Under this process (i) Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual, and (ii) the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT, will be considered deliverable within the Rest of State. Additionally, 1090 MW of imports made over the Quebec (via Chateauguay) Interface will be considered to be deliverable until the end of the 2010 Summer Capability Period.

The import limit set for External Installed Capacity not associated with UDRs, EDRs or External CRIS Rights will be set no higher than the amount of imports deliverable into Rest of State that (i) would not increase the LOLE as determined in the upcoming Capability Year IRM consistent with Section 2.7 of the NYISO Installed Capacity Manual, "Limitations on Unforced Capacity Flow in External Control Areas," (ii) are deliverable within the Rest of State Capacity Region when evaluated with the New York Control Area CRIS resources (including EDRs and

UDRs) and External CRIS Rights forecast for the upcoming Capability Year, and (iii) would not degrade the transfer capability of any Other Interface by more than the threshold identified in Section 25.7.9 of Attachment S to the ISO OATT. Import limits set for External Installed Capacity will reflect the modeling of awarded External CRIS rights, but the awarded External CRIS rights will not be adjusted as part of import limit-setting process. Procedures for qualifying selling, and delivery of External Installed Capacity are detailed in the Installed Capacity Manual.

Until the grandfathered import rights over the Quebec (via Chateauguay) Interface expire at the end of the 2010 Summer Capability Period, the 1090 MW of grandfathered import rights will be made available on a first-come, first-served basis pursuant to ISO Procedures. Any of the grandfathered import rights over the Quebec (via Chateauguay) Interface not utilized for a Capability Period will be made available to other external resources for that Capability Period, pursuant to ISO Procedures, to the extent the unutilized amount is determined to be deliverable.

Additionally, any of the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation not utilized by New York State Electric & Gas Corporation for a Capability Period will be made available to other external resources for that Capability Period, pursuant to ISO procedures, to the extent the unutilized amount is determined to be deliverable within the Rest of State Capacity Region.

LSEs with External Installed Capacity as of the effective date of this Tariff will be entitled to designate External Installed Capacity at the same NYCA Interface with another Control Area, in the same amounts in effect on the effective date of this Tariff. To the extent such External Installed Capacity corresponds to Existing Transmission Capacity for Native Load as reflected in Table 3 of Attachment L to the ISO OATT, these External Installed Capacity rights will continue without term and shall be allocated to the LSE's retail access customers in accordance with the LSE's retail access program on file with the PSC and subject to any necessary filings with the Commission. External Installed Capacity rights existing as of September 17, 1999 that do not correspond to Table 3 of Attachment L to the ISO OATT shall survive for the term of the relevant External Installed Capacity contract or until the relevant External Generator is retired.

5.12.2.3 One-Time Conversion of Grandfathered Quebec (via Chateauguay) Interface Rights.

An entity can request to convert a specified number of MW, up to 1090 MW over the Quebec External Interface (via Chateauguay), into External CRIS Rights by making either a Contract Commitment or Non-Contract Commitment that satisfies the requirements of Section 25.7.11.1 of Attachment S to the ISO OATT. The converted number of MW will not be subject to further evaluation for deliverability within a Class Year Deliverability Study under Attachment S to the ISO OATT, as long as the External CRIS Rights are in effect.

5.12.2.3.1 The External CRIS Rights awarded under this conversion process will first become effective for the 2010-2011 Winter Capability Period.

5.12.2.3.2 Requests to convert these grandfathered rights must be received by the NYISO on or before 5:00 pm Eastern Time on February 1, 2010, with the following information: (a) a statement that the entity is electing to convert by satisfying the requirements of a Contract Commitment or a Non-Contract Commitment in accordance with Section 25.7.11.1 of Attachment S to the ISO OATT; (b) the length of the commitment in years; (c) for the Summer Capability Period, the requested number of MW; (d) for the Winter Capability Period, the Specified Winter Months, if any, and the requested number of MW; and (e) a minimum number of MW the entity will accept if granted ("Specified Minimum") for the Summer Capability Period and for all Specified Winter Months, if any.

5.12.2.3.3 An entity cannot submit one or more requests to convert in the aggregate more than 1090 MW in any single month.

5.12.2.3.4 If requests to convert that satisfy all other requirements stated herein are equal to or less than the 1090 MW limit, all requesting entities will be awarded the requested number of MW of External CRIS Rights. If conversion requests exceed the 1090 MW limit, the NYISO will prorate the allocation based on the weighted average of the requested MW times the length of the contract/commitment (*i.e.*, number of Summer Capability Periods) in accordance with the following formula:

$$Rights\ allocated\ to\ entity\ i = 1090 * (MW_i * contract/commitment\ length_i) / \sum_j \left(MW_j * contract/commitment\ length_j\right)$$

j = l,…# entities requesting import rights

In the formula, contract/commitment length means the lesser of the requested contract/commitment length and twenty (20) years. The NYISO will perform separate calculations for the Summer and Winter Capability Periods. The NYISO will determine whether the prorated allocated number of MW for any requesting entity is less than the entity's Specified Minimum. If any allocation is less, the NYISO will remove such request(s) and recalculate the prorated allocations among the remaining requesting entities using the above formula. This process will continue until the prorated allocation meets or exceeds the specified minimum for all remaining requests.

5.12.2.3.5 Any portion of the previously grandfathered 1090 MW not converted through this process will no longer be grandfathered from deliverability. Previously grandfathered rights converted to External CRIS Rights but then terminated will no longer be grandfathered from deliverability.

5.12.2.4 Offer Cap Applicable to Certain External CRIS Rights

Notwithstanding any other capacity mitigation measures or obligations that may apply, the offers of External Installed Capacity submitted pursuant to a Non-Contract Commitment, as described in Section 25.7.11.1.2 of Attachment S of the ISO OATT, will be subject to an offer cap in each month of the Summer Capability Period and for all Specified Winter Months. This offer cap will be determined as the higher of:

5.12.2.4.1 1.1 times the price corresponding to all available Unforced Capacity determined from the NYCA ICAP Demand Curve for that Period; and

5.12.2.4.2 The most recent auction clearing price (a) in the External market supplying the External Installed Capacity, if any, and if none, then the most recent auction clearing price in an External market to which the capacity may be wheeled, less (b) any transmission reservation costs in the External market associated with providing the Installed Capacity, in accordance with ISO Procedures.

5.12.3 Installed Capacity Supplier Outage Scheduling Requirements

All Installed Capacity Suppliers, except for Control Area System Resources and Responsible Interface Parties, that intend to supply Unforced Capacity to the NYCA shall submit a confidential notification to the ISO of their proposed outage schedules in accordance with the ISO Procedures. Transmission Owners will be notified of these and subsequently revised outage schedules. Based upon a reliability assessment, if Operating Reserve deficiencies are projected to occur in certain weeks for the upcoming calendar year, the ISO will request voluntary rescheduling of outages. In the case of Installed Capacity Suppliers actually supplying Unforced Capacity to the NYCA, if voluntary rescheduling is ineffective, the ISO will invoke forced rescheduling of their outages to ensure that projected Operating Reserves over the upcoming year are adequate.

An Installed Capacity Supplier 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.

An Installed Capacity Supplier that intends to supply Unforced Capacity in a given month that did not qualify as an Installed Capacity Supplier prior to the beginning of the Capability Period must notify the ISO in accordance with the ISO Procedures so that it may be subject to forced rescheduling of its proposed outages in order to qualify as an Installed Capacity Supplier. A Resource 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 or EDRs 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 (if applicable.)

(c) On and after the execution of an RMR Agreement, and for the duration of its term, an RMR Generator shall not enter into any new agreement or extend any other agreement that impairs or otherwise diminishes its ability to comply with its obligation under an RMR Agreement, or that limits its ability to provide Energy, Capacity, or Ancillary Services directly to the ISO Administered Markets. An Interim Service Provider shall not enter into any new agreement or extend any other agreement that limits its ability to provide Energy, Capacity, or Ancillary Services directly to the ISO Administered Markets or otherwise meet its obligations as an Interim Service Provider.

5.12.5 Operating Data Reporting Requirements

To qualify as Installed Capacity Suppliers in the NYCA, Resources shall submit to the ISO Operating Data in accordance with this Section 5.12.5 and the ISO Procedures. Resources that do not submit Operating Data in accordance with the following subsections and the ISO Procedures may be subject to the sanctions provided in Section 5.12.12.1 of this Tariff.

Resources that were not in operation on January 1, 2000 shall submit Operating Data to the ISO no later than one month after such Resources commence commercial operation, and in accordance with the ISO Procedures and the following subsections as applicable.

5.12.5.1 Generators, System Resources, Energy Limited Resources, Energy storage Resources Responsible Interface Parties, Intermittent Power Resources, Limited Control Run-of-River Hydro Resources, ~~and~~ Municipally Owned Generation and Distributed Energy Resources

To qualify as Installed Capacity Suppliers in the NYCA, Generators, External Generators, System Resources, External System Resources, Energy Limited Resources, Responsible Interface Parties, Intermittent Power Resources, Limited Control Run-of-River Hydro Resources, Energy Storage Resources, and municipally owned generation and Distributed Energy Resources or the purchasers of Unforced Capacity associated with those Resources shall submit GADS Data, data equivalent to GADS Data, and/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.

5.12.5.4 Transmission Projects Granted External-to ROS Deliverability Rights

An owner of a transmission project that receives EDRs must, among other obligations, submit outage data or other operational information when determined applicable by the ISO and in accordance with ISO Procedures.

5.12.6 Capacity Calculations, Operating Data Default, Value and Collection

5.12.6.1 ICAP Calculation for Behind-the-Meter Net Generation Resources

The ISO shall calculate the amount of Net-ICAP for each Behind-the-Meter Net Generation Resource as the Adjusted DMGC of the Generator of the Behind-the-Meter Net Generation Resource minus the Resource's Adjusted Host Load in accordance with this Tariff and ISO Procedures.

5.12.6.1.1 Adjusted DMGC

The ISO's calculation of the Adjusted DMGC of a Behind-the-Meter Net Generation Resource shall be the least of: (i) its DMGC for the Capability Period; (ii) its Adjusted Host Load plus its applicable Injection Limit; and (iii) its Adjusted Host Load plus the number of MW of CRIS it has obtained, as determined in accordance with OATT Section 25 (OATT Attachment S) and ISO Procedures.

If the Station Power of a Behind-the-Meter Net Generation Resource is separately metered from all other Load of the Resource, such that the Station Power Load can be independently measured and verified, the Generator of a Behind-the-Meter Net Generation

Resource may elect to perform a DMNC Test instead of a DMGC Test pursuant to ISO Procedures. Such election must be made in writing to the ISO prior to the start of the DMNC Test Period.

If a Behind-the-Meter Net Generation Resource elects to take a DMNC Test, the Station Power measured during such DMNC Test shall not be included in the Resource's Host Load. A Behind-the-Meter Net Generation Resource's DMNC value for the Capability Period shall be used in lieu of a DMGC value in the calculation of the Resource's Adjusted DMGC for the purposes of Sections 5.12.6.1 and 5.12.6.2 of this Services Tariff.

5.12.6.1.2 Adjusted Host Load

A Behind-the-Meter Net Generation Resource's Adjusted Host Load shall be equal to the product of the Average Coincident Host Load multiplied by one plus the Installed Reserve Margin.

The Adjusted Host Load shall be calculated by the ISO on an annual basis prior to the start of the Summer Capability Period and in accordance with ISO Procedures, based upon the Behind-the-Meter Net Generation Resource's Average Coincident Host Load for the prior Summer Capability Period and the Winter Capability Period before that.

5.12.6.1.2.1 Average Coincident Host Load

The ISO must receive the Behind-the-Meter Net Generation Resource's applicable metered Load data required to calculate an Average Coincident Host Load in accordance with ISO Procedures. The ISO shall compute the Average Coincident Host Load for each Capability Year (i) using the metered Host Load data for the applicable NYCA peak Load hours, except as provided below in this Section, and (ii) adjusted for weather normalization and Load growth as determined by the ISO in relation to developing the NYCA Minimum Installed Capacity Requirement in accordance with ISO Procedures.

For each Capability Year, the NYISO shall use the average of the highest twenty (20) one-hour peak Loads of the Host Load of the Behind-the-Meter Net Generation Resource that occur during the top forty (40) NYCA peak Load hours of the prior Summer Capability Period and the Winter Capability Period before that to calculate the Average Coincident Host Load.

If a facility meets the criteria to be, and has not previously been, a Behind-the-Meter Net Generation Resource, but does not have all of the appropriate meter data, its Average Coincident Host Load shall be a value forecasted by the Behind-the-Meter Net Generation Resource. The Behind-the-Meter Net Generation Resource's forecast shall be based on actual meter data, or if not available, billing data or other business data of the Host Load. An estimated Average Coincident Host Load can only be applicable to a Behind-the-Meter Net Generation Resource until actual data becomes available, but in any event no longer than three (3) consecutive Capability Years beginning with the Capability Year it is first an Installed Capacity Supplier.

5.12.6.1.2.2 Determination of Adjusted Host Load

After the ISO has calculated a Behind-the-Meter Net Generation Resource's Average Coincident Host Load, it shall then apply the NYCA Installed Reserve Margin. The Behind-the-Meter Net Generation Resource's Adjusted Host Load will be established by multiplying the Resource's Average Coincident Host Load for the Capability Year by the quantity of one plus the NYCA Installed Reserve Margin.

5.12.6.2 UCAP Calculations

The ISO shall calculate for each Resource the amount of Unforced Capacity that each Installed Capacity Supplier is qualified to supply in the NYCA in accordance with formulae provided in the ISO Procedures. A Resource's Unforced Capacity will be the applicable Adjusted Installed Capacity multiplied by the quantity of 1 minus the Resource's derating factor.

The amount of Unforced Capacity that each Generator, except for the Generator of a Behind-the-Meter Net Generation Resource, System Resource, Energy Limited Resource, Special Case Resource, and municipally-owned generation is authorized to supply in the NYCA shall be based on the ISO's calculations of individual Equivalent Demand Forced Outage Rates. The amount of Unforced Capacity that each Energy Storage Resource, Aggregation that is comprised entirely of Energy Storage Resources, and DER Aggregation is authorized to supply in the NYCA shall be based on the individual availability of the Energy Storage Resource or the availability of the Aggregation in the Real-Time Market and calculated by the ISO in accordance with ISO Procedures. Except as provided in Section 5.12.6.2.1 of this Services Tariff, this calculation shall not include hours in any month that the Energy Storage Resource or Aggregation was in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market. The amount of Unforced Capacity that each 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 or an Aggregation that is entirely comprised of Intermittent Power Resources that depend on the same type of fuel 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 or an Aggregation that is entirely comprised of Intermittent Power Resources that depend on the same type of fuel can reliably provide during system peak Load hours in accordance with ISO Procedures. Except as provided in Section 5.12.6.2.1 of this Services Tariff, this calculation shall not include hours in any month that the Intermittent Power Resource or an Aggregation that is entirely comprised of Intermittent Power Resources that depend on the same type of fuel was in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market. The amount of Unforced Capacity that each Limited Control Run-of-River Hydro Resource is authorized to provide in the NYCA shall be determined separately for Summer and Winter Capability Periods as the rolling average of the hourly net Energy provided by each such Resource during the 20 highest NYCA integrated real-time load hours in each of the five previous Summer or Winter Capability Periods, as appropriate, stated in megawatts. Except as provided in Section 5.12.6.2.1 of this Services Tariff, for a Limited Control Run-of-River Hydro Resource in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market during one of the 20 highest NYCA integrated real-time load hours in any one of the five previous Summer or Winter Capability Periods, the ISO shall replace that Winter or Summer Capability Period, as appropriate, with the next most recent Winter or Summer Capability Period such that the rolling average of the hourly net Energy provided by each such Resource shall be calculated from the 20 highest NYCA integrated real-time load hours in the five most recent prior Summer or Winter Capability Periods in which the Resource was not in an outage state that precluded its eligibility to participate in the Installed Capacity market on one of the 20 highest NYCA integrated real-time load hours in that Capability Period.

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for each Generator, System Resource, Special Case Resource, Energy Limited Resource, and municipally owned generation and update them periodically using a twelve-month calculation in accordance with formulae provided in the ISO Procedures; provided**,** however, except as provided in Section 5.12.6.2.1 of this Services Tariff, for a Generator in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market at any time during any month from which GADS or other operating data would otherwise be used to calculate an individual Equivalent Demand Forced Outage Rate, the ISO shall replace such month's GADS or other operating data with GADS or other operating data from the most recent prior month in which the Generator was not in an outage state that precluded its eligibility to participate in the Installed Capacity market.

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for Energy Storage Resources and individual Distributed Energy Resources and update them seasonally as described in 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.

The amount of Unforced Capacity that each Behind-the-Meter Net Generation Resource is authorized to supply in the NYCA shall be its Net-UCAP. Net-UCAP is the lesser of (i) the ISO's calculation of the Generator of the Behind-the-Meter Net Generation Resource Adjusted DMGC multiplied by one minus its Equivalent Demand Forced Outage Rate, and then decreased by its Adjusted Host Load translated into Unforced Capacity terms consistent with Section 5.11.1 of this Tariff, and (ii) the Resource's Net-ICAP.

5.12.6.2.1 Exceptions

A Resource returning to the Energy market after taking an outage that precluded its participation in the Installed Capacity market and which returns with modifications to its operating characteristics determined by the ISO to be material and which, therefore, requires the submission of a new Interconnection Request will receive, as the initial derating factor for calculation of the Resource's Unforced Capacity upon its return to service, the derating factor it would have received as a newly connecting unit in lieu of a derating factor developed from unit-specific data. A Resource returning to the Energy market after taking an outage that precluded its participation in the Installed Capacity market and which, upon its return, uses as its primary fuel a fuel not previously used at the facility for any purpose other than for ignition purposes will receive, as the initial derating factor for calculation of the Resource's Unforced Capacity upon its return to service, the default derating factor in lieu of a derating factor developed from unit-specific data even if the modifications to allow use of a new primary fuel are not material and do not require the submission of a new Interconnection Request.

This Section 5.12.6.2.1 shall apply to a Resource returning to the Energy market after taking an outage that started on or after May 1, 2015 and that precluded its participation in the Installed Capacity market.

5.12.6.3 Default Unforced Capacity

In its calculation of Unforced Capacity, the ISO shall deem a Resource to be completely forced out for each month for which the Resource has not submitted its Operating Data in accordance with Section 5.12.5 of this Tariff and the ISO Procedures. A Resource that has been deemed completely forced out for a particular month may submit new Operating Data, for that month, to the ISO at any time. The ISO will use such new Operating Data when calculating, in a timely manner in accordance with the ISO Procedures, an Unforced Capacity value for the Resource.

Upon a showing of extraordinary circumstances, the ISO retains the discretion to accept at any time Operating Data which have not been submitted in a timely manner, or which do not fully conform with the ISO Procedures.

5.12.6.4 Exception for Certain Equipment Failures

When a Generator, Special Case Resource, Energy Limited Resource, or System Resource is forced into an outage by an equipment failure that involves equipment located on the high voltage side of the electric network beyond the step-up transformer, and including such step-up transformer, the outage will not be counted for purposes of calculating that Resource's Equivalent Demand Forced Outage Rate.

5.12.6.5 Unforced Capacity, Outage Data and Operational Information Associated with External-to-ROS Deliverability Rights

The ISO shall calculate the availability of the External interface associated with each project granted EDRs, in accordance with ISO Procedures. The availability factor (percentage) of the interface will be used to reduce the amount of EDRs for which Unforced Capacity may be offered. This calculation is distinct from and in addition to the calculation the ISO performs for each Installed Capacity Resource qualified for use with EDRs.

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. Installed Capacity Suppliers with Energy Duration Limitations corresponding to a Duration Adjustment Factor, as described in Section 5.12.14 below, must on a daily basis during the Peak Load Window and for the number of consecutive hours that correspond to its Energy Duration Limitation, or for the entirety of the Peak Load Window for an Energy Storage Resource or an Aggregation comprised entirely of Energy Storage Resources: (i) schedule a Bilateral Transaction; (ii) Bid Energy in 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 ISO may adjust the Peak Load Window that Installed Capacity Suppliers with Energy Duration Limitations will be responsible for scheduling, bidding, or notifying for, with scheduling or bidding in hours outside the Peak Load Window in Section 5.12.14. An RMR Generator can only schedule a Bilateral Transaction to the extent expressly authorized in its RMR Agreement. The total amount of Energy that an Installed Capacity Supplier schedules, bids, or declares to be unavailable on a given day must equal or exceed the Installed Capacity Equivalent of the Unforced Capacity it supplies.

5.12.8 Unforced Capacity Sales

Each Installed Capacity Supplier will, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, be authorized to supply an amount of Unforced Capacity during each Obligation Procurement Period, based on separate seasonal Unforced Capacity calculations performed by the ISO for the Summer and Winter Capability Periods. Unforced Capacity may be sold in six-month strips, or in monthly, or multi-monthly segments.

External Unforced Capacity (except External Installed Capacity associated with UDRs) may only be offered into Capability Period Auctions or Monthly Auctions for the Rest of State, and ICAP Spot Market Auctions for the NYCA, and may not be offered into a Locality for an ICAP Auction. Bilateral Transactions which certify External Unforced Capacity using Import Rights, EDRs, or External CRIS Rights may not be used to satisfy a Locational Minimum Unforced Capacity Requirement.

UCAP from an RMR Generator may only be offered into the ICAP Spot Market Auction, except and only to the extent that the RMR Agreement expressly permits the RMR Generator's UCAP to be certified in a Bilateral Transaction.

If an Energy Limited Resource's, Generator's, System Resource's, ~~or~~ Control Area System Resource's, or Aggregation's DMNC rating, or the DMGC rating of a Generator of a Behind-the-Meter Net Generation Resource, if applicable, is determined to have increased during an Obligation Procurement Period, pursuant to testing procedures described in the ISO Procedures, the amount of Unforced Capacity that it shall be authorized to supply in that or future Obligation Procurement Periods shall also be increased on a prospective basis in accordance with the schedule set forth in the ISO Procedures provided that it first has satisfied the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT.

New Resources~~Generators~~ and Resources~~Generators~~ that have increased their Capacity since the previous Summer Capability Period due to changes in their generating equipment and/or Demand Reduction capabilities may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Summer Capability Period based upon a DMNC test, or the DMGC test of a Resource~~Generator~~ of a Behind-the-Meter Net Generation Resource, that is performed and reported to the ISO after March 1 and prior to the beginning of the Summer Capability Period DMNC Test Period. The Resource~~Generator~~ will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Summer DMNC Test Period. Any shortfall between the amount of Unforced Capacity supplied by the Resource~~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 Resource'S~~Generator's~~ previous Summer Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Resource~~Generator~~ supplied for the Summer Capability Period.

New Resources~~Generators~~ and Resources~~Generators~~ that have increased their Capacity since the previous Winter Capability Period due to changes in their generating equipment and/or Demand Reduction capabilities may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachment X, Attachment Z and Attachment S to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Winter Capability Period based upon a DMNC test, or the DMGC test of a Resource~~Generator~~ of a Behind-the-Meter Net Generation Resource, that is performed and reported to the ISO after September 1 and prior to the beginning of the Winter Capability Period DMNC Test Period. The Resource~~Generator~~ will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Winter Capability Period DMNC Test Period. Any shortfall between the amount of Unforced Capacity certified by the Resource~~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 Resource's~~Generator's~~ previous Winter Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Resource~~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 0.1 MW, or rounded down to the nearest whole MW for an External Installed Capacity Suppler, is subject to sanctions pursuant to Section 5.12.12.2 of this Tariff. If an entity other than the owner of an Energy Limited Resource, Generator, System Resource, Behind-the-Meter Net Generation Resource, ~~or~~ Control Area System Resource, or Aggregation that is providing Unforced Capacity is responsible for fulfilling bidding, scheduling, and notification requirements, the owner and that entity must designate to the ISO which of them will be responsible for complying with the scheduling, bidding, and notification requirements. The designated bidding and scheduling entity shall be subject to sanctions pursuant to Section 5.12.12.2 of this ISO Services Tariff.

5.12.9 Sales of Unforced Capacity by System Resources

Installed Capacity Suppliers offering to supply Unforced Capacity associated with Internal System Resources shall submit for each of their Resources the Operating Data and DMNC testing data or historical data described in Sections 5.12.1 and 5.12.5 of this ISO Services Tariff in accordance with the ISO Procedures. Such Installed Capacity Suppliers will be allowed to supply the amount of Unforced Capacity that the ISO determines pursuant to the ISO Procedures to reflect the appropriate Equivalent Demand Forced Outage Rate. Installed Capacity Suppliers offering to sell the Unforced Capacity associated with System Resources may only aggregate Resources in accordance with the ISO Procedures.

5.12.10 Curtailment of External Transactions In-Hour

All Unforced Capacity that is not out of service, or scheduled to serve the Internal NYCA Load in the Day-Ahead Market may be scheduled to supply Energy for use in External Transactions provided, however, that such External Transactions shall be subject to Curtailment within the hour, consistent with ISO Procedures. Such Curtailment shall not exceed the Installed Capacity Equivalent committed to the NYCA.

5.12.11 Responsible Interface Parties, Municipally-Owned Generation, Energy Limited Resources, Intermittent Power Resources, and Installed Capacity Suppliers with Energy Duration Limitations

5.12.11.1 Responsible Interface Parties

Responsible Interface Parties may qualify as Installed Capacity Suppliers, without having to comply with the daily bidding, scheduling, and notification requirements set forth in Section 5.12.7 of this Tariff, if their Special Case Resources are available to operate at the direction of the ISO in order to reduce Load from the NYS Transmission System and/or the distribution system for a minimum of four (4) consecutive hours each day 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. Special Case Resources will be considered to have a four (4) hour Energy Duration Limitation to align with their obligation. In order for a Responsible Interface Party to enroll an SCR that uses an eligible Local Generator, any amount of generation that can reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO that was produced by the Local Generator during the hour coincident with the NYCA or Locality peaks, upon which the LSE Unforced Capacity Obligation of the LSE that serves that SCR is based, must be accounted for when the LSE's Unforced Capacity Obligation for the upcoming Capability Year is established. Responsible Interface Parties must provide this generator data in accordance with ISO Procedures so that the ISO can adjust upwards the LSE Unforced Capacity Obligation to prevent double-counting.

Responsible Interface Parties supplying Unforced Capacity cannot offer the Demand Reduction associated with such Unforced Capacity in the Emergency Demand Response Program. A Resource with sufficient metering to distinguish MWs of Demand Reduction may participate as a Special Case Resource and in the Emergency Demand Response Program provided that the same MWs are not committed both as Unforced Capacity and to the Emergency Demand Response Program.

The ISO will have discretion, pursuant to ISO Procedures, to exempt Local Generators that are incapable of starting in two (2) hours from the requirement to operate on two (2) hours notification. Local Generators that can be operated to reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO and Loads capable of being interrupted upon demand, that are not available on certain hours or days will be derated by the ISO, pursuant to ISO Procedures, to reflect the Load serving equivalence of the hours they are actually available.

Responsible Interface Parties must submit a Minimum Payment Nomination, in accordance with ISO Procedures. The ISO may request Special Case Resource performance from less than the total number of Special Case Resources within the NYCA or a Load Zone in accordance with ISO Procedures.

Special Case Resources with Local Generators that can be operated to reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO and Special Case Resources with Loads capable of being interrupted upon demand will be required to comply with verification and validation procedures set forth in the ISO Procedures. Such procedures will not require metering other than interval billing meters on customer Load or testing other than DMNC or sustained disconnect, as appropriate, unless agreed to by the customer, except that Special Case Resources not called to supply Energy in a Capability Period will be required to run a test once every Capability Period in accordance with the ISO Procedures.

Unforced Capacity supplied in a Bilateral Transaction by a Special Case Resource pursuant to this subsection may only be resold if the purchasing entity or the Installed Capacity Marketer has agreed to become a Responsible Interface Party and comply with the ISO notification requirements for Special Case Resources. LSEs and Installed Capacity Marketers may become Responsible Interface Parties and aggregate Special Case Resources and sell the Unforced Capacity associated with them in an ISO-administered auction if they comply with ISO notification requirements for Special Case Resources.

Responsible Interface Parties that were requested to reduce Load in any month shall submit performance data to the NYISO, within 75 days of each called event or test, in accordance with ISO Procedures. Failure by a Responsible Interface Party to submit performance data for any Special Case Resources required to respond to the event or test within the 75-day limit will result in zero performance attributed to those Special Case Resources for purposes of satisfying the Special Case Resource's capacity obligation as well as for determining energy payments. All performance data are subject to audit by the NYISO and its market monitoring unit. If the ISO determines that it has made an erroneous payment to a Responsible Interface Party, the ISO shall have the right to recover it either by reducing other payments to that Responsible Interface Parties or by resolving the issue pursuant to other provisions of this Services Tariff or other lawful means.

Provided the Responsible Interface Party supplies evidence of such reductions in 75 days, the ISO shall pay the Responsible Interface Party that, through their Special Case Resources, caused a verified Load reduction in response to (i) an ISO request to perform due to a forecast reserve shortage (ii) an ISO declared Major Emergency State, (iii) an ISO request to perform made in response to a request for assistance for Load relief purposes or as a result of a Local Reliability Rule, or (iv) a test called by the ISO, for such Load reduction, in accordance with ISO Procedures. Subject to performance evidence and verification, in the case of a response pursuant to clauses (i), (ii), of (iii) of this subsection, Suppliers that schedule Responsible Interface Parties shall be paid the zonal Real-Time LBMP for the period of requested performance or four (4) hours, whichever is greater, in accordance with ISO Procedures~~; provided, however, Special Case Resource Capacity shall settle Demand Reductions, in the interval and for the capacity for which Special Case Resource Capacity has been scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy, as being provided by a Supplier of Operating Reserves, Regulation Service or Energy~~.

In the event that a Responsible Interface Party's Minimum Payment Nomination for a Special Case Resource, for the number of hours of requested performance or the minimum four (4) hour period, whichever is greater, exceeds the LBMP revenue received, the Special Case Resource will be eligible for a Bid Production Cost Guarantee to make up the difference, in accordance with Section 4.23 of this Services Tariff and ISO Procedures~~; provided, however, the ISO shall set to zero the Minimum Payment Nomination for Special Case Resource Capacity in each interval in which such Capacity was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy~~. Subject to performance evidence and verification, in the case of a response pursuant to clause (iv) of this subsection, payment for participation in tests called by the ISO shall be equal to the zonal Real Time LBMP for the MWh of Energy reduced within the test period.

Transmission Owners that require assistance from enrolled Special Case Resources with Local Generators larger than 100 kW and Special Case Resources with Loads capable of being interrupted upon demand for Load relief purposes or as a result of a Local Reliability Rule, shall direct their requests for assistance to the ISO for implementation consistent with the terms of this section. Within Load Zone J, participation in response to an ISO request to perform made as a result of a request for assistance from a Transmission Owner for less than the total number of Special Case Resources, for Load relief purposes or as a result of a Local Reliability Rule, in accordance with ISO Procedures, shall be voluntary and the responsiveness of the Special Case Resource shall not be taken into account for performance measurement.

5.12.11.1.1 Special Case Resource Average Coincident Load

The ISO must receive from the Responsible Interface Party that enrolls a Special Case Resource, the applicable metered Load data required to calculate an ACL for that SCR as provided below and in accordance with ISO Procedures. The ACL shall be computed using the metered Load for the applicable Capability Period SCR Load Zone Peak Hours that indicates the Load consumed by each SCR that is supplied by the NYS Transmission System and/or distribution system and is exclusive of any generation produced by a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter, that served some of the SCR's Load.

Beginning with the Winter 2011-2012 Capability Period and thereafter, the ISO shall use the average of the highest twenty (20) one-hour peak Loads of the SCR taken from the Load data reported for the Capability Period SCR Load Zone Peak Hours during the Prior Equivalent Capability Period, and taking into account the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours, to create a SCR ACL baseline. ~~In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours will be taken into account when creating the SCR ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence.~~ The ISO will post to its website the Capability Period SCR Load Zone Peak Hours for each zone ninety (90) days prior to the beginning of the Capability Period for which the ACL will be in effect.

In the SCR enrollment file uploaded by the RIP each month within the Capability Period, among other required information, the RIP shall provide the SCR's metered Load values for the applicable Capability Period SCR Load Zone Peak Hours necessary to compute the ACL for each SCR.

The exception to this requirement to report the required metered Load data for the ACL, when enrolling a SCR prior to the Summer 2014 Capability Period, is if (i) the SCR has not previously been enrolled with the ISO and (ii) never had interval metering Load data for each month in the Prior Equivalent Capability Period needed to compute the SCR's ACL. Beginning with the Summer 2014 Capability Period, the exception to this requirement to report the required metered Load data for the ACL, is dependent upon one or more of the eligibility conditions for SCR enrollment with a Provisional ACL provided in Section 5.12.11.1.2 of this Services Tariff and ISO Procedures. For SCRs that meet the criteria to enroll with a Provisional ACL, the ISO must receive from the RIP a Provisional ACL as provided in Section 5.12.11.1.2 of this Services Tariff and in accordance with ISO Procedures.

Beginning with the Summer 2014 Capability Period, in addition to the requirement for RIPs to report each SCR's metered Load values that occurred during the Capability Period SCR Load Zone Peak Hours, in accordance with this Services Tariff and ISO Procedures during the enrollment process, any qualifying increase in a SCR's Load that will be supplied by the NYS Transmission System and/or distribution system may be reported as an Incremental ACL, subject to the limitations and verification reporting requirements provided in Section 5.12.11.1.5 of this Services Tariff and in accordance with ISO Procedures. Incremental ACL values must be reported using the required enrollment file that may be uploaded by the RIP during each month's enrollment period. RIPs may not report Incremental ACL values for any SCRs that are enrolled in the Capability Period with a Provisional ACL.

A reduction in a SCR's Load that is supplied by the NYS Transmission System and/or distribution system and meets the criteria for a SCR Change of Status must be reported as a SCR Change of Status as provided by Section 5.12.11.1.3 of this Services Tariff and in accordance with ISO Procedures.

The ACL is the basis for the upper limit of ICAP, except in circumstances when the SCR has reported a SCR Change of Status or reported an Incremental ACL pursuant to Sections 5.12.11.1.3 and 5.12.11.1.5 of this Services Tariff. The basis for the upper limit of ICAP for a SCR that has experienced a SCR Change of Status or reported an Incremental ACL shall be the Net ACL.

5.12.11.1.2 Use of a Provisional Average Coincident Load

Prior to the Summer 2014 Capability Period, as provided in Section 5.12.11.1.1 of this Services Tariff, if a new Special Case Resource has not previously been enrolled with the ISO and never had interval billing meter data from the Prior Equivalent Capability Period, its Installed Capacity value shall be its Provisional Average Coincident Load for the Capability Period for which the new SCR is enrolled. The Provisional ACL may be applicable to a new SCR for a maximum of three (3) consecutive Capability Periods, beginning with the Capability Period in which the SCR is first enrolled.

Beginning with the Summer 2014 Capability Period, a SCR may be enrolled using a Provisional ACL in lieu of an ACL when one of the following conditions has been determined by the ISO to apply: (i) the SCR has not previously been enrolled with the ISO for the seasonal Capability Period for which the SCR enrollment with a Provisional ACL is intended, (ii) the SCR was enrolled with a Provisional ACL in the Prior Equivalent Capability Period and was required to report fewer than twenty (20) hours of metered Load verification data that correspond with the Capability Period SCR Load Zone Peak Hours based on the meter installation date of the SCR, (iii) the RIP attempting to enroll the SCR with a Provisional ACL is not the same RIP that enrolled the SCR in the Prior Equivalent Capability Period and interval billing meter data for the SCR from the Prior Equivalent Capability Period is not obtainable by the enrolling RIP and not available to be provided to the enrolling RIP by the ISO. The Provisional ACL may be applicable to a SCR for a maximum of three (3) consecutive Capability Periods when enrolled with the same RIP, beginning with the Capability Period in which the SCR is first enrolled by the RIP.

A SCR enrolled in the Capability Period with a Provisional ACL may not be enrolled by another RIP for the remainder of the Capability Period and the Provisional ACL value shall apply to the resource for the entire Capability Period for which the value is established.

The Provisional ACL is the RIP's forecast of the SCR's ACL and shall be the basis for the upper limit of ICAP for which the RIP may enroll the SCR during the Capability Period.

Any SCR enrolled with a Provisional ACL shall be subject to actual in-period verification. A Verified ACL shall be calculated by the ISO using the top twenty (20) one-hour peak Loads reported for the SCR from the Capability Period SCR Load Zone Peak Hours that are applicable to verify the Provisional ACL in accordance with ISO Procedures and taking into account the resource's reported verified Load reductions in a Transmission Owner's demand response program that are coincident with any of the applicable Capability Period SCR Load Zone Peak Hours. ~~In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours~~

~~will be taken into account when creating the SCR Verified ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the Verified ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence.~~

Following the Capability Period for which a resource with a Provisional ACL was enrolled, the RIP shall provide to the ISO the metered Load data required to compute the Verified ACL of the resource. The ISO shall compare the Provisional ACL to the Verified ACL to determine, after applying the applicable performance factor, whether the UCAP of the SCR had been oversold and whether a shortfall has occurred as provided under Section 5.14.2 of this Services Tariff. If the RIP fails to provide verification data required to compute the Verified ACL of the resource enrolled with a Provisional ACL by the deadline: (a) the Verified ACL of the resource shall be set to zero for each Capability Period in which the resource with a

Provisional ACL was enrolled and verification data was not reported, and (b) the RIP may be subject to penalties in accordance with this Services Tariff.

5.12.11.1.3 Reporting a SCR Change of Load or SCR Change of Status

5.12.11.1.3.1 SCR Change of Load

The Responsible Interface Party shall report any SCR Change of Load in accordance with ISO Procedures. The RIP is required to document the SCR Change of Load and when the total Load reduction for SCRs that have a SCR Change of Load within the same Load Zone is greater than or equal to 5 MWs, the RIP shall report the SCR Change of Load for each SCR in accordance with ISO Procedures.

5.12.11.1.3.2 SCR Change of Status

The Responsible Interface Party shall report any SCR Change of Status in accordance with ISO Procedures. The ISO shall adjust the reported ACL of the SCR for a reported SCR Change of Status to the Net ACL, for all prospective months to which the SCR Change of Status is applicable. When a SCR Change of Status is reported under clause (i), (ii) or (iii) within the definition of a Qualified Change of Status Condition and the SCR has sold capacity, the SCR shall be evaluated for a potential shortfall under Section 5.14.2 of this Services Tariff. Failure by the RIP to report a SCR Change of Status shall be evaluated as a potential shortfall under Section 5.14.2 of this Service Tariff and evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

Beginning with the Summer 2014 Capability Period, SCRs that were required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and that subsequently report or change a reported SCR Change of Status value after the first performance test in the Capability Period shall be required to demonstrate the performance of the resource against the Net ACL value in the second performance test in the Capability Period. The exceptions to this provision occur when a SCR's eligible Installed Capacity is set to zero throughout the period of the SCR Change of Status, when a SCR's eligible Installed Capacity is decreased by at least the same kW value as the reported SCR Change of Status, or if a SCR Change of Status is reported, and prior to the second performance test, the SCR returns to the full applicable ACL enrolled prior to the SCR Change of Status. Performance in both performance tests shall be used in calculation of the resource's performance factors and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a resource that was required to perform in the second performance test in the Capability Period: (a) the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

5.12.11.1.4 Average Coincident Load of an SCR Aggregation

The ISO shall compute the Average Coincident Load of an SCR Aggregation each month in accordance with ISO Procedures.

5.12.11.1.5 Use of an Incremental Average Coincident Load

Beginning with the Summer 2014 Capability Period, a Responsible Interface Party may report any qualifying increase to a Special Case Resource's Average Coincident Load as Incremental Average Coincident Load in the RIP enrollment file upload and in accordance with this Services Tariff and ISO Procedures.

For SCRs with a total Load increase equal to or greater than twenty (20) percent and less than thirty (30) percent of the applicable ACL, the RIP may enroll the SCR with an Incremental ACL provided that the eligible Installed Capacity does not increase from the prior enrollment months within the same Capability Period and prior to enrollment with an Incremental ACL. If the SCR is enrolled with an Incremental ACL and it is the first month of the SCR's enrollment in the applicable Capability Period, the enrolled eligible Installed Capacity value shall not exceed the maximum eligible Installed Capacity of the SCR from the Prior Equivalent Capability Period. When no enrollment exists for the SCR in the Prior Equivalent Capability Period and it is the first month of the SCR's enrollment in the applicable Capability Period, the enrolled eligible Installed Capacity of the SCR shall not exceed the ACL calculated from the Capability Period SCR Load Zone Peak Hours. For SCRs with a total Load increase equal to or greater than thirty (30) percent of the applicable ACL, the RIP may enroll the SCR with an Incremental ACL and an increase to the SCR's eligible Installed Capacity and is required to test as described in this section of the Service Tariff.

The ISO shall adjust the ACL of the SCR for an Incremental ACL for all months for which the Incremental ACL is reported by the RIP. For resources reporting an Incremental ACL, the Net ACL shall equal the enrolled ACL plus the reported Incremental ACL less any applicable SCR Change of Status and shall be the basis for the upper limit of ICAP for which the RIP may enroll the SCR during the Capability Period.

An Incremental ACL is a discrete change to the SCR operations that is expected to result in an increase to the Load that the SCR will consume from the NYS Transmission System and/or distribution system. It is not available to account for random fluctuations in Load, such as those caused by weather or other seasonal Load variations. Therefore, the ACL of a SCR may only be increased once per Capability Period and the amount of the increase enrolled must remain the same for all months for which the Incremental ACL is reported. A SCR enrolled in the Capability Period with an Incremental ACL may not be enrolled by another RIP for the remainder of the Capability Period. A SCR enrolled in the Capability Period with a Provisional ACL is not eligible to enroll with an Incremental ACL.

Following the Capability Period for which a SCR has been enrolled with an Incremental ACL, the RIP shall provide the hourly metered Load verification data that corresponds to the Monthly SCR Load Zone Peak Hours identified by the ISO for all months in which an Incremental ACL value was reported for the SCR. For each month for which verification data was required to be reported, the ISO shall calculate a Monthly ACL that will be used in the calculation of a Verified ACL. The Monthly ACL shall equal the average of the SCR's top twenty (20) one-hour metered Load values that correspond with the applicable Monthly SCR Load Zone Peak Hours, and taking into account (i) the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours~~, and (ii) the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of these hours. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Monthly SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the Monthly ACL for each hour during the Monthly SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Monthly SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Monthly SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and~~

~~continues into consecutive hours, and the consecutive hour is identified as being a Monthly SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Monthly SCR Load Zone Peak Hour, in accordance with the preceding sentence.~~ The Verified ACL shall be the average of the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period.

For any month in which verification data for the Incremental ACL is required but not timely submitted to the ISO in accordance with ISO procedures, the ISO shall set the metered Load values to zero. When a Monthly ACL is set to zero, the Verified ACL will be calculated as the average of: a) the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period; plus b) the Monthly ACLs for all months in which the SCR was enrolled within the same Capability Period with an Incremental ACL in the Capability Period in which the RIP failed to provide the minimum verification data required. In addition, a RIP may be subject to a penalty for each month for which verification data was required and not reported in accordance with this Services Tariff.

For each SCR that is enrolled with an Incremental ACL, the ISO shall compare the Net ACL calculated from the resource enrollment (ACL plus Incremental ACL less any applicable SCR Change of Status) to the Verified ACL calculated for the SCR to determine if the RIP's use of an Incremental ACL may have resulted in a shortfall pursuant to Section 5.14.2.

A Special Case Resource that was required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and was subsequently enrolled using an

Incremental ACL and an increase in the amount of Installed Capacity that the SCR is eligible to sell, shall be required to demonstrate performance against the maximum amount of eligible Installed Capacity reported for the SCR in the second performance test in the Capability Period. Performance in this test shall be measured from the Net ACL. Performance in both performance tests shall be used in calculation of the resource's performance factor and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a resource that was required to perform in the second performance test in the Capability Period: (a) the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

5.12.11.2 Existing Municipally-Owned Generation

A municipal utility that owns existing generation in excess of its Unforced Capacity requirement, net of NYPA-provided Capacity may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, offer the excess Capacity for sale as Installed Capacity provided that it is willing to operate the generation at the ISO's request, and provided that the Energy produced is deliverable to the New York State Power System. Such a municipal utility shall not be required to comply with the requirement of Section 5.12.7 of this Tariff that an Installed Capacity Supplier bid into the Energy market or enter into Bilateral Transactions. Municipal utilities shall, however, be required to submit their typical physical operating parameters, such as their start-up times, to the ISO. This subsection is only applicable to municipally-owned generation in service or under construction as of December 31, 1999.

5.12.11.3 Energy Limited Resources

An Energy Limited Resource or an Aggregation that is comprised entirely of a single Resource-type 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 the number of consecutive hours that correspond to its Energy Duration Limitation each day. Energy Limited Resources or Aggregations that are 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 or Aggregations that are 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 or an Aggregation that is an Energy Limited Resource may not be capable of responding.

5.12.11.4 Intermittent Power Resources

Intermittent Power Resources that depend upon wind or solar as their fuel or Aggregations that are entirely comprised of Intermittent Power Resources that depend on the same type of fuel, with that fuel being wind or solar, 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.

5.12.11.5 Installed Capacity Suppliers with an Energy Duration Limitation

A Resource with an Energy Duration Limitation may, consistent with the deliverability requirements set forth in Attachment X and Attachment S to the ISO OATT, qualify as an Installed Capacity Supplier with an Energy Duration Limitation 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 the number of consecutive hours that correspond to its Energy Duration Limitation each day. Installed Capacity Suppliers with an Energy Duration Limitation shall also Bid a Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, designating their desired operating limits. Installed Capacity Suppliers with an Energy Duration Limitation 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 Installed Capacity Suppliers with an Energy Duration Limitation may not be capable of responding.

5.12.12 Sanctions Applicable to Installed Capacity Suppliers and Transmission Owners

Pursuant to this section, the ISO may impose financial sanctions on Installed Capacity Suppliers and Transmission Owners that fail to comply with certain provisions of this Tariff. The ISO shall notify Installed Capacity Suppliers and Transmission Owners prior to imposing any sanction and shall afford them a reasonable opportunity to demonstrate that they should not be sanctioned and/or to offer mitigating reasons why they should be subject to a lesser sanction.

The ISO may impose a sanction lower than the maximum amounts allowed by this section at its sole discretion. Installed Capacity Suppliers and Transmission Owners may challenge any sanction imposed by the ISO pursuant to the ISO Dispute Resolution Procedures.

Any sanctions collected by the ISO pursuant to this section will be applied to reduce the Rate Schedule 1 charge under this Tariff.

5.12.12.1 Sanctions for Failing to Provide Required Information

If (i) an Installed Capacity Supplier fails to provide the information required by Sections 5.12.1.1, 5.12.1.2, 5.12.1.3, 5.12.1.4, 5.12.1.7 or 5.12.1.8 of this Tariff in a timely fashion, or (ii) a Supplier of Unforced Capacity from External System Resources located in an External Control Area or from a Control Area System Resource that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to provide the information required for certification as an Installed Capacity Supplier established in the ISO Procedures, the ISO may take the following actions: On the first day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of $500 or $5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing. Starting on the tenth day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of $1000 or $10 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

If an Installed Capacity Supplier fails to provide the information required by Subsection 5.12.1.5 of this Tariff in a timely fashion, the ISO may take the following actions: On the first calendar day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of that first calendar day. Starting on the second calendar day that the required information is late, the ISO may impose a daily financial sanction up to the higher of $500 or $5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

If a TO fails to provide the information required by Subsection 5.11.3 of this Tariff in a timely fashion, the ISO may take the following actions: On the first day that required information is late, the ISO shall notify the TO that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may impose a daily financial sanction up to $5,000 a day. Starting on the tenth day that required information is late, the ISO may impose a daily financial sanction up to $10,000.

5.12.12.2 Sanctions for Failing to Comply with Scheduling, Bidding, and Notification Requirements

On any day in which an Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or in which a Supplier of Installed Capacity from External System Resources or Control Area System Resources located in an External Control Area that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to comply with scheduling, bidding, or notification requirements for certification as an Installed Capacity Supplier established in the

ISO Procedures, the ISO may impose a financial sanction up to the product of a deficiency charge (pro-rated on a daily basis for Installed Capacity Suppliers) 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 0.1 MW, or rounded down to the nearest whole MW for an External Installed Capacity Supplier. For Installed Capacity Suppliers that have an Energy Duration Limitation, the deficiency charge will be pro-rated on a daily basis only taking into account hours during the Peak Load Window corresponding with the Resource's Energy Duration Limitation obligation, excluding Energy Storage Resources which will be evaluated over all hours during the Peak Load Window, and the maximum number of MWs that the Installed Capacity Supplier with an Energy Duration Limitation failed to schedule or Bid in any hour in the Peak Load Window of that day provided, however, that no financial sanction shall apply to any Installed Capacity Supplier that 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 0.1 MW. The deficiency charge may be up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction corresponding to where the Installed Capacity Supplier's capacity cleared, and for each month in which the Installed Capacity Supplier is determined not to have complied with the foregoing requirements.

In addition, if any Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or if an Installed Capacity Supplier of Unforced Capacity from an External Control

Area 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 Exports associated with NYCA Installed Capacity Suppliers consistent with Section 5.12.10 of this Tariff and with ISO Procedures, then 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.

To the extent an Installed Capacity Supplier of Unforced Capacity from an External Control Area or an External Generator associated with an Unforced Capacity sale using UDRs or EDRs fails to comply with Section 5.12.1.10 of this Tariff, the Installed Capacity Supplier or External Generator associated with an Unforced Capacity sale using UDRs or EDRs shall be subject to a deficiency charge calculated in accordance with the formula set forth below for each Obligation Procurement Period:

$$Deficiency\ charge = 1.5 * PRICE * \left(\frac{1000kW}{1MW}\right) * \left(\frac{\sum_{n=1}^{N}\left(\max\left(ICAP_n^{MWh} - SRE_n^{MWh}, 0\right)\right)}{N}\right)$$

Where:

N = total number of hours of SRE calls during the relevant Obligation Procurement Period

PRICE = ICAP Spot Market Auction clearing price for the relevant Obligation Procurement Period

$ICAP_n^{MWh}$ = for each hour *n* of SRE calls during the relevant Obligation Procurement Period, the ICAP equivalent of the UCAP sold from the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, or the Control Area System Resource in MWh, minus (x) any MWh that are unavailable due to an outage as defined in the ISO Procedures, or due to due to physical operating limitations affecting-the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, or due to other operational issues that the ISO determines to be outside the Installed Capacity Supplier's control, and (y) any MWh that were Bid as Imports to the NYCA at the appropriate Proxy Generator Bus at a price that was designed to ensure the Import was scheduled to the greatest extent possible, but that were not scheduled by the ISO

SRE_n^{MWh} = MWh provided to the NYCA at the appropriate Proxy Generator Bus from the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, or the Control Area System Resource, during each hour *n* of SRE calls during the relevant Obligation Procurement Period.

If an Installed Capacity Supplier's failure to fully comply with this Tariff would, in addition to being assessed a deficiency charge calculated in accordance with the formula set forth above, also permit the ISO to impose a different deficiency charge or a financial sanction under this Section 5.12.12.2, or to impose a deficiency charge for a shortfall under Section 5.14.2.2 of this Tariff, then the ISO shall only impose the penalty for failure to comply with Section 5.12.1.10 of this Tariff on the Installed Capacity Supplier for the hour(s) in which the Installed Capacity Supplier failed to meet its obligations under Section 5.12.1.10 of this Tariff.

If the Installed Capacity Supplier is a Responsible Interface Party that enrolled a SCR with an Incremental ACL in accordance with this Services Tariff, and also reported an increase to the Installed Capacity the SCR has eligible to sell after the first performance test in the Capability Period, the ISO may impose an additional financial sanction due to the failure of the RIP to report the required performance of the SCR against the Net ACL value in the second performance test in the Capability Period. This sanction shall be the value of the reported increase in the eligible Installed Capacity associated with the SCR that was sold by the RIP in each month of the Capability Period, during which the reported increase was in effect, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

If the Installed Capacity Supplier is a Responsible Interface Party, and the Average Coincident Load of the Special Case Resource has been decreased after the first performance test in the Capability Period, due to a SCR Change of Status in accordance with this Services Tariff and ISO Procedures, the ISO may impose an additional financial sanction resulting from the failure of the RIP to report the required performance of the SCR against the Net ACL value of the SCR when the SCR was required to perform in the second performance test in the Capability Period in accordance with Section 5.12.11.1.3.2 of this Services Tariff. This sanction shall be the value of the Unforced Capacity equivalent of the SCR Change of Status MW reported for the SCR during the months for which the SCR was enrolled with a SCR Change of Status and was required to demonstrate in the second performance test as specified in Section 5.12.11.1.3.2 of this Services Tariff, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

If a RIP fails to provide the information required by Section 5.12.11.1.3 of this Services Tariff in accordance with the ISO Procedures for reporting a Qualified Change of Status Condition, and the ISO determines that a SCR Change of Status occurred within a Capability Period, the ISO may impose a financial sanction equal to the difference, if positive, between the enrolled ACL and the maximum one hour metered Load for the month multiplied by up to one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each month the Installed Capacity Supplier is deemed to have a shortfall in addition to the corresponding shortfall penalty as provided in Section 5.14.2.

For each month in which a RIP fails to report required verification data and the applicable ACL value is set to zero in accordance with Section 5.12.11 of this Services Tariff, the ISO shall have the right to recover any energy payments made to the RIP for performance of the SCR by reducing other payments or other lawful means.

5.12.13 Aggregations

5.12.13.1 Resources Changing Aggregations

Individual Distributed Energy Resources may elect to leave their current Aggregation and join a new Aggregation pursuant to the Resources Changing Aggregation rules set forth in this Services Tariff section below and in Services Tariff section 4.1.10.3. The Installed Capacity of a Distributed Energy Resource that enters a new Aggregation will be assigned to the new Aggregation on a monthly basis beginning on the first day of the month in which the Distributed Energy Resource enters the new Aggregation. The Installed Capacity of a Distributed Energy Resource that exits an Aggregation will be removed from the Aggregation on the last day in which the Distributed Energy Resource is registered in the Aggregation. The specific processes for transferring a Distributed Energy Resource and its Installed Capacity to another Aggregation are located in the ISO Procedures.

An individual resource within an Aggregation and/or an Aggregation may only change from a homogenous Aggregation that is not a DER Aggregation to a DER Aggregation at the beginning of a Capability Year, provided that the Aggregation notifies the ISO by August 1 of the year prior to the beginning of the Capability Year. An individual resource within an Aggregation and/or an Aggregation may only change from a DER Aggregation to a homogeneous Aggregation that is not a DER Aggregation at the beginning of a Capability Year, provided that the Aggregation notifies the ISO by August 1 of the year prior to the beginning of the Capability Year. If the composition of a homogeneous Aggregation that is not a DER Aggregation changes during a Capability Year such that the homogeneous Aggregation that is not a DER Aggregation would no longer qualify as a homogeneous Aggregation that is not a DER Aggregation, the homogeneous Aggregation that is not a DER Aggregation will maintain the qualifications as a homogeneous Aggregation that is not a DER Aggregation for the remainder of the Capability Year, and, it will have to elect (i) a different Aggregation by August 1, (ii) to participate in the ISO Administered Markets as a Generator, if qualified, or (iii) to leave the ISO Administered Markets for the following Capability Year. If the composition of a DER Aggregation changes during a Capability Year such that the DER Aggregation would no longer qualify as a DER Aggregation, the DER Aggregation will maintain the qualifications as a DER Aggregation for the remainder of the Capability Year, and, it will have to elect (i) a different Aggregation by August 1, (ii) to participate in the ISO Administered Markets as a Generator, if qualified, or (iii) to leave the ISO Administered Markets for the following Capability Year. An individual Distributed Energy Resource seeking to participate in the ISO-administered Installed

Capacity auctions that has previously acted as a retail load modifier may only register as an Installed Capacity Supplier for the upcoming Capability Year, provided that Resource notified the ISO of its intention to become an Installed Capacity Supplier by August 1 of the year prior to the start of the Capability Year and provided the output data in accordance with ISO Procedures.

5.12.13.2 Time-stacking Resources in an Aggregation

An Aggregator may sequentially stack individual Distributed Energy Resources within an Aggregation in order to meet the Energy Duration Limitations specified in Section 5.12.14. In addition to the requirements and obligations described in this section 5.12.13, the following rules apply to an Aggregation that seeks to sequentially stack individual Distributed Energy Resources:

5.12.13.2.1 each individual Distributed Energy Resource must be able to provide Energy for a minimum of one 1-hour block each day;

5.12.13.2.2 individual Distributed Energy Resources duration will be rounded-down to the nearest hour and stacked in whole-hour increments;

5.12.13.2.3 Time-stacked Aggregations will be qualified for the amount of Capacity it can sustain over the run-time requirement; and

The specific processes related to time-stacking Distributed Energy Resources in an Aggregation are located in the ISO Procedures.

5.12.14 Energy Duration Limitations and Duration Adjustment Factors for Installed Capacity Suppliers

Starting with the Capability Year that begins on May 1, 2021, Resources with a limited run-time that meet the Energy Duration Limitations identified in the tables below may qualify to participate as Installed Capacity Suppliers. Resources with a limited run-time must elect an

Energy Duration Limitation that is less than or equal to the Resource's ability to demonstrate sustained output at its qualified MW amount. Resources that do not have an Energy Duration Limitation will have a Duration Adjustment Factor of 100%. The Adjusted Installed Capacity for an Installed Capacity Supplier shall be calculated using the applicable Energy Duration Limitations and Duration Adjustment Factors, and in accordance with ISO Procedures, starting with the 2021/2022 Capability Year, as determined by the MW count of incremental penetration of Resources with Energy Duration Limitations as listed below:

Table 1:

Incremental Penetration of Resources with Energy Duration Limitations is less than 1000 MW	
Energy Duration Limitations (hours)	Duration Adjustment Factor (%)
8	100
6	100
4	90
2	45

Table 2:

Incremental Penetration of Resources with Energy Duration Limitations 1000 MW and above	
Energy Duration Limitations (hours)	Duration Adjustment Factor (%)
8	100
6	90
4	75
2	37.5

While Table 1 is in effect, Resources with an Energy Duration Limitation of 6 hours or less must fulfill the availability requirements given in Section 5.12.7 for a 6-hour Peak Load Window. While Table 2 is in effect, Resources with an Energy Duration Limitation of 6 hours or less must fulfill the availability requirements given in Section 5.12.7 for an 8-hour Peak Load Window. Resources with an Energy Duration Limitation of 8 hours must always fulfill the availability requirements given in Section 5.12.7 for an 8-hour Peak Load Window. The 6 hour Peak Load Window for the Summer Capability Period is HB 13 through HB 18, and the 6 hour Peak Load Window for the Winter Capability Period is HB 16 through HB 21. The 8 hour Peak Load Window for the Summer Capability Period is HB 12 through HB 19, and the 8 hour Peak Load Window for the Winter Capability Period is HB 14 through HB 21.

5.12.14.1 Counting Incremental Penetration of Resources with Energy Duration Limitations

The penetration levels of CRIS MW will be the sum of CRIS for Resources with Energy Duration Limitations that have elected to participate in ISO Administered Markets with less than 8 hour duration and that have entered into service after January 1, 2019 and incremental CRIS awarded after January 1, 2019 to Resources with Energy Duration Limitations that have elected to participate in ISO Administered Markets with less than 8 hour duration as specified below.

Penetration levels of CRIS MW for Resources with Energy Duration Limitations will be calculated in accordance with ISO Procedures as the sum of CRIS for Resources with Energy Duration Limitations of 2 hours, CRIS for Resources with Energy Duration Limitations of 4 hours and CRIS for Resources with Energy Duration Limitations of 6 hours that have entered into service and have participated in the ISO Administered Markets after January 1, 2019. Penetration levels of Demand Side Resources will be calculated as the sum of the Demand Side Resource MW that have elected to participate in the ISO Capacity markets with less than 8 hour duration as of July 1, as pursuant to ISO Procedures. The MW count of Resources with Energy Duration Limitations that were in service prior to January 1, 2019 and have Retired will include CRIS for Resources with Energy Duration Limitations of 2 hours, CRIS for Resources with Energy Duration Limitations of 4 hours and CRIS for Resources with Energy Duration Limitations of 6 hours that have Retired as of July 1 each year, pursuant to ISO Procedures. Resources that obtained CRIS and were in service prior to January 1, 2019 that qualify as Resources with Energy Duration Limitations at a later date will not be included in the penetration levels of Resources with Energy Duration Limitations.

The MW count of incremental penetration of Resources with Energy Duration Limitations used to determine the applicable Duration Adjustment Factors provided in Section 5.12.14 for the upcoming Capability Year will be calculated in accordance with ISO Procedures as the sum of the penetration levels of CRIS MW, as described above, and penetration levels of Demand Side Resources, as described above, less the sum of CRIS MW for Resources with Energy Duration Limitations that have Retired, as described above, and less 1309.1 MW of SCR MW. The MW count of incremental penetration of Resources with Energy Duration Limitations with their Energy Duration Limitation election will be counted as of July 1 and posted by July 15. Once there are 1000 MW or more incremental penetration of Resources with Energy Duration Limitations, the Duration Adjustment Factors listed in Table 2 provided above in Section 5.12.14 will be effective May 1 of the following Capability Year and Table 2 will be effective notwithstanding future MW count of incremental penetration of Resources with Energy Duration Limitations.

5.12.14.2 Adjusted Installed Capacity

Starting with the Capability Year beginning May 1, 2021, a Resource's Unforced Capacity shall reflect the applicable Duration Adjustment Factor for the Resource's elected Energy Duration Limitation. The Adjusted Installed Capacity is equal to a Resource's Installed Capacity multiplied by the Duration Adjustment Factor. If a Resource or Aggregation wants to change its duration election it must inform the ISO by August 1 preceding the upcoming Capability Year.

5.12.14.3 Periodic Review of Capacity Values

Starting in 2022 and occurring every four (4) years, the independent consultant for the ISO shall perform a review of the Capacity Values to re-evaluate the reliability benefit of Resources with Energy Duration Limitations in meeting Resource Adequacy criteria for the four (4) year period coinciding with the four (4) Capability Years covered by the next Demand Curve Reset filing, pursuant to Services Tariff Section 5.14.1.2.2. The periodic review shall: (i) identify the methodologies and data used to determine the Duration Adjustment Factors, (ii) evaluate the appropriate Energy Duration Limitations, (iii) re-evaluate the Duration Adjustment Factors for Resources with Energy Duration Limitations, and (iv) re-evaluate the Peak Load Window associated with the bidding requirement for Resources with Energy Duration Limitations specified below.

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 stakeholders no later than September 1 of the second year prior to the Demand Curve Reset filing year, pursuant to Section 5.14.1.2.2. The schedule and procedures shall provide for:

5.12.14.3.1 ISO development, with stakeholder review and comment, of a request for study, scope, assumptions, and methodology to provide consulting services to determine recommended values for the Duration Adjustment Factors specified above, and appropriate methodologies for such determination;

5.12.14.3.2 Selection of a consultant in accordance with the request in Section 5.12.14.3.1;

5.12.14.3.3 Submission to the ISO and the stakeholders of a draft report from the consultant on the consultant's determination of recommended values for the Energy Duration Limitations and the associated Duration Adjustment Factors, and Peak Load Windows specified above;

5.12.14.3.4 Stakeholder review of and comment on the data, assumptions and conclusions in the consultant's draft report, with participation by the responsible person or persons providing the consulting services;

5.12.14.3.5 An opportunity for the Market Monitoring Unit to review and comment on the draft request for the proposals, the consultant's report, and the ISO's proposed Energy Duration Limitations and the associated Duration Adjustment Factors, and Peak Load Windows for Resources with Energy Duration Limitations (the responsibilities of the Market Monitoring Unit that are addressed in this section of the Service's Tariff are also addressed in Section 30.4.6.3.1 of Attachment O);

5.12.14.3.6 Issuance by the consultant of a final report;

5.12.14.3.7 Issuance of a draft of the ISO's recommended adjustments to the Energy Duration Limitations and the associated Duration Adjustment Factors, and Peak

Load Windows for Resources with Energy Duration Limitations for stakeholder review and comment; and

5.12.14.3.8 Issuance of the ISO's proposed Energy Duration Limitations and the associated Duration Adjustment Factors, and Peak Load Windows for Resources with Energy Duration Limitations, taking into account the report of the 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.

15.3 Rate Schedule 3 - Payments for Regulation Service

This Rate Schedule applies to Suppliers that provide Regulation Service to the ISO. ~~A~~ The following Resources are not eligible to provide Regulation Service: (1) Behind-the-Meter Net Generation Resources that ~~is~~ are comprised of more than one generating unit and that ~~is~~ are dispatched as a single aggregate unit, (2) Aggregations that are comprised of one or more generating units (unless each of those generating units use inverter-based energy storage technology), and (3) Aggregations of Demand Side Resources where at least one Demand Side Resource facilitates its Demand Reduction by utilizing a Local Generator (unless each Local Generator uses inverter-based energy storage technology) ~~is not qualified to provide Regulation Service to the ISO~~. Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

15.3.1 Obligations of the ISO and Suppliers

15.3.1.1 The ISO shall:

(a) Establish Regulation Service criteria and requirements in the ISO Procedures to ensure that Suppliers follow changes in Load consistent with the Reliability Rules;

(b) Provide RTD Base Point Signals and AGC Base Point Signals to Suppliers providing Regulation Service to direct their output;

(c) Establish criteria in the ISO Procedures that Suppliers must meet to qualify, or re-qualify, to supply Regulation Service;

(d) Establish minimum metering requirements and telecommunication capability required for a Supplier to be able to respond to AGC Base Point Signals and RTD Base Point Signals sent by the ISO;

(e) Select Suppliers to provide Regulation Service in the Day-Ahead Market and Real-Time Market and establish Regulation Service schedules, in MWs of Regulation Capacity, for each scheduled Regulation Supplier in the Day-Ahead and Real-Time Markets, as described in Section 15.3.2 of this Rate Schedule;

(f) Pay Suppliers for providing Regulation Service as described in this Rate Schedule;

(g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 15.3.3 of this Rate Schedule; and

(h) Take into account the speed and accuracy of regulation resources in determining reserve requirements for Regulation Service.

15.3.1.2 Each Supplier shall:

(a) Register with the ISO the Regulation Capacity its resources are qualified to bid in the Regulation Services market;

(b) Provide the ISO with the Resource's Regulation Capacity Response Rate and the Resource's Regulation Movement Response Rate;

(c) Offer only Resources that are; (i) ISO-Committed Flexible or Self-Committed Flexible~~, provided however that Demand Side Resources shall be offered as ISO-Committed Flexible;~~ within the dispatchable portion of their operating range, and; (ii) able to respond to AGC Base Point Signals sent by the ISO pursuant to the ISO Procedures, to provide Regulation Service;

(d) Not use, contract to provide, or otherwise commit Regulation Capacity that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to ~~any party~~ a Balancing Authority other than the ISO;

(e) Pay any charges imposed under this Rate Schedule;

(f) Ensure that all of its Resources that are selected to provide Regulation Service comply with Base Point Signals issued by the ISO at all times pursuant to the ISO Procedures; and ensure that all of its Resources that are selected to provide Regulation Service comply with all criteria and ISO Procedures that apply to providing Regulation Service.

15.3.2 Selection of Suppliers in the Day-Ahead Market and the Real-Time Market

(a) The ISO shall select Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day and in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day, from those that have Bid to provide Regulation Service from Resources and that meet the qualification standards and criteria established in Section 15.3.1 of this Rate Schedule and in the ISO Procedures.

(b) In order to schedule Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day, the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Day-Ahead Regulation Capacity Bid Price and b) the product of the Supplier's Day-Ahead Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.

(c) In order to schedule Suppliers in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Real-Time Regulation

Capacity Bid Price and b) the product of the Supplier's Real-Time Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.

(d) The ISO shall establish separate Regulation Capacity Market Prices in the Day-Ahead Market and the Real-Time Market under Sections 15.3.4, 15.3.5 and 15.3.7 of this Rate Schedule and shall establish a Real-Time Regulation Movement Market Price under Section 15.3.5.1 of this Rate Schedule. The ISO shall also compute Regulation Revenue Adjustment Payments and Regulation Revenue Adjustment Charges under Section 15.3.6 of this Rate Schedule.

15.3.2.1 Bidding Process

(a) A Supplier may submit a Bid in the Day- Ahead Market or the Real-Time Market to provide Regulation Service from eligible Resources, provided, however, that Bids submitted by Suppliers that are attempting to re-qualify to provide Regulation Service, after being disqualified pursuant to Section 15.3.3 of this Rate Schedule 3, may be limited by the ISO pursuant to ISO Procedures.

(b) Bids rejected by the ISO may be modified and resubmitted by the Supplier to the ISO in accordance with the terms of the ISO Tariff.

(c) Each Bid shall contain the following information: (i) the maximum amount of capability (in MW) that the Resource is willing to provide as Regulation Capacity; (ii) the Supplier's Bid Price (in $/MW) for Regulation Capacity; and (iii) the Suppliers Bid Price (in $/MW) for Regulation Movement~~; and (iv) the physical location and name or designation of the Resource~~.

(d) Regulation Service Offers from Limited Energy Storage Resources: The ISO may reduce the real-time Regulation Capacity offer (in MWs) from a Limited Energy

Storage Resource or an Aggregation of Limited Energy Storage Resources to account for the Energy storage capacity of such Resource.

(e) Regulation Service Offers from Energy Storage Resources: The ISO may reduce the real-time Regulation Capacity (in MW) from an Energy Storage Resource or an Aggregation of Limited Energy Storage Resources to account for the Energy Level of such Resource.

15.3.3 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

(a) The ISO shall establish (i) Resource performance measurement criteria; (ii) procedures to disqualify Suppliers whose Resources consistently fail to meet those criteria; and (iii) procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.

(b) The ISO shall establish and implement a Performance Tracking System to monitor the performance of Suppliers that provide Regulation Service. The ISO shall develop performance indices, which may vary with Control Performance, as part of the ISO Procedures. The ISO shall use the values provided by the Performance Tracking System to adjust settlements for real-time Regulation Movement pursuant to Section 15.3.5.4.1 and to compute a performance charge to apply to real-time Regulation Service providers pursuant to Section 15.3.5.4.2 of this Rate Schedule.

(c) Resources that consistently fail to perform adequately may be disqualified by the ISO, pursuant to ISO Procedures.

15.3.4 Regulation Service Settlements - Day-Ahead Market

15.3.4.1 Calculation of Day-Ahead Market Prices

The ISO shall calculate a Day-Ahead Regulation Capacity Market Price for each hour of the following day. The Day-Ahead Regulation Capacity Market Price for each hour shall equal the Day-Ahead Shadow Price of the ISO's Regulation Service constraint for that hour, which shall be established under the ISO Procedures, minus the product of i) the Day-Ahead Regulation Movement Bid Price of the marginal Resource selected to provide Regulation Service; and ii) the applicable Regulation Movement Multiplier. Day-Ahead Shadow Prices will be calculated by the ISO's SCUC. Each hourly Day-Ahead Shadow Price shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that hour, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price shall include the Day-Ahead Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale (or purchase by a Withdrawal-Eligible Generator) of Energy or the sale of 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 (or for a Withdrawal-Eligible Generator to withdraw) less Energy or to provide less Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Regulation Service Demand Curve.

Each Supplier that is scheduled Day-Ahead to provide Regulation Service shall be paid the Day-Ahead Regulation Capacity Market Price in each hour, multiplied by the amount of Regulation Capacity that it is scheduled Day-Ahead to provide in that hour.

15.3.4.2 Other Day-Ahead Payments

A Supplier that bids on behalf of a Generator or Aggregation that provides Regulation Service may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the ISO in the Day-Ahead Market, except to the extent that a Supplier is directed to provide the excess amount by the ISO.

15.3.5 Regulation Service Settlements - Real-Time Market

15.3.5.1 Calculation of Real-Time Market Prices

The ISO shall calculate a Real-Time Regulation Capacity Market Price and a Real-Time Regulation Movement Market Price for every RTD interval, except as noted in Section 15.3.8 of this Rate Schedule. The Real-Time Regulation Capacity Market Price for each interval shall equal the real-time Shadow Price for the ISO's Regulation Service constraint for that RTD interval, which shall be established under the ISO Procedures, minus the product of: i) the real-time Regulation Movement Bid of the marginal Resource selected to provide Real-Time Regulation Service; and ii) the applicable Regulation Movement Multiplier. Real-time Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that interval, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of

Regulation Service in that interval. As a result, the Shadow Price shall include the Real-Time Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale (or for Withdrawal-Eligible Generators, the purchase) of Energy or the sale of 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 or withdraw less Energy or to provide less Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled at a cost greater than the Demand Curve indicates.

During any period when the ISO sets Resources' Regulation Service Schedules to zero, pursuant to Section 15.3.8 of this Rate Schedule, the Real-Time Regulation Capacity Market Price and the Real-Time Regulation Movement Market Price shall automatically be set to zero, which shall be the price used for real-time balancing and settlement purposes.

The ISO shall calculate a Real-Time Regulation Movement Market Price for every RTD interval. The Real-Time Regulation Movement Market Price shall be the Regulation Movement Bid of the marginal Resource selected to provide Regulation Service in that interval.

15.3.5.2 Real-Time Regulation Capacity Balancing Payments, Regulation Movement Payments and Performance Charges

Any deviation from a Supplier's Day-Ahead schedule to provide Regulation Service shall be settled pursuant to the following rules. In addition, Suppliers scheduled to provide Regulation Service in real-time shall be settled pursuant to the following rules.

(a) When the Supplier's real-time Regulation Capacity schedule is less than its Day-Ahead Regulation Capacity schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Regulation Capacity Market

Price; and (ii) the difference between the Supplier's Day-Ahead Regulation Capacity schedule and its real-time Regulation Capacity schedule.

(b) When the Supplier's real-time Regulation Capacity schedule is greater than its Day-Ahead Regulation Capacity schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Regulation Capacity Market Price; and (ii) the difference between the Supplier's real-time Regulation Capacity schedule and its Day-Ahead Regulation Capacity schedule.

(c) The ISO shall pay Suppliers with real-time Regulation Capacity schedules a real-time payment for Regulation Movement provided in each interval. The payment amount shall equal the product of: (a) the Real-Time Regulation Movement Market Price in that interval; (b) the Regulation Movement instructed during the interval, and (c) the performance factor calculated for that Regulation Service provider in that interval pursuant to Section 15.3.5.4.1.

(d) The ISO shall assess a performance charge, pursuant to Section 15.3.5.4.2 to all Suppliers of Regulation Service with real-time Regulation Service schedules.

(e) No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the ISO in the Real Time Market, except to the extent that a Supplier is directed to provide the excess amount by the ISO.

15.3.5.3 Other Real-Time Regulation Service Payments

A Supplier that bids on behalf of a Regulation Service provider may be eligible for a real-time Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

A Supplier that bids on behalf of a Regulation Service provider may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.6.5 and Attachment J of this ISO Services Tariff.

15.3.5.4 Performance-Based Adjustment to Payments for Regulation Service Providers and Performance Based Charges

15.3.5.4.1 Performance-Based Adjustment to Payments for Regulation Service Suppliers

The amount paid to each Supplier for providing Regulation Movement in each RTD interval, pursuant to Section 15.3.5.2 shall be reduced to reflect the Supplier's performance using a performance factor developed pursuant to the following equation:

$$K_{PIi} = (PI_i - PSF)/(1 - PSF)$$

Where:

K_{PIi} = the performance factor derived from the Regulation Service Performance index for the Resource for interval *i*;

PI_i = the performance index of the Resource for interval *i*, with a value between 0.0 and 1.0 inclusive, derived from each Supplier's Regulation Service performance, as measured by the performance indices set forth in the ISO Procedures; and

PSF = the payment scaling factor, established pursuant to ISO Procedures. The PSF shall be set between 0 and the minimum performance index required for payment for Regulation Service.

The PSF is established to reflect the extent of ISO compliance with the standards established by NERC, NPCC or Good Utility Practice for Control Performance and System Security. The PSF is set initially at zero. Should the ISO's compliance with these measures deteriorate, in a manner that can be improved if regulation performance improves, the PSF will be increased. Resources providing Regulation Service will be required to increase their performance index to obtain the same total Regulation Service payment as they received during periods of good ISO performance, as measured by these standards.

15.3.5.4.2 Performance-Based Charge to Suppliers of Regulation Service

In addition, each Supplier that is scheduled in real-time to provide Regulation Service shall be assessed a performance charge for interval *i* in accordance with the following formula.

$$Performance\ Charge_i = \Big(\big((1-K_{PIi}) * RTRinccap_i * \text{-}1.1 * RTMPreg_i\big) + \Big(\big((1-K_{PIi}) * (RTRcap_i - RTRinccap_i) * \text{-}1.1\big) * Max\big(DAMPreg_i, RTMPreg_i\big)\Big)\Big) * (S_i/3600)$$

$DAMPreg_i$ = is the applicable Regulation Capacity Market Price (in \$/MW), in the Day-Ahead Market, as established by the ISO pursuant to Section 15.3.4.1 of this Rate Schedule for the hour that includes RTD interval *i*;

$RTMPreg_i$ = is the applicable Regulation Capacity Market Price (in \$/MW), in the Real-Time Market as established by the ISO under Section 15.3.5.1 of this Rate Schedule in RTD interval *i*;

$RTRcap_i$ = is the Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in RTD interval *i*;

$RTRinccap_i$ = is the incremental Regulation Capacity (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in the RTD interval i which is in excess of Regulation Capacity offered and selected by the ISO in the Day-Ahead Market for the hour that includes interval *i*;

S_i = is the number of seconds in interval *i*; and

K_{PIi} = is the performance factor for the Resource for interval *i* as defined in Section 15.3.5.4.1.

15.3.6 Energy Settlement Rules for ~~Generators~~ Suppliers Providing Regulation Service

15.3.6.1 Energy Settlements

A. For any interval in which a Generator or Aggregation that is not a Limited Energy Storage Resource or an Aggregation of Limited Energy Storage Resources 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~~ the actual ~~generation~~ Energy it provides or its AGC Base Point Signal. Demand Side Resources providing Regulation Service shall not receive a settlement payment for Energy.

B. Demand Reductions from Aggregations providing Regulation Service are only eligible for payment for Energy when the real-time LBMP, at the Aggregation's Transmission Node, meets or exceeds the Net Benefits Test Threshold calculated in accordance with Section 4.5.7 of the Services Tariff for the applicable period. When the Net Benefits Test Threshold is satisfied, such Aggregations shall receive an Energy payment for Demand Reductions equal to the lower of the Demand Reductions' contribution to the actual Energy provided or the Aggregation's AGC Base Point Signal.

~~B~~C. For any hour in which a Limited Energy Storage Resource or Aggregation of Limited Energy Storage Resources has injected or withdrawn Energy, pursuant to an ISO schedule to do so, it shall receive a settlement payment (if the amount calculated below is positive) or charge (if the amount calculated below is negative) for Energy pursuant to the following formula:

$$Energy\ Settlements_h = Net\ MWHR_h * LBMP_h$$

Where:

$Net\ MWHR_h$ = the amount of Energy injected by the Limited Energy Storage Resource in hour *h* minus the amount of Energy withdrawn by that Limited Energy Storage Resource in hour *h*

$LBMP_h$ = the time-weighted average LBMP in hour *h* calculated for the location of that Limited Energy Storage Resource

15.3.6.2 Additional Payments/Charges

For any interval in which a ~~Generator~~ Supplier that is providing Regulation Service receives an AGC Base Point Signal that differs from its RTD Base Point Signal, it shall receive or pay a Regulation Revenue Adjustment Payment ("RRAP") or Regulation Revenue Adjustment Charge ("RRAC") calculated under the terms of this subsection, provided however no RRAP shall be payable and no RRAC shall be charged to a Limited Energy Storage Resource or Aggregation of Limited Energy Storage Resources.

15.3.6.2.1 Additional Payments/Charges When AGC Base Point Signals Exceed RTD Base Point Signals

For any interval in which a ~~Generator~~ Supplier that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a ~~Generator~~ Supplier is higher than the LBMP at its location in that interval, the ~~Generator~~ Supplier shall receive a RRAP. Conversely, for any interval in which such a ~~Generator~~ Supplier's Energy Bid Price is lower than the LBMP at is location at that interval, the

~~Generator~~Supplier shall be assessed a RRAC. RRAPs and RRACs shall be calculated using the following formula:

$$Payment/Charge = \int_{RTD\ Base\ Point\ Signal}^{max(RTD\ BasePoint\ Signal, min(AGC\ BasePoint\ Signal, Actual\ Output))} [Bid - LBMP] * S/3600$$

Where:

S = the number of seconds in the RTD interval;

If the result of the calculation is positive then the ~~Generator~~ Supplier shall receive a RRAP. If it is negative then the ~~Generator~~ Supplier shall be subject to a RRAC. For purposes of applying this formula, whenever the ~~Generator~~ Supplier's actual Bid exceeds the applicable LBMP the "Bid" term shall be set at a level equal to the lesser of the ~~Generator~~ Supplier's actual Bid or its reference Bid plus $100/MWh~~. Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC~~.

15.3.6.2.2 Additional Charges/Payments When AGC Base Point Signals Are Lower than RTD Base Point Signals

For any interval in which a ~~Generator~~ Supplier 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~~ Supplier is higher than the LBMP at its location in that interval, the ~~Generator~~ Supplier shall be assessed a RRAC. Conversely, for any interval in which such a ~~Generator~~ Supplier's Energy Bid Price is lower than the LBMP at its location in that interval, the ~~Generator~~ Supplier shall receive a RRAP. RRAPs and RRACs shall be calculated using the following formula:

$$Payment/Charge = \int_{min(RTD\ BasePoint\ Signal, max(AGC\ BasePoint\ Signal, Actual\ Output))}^{RTD\ BasePoint\ Signal} -[Bid - LBMP] * S/3600$$

Where:

S = the number of seconds in the RTD interval;

If the result of the calculation is positive then the ~~Generator~~ Supplier shall receive a RRAP. If it is negative then the ~~Generator~~ Supplier shall be subject to a RRAC. For purposes of this formula, whenever the ~~Generator~~ Supplier'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~~ Supplier's actual Bid or its reference Bid minus $100/MWh.

~~Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.~~

15.3.7 Regulation Service Demand Curve

The ISO shall establish a Regulation Service Demand Curve that will apply to both the Day-Ahead and real-time Regulation Capacity Market Price and settlements. The Regulation Capacity Market Prices calculated pursuant to Sections 15.3.4.1 and 15.3.5.1 of this Rate Schedule shall take account of the demand curve established in this Section so that Regulation Capacity is not scheduled by SCUC, RTC, or RTD at a cost higher than the demand curve indicates should be paid in the relevant market.

The ISO shall establish and post a target level of Regulation Service for each hour, which will be the number of MW of Regulation Capacity that the ISO would seek to maintain as its Regulation Service requirement in that hour. The ISO will then define a Regulation Service demand curve for that hour as follows:

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service minus 80 MW, the price on the Regulation Service demand curve shall be $775/MW.

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service minus 25 MW but that exceed the target level of Regulation Service minus 80 MW, the price on the Regulation Service demand curve shall be $525/MW.

For quantities of Regulation Capacity that are less than or equal to the target level of Regulation Service but that exceed the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be $25/MW.

For all other quantities, the price on the Regulation Service demand curve shall be $0/MW. However, the ISO shall not schedule more Regulation Service than the target level for the requirement for that hour.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure Regulation Capacity at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Regulation Service Demand Curve the ISO, in consultation with its Advisor, shall conduct an initial review in accordance with the ISO Procedures. The scope of the review shall be upward or downward in order to optimize the economic efficiency of any, or all, the ISO-Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.3.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Regulation Service Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 3 to the Services Tariff are also addressed in Section 30.4.6.4.1 of Attachment O.

15.3.8 Temporary Suspension of Regulation Service Markets During Reserve Pickups and Maximum Generation

During any period in which the ISO has activated its RTD-CAM software and called for a "large event" or "small event" reserve or maximum generation pickup, as described in Article 4.4.4.1 of this ISO Services Tariff, the ISO will set all Regulation Service schedules to zero-, The ISO will establish real-time Regulation Market Prices for Regulation Capacity and Regulation Movement of zero for settlement and balancing purposes. The ISO will restore real-time Regulation Service schedules as soon as possible after the end of the reserve or maximum generation pickup.

15.4 Rate Schedule 4 - Payments for Supplying Operating Reserves

This Rate Schedule applies to payments to Suppliers that provide Operating Reserves to the ISO. Transmission Customers will purchase Operating Reserves from the ISO under Rate Schedule 5 of the ISO OATT.

15.4.1 General Responsibilities and Requirements

15.4.1.1 ISO Responsibilities

The ISO shall procure on behalf of its Customers a sufficient quantity of Operating Reserve products to comply with the Reliability Rules and with other applicable reliability standards, as well as Scarcity Reserve Requirements. These quantities shall be established under Section 15.4.7 of this Rate Schedule for locational Operating Reserve requirements and Section 15.4.6.2 of this Rate Schedule for Scarcity Reserve Requirements. To the extent that the ISO enters into Operating Reserve sharing agreements with neighboring Control Areas its Operating Reserves requirements shall be adjusted as, and where, appropriate.

The ISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible, under Section 15.4.1.2 of this Rate Schedule, to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The ISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central-East, in Southeastern New York, in New York City, and on Long Island. In addition to being subject to the preceding limitations on Suppliers that can meet each of these requirements, the requirements for Operating Reserve located East of Central-East may only be met by eligible Suppliers that are located East of Central-East, requirements for

Operating Reserve located in Southeastern New York may only be met by eligible Suppliers that are located in Southeastern New York, requirements for Operating Reserve located in New York City may only be met by eligible Suppliers that are located in New York City, and requirements for Operating Reserve located on Long Island may only be met by eligible Suppliers located on Long Island. Each of these Operating Reserve requirements shall be defined consistent with the Reliability Rules and other applicable reliability standards. The ISO shall also establish Scarcity Reserve Requirements in the Real-Time Market pursuant to Section 15.4.6.2 of this Rate Schedule, which may be met by Suppliers eligible to provide 30-Minute Reserve. Scarcity Reserve Requirements may only be met by eligible Suppliers that are located in the Scarcity Reserve Region associated with a given Scarcity Reserve Requirement. The ISO shall select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements and Scarcity Reserve Requirements, as part of its overall co-optimization process.

The ISO shall select Operating Reserves Suppliers that are properly located electrically so that all locational Operating Reserves requirements determined consistently with the requirements of Section 15.4.7 of this Rate Schedule and Scarcity Reserve Requirements determined consistently with the requirements of Section 15.4.6.2 of this Rate Schedule are satisfied, and so that transmission Constraints resulting from either the commitment or dispatch of Generators do not limit the ISO’s ability to deliver Energy to Loads in the case of a Contingency. The ISO will ensure that Suppliers that are compensated for using Capacity to provide one Operating Reserve product are not simultaneously compensated for providing another Operating Reserve product, or Regulation Service, using the same Capacity (consistent with the additive market clearing price calculation formulae in Sections 15.4.5.1 and 15.4.6.1 of this Rate Schedule).

15.4.1.2 Supplier Eligibility Criteria

The ISO shall enforce the following criteria, which define which types of Suppliers are eligible to supply particular Operating Reserve products.

15.4.1.2.1 Spinning Reserve:

Suppliers that are ISO-Committed Flexible or Self-Committed Flexible, are operating within the dispatchable portion of their operating range, are capable of responding to ISO instructions to change their output level within ten minutes, and that meet the criteria set forth in the ISO Procedures shall be eligible to supply Spinning Reserve. ~~(except for Demand Side Resources that are Local Generators not utilizing inverter-based energy storage technology~~ The following types of resources are only eligible to provide Spinning Reserve if all of the generating units use inverter-based energy storage technology and meet the criteria set forth in the ISO Procedures: (a) Aggregations comprised of one or more generating units, (b) Aggregations that include Demand Side Resource(s) where at least one Demand Side Resource facilitates its Demand Reduction by utilizing a Local Generator, and (c) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit~~)~~. Suppliers utilizing inverter-based energy storage technology, and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply Spinning Reserve when withdrawing or injecting Energy, and when idle.

15.4.1.2.2 10-Minute Non-Synchronized Reserve:

(i) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes; (ii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within ten (10) minutes; and (iii) ~~Demand Side Resources that are capable of reducing their Energy usage~~ Aggregations comprised solely of generating units that are capable of increasing their supply level within ten (10) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply 10-Minute Non-Synchronized Reserve.

15.4.1.2.3 30-Minute Reserve:

(i) Generators, except Behind-the-Meter Net Generation Resources and Aggregations that are comprised of more than one generating unit~~ and dispatched as a single aggregate unit~~, that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range shall be eligible to supply synchronized 30-Minute Reserves. Aggregations that include~~and~~ Demand Side Resource(s) that do not facilitate demand reduction using Local Generators, or that facilitate demand reduction using a Local Generator utilizing inverter-based energy storage technology, that are capable of reducing their Energy usage within thirty (30) minutes shall be eligible to supply synchronized 30-Minute Reserves Suppliers utilizing inverter-based energy storage technology, including Aggregations with a combination of Resources utilizing inverter-based energy storage technology and Demand Side Resources, and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply synchronized 30-Minute Reserves when withdrawing or when injecting Energy, and when idle; (ii) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes; (iii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within thirty (30) minutes; and ~~(iv) Demand Side Resources that are capable of reducing their Energy usage~~ (iv) Aggregations comprised of one or more generating units ~~and~~ that are capable of increasing their output level within thirty (30) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply non-synchronized 30-Minute Reserves.

15.4.1.2.4 Self-Committed Fixed and ISO-Committed Fixed Generators and Aggregations:

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~~Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market ~~or any supplemental commitment~~ may increase their Incremental Energy Bids ~~or Demand Reduction Bids~~ for portions of their Resources that have been scheduled ~~through those processes~~; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Withdrawal-Eligible

Generators or Aggregations comprised of one or more Withdrawal-Eligible Generators that are scheduled to withdraw Energy, and that are selected to provide Operating Reserve in the Day-Ahead Market ~~or any supplemental commitment~~, may decrease their Bids to withdraw Energy for portions of their resources that have been scheduled through those processes; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. ~~Generators or Demand Side Resources~~Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market ~~or any supplemental commitment~~ may not, however, reduce the UOL_N in their Real-Time Market Bids below the sum of their Day-Ahead Market schedules for Energy, Operating Reserve, and Regulation Service, ~~or supplemental commitments in real-time~~ except to the extent that they are directed to do so by the ISO. The ISO may reduce the real-time Operating Reserve schedule (in MW) from an Energy Storage Resource to account for the Energy Level of such Resource, as discussed in Section 4.4.2.1 of this ISO Services Tariff. ~~Generators and Demand Side Resources~~ Suppliers 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 least of the Resource's emergency response rate multiplied by ten, or the Resource's applicable Upper Operating Limit (i.e., UOL_N, UOL_E); (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 least of the Resource's emergency response rate multiplied by twenty and its applicable Upper Operating Limit..

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. For an Energy Storage Resource or an Aggregation of Energy Storage Resources, the Resource's Energy schedule minus its Regulation Service schedule shall not be less than the Resource's Lower Operating Limit.

For an Energy Limited Resource or Aggregation of Energy Limited Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy Schedule, the amount of Regulation Capacity it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed the lesser of zero or its Upper Operating Limit. For an Energy Storage Resource or Aggregation ~~thereof)~~of Energy Storage Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy Schedule, the amount of Regulation Capacity it is scheduled to provide, and the amount of Operating Reserves product it is scheduled to provide shall not exceed its Upper Operating Limit.

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 Section 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~~,~~ or 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 least of the Resource's emergency response rate multiplied by ten and the Resource's applicable Upper Operating Limit (UOL_N or UOL_E); (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 least of the Resource's emergency response rate multiplied by twenty and the Resource's applicable Upper Operating Limit (UOL_N or UOL_E). 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.

For an Energy Limited Resource or an Aggregation of Energy Limited Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy schedule, the amount of Regulation Capacity it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed the lesser of zero or its UOL. For an Energy Storage Resource or an Aggregation of Energy Storage Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy Schedule, the amount of Regulation Capacity it is scheduled to provide and the amount of Operating Reserves product it is scheduled to provide shall not exceed its UOL. The ISO may limit the availability of a Withdrawal-Eligible Generator to provide Operating Reserves based on its Energy Level constraints.

Suppliers will thus be selected on the basis of their response rates, their applicable upper operating limits, and their Energy Bids (which will reflect their opportunity costs) through a co-optimized real-time commitment process that minimizes the total bid cost of Energy~~, or Demand Reduction~~, Regulation Service, and Operating Reserves. As part of the process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements and Scarcity Reserve Requirements specified above.

15.4.3.2 ISO Notice Requirement

The ISO shall notify each Supplier of Operating Reserve that has been scheduled by RTD of the amount of Operating Reserve that it must provide.

15.4.3.3 Obligation to Make Resources Available to Provide Operating Reserves

Any Resource that is eligible to supply Operating Reserves and that is made available to ISO for dispatch in Real-Time must also make itself available to provide Operating Reserves.

15.4.3.4 Activation of Operating Reserves

All Resources that are selected by the ISO to provide Operating Reserves shall respond to the ISO's directions to activate in real-time.

15.4.3.5 Performance Tracking and Supplier Disqualifications

When a Supplier committed to supply Operating Reserves is activated, the ISO shall measure and track its actual Energy injections, ~~and~~ withdrawals, and~~or its~~ Demand Reductions against its expected performance in real-time. The ISO may disqualify Suppliers that consistently fail to provide Energy, ~~or~~ Demand Reduction, or to reduce Energy withdrawals, when called upon to do so in real-time from providing Operating Reserves in the future. If a Resource has been disqualified, the ISO shall require it to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from it. Disqualification and re-qualification criteria shall be set forth in the ISO Procedures.

15.4.4 Operating Reserves Settlements - General Rules

15.4.4.1 Establishing Locational Reserve and Scarcity Reserve Requirement Prices

Except as noted below, the ISO shall calculate separate Day-Ahead Market and Real-Time Market prices for each of the products in five locations: (i) West of Central-East ("West" or "Western"); (ii) East of Central-East excluding Southeastern New York ("Eastern"); (iii) Southeastern New York excluding New York City and Long Island ("Southeastern"); (iv) New York City ("N.Y.C."); and (v) Long Island ("L.I."). The ISO will thus calculate fifteen different locational Operating Reserve prices in both the Day-Ahead Market and the Real-Time Market. The ISO will also calculate prices in the Real-Time Market for each of the products in a Scarcity Reserve Region, if applicable. Day-Ahead locational reserve prices shall be calculated pursuant to Section 15.4.5 of this Rate Schedule. Real-Time locational Operating Reserves prices and Scarcity Reserve Requirement prices shall be calculated pursuant to Section 15.4.6 of this Rate Schedule.

15.4.4.2 Settlements Involving Suppliers of Operating Reserves Located on Long Island

Suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York, except in the case of a Scarcity Reserve Requirement for a Scarcity Reserve Region that includes Long Island in addition to one or more other Load Zones. In this instance, suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York and in the applicable Scarcity Reserve Region. The ISO will calculate separate locational Long Island Operating Reserves prices and Long Island Scarcity Reserve Requirement prices for Scarcity Reserve Regions that include Long Island but will not post them or use them for settlement purposes.

15.4.4.3 "Cascading" of Operating Reserves

The ISO will deem Spinning Reserve to be the "highest quality" Operating Reserve, followed by 10-Minute Non-Synchronized Reserve and by 30-Minute Reserve. The ISO shall substitute higher quality Operating Reserves in place of lower quality Operating Reserves, when doing so lowers the total as-bid cost, *i.e.*, when the marginal cost for the higher quality Operating Reserve product is lower than the marginal cost for the lower quality Operating Reserve product, and the substitution of a higher quality for the lower quality product does not cause locational Operating Reserve requirements or Scarcity Reserve Requirements to be violated. To the extent, however, that reliability standards require the use of higher quality Operating Reserves, substitution cannot be made in the opposite direction.

The market clearing price of higher quality Operating Reserves will not be set at a price below the market clearing price of lower quality Operating Reserves in the same location or Scarcity Reserve Region. Thus, the market clearing price of Spinning Reserves will not be below the price for 10-Minute Non-Synchronized Reserves or 30-Minute Reserves and the market clearing price for 10-Minute Non-Synchronized Reserves will not be below the market clearing price for 30-Minute Reserves.

15.4.5 Operating Reserve Settlements – Day-Ahead Market

15.4.5.1 Calculation of Day-Ahead Market Clearing Prices

The ISO shall calculate hourly Day-Ahead Market clearing prices for each Operating Reserve product at each location. Each Day-Ahead Market clearing price shall equal the sum of the relevant Day-Ahead locational Shadow Prices for that product in that hour, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

The Day-Ahead Market clearing price for a particular Operating Reserve product in a particular location shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements, that a particular Operating Reserves product from a particular location may be used to satisfy in a given hour. The ISO shall calculate Day-Ahead Market clearing prices using the following formulae:

Market clearing price for Western 30-Minute Reserves = SP1

Market clearing price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2

Market clearing price for Western Spinning Reserves = SP1 + SP2 + SP3

Market clearing price for Eastern 30-Minute Reserves = SP1 + SP4

Market clearing price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5

Market clearing price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6

Market clearing price for Southeastern 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for Southeastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Market clearing price for N.Y.C. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

Market clearing price for N.Y.C. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11

Market clearing price for N.Y.C. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 + SP12

Market clearing price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP13

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP13 + SP14

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP13 + SP14 + SP15

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint for the hour

SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the hour

SP3 = Shadow Price for total Spinning Reserve requirement constraint for the hour

SP4 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. 30-Minute Reserve requirement constraint for the hour

SP5 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the hour

SP6 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the hour

SP7 = Shadow Price for Southeastern, N.Y.C., or L.I. 30-Minute Reserve requirement constraint for the hour

SP8 = Shadow Price for Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the hour

SP9 =Shadow Price for Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the hour

SP10 = Shadow Price for New York City 30-Minute Reserve requirement constraint for the hour

SP11 = Shadow Price for New York City 10-Minute Reserve requirement constraint for the hour

SP12 =Shadow Price for New York City Spinning Reserve requirement constraint for the hour

SP13 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour

SP14 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour

SP15 = Shadow Price for Long Island Spinning Reserve requirement constraint for the hour

Day-Ahead locational Shadow Prices will be calculated by SCUC. Each hourly Day-Ahead Shadow Price for each Operating Reserves requirement shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that hour, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement shall include the Day-Ahead Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Day-Ahead Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by SCUC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If more Operating Reserve of a particular quality than is needed is scheduled to meet a particular locational Operating Reserve requirement, the Shadow Price for that Operating Reserve requirement constraint shall be set at zero.

Each Supplier that is scheduled Day-Ahead to provide Operating Reserve shall be paid the applicable Day-Ahead Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each hour.

15.4.5.2 Other Day-Ahead Payments

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a ~~Demand Side Resource~~ Aggregation that provides Operating Reserves may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

15.4.6 Operating Reserve Settlements – Real-Time Market

15.4.6.1 Calculation of Real-Time Market Clearing Prices

The ISO shall calculate Real-Time Market clearing prices for each Operating Reserve product for each location in every interval and Scarcity Reserve Region in each interval for which a Scarcity Reserve Requirement is established by the ISO. Each real-time market-clearing price shall equal the sum of the relevant real-time locational Shadow Prices and Scarcity Reserve Requirement Shadow Prices for a given product, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

The Real-Time Market clearing price for a particular Operating Reserve product for a particular location or Scarcity Reserve Region shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements and Scarcity Reserve Requirements, that a particular Operating Reserves product from that location or Scarcity Reserve Region may be used to satisfy in a given interval. The ISO shall calculate the Real-Time Market clearing prices using the following formulae:

Market clearing price for Western 30-Minute Reserves = SP1

Market clearing price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2

Market clearing price for Western Spinning Reserves = SP1 + SP2 + SP3

Market clearing price for Eastern 30-Minute Reserves = SP1 + SP4

Market clearing price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5

Market clearing price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6

Market clearing price for Southeastern 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for Southeastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Market clearing price for N.Y.C. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

Market clearing price for N.Y.C. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11

Market clearing price for N.Y.C. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 + SP12

Market clearing price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP13

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP13 + SP14

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP13 + SP14 +SP15

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the interval

SP3 = Shadow Price for total Spinning Reserve requirement constraint for the interval

SP4 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP5 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the interval

SP6 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the interval

SP7 = Shadow Price for Southeastern, N.Y.C., or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP8 = Shadow Price for Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the interval

SP9 = Shadow Price for Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the interval

SP10 = Shadow Price for New York City 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP11 = Shadow Price for New York City 10-Minute Reserve requirement constraint for the interval

SP12 =Shadow Price for New York City Spinning Reserve requirement constraint for the interval

SP13 = Shadow Price for Long Island 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP14 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP15 = Shadow Price for Long Island Spinning Reserve requirement constraint for the interval

Real-time locational and Scarcity Reserve Requirement Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that interval, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that interval, as calculated during the second RTD pass described in Section 17.1.2.1.2.2 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, shall include the Real-Time Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve or Scarcity Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Real-Time Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the

Operating Reserve Demand Curves and Scarcity Reserve Demand Curve described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by RTC at a cost greater than the relevant Operating Reserve Demand Curve or Scarcity Reserve Demand Curve indicates should be paid. If there is more Operating Reserve of the required quality than is needed to meet a particular locational Operating Reserve requirement or Scarcity Reserve Requirement then the Shadow Price for that Operating Reserve requirement or Scarcity Reserve Requirement constraint shall be zero.

Each Supplier that is scheduled in real-time to provide Operating Reserve shall be paid the applicable Real-Time Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each interval that was not scheduled Day-Ahead.

15.4.6.1.1 The Real-Time Market clearing price shall also reflect the Shadow Price for any Scarcity Reserve Requirement constraint as part of the applicable 30-Minute Reserve requirement constraint Shadow Price for the Load Zones included in the Scarcity Reserve Region. The inclusion of Scarcity Reserve Requirement constraint Shadow Prices in the calculation of Real-Time Market clearing prices is as set forth below:

(a) When the Load Zones included in a Scarcity Reserve Region are identical to the Load Zones of an existing locational reserve region, the Scarcity Reserve Requirement will be added to the existing 30-Minute Reserve requirement for the locational reserve region and the Shadow Price for the Scarcity Reserve Requirement will be the Shadow Price for the revised 30-Minute Reserve requirement. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones A, B, C, D, E, F, G, H, I, J, and K (*i.e.*, all Load Zones), then the Shadow Price for the Scarcity Reserve Requirement shall be SP1. SP1 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones F, G, H, I, J, and K (*i.e.*, all East of Central-East Load Zones), but does not include Load Zones A, B, C, D, or E, then the Shadow Price for the Scarcity Reserve Requirement shall be SP4. SP4 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones G, H, I, J, and K (*i.e.*, all Southeastern New York Load Zones), but does not include Load Zones A, B, C, D, E, or F, then the Shadow Price for the Scarcity Reserve Requirement shall be SP7. SP7 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;

iv. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zone J (*i.e.*, New York City only), but does not include Load Zones A, B, C, D, E, F, G, H, I, or K, then the Shadow Price for the Scarcity Reserve Requirement shall be SP10. SP10 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices; or

v. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zone K (*i.e.*, Long Island only), but does not include Load Zones A, B, C, D, E, F, G, H, I, or J, then the Shadow Price for the Scarcity Reserve Requirement shall be SP13. SP13 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices.

(b) When the Load Zones included in the Scarcity Reserve Region are not identical to the Load Zones of an existing locational reserve region, the Shadow Price attributable to the Scarcity Reserve Requirement will be added to the applicable Shadow Price for the 30-Minute Reserve requirement for the existing locational reserve region to which all of the Load Zones included in the Scarcity Reserve Region belong. The inclusion of the Scarcity Reserve Requirement Shadow Prices shall apply only to the Load Zones included as part of a Scarcity Reserve Region. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones A, B, C, D, or E and Section 15.4.6.1.1(a)(i) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP1 for each of the Load Zones included in the Scarcity Reserve Region. This SP1 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time

Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region;

ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least Load Zone F, but does not include Load Zones A, B, C, D, or E and Section 15.4.6.1.1(a)(ii) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP4 for each of the Load Zones included in the Scarcity Reserve Region. This SP4 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region; or

iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones G, H, I, J, or K but does not include Load Zones A, B, C, D, E or F and Sections 15.4.6.1.1(a)(iii), 15.4.6.1.1(a)(iv), or 15.4.6.1.1(a)(v) of this Rate Schedule are not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP7 for each of the Load Zones included in the Scarcity Reserve Region. This SP7 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region.

15.4.6.2 Establishment of Scarcity Reserve Requirements in the Real-Time Market During EDRP/SCR Activations

The ISO will establish a Scarcity Reserve Requirement for each Scarcity Reserve Region when it has called upon the EDRP and/or SCRs in identified Load Zones to reduce Load to address a reliability need. The Scarcity Reserve Requirement will be applicable for all real-time intervals during which the ISO has activated EDRP and/or SCRs within the applicable Scarcity Reserve Region to provide Load reduction. The Scarcity Reserve Requirement for each affected real-time interval shall be an amount equal to the sum of the applicable values for the Expected EDRP/SCR MW for all of the Load Zones included in a Scarcity Reserve Region, less the Available Operating Capacity in the Scarcity Reserve Region; provided, however, that a Scarcity Reserve Requirement shall not have a value less than zero.

The applicable value of the Expected EDRP/SCR MW for each Load Zone included in a Scarcity Reserve Region to be used in calculating the Scarcity Reserve Requirement is dependent upon whether the Load reduction for a given interval is deemed voluntary or mandatory for purposes of calculating the Scarcity Reserve Requirement, as further described below. If the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of this ISO Services Tariff for the SCRs within any Load Zone for any hour encompassed by the EDRP/SCR activation(s) for the day at issue, the Load reduction for all intervals encompassed by such activation(s) are deemed to be mandatory for the purposes of calculating any Scarcity Reserve Requirement only and the corresponding value for a mandatory Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. In all other circumstances not encompassed by the preceding sentence, the Load reduction for all intervals encompassed by such EDRP/SCR activation(s) are deemed to be voluntary for the day at issue and the corresponding value for a voluntary Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. For EDRP, Load reduction is deemed to be voluntary in all intervals and the value for EDRP included in the Expected EDRP/SCR MW value for each Load Zone reflects the voluntary nature of the Load reduction.

15.4.6.3 Operating Reserve Balancing Payments

Any deviation in performance from a Supplier's Day-Ahead schedule to provide Operating Reserves, including deviations that result from schedule modifications made by the ISO, shall be settled pursuant to the following rules.

(a) When the Supplier's real-time Operating Reserves schedule is less than its Day-Ahead Operating Reserves schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserves Product in the relevant location or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

(b) When the Supplier's real-time Operating Reserves schedule is greater than its Day-Ahead Operating Reserves schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserve product in the relevant location or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

15.4.6.4 Other Real-Time Payments

The ISO shall pay Generators and Aggregations that are selected to provide Operating Reserves Day-Ahead, but are directed to convert to Energy production or, for Withdrawal-Eligible Generators and Aggregations that include Withdrawal-Eligible Generator(s), to reduce Energy withdrawals in real-time, the applicable Real-Time LBMP for all Energy they are directed to provide in excess of their Day-Ahead Energy schedule.

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) an ~~Demand Side Resource~~Aggregation that provides Operating Reserves may be eligible for a Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

A Supplier that provides Operating Reserves may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.6.5 and Attachment J of this ISO Services Tariff.

15.4.7 Operating Reserve Demand Curves and Scarcity Reserve Demand Curve

The ISO shall establish Operating Reserve Demand Curves for each locational Operating Reserves requirement. Specifically, there shall be a demand curve for: (i) Total Spinning Reserves; (ii) Eastern, Southeastern, New York City, or Long Island Spinning Reserves; (iii) Southeastern, New York City, or Long Island Spinning Reserves; (iv) New York City Spinning Reserves; (v) Long Island Spinning Reserves; (vi) Total 10-Minute Reserves; (vii) Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves; (viii) Southeastern, New York City, or Long Island 10-Minute Reserves; (ix) New York City 10-Minute Reserves; (x) Long Island 10-Minute Reserves; (xi) Total 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement); (xii) Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); (xiii) Southeastern, New York City, or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); (xiv) New York City 30-Minute Reserves (including a separate demand curve applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply); and (xv) Long Island 30-Minute Reserves (including a separate demand curve applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(v) of this Rate Schedule apply). Each Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location, except for those demand curves that apply to certain Scarcity Reserve Requirements which will be applicable only during the real-time intervals that a Scarcity Reserve Requirement has been established by the ISO. The ISO shall also establish a Scarcity Reserve Demand Curve for each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. A Scarcity Reserve Demand Curve will be applicable only during the real-time intervals that such a Scarcity Reserve Requirement has been established by the ISO.

The market clearing pricing for Operating Reserves shall be calculated pursuant to Sections 15.4.5.1 and 15.4.6.1 of this Rate Schedule and in a manner consistent with the demand curves established in this Section so that Operating Reserves are not purchased by SCUC, RTC or RTD at a cost higher than the relevant demand curve indicates should be paid.

The ISO Procedures shall establish and post a target level for each locational Operating Reserves requirement for each hour, which will be the number of MW of Operating Reserves meeting that requirement that the ISO would seek to maintain in that hour. To the extent not otherwise already adjusted pursuant to Section 15.4.6.1.1(a) of this Rate Schedule, during each real-time interval in which the ISO has established a Scarcity Reserve Requirement, the ISO will adjust the target level for the locational 30-Minute Reserves requirement to account for the

Scarcity Reserve Requirement within the existing locational reserve region(s) to which all the Load Zones included in the Scarcity Reserve Region belong. The ISO will then define an Operating Reserves demand curve for that hour corresponding to each Operating Reserves requirement as follows:

(a) Total Spinning Reserves: For quantities of Operating Reserves meeting the total Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total Spinning Reserves demand curve shall be $775/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be $0/MW.

(b) Eastern, Southeastern, New York City, or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $0/MW.

(c) Southeastern, New York City, or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be $0/MW.

(d) New York City Spinning Reserves: For quantities of Operating Reserves meeting the New York City Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York City Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the New York City Spinning Reserves demand curve shall be $0/MW.

(e) Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island Spinning Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island Spinning Reserves demand curve shall be $0/MW.

(f) Total 10-Minute Reserves: For quantities of Operating Reserves meeting the total 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total 10-minute reserves demand curve shall be $750/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be $0/MW.

(g) Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern, New York City, or Long Island 10-minute reserves demand curve shall be $775/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 10-minute reserves demand curve shall be $0/MW.

(h) Southeastern, New York City, or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 10-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern, New York City, or Long Island 10-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 10-Minute Reserves demand curve shall be $0/MW.

(i) New York City 10-Minute Reserves: For quantities of Operating Reserves meeting the New York City 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York City 10-minute reserves demand curve shall be $25/MW. For all other quantities, the price on the New York City 10-minute reserves demand curve shall be $0/MW.

(j) Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 10-minute reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 10-minute reserves demand curve shall be $0/MW.

(k) Total 30-Minute Reserves: For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 955 MW, the price on the total 30-Minute

Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 655 MW but that exceed the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $200/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 300 MW but that exceed the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be $100/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement but that exceed the target level for that locational requirement minus 300 MW, the price on the total 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the requirement for that hour. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("NYCA scarcity target level") that are less than or equal to the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the NYCA scarcity target level that are less than or equal to the NYCA scarcity target level but that exceed the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the Scarcity Reserve Requirement for that interval.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted NYCA target level") that are less than or equal to the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be $750/MW. For quantities of Operating Reserves meeting the adjusted NYCA target level that are less than or equal to the adjusted NYCA target level but that exceed the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute

Reserves demand curve shall be $500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be $0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the applicable Scarcity Reserve Requirement(s) for that interval.

(l) Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Eastern scarcity target level") that are less than or equal to the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Eastern scarcity target level that are less than or equal to the Eastern scarcity target level but exceed the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the East of Central-East reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted Eastern target level") that are less than or equal to the adjusted Eastern target level, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

(m) Southeastern, New York City, or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Southeastern scarcity target level") that are less than or equal to the Southeastern scarcity target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $500/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be $0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the Southeastern New York reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) ("adjusted Southeastern target level") that are less than or equal to the adjusted Southeastern target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

(n) New York City 30-Minute Reserves: For quantities of Operating Reserves meeting the New York City 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York City 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the New York City 30-Minute Reserves demand curve shall be \$0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply, the applicable Operating Reserves demand curve for New York City 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the New York City 30-

Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("N.Y.C. scarcity target level") that are less than or equal to the N.Y.C. scarcity target level minus an amount equal to the New York City 30-Minute Reserves locational requirement target, the price on the New York City 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the N.Y.C. scarcity target level that are less than or equal to the N.Y.C. scarcity target level but exceed the N.Y.C. scarcity target level minus an amount equal to the New York City 30-Minute Reserves locational requirement target level, the price on the New York City 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the New York City 30-Minute Reserves demand curve shall be $0/MW.

(o) Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be $0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(v) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement ("Long Island scarcity target level") that are less than or equal to the

Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target, the price on the Long Island 30-Minute Reserves demand curve shall be $500/MW. For the quantities of Operating Reserves meeting the Long Island scarcity target level that are less than or equal to the Long Island scarcity target level but exceed the Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target level, the price on the Long Island 30-Minute Reserves demand curve shall be $25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be $0/MW.

The ISO will procure additional Operating Reserves to meet each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. The Scarcity Reserve Demand Curve for each real-time interval in which the ISO has established such a Scarcity Reserve Requirement shall be defined as follows: For quantities of Operating Reserves meeting the Scarcity Reserve Requirement that are less than or equal to the Scarcity Reserve Requirement, the price on the Scarcity Reserve Demand Curve shall be $500/MW. For all other quantities, the price on the Scarcity Reserve Demand Curve shall be $0/MW.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure any Operating Reserve product at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Operating Reserves Demand Curves the ISO, in consultation with its Market Advisor, shall conduct an initial review of them in accordance with the ISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether any Operating Reserve Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the ISO Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.4.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 4 to the Services Tariff are also addressed in Section 30.4.6.4.2 of Attachment O.

15.4.8 Self-Supply

Transactions may be entered into to provide for Self-Supply of Operating Reserves. Except as noted in the next paragraph, Customers seeking to Self-Supply Operating Reserves must place the Generator(s) or Aggregation(s) supplying any one of the Operating Reserves under ISO control. The Generator(s) or Aggregation(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) or Aggregation(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.

17.1 LBMP Calculation

The Locational Based Marginal Prices ("LBMPs" or "prices") for Suppliers and Loads in the Real-Time Market will be based on the system marginal costs produced by the Real-Time Dispatch ("RTD") program and during intervals when certain conditions exist at Proxy Generator Buses, the Real-Time Commitment ("RTC") program. LBMPs for Suppliers and Loads in the Day-Ahead Market will be based on the system marginal costs produced by the Security Constrained Unit Commitment ("SCUC"). LBMPs calculated by SCUC and RTD will incorporate the incremental dispatch costs of Resources that would be scheduled to meet an increment of Load and, to the extent that tradeoffs exist between scheduling providers to produce Energy or reduce demand, and scheduling them to provide Regulation Service or Operating Reserves, LBMPs shall reflect the effect of meeting an increment of Load, given those tradeoffs, at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Bids for Regulation Service or Operating Reserves; or (ii) shortage costs associated with the inability to meet a Regulation Service or Operating Reserves requirement under the Regulation Service Demand Curve set forth in Rate Schedule 3 of this ISO Services Tariff and Operating Reserve Demand Curves and Scarcity Reserve Demand Curve set forth in Rate Schedule 4 of this ISO Services Tariff. For the purposes of calculating LBMPs under this Services Tariff Section 17, Energy withdrawals by Withdrawal-Eligible Generators are treated as negative generation, and can set price.

Additionally, for the purpose of calculating Real-Time LBMPs when RTD is committing and dispatching Resources meeting Minimum Generation Levels and capable of starting in ten minutes pursuant to Section 4.4.2.4 of this ISO Services Tariff, RTD shall include in the incremental dispatch cost of each such Resource a start-up cost based on the Start-Up Bid of each such Resource and shall assume for each such Resource a zero downward response rate.

17.1.1 LBMP Bus Calculation Method

System marginal costs will be utilized in an *ex ante* computation to produce Day-Ahead and Real-Time LBMP bus prices using the following equations.

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma_i^L + \gamma_i^C$$

Where:

γ_i	=	LBMP at bus *i* in $/MWh
λ^R	=	the system marginal price at the Reference Bus
γ_i^L	=	Marginal Losses Component of the LBMP at bus *i* which is the marginal cost of losses at bus *i* relative to the Reference Bus
γ_i^C	=	Congestion Component of the LBMP at bus *i* which is the marginal cost of Congestion at bus *i* relative to the Reference Bus

The Marginal Losses Component of the LBMP at any bus i is calculated using the equation:

$$\gamma_i^L = (DF_i - 1)\lambda^R$$

Where:

DF_i = delivery factor for bus *i* to the system Reference Bus and:

$$DF_i = \left(1 - \frac{\partial L}{\partial P_i}\right)$$

Where:

L	=	NYCA losses; and
P_i	=	injection at bus *i*

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

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

Where:

K = the set of Constraints;

GF_{ik} = Shift Factor for bus *i* on Constraint *k* in the pre- or post-Contingency case which limits flows across that Constraint (the Shift Factor measures the incremental change in flow on Constraint *k*, expressed in per unit, for an increment of injection at bus *i* and a corresponding withdrawal at the Reference Bus); and

μ_k = the Shadow Price of Constraint *k* expressed in \$/MWh, provided however, this Shadow Price shall not exceed the Transmission Shortage Cost.

Substituting the equations for γ_i^L and γ_i^C into the first equation yields:

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

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.

17.1.1.1 Determining Shift Factors and Incremental System Losses

For the purposes of pricing and scheduling, Shift Factors, GF_{ik}, and loss delivery factors, DF_i, will reflect expected power flows, including expected unscheduled power flows. When determining prices and schedules, SCUC, RTC and RTD shall include both the expected power flows resulting from NYISO interchange schedules (*see* Section 17.1.1.1.2), and expected unscheduled power flows (*see* Section 17.1.1.1.1). All NYCA Resource, NYCA Load and Proxy

Generator Bus Shift Factors and loss delivery factors will incorporate internal and coordinated external transmission facility outages, power flows due to schedules, and expected unscheduled power flows.

17.1.1.1.1 Determining Expected Unscheduled Power Flows

In the Day-Ahead Market, expected unscheduled power flows will ordinarily be determined based on historical, rolling 30-day on-peak and off-peak averages. To ensure expected unscheduled power flows accurately reflect anticipated conditions, the frequency and/or period used to determine the historical average may be modified by the NYISO to address market rule, system topology, operational, or other changes that would be expected to significantly impact unscheduled power flows. The NYISO will publicly post the Day-Ahead on-peak and off-peak unscheduled power flows on its web site.

In the Real-Time Market, expected unscheduled power flows will ordinarily be determined based on current power flows, modified to reflect expected changes over the real-time scheduling horizon.

17.1.1.1.2 Determining Expected Power Flows Resulting from NYISO Interchange Schedules

In the Day-Ahead Market, for purposes of scheduling and pricing, SCUC will establish expected power flows for the ABC interface, JK interface and Branchburg-Ramapo interconnection based on the following:

a. Consolidated Edison Company of New York’s Day-Ahead Market hourly election under OATT Attachment CC, Schedule C;

b. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the Branchburg-Ramapo interconnection. The expected flow may also be adjusted by a MW offset to reflect expected operational conditions;

c. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the ABC interface; and

d. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the JK interface.

The terms "ABC interface" and "JK interface" have the meaning ascribed to them in Schedule C to Attachment CC to the OATT.

The NYISO shall post the percentage values it is currently using to establish Day-Ahead and real-time expected Branchburg-Ramapo interconnection, ABC interface and JK interface flows for purposes of scheduling and pricing on its web site. If the NYISO determines it is necessary to change the posted Branchburg-Ramapo, ABC or JK percentage values, it will provide notice to its Market Participants as far in advance of the change as is practicable under the circumstances.

In the Day-Ahead Market, scheduled interchange that is not expected to flow over the ABC interface, JK interface or Branchburg-Ramapo interconnection (or on Scheduled Lines) will be expected to flow over the NYISO's other interconnections. Expected flows over the NYISO's other interconnections will be determined consistent with the expected impacts of scheduled interchange and consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

For pricing purposes, flows in the Real-Time Market will be established for the ABC interface, JK interface, and Branchburg-Ramapo interconnection based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon in a manner that is consistent with the method used to establish Day-Ahead power flows over these facilities. Expected flows over the NYISO's other interconnections will be determined based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon, and shall be consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

17.1.1.1.3 Scheduled Lines and Chateauguay Interconnection with Hydro Quebec

For purposes of scheduling and pricing, the NYISO expects that power flows will ordinarily match the interchange schedule at Scheduled Lines, and at the NYCA's Chateauguay interconnection with Hydro Quebec, in both the Day-Ahead and Real-Time Markets.

17.1.2 Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Sections 17.1.2.1-17.1.2.1.4 to calculate Real-Time LBMPs at each Load Zone~~ and~~, Generator bus and Transmission Node. The LBMP bus and zonal calculation procedures are described in Sections 17.1.1 and 17.1.5 of this Attachment B, respectively. Procedures governing the calculation of LBMPs at Proxy Generator Buses are set forth below in Section 17.1.6 of this Attachment B.

17.1.2.1 General Procedures

17.1.2.1.1 Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes of each RTD run, except as noted below in Section 17.1.2.1.3. A new RTD run will initialize every five minutes and each run will produce prices and schedules for five points in time (the optimization period). Only the prices and schedules determined for the first time point of the optimization period will be binding. Prices and schedules for the other four time points of the optimization period are advisory.

Each RTD run shall, depending on when it occurs during the hour, have a bid optimization horizon of fifty, fifty-five, or sixty minutes beyond the first, or binding, point in time that it addresses. The posting time and the first time point in each RTD run, which establishes binding prices and schedules, will be five minutes apart. The remaining points in time in each optimization period can be either five, ten, or fifteen minutes apart depending on when the run begins within the hour. The points in time in each RTD optimization period are arranged so that they parallel as closely as possible RTC's fifteen minute evaluations.

For example, the RTD run that posts its results at the beginning of an hour ("RTD_0") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD_0 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at the beginning of the hour) and ending at the first time point in its optimization period (i.e., five minutes after the hour). It will produce advisory prices and schedules for its second time point, which is ten minutes after the first time point in its optimization period, and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at five minutes after the beginning of the hour ("RTD_5") will initialize at the beginning of the hour and produce prices over a fifty minute optimization period. RTD_5 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at five minutes after the hour) and ending at the first time point in its optimization period (i.e., ten minutes after the hour.) It will produce advisory prices and schedules for its second time point (which is five minutes after the first time point), and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at ten minutes after the beginning of the hour (“RTD_{10}”) will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD_{10} will produce binding prices and schedules for the interval beginning when it posts its results (i.e., at ten minutes after the hour) and ending at the first time point in its optimization period (i.e., fifteen minutes after the hour.) It will produce advisory prices and schedules for its second, third, fourth and fifth time points, each of which would be fifteen minutes after the preceding time point.

17.1.2.1.2 Description of the Real-Time Dispatch Process

17.1.2.1.2.1 The First Pass

The first RTD pass consists of a least bid cost, multi-period co-optimized dispatch for Energy, Regulation Service and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO as if they were blocked on at their UOL_N or UOL_E, whichever is applicable. Resources meeting Minimum Generation Levels and capable of being started in ten minutes that have not been committed by RTC are treated as flexible (i.e. able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable). The first pass establishes “physical base points” (i.e., real-time Energy schedules) and real-time schedules for Regulation Service and Operating Reserves for the first time point of the optimization period. Physical base points and schedules established for the first time point shall be binding and shall remain in effect until the results of the next run are posted. Physical base points and schedules established for all subsequent time points shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point Signals that the ISO sends to Suppliers.

When establishing physical base points, the ISO shall assume that each Generator and Aggregation will move toward the physical base point established during the first pass of the prior RTD run at its specified response rate.

17.1.2.1.2.1.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind as Their Fuel

When setting physical base points for a Dispatchable Resource at the first time point, the ISO shall ensure that they do not fall outside of the bounds established by the Dispatchable Resource's lower and upper dispatch limits. A Dispatchable Resource's dispatch limits shall be determined based on whether it was feasible for it to reach the physical base point calculated by the last RTD run given its: (A) metered output level at the time that the RTD run was initialized; (B) response rate; (C) minimum generation level; and (D) UOL_N or UOL_E, whichever is applicable. If it was feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E, as applicable, and starting from its previous base point. If it was not feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E, as applicable, but instead starting from the feasible output level closest to its previous base point.

When setting physical base points for a Dispatchable Resource at later time points, the ISO shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper dispatch limits for that time point. A Resource's dispatch limits at later time points shall be based on its: (A) dispatch limits from the first time point; (B) response rate; (C) minimum generation; and (D) UOL_N or UOL_E, whichever is applicable.

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by increasing the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by decreasing the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level or to a Demand Side Resource's Demand Reduction level.

The RTD Base Point Signals sent to Dispatchable Resources shall be the same as the physical base points determined above.

17.1.2.1.2.1.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind as Their Fuel

For all time points of the optimization period, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind Energy Forecast.

17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators and Aggregations

When setting physical base points for Self-Committed Fixed Generators and Aggregations 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 and Aggregations 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 and Aggregations shall follow the quarter hour operating schedules that those Generators and Aggregations 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 or Aggregation's operating schedule is not feasible based on its real-time self-commitment requests then its RTD Base Point Signals shall be determined using a response rate consistent with the operating schedule changes.

17.1.2.1.2.2 The Second Pass

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats all Fixed Block Units that are committed by RTC, all Resources meeting Minimum Generation Levels and capable of starting in ten minutes that have not been committed by RTC and all units otherwise instructed to be online or remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable), regardless of their minimum run-time status. The second pass calculates real-time Energy prices and real-time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Article 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this ISO Services Tariff respectively. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Resources shall be the same as the physical base points calculated in the first pass.

17.1.2.1.2.2.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind as Their Fuel

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the higher of: (A) its upper dispatch limit from the first pass; or (B) its "pricing base point" from the first time point of the prior RTD interval adjusted up within its Dispatchable range for any possible ramping since that pricing base point was issued less the higher of: (i) the physical base point established during the first pass of the RTD immediately prior to the previous RTD minus the Resource's metered output level at the time that the current RTD run was initialized, or (ii) zero.

The lower dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the lower of: (A) its lower dispatch limit from the first pass; or (B) its "pricing base point" from the first time point of the prior RTD interval adjusted down within its Dispatchable range to account for any possible ramping since that pricing base point was issued plus the higher of: (i) the Resource's metered output level at the time that the current RTD run was initialized minus the physical base point established during the first pass of the RTD immediately prior to the previous RTD; or (ii) zero.

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource shall be determined by increasing its upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable. The lower dispatch limit for the later time points of the second pass for such a Resource shall be determined by decreasing its lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level.

17.1.2.1.2.2.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind as Their Fuel

For the first time point and later time points for Intermittent Power Resources that depend on wind as their fuel, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind Energy Forecast.

17.1.2.1.2.3 The Third Pass

The third RTD pass is reserved for future use.

17.1.2.1.3 Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 17.1.2.1.1 and 17.1.2.1.2 shall apply.

First, if the ISO enters reserve pickup mode: (i) the ISO will produce prices and schedules for a single ten minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator and Aggregations commitments before executing the three RTD passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator or Aggregation to be set to the higher of the Generator's or Aggregation's physical base point or its actual ~~generation~~supply level.

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator and Aggregation commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator and Aggregation 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 and Aggregation that are capable of starting within ten minutes before executing the three RTD passes.

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization period consisting of two five-minute time points.

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

Attachment H of this Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are implemented they shall be incorporated into the RTC software through the establishment of a second, parallel, commitment evaluation that will assess the impact of the mitigation measures. The first evaluation, referred to as the "RTC evaluation," will determine the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the "RT-AMP" evaluation, will determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow the rules governing RTC's operation that are set forth in Article 4 and this Attachment B to this ISO Services Tariff.

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, RTC_{15} and $RT\text{-}AMP_{15}$ 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).

17.1.3 Day-Ahead LBMP Calculation Procedures

LBMPs in the Day-Ahead Market are calculated using five passes. The first two passes are commitment and dispatch passes; the last three are dispatch only passes.

Pass 1 consists of a least cost commitment and dispatch to meet Bid Load and reliable operation of the NYS Power System that includes Day-Ahead Reliability Units.

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment ("SCUC") to meet Bid Load. At the end of this step, committed Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, ~~Demand Side Resources~~, and non-Fixed Block Units are dispatched to meet Bid Load with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure ("AMP") activation.

If AMP is activated, Step 1B tests to determine if the AMP will be triggered by mitigating offer prices subject to mitigation that exceed the conduct threshold to their respective reference prices. These mitigated offer prices together with all originally submitted offer prices not subject to automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This step is another iteration of the SCUC process. At the end of Step 1B, committed Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, ~~Demand Side Resources,~~ and non-Fixed Block Units are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are again calculated from this dispatch. The LBMPs determined at the end of Step 1B are compared to the LBMPs determined at the end of Step 1A to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the SCUC process. At the end of Step 1C, committed Fixed Block Units, Imports, Exports, virtual supply, virtual load, ~~Demand Side Resources,~~ and non-Fixed Block Units are again dispatched to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are again calculated from this dispatch.

All ~~Demand Side Resources and~~ non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at least to minimum load in Passes 4 through 6. All Energy Storage Resources and Aggregations dispatched in the final step of Pass 1 (which could be either Step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at the dispatch that was determined in Pass 1 in Passes 2 through 4. 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 n~~Non-Fixed Block Units committed in this step are blocked on at least to minimum Load in Passes 4 through 6. Intermittent Power Resources that depend on wind as their fuel committed in this pass as a result of the consideration of the Wind Energy Forecast are not blocked in Passes 5 or 6.

Pass 3 is reserved for future use.

Pass 4 consists of a least cost dispatch to forecast Load. It is not used to set schedules or prices. It is used for operational purposes and provides a dispatch of Fixed Block Units, Imports, Exports, ~~Demand Side Resources~~ and non-Fixed Block Units committed in Passes 1 or 2. Incremental Import Capacity committed in Pass 2 is re-evaluated and may be reduced if no longer required.

Pass 5 consists of a least cost dispatch of Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, ~~Demand Side Resources~~ and non-Fixed Block Units committed to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fixed Block Units are treated as dispatchable on a flexible basis. LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, ~~Demand Side Resources~~ and non-Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

Pass 6 consists of a least cost dispatch of all Day-Ahead committed Resources, Imports, Exports, Virtual Supply, Virtual Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units committed in the final step of Pass 1 blocked on at maximum Capacity. Final schedules for Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

17.1.4 Determination of Transmission Shortage Cost

The applicable Transmission Shortage Cost depends on whether a particular transmission Constraint is associated with a transmission facility or Interface that includes a non-zero constraint reliability margin value. The ISO shall establish constraint reliability margin values for transmission facilities and Interfaces. Non-zero constraint reliability margin values established by the ISO are normally equal to 20 MW. The ISO shall post to its website a list of transmission facilities and Interfaces assigned a constraint reliability margin value other than 20 MW.

For transmission facilities and Interfaces with a non-zero constraint reliability margin value, SCUC, RTC and RTD shall include consideration of a two step demand curve consisting of up to an additional 5 MW of available resource capacity at a cost of $350/MWh and up to an additional 15 MW of available resource capacity at a cost of $1,175/MWh when evaluating transmission Constraints associated with such facilities and Interfaces. In no event, however, shall the Shadow Price for such transmission Constraints exceed $4,000/MWh.

For transmission facilities and Interfaces with a constraint reliability margin value of zero, the Shadow Price for transmission Constraints associated with such facilities and Interfaces shall not exceed $4,000/MWh. SCUC, RTC and RTD shall not include consideration of the available resource capacity provided by the two step demand curve described above for such transmission Constraints.

In evaluating all transmission Constraints, the ISO will determine whether sufficient available resource capacity exists to solve each transmission Constraint at its applicable limit. If sufficient available resource capacity does not exist to solve the transmission Constraint at its otherwise applicable limit, the ISO shall increase the applicable limit for such transmission Constraint to an amount achievable by the available resource capacity plus 0.2 MW. For transmission facilities and Interfaces with a non-zero constraint reliability margin value, the ISO shall account for the 20 MW of available resource capacity from the two step demand curve described above in determining: (i) whether sufficient available resource capacity exists to solve transmission Constraints associated with such facilities and Interfaces at their otherwise applicable limit; and (ii) the extent of any limit adjustment required to solve such transmission Constraints.

The ISO may periodically evaluate the Transmission Shortage Cost to determine whether it is necessary to modify the Transmission Shortage Cost to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this evaluation. If the ISO determines that it is necessary to modify the Transmission Shortage Costs in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to ninety days, provided however the NYISO shall file such change with the Commission pursuant to Section 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will: (i) consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change; and (ii) notify Market Participants of any temporary modification.

The responsibilities of the ISO and the Market Monitoring Unit in evaluating and modifying the Transmission Shortage Cost, as necessary are addressed in Attachment O, Section 30.4.6.8.1 of this Market Services Tariff (“Market Monitoring Plan”).

17.1.5 Zonal LBMP Calculation Method

The computation described in Section 17.1.1 of this Attachment B is at the bus level. An eleven (11) zone model will be used for the LBMP billing related to Loads, except for Energy withdrawals by Eligible Generators for later injection onto the grid. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the Load Zone. The Load weights which will sum to unity will be calculated from the load bus MW distribution. Each component of the LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone *j* can be written as:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

where:

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;

$\gamma_j^{C,Z} = \sum W_i \gamma_i^L$ is the Congestion Component of the LBMP for zone j;

n = number of Load buses in zone j for which LBMPs are calculated; and

$W_i =$ Load weighting factor for bus i.

The NYISO also calculates and posts zonal LBMP for four (4) external zones for informational purposes only. Settlements for External Transactions are determined using the Proxy Generator Bus LBMP. Each external zonal LBMP is equal to the LBMP of the Proxy Generator Bus associated with that external zone. The table below identifies which Proxy Generator Bus LBMP is used to determine each of the posted external zonal LBMPs.

External Zone	External Zone PTID	Proxy Generator Bus	Proxy Generator Bus PTID
HQ	61844	HQ_GEN_WHEEL	23651
NPX	61845	N.E._GEN_SANDY_POND	24062
OH	61846	O.H._GEN_BRUCE	24063
PJM	61847	PJM_GEN_KEYSTONE	24065

Consistent with the ISO Services Tariff**,** LBMPs at Proxy Generator Buses are determined using calculated bus prices as described in this Section 17.1.

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

17.1.6.1 Definitions

Interface ATC Constraint: An Interface ATC Constraint exists when proposed economic transactions over an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed the transfer capability for the Interface or for an associated Proxy Generator Bus.

Interface Ramp Constraint: An Interface Ramp Constraint exists when proposed interchange schedule changes pertaining to an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed any Ramp Capacity limit imposed by the ISO for the Interface or for an associated Proxy Generator Bus.

NYCA Ramp Constraint: A NYCA Ramp Constraint exists when proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole.

Proxy Generator Bus Constraint: Any of an Interface ATC Constraint, an Interface Ramp Constraint, or a NYCA Ramp Constraint (individually and collectively).

External Interface Congestion: The product of: (i) the portion of the Congestion Component of the LBMP at a Proxy Generator Bus that is associated with a Proxy Generator Bus Constraint and (ii) a factor, between zero and 1, calculated pursuant to ISO Procedures.

Proxy Generator Bus Border LBMP: The LBMP at a Proxy Generator Bus minus External Interface Congestion at that Proxy Generator Bus.

Unconstrained RTD LBMP: The LBMP as calculated by RTD less any congestion associated with a Proxy Generator Bus Constraint.

17.1.6.2 General Rules

Transmission Customers and Customers with External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. Those with External Generators may arrange LBMP Market sales and/or Bilateral Transactions with Internal or External Loads and External Loads may arrange LBMP Market purchases and/or Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of Proxy Generator Buses. LBMPs will be calculated for each Proxy Generator Bus within this limited set. When an Interface with multiple Proxy Generator Buses is constrained, the ISO will apply the constraint to all of the Proxy Generator Buses located at that Interface. Except as set forth in Sections 17.1.6.3 and 17.1.6.4, the NYISO will calculate the three components of LBMP for Transactions at a Proxy Generator Bus as provided in the tables below.

When determining the External Interface Congestion, if any, to apply to determine the LBMP for RTD intervals that bridge two RTC intervals, the NYISO shall use the External Interface Congestion associated with the second (later) RTC interval.

17.1.6.2.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses

The pricing rules for Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.2.2 Pricing rules for Variably Scheduled Proxy Generator Buses

The pricing rules for Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
2	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$

17.1.6.2.3 Pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled

The pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
3	RTC_{15} is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$

17.1.6.3 Rules for Non-Competitive Proxy Generator Buses and Associated Interfaces

Real-Time LBMPs for an Interface that is associated with one or more Non-Competitive Proxy Generator Buses or for a Non-Competitive Proxy Generator Bus shall be determined as provided in the tables below. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

17.1.6.3.1 Pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses are to be determined.

17.1.6.3.2 Pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface RampConstraint	Into NYCA (Import)	If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.3.3 Pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
6	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
7	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.4 Special Pricing Rules for Proxy Generator Buses Associated with Designated Scheduled Lines

Real-Time LBMPs for the Proxy Generator Buses associated with designated Scheduled Lines shall be determined as provided in the tables below. The Proxy Generator Buses that are associated with designated Scheduled Lines are identified in Section 4.4.4 of the Services Tariff.

17.1.6.4.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are to be determined.

17.1.6.4.2 Pricing rules for Variably Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Variably Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Into NYCA (Import)	If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Out of NYCA (Export)	If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + Rolling RTC External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$)

17.1.6.4.3 Pricing rules for Proxy Generator Buses that are associated with Designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Proxy Generator Buses that are associated with designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses, are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
6	RTC_{15} is subject to an Interface ATC Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = Minimum of (i) RTD $LBMP_a$ and (ii) zero

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location *a*	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location *a*)
7	RTC_{15} is subject to an Interface ATC Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a$ = RTD $LBMP_a$ + RTC_{15} External Interface $Congestion_a$ Otherwise, Real-Time $LBMP_a$ = RTD $LBMP_a$

17.1.6.5 Method of Calculating Marginal Loss and Congestion Components of Real-Time LBMP at Non-Competitive Proxy Generator Buses and Proxy Generator Buses that are Subject to the Special Pricing Rule for Designated Scheduled Lines

Under the conditions specified below, the Marginal Losses Component and the Congestion Component of the Real-Time LBMP, calculated pursuant to the preceding paragraphs in Sections 17.1.6.3 and 17.1.6.4, shall be constructed as follows:

When the Real-Time LBMP is set to zero and that zero price was not the result of using the RTD, RTC or SCUC-determined LBMP;

$$Marginal\ Losses\ Component\ of\ the\ Real\text{-}Time\ LBMP = \ Losses_{RTD\ PROXY\ GENERATOR\ BUS}$$

and

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

where:

$Energy_{RTD\ REF\ BUS}$ = The marginal Bid cost of providing Energy at the reference Bus, as calculated by RTD for that 5-minute interval; and

$Losses_{RTD\ PROXY\ GENERATOR\ BUS}$ = The Marginal Losses Component of the LBMP as calculated by RTD for that 5-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line.

18 Attachment C -Formulas For Determining Bid Production Cost Guarantee Payments

18.1 Introduction

~~Ten~~Seven Bid Production Cost Guarantee (BPCG) payments for eligible Suppliers are described in this attachment: (i) a Day-Ahead BPCG for Generators; (ii) a Day-Ahead BPCG for Imports; (iii) a real-time BPCG for Generators and Aggregations in RTD intervals other than Supplemental Event Intervals ; (iv) a BPCG for Generators and Aggregations for Supplemental Event Intervals; (v) a real-time BPCG for Imports; (vi) a BPCG for long start-up time Generators (i.e., Generators that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) whose start is aborted by the ISO prior to their dispatch; and (vii) ~~a BPCG for Demand Reduction in the Day-Ahead Market; (viii)~~ a Special Case Resources BPCG~~; (ix) a BPCG for Demand Side Resources providing synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market; and (x) a BPCG for Demand Side Resources providing synchronized Operating Reserves and / or Regulation Service in the Real-Time Market~~. Suppliers shall be eligible for these payments in accordance with the eligibility requirements and formulas established in this Attachment C.

The Bid Production Cost guarantee payments described in this Attachment C are each calculated and paid independently from each other. A Customer's eligibility to receive one type of Bid Production Cost guarantee payment shall have no impact on the Customer's eligibility to be considered to receive another type of Bid Production Cost guarantee payment, in accordance with the rule set forth in this Attachment C.

18.2 Day-Ahead BPCG For Generators and Aggregations

18.2.1 Eligibility to Receive a Day-Ahead BPCG for Generators and Aggregations

18.2.1.1 Eligibility.

A Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO Committed Flexible Generator or an ISO-Committed Flexible Aggregation that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment. Energy Storage Resources and Aggregations comprised entirely of Energy Storage Resources that satisfy this eligibility criteria shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment regardless of whether the Resource Self-Manages its Energy Level.

18.2.1.2 Non-Eligibility (includes both partial and complete exclusions).

Notwithstanding Section 18.2.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator, or an ISO-Committed Flexible Aggregation that is committed by the ISO in the Day-Ahead Market shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment if that Generator or Aggregation has been committed in the Day-Ahead Market for any other hour of the day as a result of a Self-Committed Fixed or Self-Committed Flexible bid.

Notwithstanding Section 18.2.1.1, Incremental Energy Bid costs and Minimum Generation Bids that exceed $1,000/MWh are only eligible for inclusion in a Day-Ahead Bid Production Cost guarantee payment in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.2.2 Formulas for Determining Day-Ahead BPCG for Generators and Aggregations

18.2.2.1 Applicable Formula. A Supplier's BPCG for ~~a~~ Generator or Aggregation ~~"~~g, ~~"~~ shall be as follows:

Day-Ahead Bid Production Cost Guarantee for Generator g or Aggregation g =

$$Max\left[\sum_{h=1}^{N}\left(\int_{MGH_{gh}^{DA}}^{EH_{gh}^{DA}} C_{gh}^{DA} + MGC_{gh}^{DA}MGH_{gh}^{DA} + SUC_{gh}^{DA}NSUH_{gh}^{DA} - LBMP_{gh}^{DA}EH_{gh}^{DA} - NASR_{gh}^{DA}\right), 0\right]$$

18.2.2.2 Variable Definitions. The terms used in this Section 18.2.2 shall be defined as follows:

$Supplier_g$ = Generator *g* or Aggregation *g*;

N = number of hours in the Day-Ahead Market day;

EH_{gh}^{DA} = Energy scheduled Day-Ahead to be ~~produced~~provided by ~~Generator~~Supplier *g* or withdrawn by ~~Generator~~Supplier *g*, which is eligible to withdraw Energy, in hour *h* expressed in terms of MWh;

MGH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by the minimum generation segment of ~~Generator~~Supplier *g* in hour *h* expressed in terms of MWh;

C_{gh}^{DA} = Bid cost submitted by ~~Generator~~Supplier g, or when applicable the mitigated Bid cost curve for ~~Generator~~Supplier *g*, in the Day-Ahead Market for hour *h* expressed in terms of $/MWh;

MGC_{gh}^{DA} = Minimum Generation Bid by ~~Generator~~Supplier g, or when applicable the mitigated Minimum Generation Bid for ~~Generator~~Supplier *g*, for hour *h* in the Day-Ahead Market, expressed in terms of $/MWh.

If ~~Generator~~Supplier g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day and ~~Generator~~Supplier g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), then ~~Generator~~Supplier g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Day-Ahead Bid Production Cost guarantee until

~~Generator~~Supplier g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gh}^{DA} = Start-Up Bid by ~~Generator~~Supplier *g* in hour *h*, or when applicable the mitigated Start-Up Bid for ~~Generator~~Supplier *g*, in hour *h* in the Day-Ahead Market expressed in terms of $/start; *provided, however*, that the Start-Up Bid for ~~Generator~~Supplier *g* in hour *h* or, when applicable, the mitigated Start-Up Bid, for ~~Generator~~Supplier *g* in hour *h*, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled, and to operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of ~~Generator~~Supplier *g*'s Day-Ahead or SRE schedule.

If ~~Generator~~Supplier *g* was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* ~~Generator~~Supplier g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* ~~Generator~~Supplier *g* shall have its Start-Up Bid set to zero for purposes of calculating a Day-Ahead Bid Production Cost guarantee.

For a long start-up time ~~Generator~~Supplier (*i.e.*, a ~~Generator~~Supplier that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the ISO and runs in real-time, the Start-Up Bid for ~~Generator~~Supplier g in hour h shall be the ~~Generator~~Supplier's Start-Up Bid, or when applicable the mitigated Start-Up Bid for ~~Generator~~Supplier g, for the hour (as determined at the point in time in which the ISO provided notice of the request for start-up):

$NSUH_{gh}^{DA}$ = number of times ~~Generator~~Supplier g is scheduled Day-Ahead to start up in hour h;

$LBMP_{gh}^{DA}$ = Day-Ahead LBMP at ~~Generator~~Supplier g's bus in hour h expressed in $/MWh;

$NASR_{gh}^{DA}$ = Net Ancillary Services revenue, expressed in terms of $, paid to ~~Generator~~Supplier g as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Voltage Support Service payments received by that ~~Generator~~Supplier 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~~Supplier for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less that ~~Generator~~Supplier's Day-Ahead Regulation Capacity Bid to provide that amount of Regulation Service in that hour; and (3) payments made to that ~~Generator~~Supplier 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~~Supplier's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.3 Day-Ahead BPCG For Imports

18.3.1 Eligibility to Receive a Day-Ahead BPCG for Imports

A Supplier that bids an Import that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment.

18.3.2 BPCG Calculated by Transaction ID

For purposes of calculating a Day-Ahead Bid Production Cost guarantee payment for an Import under this Section 18.3, the ISO shall treat the Import as being from a single Resource for all hours of the Day-Ahead Market day in which the same Transaction ID is used, and the ISO shall treat the Import as being from a different Resource for all hours of the Day-Ahead Market day in which a different Transaction ID is used.

18.3.3 Formula for Determining Day-Ahead BPCG for Imports

Day-Ahead Bid Production Cost guarantee for Import t by Supplier =

$$max\left[\sum_{h=1}^{N}(DecBid_{th}^{DA} - LBMP_{th}^{DA}) * SchImport_{th}^{DA}, 0\right]$$

Where;

N = number of hours in the Day-Ahead Market day;

$DecBid_{th}^{DA}$ = Decremental Bid, in \$/MWh, supplied for Import t for hour h;

$LBMP_{th}^{DA}$ = Day-Ahead LBMP, in \$/MWh, for hour h at the Proxy Generator Bus that is the source of the Import t and

$SchImport_{th}^{DA}$ = total Day-Ahead schedule, in MWh, for Import t in hour h.

18.4 Real-Time BPCG For Generators and Aggregations In RTD Intervals Other Than Supplemental Event Intervals

18.4.1 Eligibility for Receiving Real-Time BPCG for Generators and Aggregations in RTD Intervals Other Than Supplemental Event Intervals

18.4.1.1 Eligibility.

A Supplier shall be eligible to receive a real-time Bid Production Cost guarantee payment for intervals (excluding Supplemental Event Intervals) if it bids on behalf of:

18.4.1.1.1 an ISO-Committed Flexible Generator or an ISO-Committed Fixed Generator that is committed by the ISO in the Real-Time Market; or

18.4.1.1.2 a Self-Committed Flexible Generator if the Generator's minimum operating level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; or

18.4.1.1.3 a Generator or Aggregation committed via SRE, or committed or dispatched by the ISO as Out-of-Merit generation to ensure NYCA or local system reliability for the hours of the day that it is committed via SRE or is committed or dispatched by the ISO as Out-of-Merit generation to meet NYCA or local system reliability without regard to the Bid mode(s) employed during the Dispatch Day, except as provided in Sections 18.4.2 and 18.9~~12~~, below, or~~.~~

18.4.1.1.4 an ISO-Committed Flexible Aggregation comprised entirely of Energy Storage Resources that Self-Manages its Energy Level.

18.4.1.2 Non-Eligibility (includes both partial and complete exclusions).

18.4.1.2.1 Notwithstanding Section 18.4.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Fixed Aggregation or an ISO-Committed Flexible Generator that is committed by the ISO in the Real-Time Market shall not be eligible to receive a real-time Bid Production Cost guarantee payment if that Generator or Aggregation has been committed in real-time, in any other hour of the day, as the result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule, *provided however*, a Generator or Aggregation that has been committed in real time as a result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule will not be precluded from receiving a real-time Bid Production Cost guarantee payment for other hours of the Dispatch Day, in which it is otherwise eligible, due to these Self-Committed mode Bids if such ~~b~~Bid mode was used for: (i) an ISO authorized Start-Up, Shutdown or Testing Period, or (ii) for hours in which such Generator or Aggregation was committed via SRE or committed or dispatched by the ISO as Out-of-Merit to meet NYCA or local system reliability.

18.4.1.2.2 Notwithstanding Section 18.4.1.1, Incremental Energy Bid costs and Minimum Generation Bids that exceed $1,000/MWh are only eligible for inclusion in a real-time Bid Production Cost guarantee payment for intervals other than Supplemental Event Intervals, in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.4.1.2.3 Notwithstanding Section 18.4.1.1, an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources with an ISO-Managed Energy Level for any hour of the Real-Time Market day shall not be eligible to receive a real-time Bid Production Cost guarantee payment for that day, provided however, an Energy Storage Resource or Aggregation comprised entirely of Energy Storage Resources shall be eligible for a real-time Bid Production Cost guarantee payment in accordance with Section 18.4.1.1.3 of this ISO Services Tariff regardless of whether the Energy Level is ISO-Managed.

18.4.1.2.4 Notwithstanding Section 18.4.1.1, Energy Storage Resources and Aggregations shall not be eligible to receive a real-time Bid Production Cost guarantee payment for a day if such Resources' Real-Time Market Bids for any hour of that day do not permit the Resource to receive a schedule of zero MW. However, such Resources shall be eligible for a real-time Bid Production Cost guarantee payment in accordance with Section 18.4.1.1.3 of this ISO Services Tariff.

18.4.2 Formula for Determining Real-Time BPCG for Generators and Aggregations in RTD Intervals Other Than Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee for ~~Generator~~Supplier g, which is not an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$Max\left[\left(\sum_{i\in M}\left(\left(\int_{max(EI_{gi}^{DA},MGI_{gi}^{RT})}^{max(EI_{gi}^{RT},MGI_{gi}^{RT})} C_{gi}^{RT} + MGC_{gi}^{RT} * \left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right) - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - EI_{gi}^{DA}\right)\right) * \frac{S_i}{3600}\right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi} + \sum_{j\in L} SUC_{gj}^{RT} * \left(NSUI_{gj}^{RT} - NSUI_{gj}^{DA}\right)\right), 0\right]$$

Real-Time Bid Production Cost Guarantee for ~~Generator~~Supplier g, which is an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$Max\left(0, \sum_{i\in M}\left(InjBPCG_{gi} + WthBPCG_{gi}\right)\right)$$

where, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to inject Energy:

$$InjBPCG_{gi} = \left(\left(\int_{max\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - max\left(EI_{gi}^{DA},0\right) \right) \right) * \frac{S_i}{3600} \right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA} \right) - RRAP_{gi} + RRAC_{gi}$$

and, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to withdraw Energy =

$$WthBPCG_{gi} = \left(\left(\int_{min\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - min\left(EI_{gi}^{DA},0\right) \right) \right) * \frac{S_i}{3600} \right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA} \right) - RRAP_{gi} + RRAC_{gi}$$

where:

$Supplier_g$ = Generator g or Aggregation g;

S_i = number of seconds in RTD interval i;

C_{gi}^{RT} = Bid cost submitted by ~~Generator~~Supplier g, or when applicable the mitigated Bid cost for ~~Generator~~Supplier g, in the RTD for the hour that includes RTD interval i expressed in terms of $/MWh, except in intervals in which the dispatch of the ~~Generator~~Supplier is constrained by its downward ramp rate for that interval, unless that ~~Generator~~Supplier was scheduled to provide Regulation Service in that interval and its RTD basepoint was less than its AGC basepoint, and except in hours in which the NYISO has increased ~~Generator~~Supplier g's minimum operating level, either (i) at the ~~Generator~~Supplier's request including through an adjustment to the Resource's self-commitment schedule, or (ii) in order to reconcile the ISO's dispatch with the ~~Generator~~Supplier's actual output or to address reliability concerns that arise because the ~~Generator~~Supplier is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

MGI_{gi}^{RT} = metered Energy ~~produced~~provided by minimum generation segment of ~~Generator~~Supplier 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~~Supplier g in RTD interval i expressed in terms of MW;

MGC_{gi}^{RT} = Minimum Generation Bid by ~~Generator~~Supplier g, or when applicable the mitigated Minimum Generation Bid for ~~Generator~~Supplier g, in the Real-Time Market for the hour that includes RTD interval i, expressed in terms of $/MWh, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

If ~~Generator~~Supplier g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day *and* ~~Generator~~Supplier g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), *then* ~~Generator~~Supplier g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Real-Time Bid Production Cost guarantee until ~~Generator~~Supplier g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gj}^{RT} = Start-Up Bid by ~~Generator~~Supplier g, or when applicable the mitigated Start-Up Bid for ~~Generator~~Supplier g, for hour j into RTD expressed in terms of $/start, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

provided, however,

(i) the Start-Up Bid shall be deemed to be zero for (1) Self-Committed Fixed and Self-Committed Flexible ~~Generators~~Suppliers,
(2) ~~Generators~~Supplier that are economically committed by RTC or RTD that have 10-minute start-up times that are not synchronized and producing Energy within 20 minutes after their scheduled start time, and
(3) ~~Generators~~Suppliers that are economically committed by RTC that have greater than 10-minute start-up times that are not synchronized and producing Energy within 45 minutes after their scheduled start time;

(ii) if a ~~Generator~~Supplier 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~~Supplier's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be the

Start-Up Bid submitted in response to the SRE request (subject to mitigation, where appropriate);

(iii) if a ~~Generator~~Supplier 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~~Supplier's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be set to zero;

(iv) the real-time Start-Up Bid for ~~Generator~~Supplier g for hour j or, when applicable, the mitigated real-time Start-Up Bid, for ~~Generator~~Supplier g for hour j, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled and operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of ~~Generator~~Supplier g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of ~~Generator~~Supplier g's Day-Ahead or SRE schedule; and

(v) if ~~Generator~~Supplier g was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* ~~Generator~~Supplier g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* ~~Generator~~Supplier g shall have its Start-Up Bid set to zero for purposes of calculating a Real-Time Bid Production Cost guarantee.

$NSUI_{gj}^{RT}$ = number of times ~~Generator~~Supplier g started up in hour j;

$NSUI_{gj}^{DA}$ = number of times ~~Generator~~Supplier g is scheduled Day-Ahead to start up in hour j;

$LBMP_{gi}^{RT}$ = Real-Time LBMP at ~~Generator~~Supplier g's bus in RTD interval i expressed in terms of \$/MWh;

M = the set of eligible RTD intervals in the Dispatch Day consisting of all of the RTD intervals in the Dispatch Day except:

(i) Supplemental Event Intervals (which are addressed separately in Section 18.5 below);

(ii) intervals during authorized Start-Up Periods, Shutdown Periods, or Testing Periods for ~~Generator~~Supplier g;

L	=	the set of all hours in the Dispatch Day
EI_{gi}^{RT}	=	either, as the case may be:

(i) if $EOP_{ig} > AE~~I~~_{ig}$ + ADR_{ig} then min(max((AE~~I~~$_{ig}$,+ ADR_{ig}),$RTSen_{ig}$),EOP_{ig}); or

(ii) if otherwise, then max(min((AE~~I~~$_{ig}$ + ADR_{ig}),$RTSen_{ig}$),EOP_{ig}).

EI_{gi}^{DA} = Energy scheduled in the Day-Ahead Market to be ~~produced~~provided or withdrawn by ~~Generator~~Supplier g in the hour that includes RTD interval i expressed in terms of MW;

$RTSen_{ig}$ = Real-time Energy scheduled for ~~Generator~~Supplier g in interval i, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to ~~Generator~~Supplier g during the course of interval i expressed in terms of MW;

$AE\cancel{I}_{ig}$ = either, (1) average Actual Energy Injection by ~~Generator~~Supplier g in interval i but not more than $RTSen_{ig}$ plus any Compensable Overgeneration expressed in terms of MW; or (2) average Actual Energy Withdrawal by Generator or Aggregation g in interval i expressed in terms of MW;

ADR_{ig} = average Actual Demand Reduction~~s~~ by Supplier g in interval *i*;

EOP_{ig} = the Economic Operating Point of ~~Generator~~Supplier g in interval i expressed in terms of MW;

$NASR_{gi}^{TOT}$ = Net Ancillary Services revenue, expressed in terms of $, paid to ~~Generator~~Supplier g as a result of either having been committed Day-Ahead to operate in the hour that includes RTD interval i or having operated in interval i which is computed by summing the following: (1) Voltage Support Service payments received by that ~~Generator~~Supplier for that RTD interval, if it is not a Supplier of Installed Capacity; (2) Regulation Service payments that would be made to that ~~Generator~~Supplier for that hour based on a Performance Index of 1, less the Regulation Capacity and Regulation Movement Bids placed by that ~~Generator~~Supplier to provide Regulation Service in that hour at the time it was committed to produce Energy for the LBMP Market and/or Ancillary Services to do so; (3) payments made to that ~~Generator~~Supplier for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by that ~~Generator~~Supplier 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~~Supplier in that hour as a result of reducing that ~~Generator~~Supplier's output in order for it to provide Voltage Support Service.

$NASR_{gi}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, expressed in terms of $, that is applicable to interval i calculated by multiplying the $NASR_{gh}^{DA}$ for the hour that includes interval i by s_i/3600.

$RRAP_{gi}$ = Regulation Revenue Adjustment Payment for ~~Generator~~Supplier g in RTD interval i expressed in terms of $.

$RRAC_{gi}$ = Regulation Revenue Adjustment Charge for ~~Generator~~Supplier g in RTD interval i expressed in terms of $.

18.4.3 Bids Used For Intervals at the End of the Hour

For RTD intervals in an hour that start 55 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour in accordance with ISO Procedures. For RTD-CAM intervals in an hour that start 50 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour, in accordance with ISO Procedures.

18.5 BPCG For Generators and Aggregations In Supplemental Event Intervals

18.5.1 Eligibility for BPCG for Generators and Aggregations in Supplemental Event Intervals

18.5.1.1 Eligibility

For intervals in which the ISO has called a large event reserve pick-up, as described in Section 4.4.4.1.1 of this ISO Services Tariff, or an emergency under Section 4.4.4.1.2 of this ISO Services Tariff, any Supplier who meets the eligibility requirements for a real-time Bid Production Cost guarantee payment described in subsection 18.4.1.1 of this Attachment C, shall be eligible to receive a BPCG under this Section 18.5.

18.5.1.2 Non-Eligibility (includes both partial and complete exclusions)

(A) Notwithstanding subsection 18.5.1.1, a Supplier shall not be eligible to receive a Bid Production Cost guarantee payment for Supplemental Event Intervals if the Supplier is not eligible for a real-time Bid Production Cost guarantee payment for the reasons described in Section 18.4.1.2 of this Attachment C.

(B) Notwithstanding subsection 18.5.1.1, Incremental Energy Bid costs and Minimum Generation Bids that exceed $1,000/MWh are only eligible for inclusion in a real-time Bid Production Cost guarantee payment for Supplemental Event Intervals, in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.

18.5.1.3 Additional Eligibility

Notwithstanding Section 18.5.1.2(A), a Supplier shall be eligible to receive a Bid Production Cost guarantee payment for a Generator or Aggregation providing~~producing~~ energy during Supplemental Event Intervals occurring as a result of an ISO emergency under Section 4.4.4.1.2 of this ISO Services Tariff regardless of bid mode used for the day.

18.5.2 Formula for Determining BPCG for Generators and Aggregations in Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee Payment for Generator or Aggregation g, which is not an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$\sum_{i \in P} \left(\max \left(\begin{array}{l} \left(\int_{max\left(EI_{gi}^{DA}, MGI_{gi}^{RT}\right)}^{max\left(EI_{gi}^{RT}, MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT} * \left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right) \right) * \frac{S_i}{3600} \\ - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - EI_{gi}^{DA}\right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi} \end{array} \right), 0 \right)$$

Real-Time Bid Production Cost Guarantee for ~~Generator~~Supplier *g*, which is an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) =

$$Max\left(0, \sum_{i \in P} \left(InjBPCG_{gi} + WthBPCG_{gi}\right)\right)$$

where, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to inject Energy:

$$InjBPCG_{gi} = \left(\left(\int_{max\left(EI_{gi}^{DA}, 0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - max\left(EI_{gi}^{DA}, 0\right)\right) \right) * \frac{S_i}{3600} \right) - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}$$

and, when an Energy Storage Resource or an Aggregation that contains Energy Storage Resource(s) has a real-time schedule to withdraw Energy =

$$WthBPCG_{gi} = \left(\left(\int_{min\left(EI_{gi}^{DA},0\right)}^{EI_{gi}^{RT}} C_{gi}^{RT} - LBMP_{gi}^{RT} * \left(EI_{gi}^{RT} - min(EI_{gi}^{DA},0)\right)\right) * \frac{S_i}{3600}\right)$$

$$- \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}$$

where:

$Supplier_g$ = Generator g or Aggregation g;

P = the set of Supplemental Event Intervals in the Dispatch Day but excluding any intervals in which there are maximum generation pickups or large event reserve pickups where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA}; and

EI_{gi}^{RT} = (i) for any intervals in which there are maximum generation pickups, and the three intervals following, for ~~Generator~~Suppliers in the location for which the maximum generation pickup has been called -- the average Actual Energy Injections, expressed in MWh, for Generator g in interval i, and for all other ~~Generator~~Suppliers EI_{gi}^{RT} is as defined in Section 18.4.2 above.

(ii) for any intervals in which there are large event reserve pickups and the three intervals following, EI_{gi}^{RT} is as defined in Section 18.4.2 above.

C_{gi}^{RT} = Bid cost submitted by ~~Generator~~Supplier g, or when applicable the mitigated Bid cost for ~~Generator~~Supplier 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~~Supplier g's minimum operating level, either (i) at the ~~Generator~~Supplier's request, or (ii) in order to reconcile the ISO's dispatch with the ~~Generator~~Supplier's actual output or to address reliability concerns that arise because the ~~Generator~~Supplier is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

The definition of all other variables is identical to those defined in Section 18.4 above.

In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 15.3.8 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

18.6 Real-Time BPCG For External Transactions

External Transactions are not eligible to receive Bid Production Cost guarantee payments in the Real-Time Market.

18.7. BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their dispatch

18.7.1 Eligibility for BPCG for Long Start-Up Time Generators Whose Starts Are Aborted by the ISO Prior to their Dispatch

A Supplier that bids on behalf of a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the ISO for reliability purposes as a result of a Supplemental Resource Evaluation and whose start is aborted by the ISO prior to its dispatch, as described in Section 4.2.5 of the ISO Services Tariff, shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.7.

18.7.2 Methodology for Determining BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their Dispatch

A Supplier whose long start-up time Generator's start-up is aborted shall receive a prorated portion of its Start-Up Bid submitted for the hour in which the ISO requested that the Generator begin its start-up sequence, based on the portion of the start-up sequence that it has completed prior to the signal to abort the start-up (*e.g.*, if a long start-up time Generator with a seventy-two (72) hour start-up time has its start-up sequence aborted after forty-eight (48) hours, it would receive two-thirds (2/3) of its Start-Up Bid).

~~18.8 BPCG For Demand Reduction In The Day-Ahead Market~~

~~18.8.1 Eligibility for BPCG for Demand Reduction in the Day-Ahead Market~~

~~A Demand Reduction Provider that bids a Demand Side Resource that is committed by the ISO in the Day-Ahead Market to provide Demand Reduction shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.8. However, incremental Curtailment Bid costs and minimum Curtailment initiation Bids that exceed $1,000/MWh are only eligible for inclusion in a Day-Ahead Bid Production Cost guarantee payment in accordance with Sections 21.4.1 and 23.7 of this ISO Services Tariff.~~

~~18.8.2 Formula for Determining BPCG for Demand Reduction in the Day-Ahead Market~~

~~*Day-Ahead BPCG for Demand Reduction Provider d =*~~

$$Max\left(\sum_{h=1}^{N}\left(MinCurCost_d^h + IncrCurCost_d^h - CurRev_d^h\right) + CurInitCost_d, 0\right)$$

~~where:~~

$$CurInitCost_d = \left(\sum_{h=1}^{N}\left(Min\left(ActCur_d^h, SchdCur_d^h\right)\right) / \left(\sum_{h=1}^{N} SchdCur_d^h\right)\right) * CurCost_d$$

$$MinCurCost_d^h = Min\left(\left(max\left(ActCur_d^h, 0\right), MinCur_d^h\right)\right) * MinCurBid_d^h$$

$$IncrCurCost_d^h = \left(\int_{MinCur_d^h}^{max\left(MinCur_d^h, min\left(SchdCur_d^h, ActCur_d^h\right)\right)} IncrCurBid_d^h\right)$$

$$CurRev_d^h = LBMP_{dh}^{DA} * min\left(max\left(ActCur_d^h, 0\right), SchdCur_d^h\right)$$

~~N = number of hours in the Day-Ahead Market day.~~

~~$CurInitCost_d$ = daily Curtailment Initiation Cost credit for Day-Ahead Demand Reduction Provider *d*;~~

~~$MinCurCost_d^h$ = minimum Curtailment cost credit for Day-Ahead Demand Reduction Provider d in hour h;~~

~~$IncrCurCost_d^h$ = incremental Curtailment cost credit for Day-Ahead Demand Reduction Provider d for hour h;~~

~~$CurCost_d$ = total bid Curtailment Initiation Costs for Day-Ahead Demand Reduction Provider d for the day;~~

~~$CurRev_d^h$ = actual revenue for Day-Ahead Demand Reduction Provider d in hour h;~~

~~$ActCur_d^h$ = actual Energy curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;~~

~~$SchdCur_d^h$ = Energy scheduled Day-Ahead to be curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;~~

~~$MinCurBid_d^h$ = minimum Curtailment initiation Bid submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of \$/MWh;~~

~~$IncrCurBid_d^h$ = Bid cost submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of \$/MWh;~~

~~$MinCur_d^h$ = Energy scheduled Day-Ahead to be produced by the minimum Curtailment segment of Day-Ahead Demand Reduction Provider d for hour h expressed in terms of MWh; and~~

~~$LBMP_{dh}^{DA}$ = Day-Ahead LBMP for Day-Ahead Demand Reduction Provider d for hour h expressed in \$/MWh.~~

18.8~~9~~ BPCG For Special Case Resources

18.8~~9~~.1 Eligibility for Special Case Resources BPCG

Any Supplier that bids a Special Case Resource that is committed by the ISO for an event in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.8~~9~~. Suppliers shall not be eligible for a Special Case Resource Bid Production Cost guarantee payment for the period over which a Special Case Resource is performing a test.

18.8~~9~~.2 Methodology for Determining Special Case Resources BPCG

A Special Case Resource Bid Production Cost guarantee payment shall be made when the Minimum Payment Nomination for any Special Case Resource committed by the ISO over the period of requested performance or four (4) hours, whichever is greater, exceeds the LBMP revenue received for performance by that Special Case Resource; provided, however, that the ISO shall set to zero the Minimum Payment Nomination for Special Case Resource Capacity in each interval in which such capacity was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy.

~~18.10 BPCG For Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service In The Day-Ahead Market~~

~~18.10.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market~~

~~Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service in the Day-Ahead Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.10.~~

~~18.10.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market~~

~~A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves and/or Regulation Service schedule in the Day-Ahead Market shall be calculated as follows:~~

~~BPCG for Demand Side Resource d Providing synchronized Operating Reserves and/or Regulation Service Day-Ahead =~~

$$\cancel{max\left(\left(-\sum_{h=1}^{N} NASR_{dh}^{DA}\right), 0\right)}$$

~~where:~~

~~N~~	~~=~~	~~number of hours in the Day-Ahead Market day.~~
~~$NASR_{dh}^{DA}$~~	~~=~~	~~Net Ancillary Services revenue, in \$, paid to Demand Side Resource d as a result of having been committed to provide Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Regulation Service payments made to that Demand Side Resource for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less Demand Side Resource d's Day-Ahead Regulation Capacity Bid to provide that amount of Regulation Service in that hour; and (2) payments made to Demand Side Resource d for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less Demand Side Resource d's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.~~

~~18.11 BPCG For Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service In The Real-Time Market~~

~~18.11.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Real-Time Market~~

~~Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.11.~~

~~18.11.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Real-Time Market~~

~~A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves and/or Regulation Service schedule in the real-time Market shall be calculated as follows:~~

~~BPCG for Demand Side Resource d Providing synchronized Operating Reserves and/or Regulation Service in Real-Time =~~

$$\cancel{max\left(-\sum_{i \in L}\left(NASR_{di}^{TOT} - NASR_{di}^{DA}\right), 0\right)}$$

~~where:~~

$\cancel{L}$ ~~= set of RTD intervals in the Dispatch Day;~~

$\cancel{NASR_{di}^{TOT}}$ ~~= Net Ancillary Services revenue, in \$, paid to Demand Side Resource d as a result of either having been scheduled Day-Ahead in the hour that includes RTD interval i or having been scheduled in real-time interval i which is computed by summing the following: (1) Regulation Service payments that would be made to Demand Side Resource d for that hour based on a Performance Index of 1, less the Regulation Capacity and Regulation Movement Bids placed by Demand Side Resource d to provide Regulation Service in that hour at the time it was committed to provide Ancillary Services; and (2) payments made to Demand Side Resource d for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by Demand Side Resource d to provide such reserves in that hour at the time it was scheduled to do so; and~~

~~$NASR_{di}^{DA}$ – The proportion of the Day-Ahead net Ancillary Services revenue, in $, that is applicable to interval i calculated by multiplying the $NASR_{dh}^{DA}$ for the hour that includes interval i by the quotient of the number of seconds in RTD interval i divided by 3600.~~

18.9~~12~~ Proration Of Start-Up Bid For Generators That Are Committed In The Day-Ahead Market, Or Via Supplemental Resource Evaluation

18.9~~12~~.1 Eligibility to Recover Operating Costs and Resulting Obligations

Generators committed in the Day-Ahead Market or via SRE that are not able to complete their minimum run time within the Dispatch Day in which they are committed are eligible to include in their Start-Up Bid expected net costs of operating on the day following the dispatch day at the minimum operating level specified for the hour in which the Generator is committed, for the hours necessary to complete the Generator's minimum run time.

Generators that receive Day-Ahead or SRE schedules that are not scheduled to operate in real-time, or that do not operate in real-time, at the MW level included in the Minimum Generation Bid for the first hour of the Generator's Day-Ahead or SRE schedule, for the longer of (a) the duration of the Generator's Day-Ahead or SRE schedule, or (b) the minimum run time specified in the Bid that was accepted for the first hour of the Generator's Day-Ahead or SRE schedule, will have the start-up cost component of the Bid Production Cost guarantee calculation prorated in accordance with the formula specified in Section 18.9~~12~~.2, below. The rules for prorating the start-up cost component of the Bid Production Cost guarantee calculation apply both to operation within the Dispatch Day and to operation on the day following the Dispatch Day to satisfy the minimum run time specified for the hour in which the Generator was scheduled to start-up on the Dispatch Day.

Rules for calculating the reference level that the NYISO uses to test Start-Up Bids for possible mitigation are included in the Market Power Mitigation Measures that are set forth in Attachment H to the ISO Services Tariff. Proration of the start-up cost component of a Generator's Bid Production Cost guarantee based on the Generator's operation in real-time is different/distinct from the mitigation of a Start-Up Bid.

18.~~912~~.2 Proration of Eligible Start-Up Cost when a Generator Is Not Scheduled, or Does Not Operate to Meet the Schedule Specified in the Accepted Day-Ahead or SRE Start-Up Bid.

The start-up costs included in the Bid Production Cost guarantee calculation may be reduced *pro rata* based on a comparison of the actual MWs delivered in real-time to an hourly minimum MW requirement. The hourly MWh requirement is determined based on the MW component of the Minimum Generation Bid submitted for the Generator's accepted start hour (as mitigated, where appropriate).

18.~~912~~.2.1 Total Energy Required to be Provided in Order to Avoid Proration of a Generator's Start-Up Costs

$$TotMWReq_{g,s} = MinOpMW_{g,s} * n_{g,s}$$

Where:

$TotMWReq_{g,s}$ = Total amount of Energy that Generator g, when started in hour s, must provide for its start-up costs not to be prorated

$MinOpMW_{g,s}$ = Minimum operating level (in MW) specified by Generator g in its hour s Bid

$n_{g,s}$ = The last hour that Generator g must operate when started in hour s to complete both its minimum run time and its Day-Ahead schedule. The variable $n_{g,s}$ is calculated as follows:

$$n_{g,s} = max(LastHrDASched_{g,s}, LastMinRunHr_{g,s})$$

Where:

$LastHrDASched_{g,s}$ = The last date/hour in a contiguous set of hours in the Dispatch Day, beginning with hour s, in which Generator g is scheduled to operate in the Day-Ahead Market

$LastMinRunHr_{g,s}$ = The last date/hour in a contiguous set of hours in which Generator g would need to operate to complete its minimum run time if it starts in hour s

18.9~~12~~.2.2 Calculation of Prorated Start-Up Cost

$$ProratedSUC_{g,s} = SubmittedSUC_{g,s} * \frac{\sum_{h=s}^{n_{g,s}} MinOpEnergy_{g,h,s}}{TotalMWReq_{g,s}}$$

Where:

$ProratedSUC_{g,s}$ = the prorated start-up cost used to calculate the Bid Production Cost guarantee for Generator g that is scheduled to start in hour s

$SubmittedSUC_{g,s}$= the Start-Up Bid submitted (as mitigated, where appropriate) for Generator g that is scheduled to start in hour s

$MinOpEnergy_{g,h,s}$ = the amount of Energy produced during hour h by Generator g during the time required to complete both its minimum run time and its Day-Ahead schedule, if that generator is started in hour s. $MinOpEnergy_{g,h,s}$ is calculated as follows:

$$MinOpEnergy_{g,h,s} = min\left(MetActEnergy_{g,h}, MinOpMW_{g,s}\right)$$

Where:

$MetActEnergy_{g,h}$ = the metered amount of Energy produced by Generator g during hour h

18.9~~12~~.2.3 Additional Rules/Clarifications that Apply to the Calculation of Prorated Start-Up Cost

a. For any hour that a Generator is derated below the minimum operating level specified in its accepted Start-Up Bid for reliability, either by the ISO or at the request of a Transmission Owner, the Generator will receive credit for that hour as if the Generator had produced metered actual MWh equal to its $MinOpMW_{g,s}$.

b. A Generator must be scheduled and operate in real-time to produce Energy consistent with the $MinOpMW_{g,s}$ specified in the accepted Start-Up Bid for each hour that it is expected to run. *See* Section 18.9~~12~~.2.1, above. These rules do not specify or require any particular bidding construct that must be used to achieve the desired commitment. However, submitting a self-committed Bid may preclude a Generator from receiving a BPCG. *See, e.g.*, Sections 18.2.1.2.2 and 18.4.1.2.3 of this Attachment C.

25 Attachment J – Determination of Day-Ahead Margin Assurance Payments and Import Curtailment Guarantee Payments

25.1 Introduction

If a Supplier that is eligible pursuant to Section 25.2 of this Attachment J buys out of a Day-Ahead Energy, Regulation Service or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin it shall receive a Day-Ahead Margin Assurance Payment, except as noted in Sections 25.2, 25.3, 25.4, and 25.5 of this Attachment J. The purpose of such payments is to protect Suppliers' Day-Ahead Margins associated with real-time reductions after accounting for: (i) any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve schedules; and (ii) any Supplier-requested real-time de-rate granted by the ISO.

In addition, a Supplier may be eligible to receive an Import Curtailment Guarantee Payment if its Import is curtailed at the request of the ISO as determined pursuant to Section 25.6 of this Attachment J.

25.2 Eligibility for Receiving Day-Ahead Margin Assurance Payments

25.2.1 General Eligibility Requirements for Suppliers to Receive Day-Ahead Margin Assurance Payments

Subject to Section 25.2.2 of this Attachment J, the following categories of Resources bid by Suppliers shall be eligible to receive Day-Ahead Margin Assurance Payments:

(i) ~~(i)~~ all Self-Committed Flexible and ISO-Committed Flexible Generators, other than Energy Storage Resources and Aggregations, that are either online and dispatched by RTD or available for commitment by RTC; ~~(ii) Demand Side Resources committed to provide Operating Reserves or Regulation Service;~~

(ii) ~~(iii)~~ any Resource, including an Energy Storage Resource or an Aggregation, 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;

(iii) ~~(iv)~~ any Resource, including an Energy Storage Resource~~s~~ or an Aggregation, internal to the NYCA that is derated or decommitted by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; ~~and~~

(iv) ~~(v)~~ Energy Limited Resources or an Aggregation comprised entirely of Energy Limited Resources~~participating as an Energy Limited Resource~~ with an ISO-approved real-time reduction in scheduled output from its Day-Ahead schedule, and~~.~~

(v) Limited Energy Storage Resources and Aggregations comprised entirely of Limited Energy Storage Resources scheduled to provide Regulation Service, as described in Section 25.3.2 of this ISO Services Tariff.

25.2.2 Exceptions

Notwithstanding Section 25.2.1 of this Attachment J, no Day-Ahead Margin Assurance Payment shall be paid to:

25.2.2.1 a Resource, otherwise eligible for a Day-Ahead Margin Assurance Payment, in hours in which the NYISO has increased the Resource's real-time minimum operating level above the Resource's Day-Ahead Market Energy schedule either: (i) at the Resource's request including through an adjustment to the Resource's self-commitment schedule; or (ii) in order to reconcile the ISO's dispatch with the Resource's actual output or to address reliability concerns that arise because the Resource is not following Base Point Signals; or (iii) an Intermittent Power Resource that depends on wind as its fuel.

25.2.2.2 a Resource, otherwise eligible for Day-Ahead Margin Assurance Payments, in hours in which the NYISO has increased the Resource's real-time minimum operating level at the Resource's request, including through an adjustment to the Resource's self-commitment schedule, above the MW level determined by subtracting the Resource's Day-Ahead Market Regulation Service schedule from its Day-Ahead Market Energy schedule.

25.2.2.3 a Resource, otherwise eligible for Day-Ahead Margin Assurance Payments, in hours in which the Resource reduces the MW quantity specified in its real-time Regulation Capacity Bid below its Day-Ahead Market Regulation Service schedule.

25.2.2.4 a Generator, otherwise eligible for Day-Ahead Margin Assurance Payments, for (i) any hour in which the Incremental Energy Bids submitted in the Real-Time Market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) in which the Incremental Energy Bids submitted in the real-time market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market.

25.2.2.5 A Generator that is available for commitment by RTC and otherwise eligible for Day-Ahead Margin Assurance Payments, for (i) any hour in which the Start-Up Bids submitted in the real-time market for that Generator exceed the Start-Up Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Start-Up Bids where appropriate, and that Generator was scheduled for Energy or Regulation Service in that hour in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) in which the Start-Up Bids submitted in the real-time market for that Generator exceed the Start-Up Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Start-Up Bids where appropriate, and that Generator was scheduled for Energy or Regulation Service in that hour in the Day-Ahead Market.

25.3 Calculation of Day-Ahead Margin Assurance Payments

25.3.1 Formula for Day-Ahead Margin Assurance Payments for Generators and Aggregations, Except for Limited Energy Storage Resources and Aggregations comprised entirely of Limited Storage Resources

Subject to Sections 25.4 and 25.5 of this Attachment J, Day-Ahead Margin Assurance Payments for Generators and Aggregations, except for Limited Energy Storage Resources and Aggregations comprised entirely of Limited Energy Storage Resources, shall be determined by applying the following equations to each individual Generator or Aggregation using the terms as defined in Section 25.3.34:

$$DMAP_{hu} = max\left(0, \sum_{i \in h} CDMAP_{iu}\right)$$

where:

$$CDMAP_{iu} = CDMAPen_{iu} + \sum_{P} CDMAPres_{iup} + CDMAPreg_{iu}$$

If the Generator's or Aggregation's real-time Energy schedule is lower than its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = \left((DASen_{hu} - LL_{iu}) * RTPen_{iu} - \int_{LL_{iu}}^{DASen_{hu}} DABen_{hu} \right) * \frac{Seconds_i}{3600}$$

If the Generator's or Aggregation's real-time Energy schedule is greater than or equal to its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = min\left[\left((DASen_{hu} - UL_{iu}) * RTPen_{iu} + \int_{DASen_{hu}}^{UL_{iu}} RTBen_{iu} \right) * \frac{Seconds_i}{3600}, 0 \right]$$

If the Generator's or Aggregation's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTPres_{iup} - DABres_{hup}\right)\right] * \frac{Seconds_i}{3600}$$

If the Generator's or Aggregation's real-time schedule for a given Operating Reserve product, p, is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTPres_{iup}\right)\right] * \frac{Seconds_i}{3600}$$

If the Generator's or Aggregation's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})\right] * \frac{Seconds_i}{3600} + \left[(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})\right]$$

If the Generator's or Aggregation's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) * max\left((RTPreg_{iu} - RTBreg_{iu}), 0\right)\right] * \frac{Seconds_i}{3600} + \left[(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})\right]$$

~~25.3.2 Formula for Day-Ahead Margin Assurance Payments for Demand Side Resources~~

~~25.3.2.1 Formula for Day-Ahead Margin Assurance Payment for Demand Side Resources~~

~~Subject to Section 25.5 of this Attachment J, Day-Ahead Margin Assurance Payments for Demand Side resources scheduled to provide Operating Reserves or Regulation Service shall be determined by applying the following equations to each individual Demand Side Resource using the terms as defined in Section 25.3.4, except for RPIiu, which is defined in Section 25.3.2.2:~~

$$DMAP_{hu} = max\left(0, \sum_{i \in h} CDMAP_{iu}\right)$$

~~where:~~

$$CDMAP_{iu} = \sum_{p} CDMAPres_{iup} + CDMAPreg_{iu}$$

~~If the Demand Side Resource’s real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:~~

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTPres_{iup} - DABres_{hup}\right)\right] * RPI_{iu} * \frac{Seconds_i}{3600}$$

~~If the Demand Side Resource’s real-time schedule for a given Operating Reserve product, p, is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:~~

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) * \left(RTSPres_{iup}\right)\right] * RPI_{iu} * \frac{Seconds_i}{3600}$$

~~If the Demand Side Resource’s real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:~~

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})\right] * \frac{Seconds_i}{3600} + \left[(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})\right]$$

~~If the Demand Side Resource’s real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:~~

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) * max\left((RTPreg_{iu} - RTBreg_{iu}), 0\right)\right] * \frac{Seconds_i}{3600} + \left[(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})\right]$$

~~25.3.2.2 Reserve Performance Index for Demand Side Resource Suppliers of Operating Reserves~~

~~The ISO shall produce a Reserve Performance Index for purposes of calculating a Day Ahead Margin Assurance Payment for a Demand Side Resource providing Operating Reserves. The Reserve Performance Index shall take account of the actual Demand Reduction achieved by the Supplier of Operating Reserves following the ISO's instruction to convert Operating Reserves to Demand Reduction.~~

~~The Reserve Performance Index shall be a factor with a value between 0.0 and 1.0 inclusive. For each interval in which the ISO has not instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction, the Reserve Performance Index shall have a value of one. For each interval in which the ISO has instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction the Reserve Performance Index shall be calculated pursuant to the following formula, provided however when UAGi is zero or less, the Reserve Performance Index shall be set to zero:~~

$$\cancel{RPI_{iu} = min[(UAG_i / ADG_i + .1), 1]}$$

~~Where:~~

$\cancel{RPI_{iu}}$	~~=~~	~~Reserve Performance Index in interval *i* for Demand Side Resource *u*;~~
$\cancel{UAG_i}$	~~=~~	~~average actual Demand Reduction for interval *i*, represented as a positive generation value; and~~
$\cancel{ADG_i}$	~~=~~	~~average scheduled Demand Reduction for interval *i*, represented as a positive generation base point.~~

25.3.2~~3~~ Formula for Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources and Aggregations comprised entirely of Limited Energy Storage Resources

Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources and Aggregations comprised entirely of Limited Energy Storage Resources ("Aggregation of LESR") scheduled to provide Regulation Service shall be determined by applying the following equations to each Resource using the terms as defined in Section 25.3.3~~4~~; *provided, however*, that a Day-Ahead Margin Assurance Payment is payable only for intervals in which the NYISO has reduced the real-time Regulation Service offer (in MWs) of a Limited Energy Storage Resource or an Aggregation of LESR and the NYISO is not pursuing LESR Energy Management for such Resource for such interval, pursuant to ISO Procedures:

If the LESR's or Aggregation of LESR's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule and the real-time Regulation Capacity Market Price is greater than the Day-Ahead Regulation Capacity Bid price then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})] * K_p * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

If the LESR's or Aggregation of LESR's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule and the real-time Regulation Capacity Market price is less than or equal to the Day-Ahead Regulation Capacity Bid price then:

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) * (RTPreg_{iu} - DABreg_{hu})] * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

If the LESR's or Aggregation of LESR's real-time Regulation Service schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) * max\left((RTPreg_{iu} - RTBreg_{iu}), 0\right)\right] * \frac{Seconds_i}{3600} + [(-1 * RTMreg_{iu}) * max(0, RTPregm_{iu} - RTBregm_{iu})]$$

25.3.34 Terms Used in this Attachment J

The terms used in the formulas in this Attachment J shall be defined as follows:

h is the hour that includes interval *i*;

$DMAP_{hu}$	=	the Day-Ahead Margin Assurance Payment attributable in any hour *h* to any Supplier *u*;
$CDMAP_{iu}$	=	the contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;
$CDMAPen_{iu}$	=	the Energy contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;
$CDMAPreg_{iu}$	=	the Regulation Service contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;
$CDMAPres_{iup}$	=	the Operating Reserve contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u* determined separately for each Operating Reserve product *p*;
$DASen_{hu}$	=	Day-Ahead Energy schedule for Supplier *u* in hour *h*;
$DASreg_{hu}$	=	Day-Ahead schedule for Regulation Service for Supplier *u* in hour *h*;
$DASres_{hup}$	=	Day-Ahead schedule for Operating Reserve product p, for Supplier *u* in hour *h*;
$DABen_{hu}$	=	Day-Ahead Energy Bid cost for Supplier *u* in hour *h*, including the Minimum Generation Bid and Incremental Energy Bids;
$DABreg_{hu}$	=	Day-Ahead Regulation Capacity Bid price for Supplier *u* in hour *h*;
$DABres_{hup}$	=	Day-Ahead Availability Bid for Operating Reserve product *p* for Supplier *u* in hour *h*;
$RTSen_{iu}$	=	real-time Energy scheduled for Supplier *u* in interval *i*, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Supplier *u* during the course of interval *i*;
$RTSreg_{iu}$	=	real-time schedule for Regulation Service for Supplier *u* in interval *i*.
$RTSres_{iup}$	=	real-time schedule for Operating Reserve product *p* for Supplier *u* in interval *i*.
$RTBreg_{iu}$	=	real-time Regulation Capacity Bid price for Supplier *u* in interval *i*.
$RTBen_{iu}$	=	real-time Energy Bid cost for Supplier *u* in interval *i*, including the Minimum Generation Bid and Incremental Energy Bids.

$RTBregm_{iu}$ = real-time Regulation Movement Bid price for Supplier *u* in interval *i*.

$RTMreg_{iu}$ = real-time Regulation Movement MWs for Supplier *u* in interval *i;*

AE_{iu} = either, (1) average Actual Energy Injection by Supplier *u* in interval *i* but not more than $RTSen_{iu}$ plus Compensable Overgeneration; or (2) average Actual Energy Withdrawal by Supplier *u* in interval *i*;

ADR_{iu} = average Actual Demand Reduction by Supplier *u* in interval *i;*

$RTPen_{iu}$ = real-time price of Energy at the location of Supplier *u* in interval *i*;

$RTPreg_{iu}$ = real-time price of Regulation Capacity at the location of Supplier *u* in interval *i*;

$RTPres_{iup}$ = real-time price of Operating Reserve product *p* at the location of Supplier *u* in interval *i*;

$RTPregm_{iu}$ = real-time Regulation Movement Market Price at the location of Supplier *u* in interval *i;*

LL_{iu} = When the Day-Ahead Energy schedule is to inject, either:

(a) $if\ RTSen_{iu} < EOP_{iu}, then\ LL_{iu} = max(min\big(max\big(RTSen_{iu}, min((AE_{iu} + ADR_{iu})\ , EOP_{iu})\big), DASen_{hu}\big), 0)$; or

(b) $if\ RTSen_{iu} \geq EOP_{iu}, then\ LL_{iu} = max(min(RTSen_{iu}, max((AE_{iu} + ADR_{iu}), EOP_{iu}), DASen_{hu}), 0)$

When the Day-Ahead Energy schedule is to withdraw, either:

(a) if $RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}$

(1) $if\ (AE_{iu} + ADR_{iu}) \leq EOP_{iu}, then\ LL_{iu} = min\big(max\big(DASen_{hu}, min((AE_{iu} + ADR_{iu}), EOP_{iu})\big), RTSen_{iu}, 0\big)$; or

(2) $if\ (AE_{iu} + ADR_{iu}) > EOP_{iu}, then\ LL_{iu}$
$= min(\max\ (DASen_{hu}, (AE_{iu} + ADR_{iu}), EOP_{iu}), RTSen_{iu}, 0)$

(b) otherwise

$LL_{iu} = min\big(max\big(DASen_{hu}, min((AE_{iu} + ADR_{iu}), EOP_{iu})\big), RTSen_{iu}, 0\big)$

UL_{iu} = When the Day-Ahead Energy schedule is to inject, either:

(a) $if\ RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}, then\ UL_{iu} = max\big(min\ \big(RTSen_{iu}, max\ ((AE_{iu} + ADR_{iu}), EOP_{iu})\big), DASen_{hu}\big)$; or

(b) otherwise, then $UL_{iu} = max(RTSen_{iu}, min(AE_{iu} + ADR_{iu}), EOP_{iu}), DASen_{hu})$

When the Day-Ahead Energy schedule is to withdraw, either:

(a) if $RTSen_{iu} < EOP_{iu}$

(1) if $(AE_{iu} + ADR_{iu}) < RTSen_{iu}, then\ UL_{iu} = min\ (RTSen_{iu}, (AE_{iu} + ADR_{iu}), EOP_{iu}, DASen_{hu})$;

(2) if $RTSen_{iu} < (AE_{iu} + ADR_{iu}) < EOP_{iu}, then\ UL_{iu} = min\big(max\ \big(RTSen_{iu}, min\ ((AE_{iu} + ADR_{iu}), EOP_{iu})\big), DASen_{hu}\big); or$

(3) if $(AE_{iu} + ADR_{iu}) > EOP_{iu}$, $then\ UL_{iu} = min(max\ (RTSen_{iu}, (AE_{iu} + ADR_{iu}), EOP_{iu}), DASen_{hu})$;

(b) if $RTSen_{iu} \geq EOP_{iu}$

(1) if $(AE_{iu} + ADR_{iu}) \leq EOP_{iu}$, $then\ UL_{iu} = min\ (RTSen_{iu}, (AE_{iu} + ADR_{iu}), EOP_{iu}, DASen_{hu})$;

(2) if $EOP_{iu} < (AE_{iu} + ADR_{iu}) \leq RTSen_{iu}, then\ UL_{iu} = min(RTSen_{iu}, max\ ((AE_{iu} + ADR_{iu}), EOP_{iu}), DASen_{hu}); or$

(3) if $(AE_{iu} + ADR_{iu}) > RTSen_{iu}$, $then\ UL_{iu} = min(max\ (RTSen_{iu}, (AE_{iu} + ADR_{iu}), EOP_{iu}), DASen_{hu})$;

EOP_{iu} = the Economic Operating Point of Supplier *u* in interval *i* calculated without regard to ramp rates;

$Seconds_i$ = number of seconds in interval *i*

KPI_{pi} = the factor derived from the Regulation Service Performance index for Resource *u* for interval *i* as defined in Rate Schedule 3 of this Services Tariff.

25.4 Exception for Generators and Aggregations Lagging Behind RTD Base Point Signals

If an otherwise eligible Generator's or Aggregation'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 and Aggregations 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 or Aggregation otherwise eligible for a Day-Ahead Margin Assurance Payment in hours in which the ISO has derated the Generator's or Aggregation's Operating Capacity in order to reconcile the ISO's dispatch with the Generator's or Aggregation's actual output, or to address reliability concerns that arise because the Generator or Aggregation is not following Base Point Signals. If a Supplier's derated real-time Operating Capacity is lower than the sum of its Day-Ahead Energy, Regulation Services, and Operating Reserve schedules then when the ISO conducts the calculations described in Section 25.3 above, the DASen, DASeg and $DASres_p$ variables will be reduced by REDen, REDreg and $REDres_p$ respectively. REDen, REDreg and $REDres_p$ shall be calculated using the formulas below:

$$REDtot_{iu} = max\left(DASen_{hu} + DASreg_{hu} + \sum_p DASres_{hup} - RTUOL_{iu}, 0\right)$$

$$POTREDen_{iu} = max(DASen_{hu} - RTSen_{iu}, 0)$$

$$POTREDreg_{iu} = max(DASreg_{hu} - RTSreg_{iu}, 0)$$

$$POTREDres_{iup} = max(DASres_{hup} - RTSres_{iup}, 0)$$

$$REDen_{iu} = \left(POTREDen_{iu} / \left(POTREDen_{iu} + POTREDreg_{iu} + \sum_p POTREDres_{iup}\right)\right) * REDtot_{iu}$$

$$REDreg_{iu} = \left(POTREDreg_{iu} / \left(POTREDen_{iu} + POTREDreg_{iu} + \sum_p POTREDres_{iup}\right)\right) * REDtot_{iu}$$

$$REDres_{iup} = \left(POTREDres_{iup} / \left(POTREDen_{iu} + POTREDreg_{iu} + \sum_p POTREDres_{iup}\right)\right) * REDtot_{iu}$$

where:

$RTUOL_{iu}$	=	The real-time Emergency Upper Operating Limit or Normal Upper Operating Limit whichever is applicable of Supplier *u* in interval *i*
$REDtot_{iu}$	=	The total amount in MW that Day-Ahead schedules need to be reduced to account for the derate of Supplier *u* in interval *i*
$REDen_{iu}$	=	The amount in MW that the Day-Ahead Energy schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*
$REDreg_{iu}$	=	The amount in MW that Supplier *u*'s Day-Ahead Regulation Service schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval *i*
$REDres_{iup}$	=	The amount in MW that Supplier *u*'s Day-Ahead Operating Reserve schedule for Operating Reserves product *p* is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval *i*
$POTREDen_{iu}$	=	The potential amount in MW that Supplier *u*'s Day-Ahead Energy schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*
$POTREDreg_{iu}$	=	The potential amount in MW that Supplier *u*'s Day-Ahead Regulation Service schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*
$POTREDres_{iup}$	=	The potential amount in MW that Supplier *u*'s Day-Ahead Operating Reserve Schedule for Operating Reserve product *p* could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier *u* in interval *i*

All other variables are as defined above.

25.6 Import Curtailment Guarantee Payments

25.6.1 Eligibility for an Import Curtailment Guarantee Payment for an Import Curtailed by the ISO

In the event that the Energy injections for an Import scheduled by RTC or RTD at a Proxy Generator Bus, other than a CTS Enabled Proxy Generator Bus, are Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible for an Import Curtailment Guarantee Payment as determined in Section 25.6.2 of this Attachment J. Suppliers scheduling Imports at CTS Enabled Proxy Generator Buses shall not be eligible for Import Curtailment Guarantee payments for those Transactions.

25.6.2 Formula for an Import Curtailment Guarantee Payment for a Supplier Whose Import Was Curtailed by the ISO

A Supplier eligible under Section 25.6.1 of this Attachment J shall receive an Import Curtailment Guarantee Payment for its curtailed Energy injections that is equal to the daily sum of the hourly payments which, for each hour of Import t, is calculated as the greater of the interval payments determined for the hour or zero as seen in the formula below.

Import Curtailment Guarantee Payment to Supplier u in association with Import t =

$$\sum_{h=1}^{N} max\left(\sum_{i=1}^{H}\left(RTLBMP_{ti} - max(DADecBid_{ti}, 0)\right) * (DAen_{ti} - RTDen_{ti}) * \frac{S_i}{3600}, 0\right)$$

Where

N = the number of hours in the Dispatch Day

H = the number of intervals in hour h

i = the relevant interval in hour h;

S_i = number of seconds in interval i;

$RTLBMP_{t,i}$ = the real-time LBMP, in $/MWh, for interval i at the Proxy Generator Bus which is the source of the Import t.

$DADecBid_{t,i}$ = the Day Ahead Decremental Bid price associated with the Day-Ahead energy schedule, in $/MWh, for Import t in hour h containing interval i;

$DAen_{t,i}$ = the Day Ahead scheduled Energy injections, in MWh, for Import t in hour h containing interval i as determined by Security Constrained Unit Commitment (SCUC); and

$RTDen_{t,i}$ = the scheduled Energy injections, in MWh, for Import t in interval i as determined by Real-Time Dispatch (RTD).

26.4 Operating Requirement and Bidding Requirement

26.4.1 Purpose and Function

The Operating Requirement is a measure of a Customer's expected financial obligations to the ISO based on the nature and extent of that Customer's participation in ISO-Administered Markets. A Customer shall be required to allocate Unsecured Credit, where allowed, and/or provide collateral in an amount equal to or greater than its Operating Requirement. Upon a Customer's written request, the ISO will provide a written explanation for any changes in the Customer's Operating Requirement.

The Bidding Requirement is a measure of a Customer's potential financial obligation to the ISO based upon the bids that Customer seeks to submit in an ISO-administered TCC or ICAP auction. A Customer shall be required to allocate Unsecured Credit, where allowed, and/or provide collateral in an amount equal to or greater than its Bidding Requirement prior to submitting bids in an ISO-administered TCC or ICAP auction.

26.4.2 Calculation of Operating Requirement

The Operating Requirement shall be equal to the sum of (i) the Energy and Ancillary Services Component; (ii) the External Transaction Component; (iii) the UCAP Component; (iv) the TCC Component; (v) the WTSC Component; (vi) the Virtual Transaction Component; ~~(vii) the DADRP Component; (viii) the DSASP Component;~~ (~~ix~~vii) the Projected True-Up Exposure Component; and (~~x~~viii) the Former RMR Generator Component, where:

26.4.2.1 Energy and Ancillary Services Component

The Energy and Ancillary Services Component shall be equal to:

(a) For Customers without a prepayment agreement, the greater of either:

$$\frac{Basis\ Amount\ for\ Energy\ and\ Ancillary\ Services}{Days\ in\ Basis\ Month} * 16$$

- or -

$$\frac{\substack{Total\ Charges\ Incurred\ for\ Energy\ and \\ Ancillary\ Services\ for\ Previous\ Ten\ (10) Days}}{10} * 16$$

(b) For Customers that qualify for a prepayment agreement, subject to the ISO's credit analysis and approval, and execute a prepayment agreement in the form provided in Appendix K-1, the greater of either:

$$\frac{Basis\ Amount\ for\ Energy\ and\ Ancillary\ Services}{Days\ in\ Basis\ Month} * 3$$

-or-

$$\frac{\substack{Total\ Charges\ Incurred\ for\ Energy\ and \\ Ancillary\ Services\ for\ Previous\ Ten\ (10) Days}}{10} * 3$$

(c) For new Customers, the ISO shall determine a substitute for the Basis Amount for Energy and Ancillary Services for use in the appropriate formula above equal to:

$$EPL * 720 * AEP$$

where:

EPL = estimated peak Load for the Capability Period; and

AEP = average Energy and Ancillary Services price during the Prior Equivalent Capability Period after applying the Price Adjustment.

26.4.2.2 External Transaction Component

The External Transaction Component shall equal the sum of the Customer's (i) Import Credit Requirement, (ii) Export Credit Requirement, (iii) Wheels Through Credit Requirement, and (iv) the net amount owed to the ISO for the settled External Transaction Component Transactions.

26.4.2.2.1 Import Credit Requirement

For a given month, the Import Credit Requirement shall apply to any Customer that Bids to Import in the Day-Ahead Market ("DAM") unless (i) the Customer has at least 50 scheduled Day-Ahead Import Bids in the three-month period ending on the 15th day of the preceding month (or the six-month period ending on the 15th day of the preceding month if the Customer has fewer than 50 scheduled Day-Ahead Import Bids in the immediately preceding three-month period), and (ii) fewer than 25% of the MWhs of such scheduled Day-Ahead Import Bids were settled at a loss to the Customer.

The Import Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Import Bid until posting of the applicable DAM schedule/price.

The ISO will calculate the required credit support for pending DAM Import Bids for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for DAM Import Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The ISO will categorize each Import Bid into one of the 18 Import Price Differential (IPD) groups set forth in the IPD chart in Section 26.4.2.2.5 below, as appropriate, based upon the season and time-of-day of the Import Bid. The amount of credit support required in $/MWh that applies to an Import Bid shall equal the 97th percentile level of the following: the hourly average Energy price calculated in the Real-Time Market at the location associated with the Import Bid, minus the Energy price calculated in the DAM at the same location and time, with the dataset used to perform this calculation consisting of all hours that are in the same IPD group as the hour to which the Import Bid applies, and that occurred no earlier than April 1, 2005 nor later than the end of the calendar month preceding the month to which the Import Bid applies. The amount of credit support required in $/MWh shall not be less than $0/MWh.

The credit requirement for each Import Bid shall be calculated as follows:

$$Bid_{MWhB} * Max\ (IPD_{CS}, 0)$$

Where:

Bid_{MWhB}	=	the total quantity of MWhs that a Customer Bids to Import in a particular hour and at a particular location.
IPD_{CS}	=	the amount of credit support required, in $/MWh, for an Import Bid as described above, for the location associated with the Import Bid and for the IPD group that contains the hour to which the Import Bid applies.

(2) Upon posting of the applicable DAM schedule/price until completion of the hour Bid in real-time for a DAM Import Bid.

The credit requirement for each Import Bid shall be calculated as follows:

$$SchBid_{MWhI} * Max(IPD_{CS}, 0)$$

Where:

$SchBid_{MWhI}$	=	the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Import Bid.
IPD_{CS}	=	the amount of credit support required, in $/MWh, for an Import Bid as described above, for the location associated with the Import Bid and for the IPD group that contains the hour to which the Import Bid applies.

(3) Upon completion of the hour Bid in real-time for a DAM Import Bid until the net amount owed to the ISO is determined for settled External Transactions.

The credit requirement for each Import Bid shall be calculated as follows:

$$Max\big((BalPay_{\$} - DAMPay_{\$}), 0\big)$$

Where:

$BalPay_{\$}$	=	$(SchBid_{MWhI} – Actual_{MWhI})$ * RT $LBMP_I$
$DAMPay_{\$}$	=	$SchBid_{MWhI}$ * DAM $LBMP_I$
$SchBid_{MWhI}$	=	the total quantity of MWhs that is scheduled in the DAM in a particular hour at a particular location as a result of the Customer's Import Bid.
$Actual_{MWhI}$	=	the total quantity of MWhs that is scheduled in real-time associated with the Customer's Import Bid in a particular hour and at a particular location for the hour completed.
DAM $LBMP_I$	=	the Day-Ahead LBMP in a particular hour and at a particular location associated with the Customer's Import Bid.
RT $LBMP_I$	=	the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Import Bid.

26.4.2.2.2 Export Credit Requirement

The Export Credit Requirement shall apply to any Customer that Bids to Export from the DAM or Hour-Ahead Market ("HAM").

The Export Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Export Bid until posting of the applicable DAM schedule/price.

The ISO will calculate the required credit support for pending DAM Export Bids for a market day three days prior to the DAM market close for that market day. The ISO will calculate the required credit support for DAM Export Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The ISO will categorize each Export Bid into one of the 18 Export Price Differential (EPD) groups set forth in the EPD chart in Section 26.4.2.2.5 below, as appropriate, based upon the season and time-of-day of the Export Bid. The amount of credit support required in $/MWh that applies to an Export Bid shall equal the 97th percentile level of the following: the Energy price calculated in the DAM at the location associated with the Export Bid, minus the hourly average Energy price calculated in the Real-Time Market at the same location and time, with the dataset used to perform this calculation consisting of all hours that are in the same EPD group as the hour to which the Export Bid applies, and that occurred no earlier than April 1, 2005 nor later than the end of the calendar month preceding the month to which the Export Bid applies. The amount of credit support required in $/MWh shall not be less than $0/MWh.

The credit requirement for all DAM Export Bids with the same hour/date and location shall be calculated as follows:

$$\left(Max\left(\left(Max_N(Bid_{MWh} * \ Bid_{\$E})\right), (BidMax_{MWhB} * \ EPD_{CS})\right)\right)$$

Where:

Bid_{MWh}	=	the total quantity of MWhs that a Customer Bids to Export in the DAM in a particular hour and at a particular location at or below each Bid Price.
$Bid_{\$E}$	=	the Bid Price in $/MWh at which the Customer Bids to purchase the Bid_{MWh} of Exports in a particular hour and at a particular location.
N	=	the set of hourly Export Bid Prices in a particular hour and at a particular location.
$BidMax_{MWhB}$	=	the total quantity of MWhs that a Customer Bids to Export in the DAM in a particular hour and at a particular location.
EPD_{CS}	=	the amount of credit support required, in $/MWh, for an Export Bid as described above, for the location associated with the Export Bid and for the EPD group that contains the hour to which the Export Bid applies.

(2) Upon posting of the applicable DAM schedule/price until completion of hour Bid in real-time for a DAM Export Bid.

The credit requirement for each Export Bid shall be calculated as follows:

$$\left(SchBid_{MWhE} * \left(Max(EPD_{CS}, DAM\ LBMP_E)\right)\right)$$

Where:

$SchBid_{MWhE}$	=	the total quantity of MWhs that is scheduled in the DAM in a particular hour at a particular location as a result of the Customer's Export Bid.
EPD_{CS}	=	the amount of credit support required, in $/MWh, for an Export Bid as described above, for the location associated with the Export Bid and for the EPD group that contains the hour to which the Export Bid applies.
DAM $LBMP_E$	=	the Day-Ahead LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

(3) From submission of a HAM Export Bid until completion of the hour Bid in real-time.

i. Non-CTS Interface Bids to Export .

The ISO will calculate the required credit support for pending HAM non-CTS Interface Bids to Export for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for HAM non-CTS Interface Bids to Export that are submitted after the commencement of the initial credit evaluation upon Bid submission. The amount of credit support required in $/MWh that applies to HAM non-CTS Interface Bids Export in the same hour/date and at the same location shall equal the maximum amount of the payment potentially due to the ISO based on the MWhs of Exports Bid for purchase at each bid price in a particular hour and at a particular location.

The credit requirement for all HAM non-CTS Interface Bids to Export with the same hour/date and location shall be calculated as follows:

$$\left(Max_N\left(\left(Max(Bid_{MWhE}, 0)\right) * Bid_{\$E}\right)\right)$$

Where:

Bid_{MWhE}	=	the total quantity of MWhs that a Customer Bids to Export in the HAM in a particular hour and at a particular location at or below each bid price minus the MWhs of Exports scheduled in the DAM in the same hour at the same location.
$Bid_{\$E}$	=	the bid price in \$/MWh at which the Customer Bids to purchase the Bid_{MWhE} of Exports in a particular hour and at a particular location.
N	=	the set of hourly Export bid prices in a particular hour and at a particular location.

ii. CTS Interface Bids to Export.

For CTS Interface Bids to Export credit support will be calculated at HAM close.The amount of credit support required in \$/MWh that applies to such bid shall equal the sum of the time-weighted hourly RTC price for each of the 15-minute intervals within the bid hour, not to be less than zero.

The credit requirement for each CTS Interface Bid to Export shall be calculated as follows:

$$Max\left(\sum_{N}\left(RTC_{\$/MWhcts} * Bid_{MWhscts} * Hourly\ Weight\right), 0\right)$$

Where:

N	=	each 15-minute interval within the bid hour.
$RTC_{\$/MWhcts}$	=	most recently available RTC price for N in \$/MWh at the location associated with the CTS Interface Bid to Export
$Bid_{MWhscts}$	=	the total quantity of MWhs in a Customer's CTS Interface Bid to Export for N in a particular hour and at a particular location minus the MWhs of Exports scheduled in the DAM in same hour at the same location.
Hourly Weight	=	0.25

(4) Upon completion of the hour Bid in real-time for an Export Bid until the net amount owed to the ISO is determined for settled External Transactions.

The amount of credit support required will equal the sum of the Day-Ahead Credit Calculation and Real-Time Credit Calculation for each completed hour.

The credit requirement for each Export Bid shall be calculated as follows:

Day-Ahead Credit Calculation + Real-Time Credit Calculation

The Day-Ahead Credit Calculation only applies to DAM Export Bids and the Real-Time Credit Calculation applies to all HAM Export Bids including HAM Bids associated with a DAM Bid.

Where:

Day-Ahead Credit Calculation = Max (Adjusted Export Day-Ahead Credit Calculation, 0)

Adjusted Export Day-Ahead Credit Calculation = the credit requirement calculated in accordance with section 26.4.2.2.2(2) minus the Balancing Payment.

$$Balancing\ Payment = Max\left((SchBid_{MWhE} - Actual_{MWhE}), 0\right) * RT\ LBMP_E$$

$SchBid_{MWhE}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Export Bid.

$Actual_{MWhE}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Export Bid in a particular hour and at a particular location for the hour completed.

$RT\ LBMP_E$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

$$Real\text{-}Time\ Credit\ Calculation = Max\left(\left(Max\left((Actual_{MWhE} - SchBid_{MWhE}), 0\right) * RT\ LBMP_E\right), 0\right)$$

$Actual_{MWhE}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Export Bid in a particular hour and at a particular location for the hour completed.

$SchBid_{MWhE}$ = the total quantity of MWhs that is scheduled in the DAM in a particular hour and at a particular location as a result of the Customer's Export Bid.

$RT\ LBMP_E$ = the Real-Time LBMP in a particular hour and at a particular location associated with the Customer's Export Bid.

26.4.2.2.3 Wheels Through Credit Requirement

The Wheels Through Credit Requirement shall apply to any Customer that Bids to Wheel Through in the DAM or HAM.

The Wheels Through Credit Requirement shall equal the sum of the amounts calculated for each Bid in accordance with the appropriate formulas below:

(1) Upon submission of a DAM Wheels Through Bid until posting of the applicable DAM schedule/price.

The ISO will calculate the required credit support for pending DAM Wheels Through Bids for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for DAM Wheels Through Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The amount of credit support required in $/MWh that applies to the DAM Wheels Through Bid shall equal the maximum payment potentially due to the ISO based on the Customer's Bid Prices on the Bid curve. The credit requirement for each Wheels Through Bid shall be calculated as follows:

$$Max\left(Max_N\left(BidPt_{MWhN} * Bid\$_{\$/MWhN}\right), 0\right)$$

Where:

N	=	each Bid Price on the Bid curve.
$BidPt_{MWhN}$	=	the MWhs associated with the Bid Price on the Bid curve.
$Bid\$_{\$/MWhN}$	=	the amount that the customer is willing to pay for congestion in $/MWh on the Bid curve associated with the Customer's Wheels Through Bid.

(2) Upon posting of the applicable Wheels Through DAM schedule/price until completion of the hour Bid in real-time.

The credit requirement for each DAM Wheels Through Bid shall be calculated as follows:

$$Max(SchBid_{MWhW} * (DAM\ LBMP_{POW} - DAM\ LBMP_{POI}), 0)$$

Where:

$SchBid_{MWhW}$ = the total quantity of MWhs scheduled in the DAM as a result of the Customer's Bid to schedule Wheels Through.

$DAM\ LBMP_{POI}$ = the Day-Ahead LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

$DAM\ LBMP_{POW}$ = the Day-Ahead LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

(3) Upon creation of a HAM Wheels Through Bid until the completion of the hour Bid in real-time.

The ISO will calculate the required credit support for pending HAM Wheels Through Bids for a market day three days prior to the DAM close for that market day. The ISO will calculate the required credit support for HAM Wheels Through Bids that are submitted after the commencement of the initial credit evaluation upon Bid submission. The amount of credit support required in \$/MWh that applies to HAM Wheels Through Bid shall equal the price of the maximum value of exposure based on bid prices on the Bid curve.

The credit requirement for each Wheels Through Bid shall be calculated as follows:

$$Max\left(Max_N\left(Max(BidPt_{MWhW}, 0) * Bid\$_{\$/MWhN}\right), 0\right)$$

Where:

N = each bid price on the Bid curve.

$BidPt_{MWhW}$ = the MWhs associated with the bid price on the Bid curve minus the MWhs of the DAM Bid with same hour/date, location and Bid transaction ID.

$Bid\$_{\$/MWhN}$ = the amount that the customer is willing to pay for congestion in \$/MWh on the Bid curve associated with the Customer's Wheels Through Bid.

(4) Upon completion of the hour Bid in real-time for a Wheels Through Bid until the net amount owed to the ISO is determined for settled External Transactions.

The amount of credit support required will equal the sum of the Day-Ahead Credit Calculation and Real-Time Credit Calculation for each completed hour. The credit requirement for each Wheels Through Bid shall be calculated as follows:

Day-Ahead Credit Calculation + Real-Time Credit Calculation

The Day-Ahead Credit Calculation only applies to DAM Wheels Through Bids and the Real-Time Credit Calculation applies to all HAM Wheels Through Bids including HAM Bids associated with a DAM Bid.

Where:

Day-Ahead Credit Calculation = Max (Adjusted Wheels Through Day-Ahead Credit Calculation, 0)

Adjusted Wheels Through Day-Ahead Credit Calculation = the credit requirement calculated in section 26.4.2.2.3(2) minus the Balancing Payment.

$$Balancing\ Payment = Max\big((SchBid_{MWhW} - Actual_{MWhW}), 0\big) * (RT\ LBMP_{POW} - RT\ LBMP_{POI})$$

$SchBid_{MWhW}$ = the total quantity of MWhs that is scheduled in the DAM as a result of the Customer's Wheels Through Bid.

$Actual_{MWhW}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Wheels Through Bid for the hour completed.

$RT\ LBMP_{POI}$ = the Real-Time LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

$RT\ LBMP_{POW}$ = the Real-Time LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

$$Real\text{-}Time\ Credit\ Calculation = Max\Big(Max\big((Actual_{MWhW} - SchBid_{MWhW}), 0\big) * (RT\ LBMP_{POW} - RT\ LBMP_{POI}), 0\Big)$$

$SchBid_{MWhW}$ = the total quantity of MWhs that is scheduled in the DAM as a result of the Customer's Bid to Wheel Through Energy.

$Actual_{MWhW}$ = the total quantity of MWhs that is scheduled in real-time associated with the Customer's Wheels Through Bid for the hour completed.

$RT\ LBMP_{POI}$ = the Real-Time LBMP in the hour and at the Point of Injection associated with the Wheels Through Bid.

$RT\ LBMP_{POW}$ = the Real-Time LBMP in the hour and at the Point of Withdrawal associated with the Wheels Through Bid.

26.4.2.2. 4 Calculation of Price Differentials

Import Price Differential (IPD) Groups

Summer	**For each Proxy Generator Bus**
HB07–10	IPD-1
HB11–14	IPD-2
HB15–18	IPD-3
HB19–22	IPD-4
Weekend/ Holiday (HB07–22)	IPD-5
Night (HB23–06)	IPD-6
Winter	
HB07–10	IPD-7
HB11–14	IPD-8
HB15–18	IPD-9
HB19–22	IPD-10
Weekend/ Holiday (HB07–22)	IPD-11
Night (HB23–06)	IPD-12
Rest-of-Year	
HB07–10	IPD-13
HB11–14	IPD-14
HB15–18	IPD-15
HB19–22	IPD-16
Weekend/ Holiday (HB07–22)	IPD-17
Night (HB23–06)	IPD-18

Where:

Summer = May, June, July, and August

Winter = December, January, and February

Rest-of-Year = March, April, September, October, and November

HB07–10 = weekday hours beginning 07:00–10:00

HB11–14 = weekday hours beginning 11:00–14:00

HB15–18 = weekday hours beginning 15:00–18:00

HB19–22 = weekday hours beginning 19:00– 22:00

Weekend/Holiday = weekend and holiday hours beginning 07:00–22:00

Night = all hours beginning 23:00– 06:00

Export Price Differential (EPD) Groups

Summer	For each Proxy Generator Bus
HB07–10	EPD-1
HB11–14	EPD-2
HB15–18	EPD-3
HB19–22	EPD-4
Weekend/ Holiday (HB07–22)	EPD-5
Night (HB23–06)	EPD-6
Winter	
HB07–10	EPD-7
HB11–14	EPD-8
HB15–18	EPD-9
HB19–22	EPD-10
Weekend/ Holiday (HB07–22)	EPD-11
Night (HB23–06)	EPD-12
Rest-of-Year	
HB07–10	EPD-13
HB11–14	EPD-14
HB15–18	EPD-15
HB19–22	EPD-16
Weekend/ Holiday (HB07–22)	EPD-17
Night (HB23–06)	EPD-18

Where:

Summer = May, June, July, and August

Winter = December, January, and February

Rest-of-Year = March, April, September, October, and November

HB07–10 = weekday hours beginning 07:00–10:00

HB11–14 = weekday hours beginning 11:00–14:00

HB15–18 = weekday hours beginning 15:00–18:00

HB19–22 = weekday hours beginning 19:00– 22:00

Weekend/Holiday = weekend and holiday hours beginning 07:00–22:00

Night = all hours beginning 23:00– 06:00

26.4.2.3 UCAP Component

The UCAP Component shall be equal to the total of all amounts then-owed (billed and unbilled) for UCAP purchased in the ISO-administered markets.

26.4.2.4 TCC Component

The TCC Component shall be equal to the greater of either (a) the amount calculated in accordance with Section 26.4.2.4.1, or (b) Section 26.4.2.4.2 (Mark-to-Market Calculation) below; *provided however*, that upon initial award of a TCC until the ISO receives payment for the TCC (or payment for the first year of a two-year TCC), the ISO will hold the greater of the payment obligation for the TCC or the credit requirement for the TCC calculated in accordance with this Section 26.4.2.4.

26.4.2.4.1 Auction TCC Holding Requirement

This Section 26.4.2.4.1 applies to TCCs awarded in the Centralized TCC Auction and Balance-of-Period Auction, as well as Fixed Price TCCs.

The credit requirement pursuant to this Section 26.4.2.4.1 shall equal the sum of the amounts calculated in accordance with the appropriate per TCC term-based formulas listed below. The ISO will not impose a credit requirement on TCCs that have been sold by a Market Participant in the Centralized TCC Auction or Balance-of-Period Auction.

26.4.2.4.1.1 Two-Year TCCs:

(1) upon initial award of a two-year TCC (including a Fixed Price TCC with a two-year duration) until completion of the final round of the current two-year Sub-Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC.

Second Year:

$$+1.909\sqrt{e^{10.9729 + .6514\left(ln\left(\left|P_{ijt}\right| + e\right)\right) + .6633 * Zone\ J + 1.1607 * Zone\ K}}$$

where:

P_{ijt} = market clearing price of that two-year TCC (or, in the case of a Fixed Price TCC, a two-year TCC with the same POI and POW combination as the Fixed Price TCC) minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

(2) upon completion of the final round of the current two-year Sub-Auction until completion of the final round of the current one-year Sub-Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

Second Year:

$$+1.909\sqrt{e^{10.9729\,+\,.6514\left(ln\left(\left|P_{ijt}\right|\,+\,e\right)\right)\,+\,.6633\,*\,Zone\ J\,+\,1.1607\,*\,Zone\ K}}$$

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the current two-year Sub-Auction with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

(3) upon completion of the final round of the current one-year Sub-Auction until completion of the Balance-of-Period Auction for the first month of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the two-year TCC

Second Year:

$$+1.909\sqrt{e^{10.9729\,+\,.6514\left(ln\left(\left|P_{ijt}\right|\,+\,e\right)\right)\,+\,.6633\,*\,Zone\ J\,+\,1.1607\,*\,Zone\ K}}$$

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the current two-year Sub-Auction with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the two-year TCC

(4) upon completion of the Balance-of-Period Auction for the first month of the two-year TCC until completion of the final round of the six-month Sub-Auction in the next Centralized TCC Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formulas set forth in Section 26.4.2.4.1.6 below

Second Year:

$$+1.909\sqrt{e^{10.9729 + .6514\left(ln\left(\left|P_{ijt}\right| + e\right)\right) + .6633 * Zone\ J + 1.1607 * Zone\ K}}$$

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the two-year Sub-Auction in which the TCC was purchased (or, in the case of a Fixed Price TCC, the final round of the two-year Sub-Auction of the Centralized TCC Auction in which the six-month Sub-Auction made transmission capacity available to support the sale of TCCs for the first Capability Period in which the applicable Fixed Price TCC would be valid) with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction that directly followed the two-year Sub-Auction in which the TCC was purchased (or, in the case of a Fixed Price TCC, the two-year Sub-Auction of the Centralized TCC Auction in which the six-month Sub-Auction made transmission capacity available to support the sale of TCCs for the first Capability Period in which the applicable Fixed Price TCC would be valid) with the same POI and POW combination as the two-year TCC

(5) upon completion of the final round of the six-month Sub-Auction for the final six months of the first year of the two-year TCC until completion of the Balance-of-Period Auction immediately preceding the final six months of the first year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the six-month Sub-Auction with the same POI and POW combination as the two-year TCC

Second Year:

$$+1.909\sqrt{e^{10.9729\,+\,.6514\left(ln\left(\left|P_{ijt}\right|\,+\,e\right)\right)\,+\,.6633\,*\,Zone\ J\,+\,1.1607\,*\,Zone\ K}}$$

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the two-year Sub-Auction in which the TCC was purchased (or, in the case of a Fixed Price TCC, the final round of the two-year Sub-Auction of the Centralized TCC Auction in which the six-month Sub-Auction made transmission capacity available to support the sale of TCCs for the first Capability Period in which the applicable Fixed Price TCC would be valid) with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction that directly followed the two-year Sub-Auction in which the TCC was purchased (or, in the case of a Fixed Price TCC, the two-year Sub-Auction of the Centralized TCC Auction in which the six-month Sub-Auction made transmission capacity available to support the sale of TCCs for the first Capability Period in which the applicable Fixed Price TCC would be valid) with the same POI and POW combination as the two-year TCC

(6) upon completion of the Balance-of-Period Auction immediately preceding the final six months of the first year of the two-year TCC until ISO receipt of payment for the second year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period TCC Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

$$+1.909\sqrt{e^{10.9729 + .6514\left(ln\left(\left|P_{ijt}\right| + e\right)\right) + .6633 * Zone\ J + 1.1607 * Zone\ K}}$$

where:

P_{ijt} = market clearing price of a two-year TCC in the final round of the two-year Sub-Auction in which the TCC was purchased (or, in the case of a Fixed Price TCC, the final round of the two-year Sub-Auction of the Centralized TCC Auction in which the six-month Sub-Auction made transmission capacity available to support the sale of TCCs for the first Capability Period in which the applicable Fixed Price TCC would be valid) with the same POI and POW combination as the two-year TCC minus the market clearing price of a one-year TCC in the final round of the one-year Sub-Auction that directly followed the two-year Sub-Auction in which the TCC was purchased (or, in the case of a Fixed Price TCC, the two-year Sub-Auction of the Centralized TCC Auction in which the six-month Sub-Auction made transmission capacity available to support the sale of TCCs for the first Capability Period in which the applicable Fixed Price TCC would be valid) with the same POI and POW combination as the two-year TCC

(7) upon ISO receipt of payment for the second year of the two-year TCC until completion of the final round of the one-year Sub-Auction in the next Centralized TCC Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the one-year Sub-Auction in the prior equivalent Capability Period Centralized TCC Auction with the same POI and POW combination as the two-year TCC

(8) upon completion of the final round of the one-year Sub-Auction for the second year of the two-year TCC until completion of the Balance-of-Period Auction for the first month of the second year of the two-year TCC, the sum of the first year and second year amounts, which will be calculated as follows::

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the most recently completed one-year Sub-Auction with the same POI and POW combination as the two-year TCC

(9) upon completion of the Balance-of-Period Auction for the first month of the second year of the two-year TCC until completion of the final round of the six-month Sub-Auction in the next Centralized TCC Auction, the sum of the first year and second year amounts, which will be calculated as follows:

First Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

Second Year:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

(10) upon completion of the final round of the six-month Sub-Auction for the final six months of the two-year TCC until completion of the Balance-of-Period Auction immediately preceding the final six months of the two-year TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the most recently completed six-month Sub-Auction with the same POI and POW combination as the two-year TCC

(11) upon completion of the Balance-of-Period Auction for the first month of the final six months of a two-year TCC:

the amount calculated in accordance with the Balance-of-Period TCC formulas set forth in Section 26.4.2.4.1.5 below

26.4.2.4.1.2 One-Year TCCs:

(1) upon initial award of a one-year TCC (including a Fixed Price TCC with a one-year duration) until completion of the final round of the current one-year Sub-Auction:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

(2) upon completion of the final round of the current one-year Sub-Auction until completion of the Balance-of-Period Auction for the first month of the one-year TCC:

the amount calculated in accordance with the one-year TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a one-year TCC in the final round of the current one-year Sub-Auction with the same POI and POW combination as the one-year TCC

(3) upon completion of the Balance-of-Period Auction for the first month of the one-year TCC until completion of the final round of the six month Sub-Auction in the next Centralized TCC Auction:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

(4) upon completion of the final round of the six-month Sub-Auction for the final six months of a one-year TCC until completion of the Balance-of-Period Auction immediately preceding the final six months of a one-year TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the most recently completed six-month Sub-Auction with the same POI and POW combination as the one-year TCC

(5) upon completion of the Balance-of-Period Auction for the first month of the final six months of a one-year TCC:

the amount calculated in accordance with the appropriate Balance-of-Period Auction holding requirement formula set forth in Section 26.4.2.4.1.6 below

26.4.2.4.1.3 Six-Month TCCs:

(1) upon initial award of a six-month TCC until completion of the final round of the current six-month Sub-Auction:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

(2) upon completion of the final round of the current six-month Sub-Auction until completion of the Balance-of-Period Auction for the first month of a six-month TCC:

the amount calculated in accordance with the six-month TCC formula set forth in Section 26.4.2.4.1.5 below

where:

P_{ijt} = market clearing price of a six-month TCC in the final round of the current six-month Sub-Auction with the same POI and POW combination as the one-year TCC

(3) upon completion of the Balance-of-Period Auction for the first month of a six-month TCC:

the amount calculated in accordance with the Balance-of-Period Auction formula set forth in Section 26.4.2.4.1.6.1 below

26.4.2.4.1.4 One-Month TCCs:

upon initial award of a one-month TCC:

the amount calculated in accordance with the Balance-of-Period TCC Auction holding requirement formula set forth in Section 26.4.2.4.1.6.1 below

26.4.2.4.1.5 Centralized TCC Auction – Holding Requirement Formulas:

for one-year TCCs, representing a 5% probability curve:

$$+1.909\sqrt{e^{10.9729+.6514\left(ln\left(\left|P_{ijt}\right|+e\right)\right)+.6633*Zone\,J+1.1607*Zone\,K}}-1\,P_{ijt}$$

for six-month TCCs, representing a 3% probability curve:

$$+2.565\sqrt{e^{11.6866+.4749\left(ln\left(\left|P_{ijt}\right|+e\right)\right)+.4856*Zone\,J+.8498*Zone\,K-.0373\,Summer}}-1\,P_{ijt}$$

where:

P_{ijt} = market clearing price of i to j TCC in round t of the auction in which the TCC was purchased (or, in the case of a Fixed Price TCC, the auction in which the six-month Sub-Auction made transmission capacity available to

		support the sale of TCCs for the first Capability Period in which the applicable Fixed Price TCC would be valid);
Zone J	=	1 if TCC sources or sinks but not both in Zone J, zero otherwise;
Zone K	=	1 if TCC sources or sinks but not both in Zone K and does not source or sink in Zone J, 0 otherwise;
Summer	=	1 for six-month TCCs sold in the spring auction, 0 otherwise; and

Further, when calculating "Pijt" in Section 26.4.2.4.1, in the event there is no market clearing price for a two-year, one-year, or six-month TCC in the appropriate prior Capability Period Centralized TCC Auction with the same POI and POW combination as the awarded two-year, one-year, or six-month TCC, as appropriate, then the market clearing price shall equal a proxy price, assigned by the ISO, for a TCC with like characteristics.

Further, the NYISO may adjust any of the Zone K multipliers in Section 26.4.2.4.1 if, for TCCs of the same duration, the percentage ratio between collateral and congestion rents for Zone K TCCs deviates from the percentage ratio for Zone J TCCs by more than ten percent (10.0%).

26.4.2.4.1.6 Balance-of-Period Auction – Holding Requirement Formulas:

During the Balance-of-Period Auction, a TCC awarded in the Centralized TCC Auction (or the remaining segments of a TCC awarded in a prior Centralized TCC Auction) or a Fixed Price TCC valid during the period covered by the Balance-of-Period Auction is segmented, as appropriate, into (i) a monthly segment, corresponding to the months within the current Capability Period encompassed by the remaining duration of the TCC, (ii) a future six-month segment, corresponding to months within the next Capability Period encompassed by the remaining duration of the TCC, and (iii) a one-year segment, corresponding to all months after the Capability Period associated with the future six-month segment encompassed by the remaining duration of the TCC, such that the sum of segments (i), (ii), and (iii) covers the entire remaining duration of the TCC. The credit holding requirement for the monthly segments and the future six-month segment are calculated in accordance with the formulas below. The credit holding requirement for the one-year segment is calculated in accordance with formulas for determining the credit holding requirement for the second year of a two-year TCC as described in Section 26.4.2.4.1.1 above; provided, however, that in the case of a Historic Fixed Price TCC for which less than twelve months are assigned to the one-year segment, the applicable Sub-Auctions from which the market-clearing price (P_{ijt}) used for the formulas described in Section 26.4.2.4.1.1 shall be the most recently completed two-year Sub-Auction prior to the effective date of that Historic Fixed Price TCC and the one-year Sub-Auction that immediately followed such two-year Sub-Auction. The credit holding requirement calculated for each segment shall be determined based on the number of months that are assigned to each segment for the remaining duration of a given TCC.

26.4.2.4.1.6.1 Monthly Segment

Monthly Segment ($) = [(Monthly Margin ($) ×Monthly Index Ratio×Monthly Factor) −TCC Price ($)]×MWs

where:

Monthly Margin is calculated based on a methodology approved by Market Participants and posted to the ISO's website

Monthly Index Ratio as determined from time to time by the ISO based on historical data and a methodology approved by Market Participants and posted to the ISO's website

Monthly Factor as determined from time to time by the ISO based on historical data and a methodology approved by Market Participants and posted to the ISO's website

TCC Price is the market clearing price for the respective Capability Period month in the most recent Balance-of-Period Auction

MWs is the number of awarded TCC MWs

26.4.2.4.1.6.2 Future Six-Month Segment

Future Six-Month Segment ($) = (Six-Month Margin ($)−TCC Price ($))×MWs

where:

Six-Month Margin is calculated based on a methodology approved by Market Participants and posted on the ISO's website

TCC Price is the market clearing price, using the same POI/POW combination, resulting from the

(1) Market clearing price from the final round of the most recent one-year TCC Sub-Auction, less the

(2) Market clearing price from the second round of the most recent six-month TCC Sub-Auction

MWs is the number of awarded TCC MWs

26.4.2.4.2 Mark-to-Market Calculation

The projected amount of the Primary Holder's payment obligation to the NYISO, if any, considering the net mark-to-market value of all TCCs in the Primary Holder's portfolio, as defined for these purposes, according to the formula below:

$$\sum_{n \epsilon N} \left\{ \frac{NAP_n}{90} * RD_n \right\} + \sum_{n \epsilon N} ACR_n$$

where:

NAP	=	the net amount of Congestion Rents between the POI and POW composing each TCC_n during the previous ninety days
RD	=	the remaining number of days in the life of TCC_n; *provided, however,* that in the case of Grandfathered TCCs, RD shall equal the remaining number of days in the life of the longest duration TCC sold in an ISO-administered auction then outstanding;
N	=	the set of TCCs held by the Primary Holder; and
ACR	=	the net amount owed to the ISO for Congestion Rents between the POI and POW composing each TCC_n.

26.4.2.5 WTSC Component

The WTSC Component shall be equal to the greater of either:

$$\frac{\dfrac{\mathit{Greatest\ Amount\ Owed\ for\ WTSC\ During\ Any}}{\mathit{Single\ Month\ in\ the\ Prior\ Equivalent\ Capability\ Period}}}{\mathit{Days\ in\ Month}} * 50$$

- or –

$$\frac{\dfrac{\mathit{Total\ Charges\ Incurred\ for\ WTSC\ Based\ Upon\ the\ Most}}{\mathit{Recent\ Monthly\ Data\ Provided\ by\ the\ Transmission\ Owner}}}{\mathit{Days\ in\ Month}} * 50$$

26.4.2.6 Virtual Transaction Component

The Virtual Transaction Component shall be equal to the sum of the Customer's (i) Virtual Supply credit requirement ("VSCR") for all outstanding Virtual Supply Bids, plus (ii) Virtual Load credit requirement ("VLCR") for all outstanding Virtual Load Bids, plus (iii) net amount owed to the ISO for settled Virtual Transactions.

Where:

VSCR = $\sum(VSG_{MWh} * VSG_{CS})$

VLCR = $\sum(VLG_{MWh} * VLG_{CS})$

Where:

VSG_{MWh} = the total quantity of MWhs of Virtual Supply that a Customer Bids for all Virtual Supply positions in the Virtual Supply group

VSG_{CS} = the amount of credit support required in $/MWh for the Virtual Supply group

VLG_{MWh} = the total quantity of MWhs of Virtual Load that a Customer Bids for all Virtual Load positions in the Virtual Load group

VLG_{CS} = the amount of credit support required in $/MWh for the Virtual Load group

The ISO will categorize each Virtual Supply Bid into one of the 72 Virtual Supply groups set forth in the Virtual Supply chart below, as appropriate, based upon the season, Load Zone, and time-of-day of the Virtual Supply Bid. The amount of credit support required in $/MWh for a Virtual Transaction in a particular Virtual Supply group shall equal the price differential between the Energy price in the Day-Ahead Market and the Energy price in the Real-Time Market, at the 97th percentile, based upon all possible Virtual Supply positions in the Virtual Supply group for the period of time from April 1, 2005, through the end of the preceding calendar month.

The ISO will categorize each Virtual Load Bid into one of the 30 Virtual Load groups set forth in the Virtual Load chart below, as appropriate, based upon the season, Load Zone, and time-of-day of the Virtual Load Bid. The amount of credit support required in $/MWh for a Virtual Transaction in a particular Virtual Load group shall equal the price differential between the Energy price in the Day-Ahead Market and the Energy price in the Real-Time Market, at the 97th percentile, based upon all possible Virtual Load positions in the Virtual Load group for the period of time from April 1, 2005, through the end of the preceding calendar month.

If a Customer submits Bids for both Virtual Load and Virtual Supply for the same day, hour, and Load Zone, then for those Bids, until such time as those Bids have been evaluated by SCUC, only the greater of the Customer's (i) VLCR for the total MWhs Bid for Virtual Load, or (ii) VSCR for the total MWhs Bid for Virtual Supply will be included when calculating the Customer's Virtual Transaction Component. After evaluation of those Bids by SCUC, then only the credit requirement for the net position of the accepted Bids (in MWhs of Virtual Load or Virtual Supply) will be included when calculating the Customer's Virtual Transaction Component.

Virtual Supply Groups

Summer	Load Zones A–F	Load Zones G–I	Load Zone J	Load Zone K
HB07–10	VSG-1	VSG-7	VSG-13	VSG-19
HB11–14	VSG-2	VSG-8	VSG-14	VSG-20
HB15–18	VSG-3	VSG-9	VSG-15	VSG-21
HB19–22	VSG-4	VSG-10	VSG-16	VSG-22
Weekend/ Holiday (HB07–22)	VSG-5	VSG-11	VSG-17	VSG-23
Night (HB23–06)	VSG-6	VSG-12	VSG-18	VSG-24
Winter				
HB07–10	VSG-25	VSG-31	VSG-37	VSG-43
HB11–14	VSG-26	VSG-32	VSG-38	VSG-44
HB15–18	VSG-27	VSG-33	VSG-39	VSG-45
HB19–22	VSG-28	VSG-34	VSG-40	VSG-46
Weekend/ Holiday (HB07–22)	VSG-29	VSG-35	VSG-41	VSG-47
Night (HB23–06)	VSG-30	VSG-36	VSG-42	VSG-48
Rest-of-Year				
HB07–10	VSG-49	VSG-55	VSG-61	VSG-67
HB11–14	VSG-50	VSG-56	VSG-62	VSG-68
HB15–18	VSG-51	VSG-57	VSG-63	VSG-69
HB19–22	VSG-52	VSG-58	VSG-64	VSG-70
Weekend/ Holiday (HB07–22)	VSG-53	VSG-59	VSG-65	VSG-71
Night (HB23–06)	VSG-54	VSG-60	VSG-66	VSG-72

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
HB07–10	=	weekday hours beginning 07:00–10:00
HB11–14	=	weekday hours beginning 11:00–14:00
HB15–18	=	weekday hours beginning 15:00–18:00
HB19–22	=	weekday hours beginning 19:00– 22:00
Weekend/Holiday	=	weekend and holiday hours beginning 07:00–22:00
Night	=	all hours beginning 23:00– 06:00

Virtual Load Groups

Summer	Load Zones A–F	Load Zones G–I	Load Zone J	Load Zone K
HB07–10	VLG-1	VLG-4	VLG-8	VLG-12
HB11–14	VLG-2	VLG-5	VLG-9	VLG-13
HB15–18	VLG-2	VLG-6	VLG-10	VLG-14
HB19–22	VLG-1	VLG-4	VLG-8	VLG-15
Weekend/ Holiday (HB07–22)	VLG-3	VLG-4	VLG-8	VLG-16
Night (HB23–06)	VLG-1	VLG-7	VLG-11	VLG-12
Winter				
HB07–10	VLG-17	VLG-19	VLG-21	VLG-23
HB11–14	VLG-17	VLG-20	VLG-21	VLG-23
HB15–18	VLG-18	VLG-19	VLG-22	VLG-24
HB19–22	VLG-17	VLG-20	VLG-21	VLG-24
Weekend/ Holiday (HB07–22)	VLG-17	VLG-20	VLG-21	VLG-23
Night (HB23–06)	VLG-17	VLG-20	VLG-21	VLG-23
Rest-of-Year				
HB07–10	VLG-25	VLG-26	VLG-27	VLG-29
HB11–14	VLG-25	VLG-26	VLG-28	VLG-29
HB15–18	VLG-25	VLG-26	VLG-28	VLG-30
HB19–22	VLG-25	VLG-26	VLG-27	VLG-30
Weekend/ Holiday (HB07–22)	VLG-25	VLG-26	VLG-27	VLG-30
Night (HB23–06)	VLG-25	VLG-26	VLG-27	VLG-29

Where:

Summer	=	May, June, July, and August
Winter	=	December, January, and February
Rest-of-Year	=	March, April, September, October, and November
HB07–10	=	weekday hours beginning 07:00–10:00
HB11–14	=	weekday hours beginning 11:00–14:00
HB15–18	=	weekday hours beginning 15:00–18:00
HB19–22	=	weekday hours beginning 19:00– 22:00
Weekend/Holiday	=	weekend and holiday hours beginning 07:00–22:00
Night	=	all hours beginning 23:00– 06:00

26.4.2.7 ~~DADRP Component~~Reserved for Future Use

~~The DADRP Component shall be equal to the product of: (i) the Demand Reduction Provider's monthly average of MWh of accepted Demand Reduction Bids during the prior summer Capability Period or, where the Demand Reduction Provider does not have a history of accepted Demand Reduction bids, a projected monthly average of the Demand Reduction Provider's accepted Demand Reduction bids; (ii) the average Day-Ahead LBMP at the NYISO Reference Bus during the prior summer Capability Period; (iii) twenty percent (20%); and (iv) a factor of four (4). The ISO shall adjust the amount of Unsecured Credit and/or collateral that a Demand Reduction Provider is required to provide whenever the DADRP Component increases or decreases by ten percent (10%) or more.~~

26.4.2.8 ~~DSASP Component~~Reserved for Future Use

~~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 97th percentile of all hourly differentials between the Day-Ahead and Hour-Ahead MCPRegh for hours in the two-month period of the previous year when the Real-Time MCP exceeded the Day-Ahead MCP~~

26.4.2.9 Projected True-Up Exposure Component

The Projected True-Up Exposure Component shall apply to any Customer whose average percentage credit exposure to the NYISO is greater than ten percent of the initial invoice settlements for the four-month true-ups over the most recent period, not to exceed four months, for which the Customer has been invoiced by the NYISO. Customers subject to the Projected True-Up Exposure Component shall be required to provide secured credit to satisfy the requirement. The Projected True-Up Exposure Component shall be determined according to the following formula:

$$PTE = \left[\sum_{N4}(\text{4 month settlement - associated initial settlement})\right] + \left[\sum_{N8}(\text{Final bill close-out settlement - associated 4 month settlement})\right]$$

Where:

PTE	=	The amount of secured credit support required for the Projected True-Up Exposure Component
N4	=	Each month in the most recent four-month period with a 4 month settlement
N8	=	Each month in the most recent eight-month period with a final bill close-out settlement

26.4.2.10 Former RMR Generator Component

The Former RMR Generator Component shall apply to any Customer that is the financially responsible party under the ISO Tariffs for a former RMR Generator or former Interim Service Provider that is subject to a Monthly Repayment Obligation. The Former RMR Generator Component will apply until either (a) the Monthly Repayment Obligation associated with the former RMR Generator or former Interim Service Provider is paid in full, or (b) the former RMR Generator or former Interim Service Provider is not subject to a Monthly Repayment Obligation. Customers subject to the Former RMR Generator Component shall be required to provide collateral to satisfy the requirement.

The Former RMR Generator Component shall be calculated as follows:

$$\sum_{G \in S} MRO_G \times Term_G$$

S = the set of former RMR Generators and former Interim Service Providers for which Customer is the financially responsible party under the ISO Tariffs

G = a former RMR Generator or former Interim Service Provider in set S

MRO_G = the Monthly Repayment Obligation (as defined in Section 15.8.7 of Rate Schedule 8 to the Services Tariff) for Generator G

$Term_G$ = the lesser of 8 or the number of months remaining in the repayment term that the ISO determines in accordance with Rate Schedule 8 to the Services Tariff for Generator G

26.4.3 Calculation of Bidding Requirement

The Bidding Requirement shall be an amount equal to the sum of:

(i) the amount of bidding authorization that the Customer has requested for use in or during, as appropriate, an upcoming ISO-administered TCC auction, which shall at least cover the sum of all positive bids to purchase TCCs, plus the absolute value of the sum of all negative offers to sell TCCs; *provided, however,* that the amount of credit required for each TCC that the Customer bids to purchase, whether positive, negative, or zero shall not be less than (a) \$3,000 per MW for two-year TCCs, (b) \$1,500 per MW for one-year TCCs, (c) \$2,000 per MW for six-month TCCs, (d) \$1,800 per MW for five-month TCCs, (e) \$1,500 per MW for four-month TCCs, (f) \$1,200 per MW for three-month TCCs, (g) \$900 per MW for two-month TCCs, and (h) \$600 per MW for one-month TCCs;

(ii) the remaining amount that the Customer owes following an upcoming Centralized TCC Auction as a result of purchasing a Fixed Price TCC;

(iii) the amount of bidding authorization that the Customer has requested for use in an upcoming ISO-administered ICAP auction; and

(iv) five (5) days prior to any ICAP Spot Market Auction, the amount that the Customer may be required to pay for UCAP in the auction, calculated as follows:

$$\sum_{L\in S}\left[\left(ICPM_L * 1000 * \ Deficiency_L\right) + \left(ICPM_L * 1000 * \left(ZDOMW_L * -1\right)\right) + \left(ICPM_L * 1000 * \left(\frac{ZCP_L - 1}{2}\right) * \ RQT_L\right)\right]$$

Where:

S	equals a set containing the following locations: each Locality and Rest of State,
L	equals a location in the set S,
$ICPM_L$	equals the lesser of $UBRP_L$ or LM_L,
$UBRP_L$	equals the UCAP based reference point (in $/kW-Month) for location L, as determined on the ICAP Demand Curve for that location (or for NYCA, if L is Rest of State) for the applicable Obligation Procurement Period,
LM_L	equals (1) for any Locality L that is contained within another Locality X, the greater of CPM_L or CPM_X, or (2) for any other Locality or Rest of State, CPM_L,
CPM_L	equals for location L, (1 + $Margin_L$)*MCP_L ,
CPM_X	equals for location X, (1 + $Margin_X$)*MCP_X ,
$Margin_L$	equals 25% if location L is New York City and 100% if location L is G-J Locality, Long Island or Rest of State,
MCP_L	equals the Market-Clearing Price for location L in the most recent Monthly Auction that established such a price for the month covered by the ICAP Spot Market Auction, measured in dollars per kilowatt-month,
$Deficiency_L$	equals the number of megawatts of Unforced Capacity that are to be procured in location L on behalf of that Customer in the ICAP Spot Market Auction in order to cover any deficiency for that Customer that exists in that location after the certification deadline for that ICAP Spot Market Auction less any deficiency calculated for that Customer for any Localities contained within location L, such value not to be less than zero,
$ZDOMW_L$	equals the number of megawatts of unsold Unforced Capacity in location L that the Customer committed as zero dollar offered megawatts for that ICAP Spot Market Auction,
ZCP_L	equals the percentage determined in accordance with Services Tariff Section 5.14.1.2 for the applicable ICAP Demand Curves as established at the $0.00 point for the appropriate Capability Year, and
RQT_L	equals (1) if L is New York City or Long Island, that Customer's share of the Locational Minimum Unforced Capacity Requirement for location L or (2) if L is

G-J Locality, that Customer's share of the Locational Minimum Unforced Capacity Requirement for the G-J Locality that remains after reducing this amount by its share of the Locational Minimum Unforced Capacity Requirements for New York City or, (3) if *L* is Rest of State, that Customer's share of the NYCA Minimum Unforced Capacity Requirement that remains after reducing this amount by (a) its share of the Locational Minimum Unforced Capacity Requirements for New York City and Long Island and (b) that Customer's share of the Locational Minimum Unforced Capacity Requirement for the G-J Locality remaining after accounting for New York City, as calculated in (2) above; such value not to be less than zero.

26.10 ~~Additional Financial Assurance Policies for Demand Side Resources Offering Ancillary Services~~Reserved for future use.

~~26.10.1 Suspension~~

~~(i) If, at any time, the amount owed to the ISO by a Demand Side Resource offering Ancillary Services as a result of its market activity reaches fifty percent (50%) of the credit support provided by the Demand Side Resource offering Ancillary Services to support its market transactions, the ISO shall attempt to contact the Demand Side Resource to request either payment or additional credit support in the amount then owed by the Demand Side Resource to support its market transactions.~~

~~(ii) If the day after the ISO's request described above falls on a business day and the Demand Side Resource fails to make payment or provide additional credit support as described above by 4:00 p.m. on the day after the ISO's request described above, the ISO may immediately suspend the Demand Side Resource's authorization to engage in market transactions until payment or provision of its required amount of credit support using Unsecured Credit and/or collateral.~~

~~(iii) If the day after the ISO's request does not fall on a business day, the ISO may issue a demand for credit support and immediately suspend the Demand Side Resource's authorization to engage in market transactions until the Demand Side Resource makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.~~

~~(iv) If, at any time, the amount owed to the ISO by a Demand Side Resource as a result of its market transactions reaches one hundred percent (100%) of the credit support provided by the Demand Side Resource to support its market transactions,~~

~~the ISO may cancel any pending Day-Ahead bids and may immediately suspend the Demand Side Resource's authorization to engage in market transactions until the Demand Side Resource makes payment or provides its required amount of credit support using Unsecured Credit and/or collateral.~~

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 to the ISO in order to meet the reliability needs of the Transmission Owner's local system which request was made known to the ISO prior to the close of the Day-Ahead Market.

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

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

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

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

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

DER Aggregation: As defined in the ISO Services Tariff.

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

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

Developer: An Eligible Customer developing a generation project larger than 20 megawatts, or a Class Year Transmission Project, proposing to interconnect to the New York State Transmission System, in compliance with the NYISO Minimum Interconnection Standard and, depending on the Developer's interconnection service election, also in compliance with the NYISO Deliverability Interconnection Standard.

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

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

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

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

Distributed Energy Resource ("DER"): As defined in the ISO Services Tariff.

~~**DSASP Component:** As defined in the ISO Services Tariff.~~

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

1.9 Definitions - I

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

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

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

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

Inactive Reserves: As defined in the ISO Services Tariff.

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

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

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

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

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

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

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

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

Injection Limit: As defined in the ISO Services Tariff.

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

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

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

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

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

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

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

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

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

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

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

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

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator or Aggregation comprised entirely of Energy Storage Resources~~Demand Side Resource~~ follows Base Point Signals and is committed by the ISO. ~~A~~ BTM:NG Resources and Aggregations that are not entirely comprised of ESRs are ~~is~~ not permitted to utilize the ISO-Committed Flexible bidding mode.

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

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

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

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

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

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

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 comprised the membership of the New York Power Pool, which are: (1) Central Hudson Gas & Electric Corporation, (2) Consolidated Edison Company of New York, Inc., (3) New York State Electric & Gas Corporation, (4) Niagara Mohawk Power Corporation d/b/a National Grid, (5) Orange and Rockland Utilities, Inc., (6) Rochester Gas and Electric Corporation, (7) the Power Authority of the State of New York, and (8) Long Island Lighting Company d/b/a Long Island Power Authority.

Meter Services Entity ("MSE"): As defined in the ISO Services Tariff.

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

Minimum Generation Level: For purposes of describing the eligibility of ten minute Resources to be committed by the Real Time Dispatch for pricing purposes pursuant to the Services Tariff, Section 4.4.3.3, an upper bound, established by the ISO, on the physical minimum generation limits specified by ten minute Resources. Ten minute Resources with physical minimum generation limits that exceed this upper bound will not be committed by the Real Time Dispatch for pricing purposes. The ISO shall establish a Minimum Generation Level based on its evaluation of the extent to which it is meeting its reliability criteria including Control

Performance. The Minimum Generation Level, in megawatts, and the ISO's rationale for that level, shall be made available through the ISO's website or comparable means. If the Supplier is a BTM:NG Resource, LESR, Energy Storage Resource, or an Aggregation, it shall not submit a Minimum Generation Level.

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

Mothball Outage: As defined in the ISO Services Tariff.

1.19 Definitions - S

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

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

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

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

Scheduled Energy Injection: Energy injections or Energy provided by Demand Side Resources which are scheduled on a real-time basis by RTC.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Supplemental Resource Evaluation ("SRE"): A determination of the least cost selection of additional Generators or Aggregations, 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.

6.1.9 Recovery of Special Case Resources and Curtailment Services Providers Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of Special Case Resources and Curtailment Service Providers costs for each Billing Period. This charge shall be equal to the sum of the hourly charges for the Transmission Customer, as calculated in Sections 6.1.9.1 and 6.1.9.2 of this Rate Schedule 1, for each hour in the relevant Billing Period and, where applicable, for each Subzone.

6.1.9.1 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.9.1, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers that were called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone for which the reliability services of the Special Case Resources and Curtailment Service Providers were called shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ SCR\ and\ CSP\ Charge_{c,h} = LocalReliabilityCosts_h * \frac{SZWithdrawalUnits_{c,h}}{SZTotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Local\ Reliability\ SCR\ and\ CSP\ Charge_{c,h}$ = The amount, in \$, for which Transmission Customer c is responsible for hour h for the relevant Subzone.

$LocalReliabilityCosts_h$ = The payments, in \$, for hour h in the relevant Subzone made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of that Subzone.

$SZWithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_{h}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.9.2 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.9.2, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units except for Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

$$NYCA\ Reliability\ SCR\ and\ CSP\ Charge_{c,h} = NYCAReliabilityCosts_{h} * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_{h}}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$NYCA\ Reliability\ SCR\ and\ CSP\ Charge_{c,h}$ = The amount, in \$, for which Transmission Customer *c* is responsible for hour *h*.

$NYCAReliabilityCosts_{h}$ = The payments, in \$, for hour *h* made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h*, except for the Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as third-party providers.

6.1.10. Recovery of Day-Ahead Margin Assurance Payment Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of DAMAP costs for each Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.10.1 and 6.1.10.2 of this Rate Schedule 1, for each hour or each day, as applicable, in the relevant Billing Period and for each Subzone, where applicable.

6.1.10.1 Recovery of Costs of DAMAPs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.10.1, the ISO shall recover the costs for DAMAPs incurred to compensate Resources for meeting the reliability needs of a local system.

6.1.10.1.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ DAMAP\ Charge_{c,h} = DAMAPCosts_h * \frac{SZWithdrawalUnits_{c,h}}{SZTotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Local\ Reliability\ DAMAP\ Charge_{c,h}$ = The amount, in \$, for which Transmission Customer c is responsible for hour h for the relevant Subzone.

$DAMAPCosts_h$ = The DAMAP costs, in $, for hour *h* in the relevant Subzone incurred to compensate Resources meeting the reliability needs of that Subzone.

$SZWithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.10.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ DAMAP\ Charge_{c,d} = \frac{DAMAPCosts_d}{SZTotalWithdrawalUnits_d} * \ SZStationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$SZStationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* in day *d* in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.2 shall be determined for day *d*.

6.1.10.1.3 Local Reliability DAMAP Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.1.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Local\ Reliability\ DAMAP\ Credit_{c,d} = LocRelDAMAPCharge_d * \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period.

$Local\ Reliability\ DAMAP\ Credit_{c,d}$ = The amount, in $, that Transmission Customer c will receive for day d for the relevant Subzone.

$LocRelDAMAPCharge_d$ = The sum of charges, in $, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.10.1.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.3 shall be determined for day d.

6.1.10.2 Recovery of Costs of All Remaining DAMAPs

Pursuant to this Section 6.1.10.2, the ISO shall recover the costs of all DAMAPs not recovered through Section 6.1.10.1 of this Rate Schedule 1 from all Transmission Customers.

6.1.10.2.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

$$Remaining\ DAMAP\ Charge_{c,h} = RemainingDAMAPCosts_h * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Remaining\ DAMAP\ Charge_{c,h}$ = The amount, in \$, for which Transmission Customer *c* is responsible for hour *h*.

$RemainingDAMAPCosts_h$ = The DAMAP costs, in \$, for hour *h* not recovered by the ISO through Section 6.1.10.1 of this Rate Schedule 1.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h*, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h*, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.10.2.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$Remaining\ DAMAP\ Charge_{c,d} = \frac{RemainingDAMAPCosts_d}{TotalWithdrawalUnits_d} * \ StationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* used to supply Station Power as a third-party provider for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.2 shall be determined for day *d*.

6.1.10.2.3 Remaining DAMAP Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.2.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Remaining\ DAMAP\ Credit_{c,d} = RemainingDAMAPCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_{c,d}}$$

Where:

d = A given day in the relevant Billing Period.

$Remaining\ DAMAP\ Credit_{c,d}$ = The amount, in $, that Transmission Customer *c* will receive for day *d*.

$RemainingDAMAPCharge_d$ = The sum of charges, in $, for all Transmission Customers as calculated in Section 6.1.10.2.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.3 shall be determined for day *d*.

6.1.11 Recovery of Import Curtailment Guarantee Payment Costs

6.1.11.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the hourly charges for the Transmission Customer, as calculated in accordance with the following formula, for each hour in the relevant Billing Period.

$$Import\ Curtailment\ Guarantee\ Charge_{c,h} = ImportCurtGuarCosts_h * \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$Import\ Curtailment\ Guarantee\ Charge_{c,h}$= The amount, in \$, for which Transmission Customer *c* is responsible for hour *h*.

$ImportCurtGuarCosts_h$ = The costs, in \$, for the Import Curtailment Guarantee Payments to Import Suppliers for hour *h*.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in hour *h*, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour *h*, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.11.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a charge for each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the daily charges for the Transmission Customer, as calculated in accordance with the following formula, for each day in the relevant Billing Period.

$$Import\ Curtailment\ Guarantee\ Charge_{c,d} = \frac{ImportCurtGuarCosts_d}{TotalWithdrawalUnits_d} * StationPower_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* used to supply Station Power as a third-party provider for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.2 shall be determined for day *d*.

6.1.11.3 Import Curtailment Guarantee Credit

The ISO shall credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.11.2 of this Rate Schedule 1 above for each Billing Period. This credit shall be equal to the sum of daily payments for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

$$Import\ Curtailment\ Guarantee\ Credit_{c,d} = ImpCurtGuarCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

d = A given day in the relevant Billing Period.

$Import\ Curtailment\ Guarantee\ Credit_{c,d}$ = The amount, in \$, that Transmission Customer *c* will receive for day *d*.

$ImpCurtGuarCharge_d$ = The sum of charges, in \$, for all Transmission Customers as calculated in Section 6.1.11.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.3 shall be determined for day *d*.

6.1.12 Recovery of Bid Production Cost Guarantee Payment ~~and Demand Reduction Incentive Payment~~ Costs

~~The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of BPCG and Demand Reduction Incentive Payment costs for each Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.12.1 through 6.1.12.6 of this Rate Schedule 1, for each day in the relevant Billing Period and for each Subzone, where applicable.~~

~~6.1.12.1 Costs of Demand Reduction BPCGs and Demand Reduction Incentive Payments~~

~~After accounting for imbalance charges paid by Demand Reduction Providers, the ISO shall recover the costs associated with Demand Reduction Bid Production Cost guarantee payments and Demand Reduction Incentive Payments from Transmission Customers pursuant to the methodology established in Attachment R of this ISO OATT.~~

6.1.12.1~~2~~ Costs of BPCGs for Additional Generating Units Committed to Meet Forecast Load

If the sum of all Bilateral Transaction schedules, excluding schedules of Bilateral Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO may commit Resources in addition to the reserves that it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load. The ISO shall recover a portion of the costs associated with Bid Production Cost guarantee payments for the additional Resources committed Day-Ahead to meet the Day-Ahead forecast of Load from Transmission Customers pursuant to the methodology established in Attachment T of this ISO OATT. The ISO shall recover the residual costs of such Bid Production Cost guarantee payments not recovered through the methodology in Attachment T of the ISO OATT pursuant to Section 6.1.12.5~~6~~ of this Rate Schedule 1.

6.1.12.2~~3~~ Costs of BPCGs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.2~~3~~, the ISO shall recover the costs for Bid Production Cost guarantee payments incurred to compensate Suppliers for their Resources, other than Special Case Resources, that are committed or dispatched to meet the reliability needs of a local system.

6.1.12.2~~3~~.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ BPCG\ Charge_{c,d} = BPCGCosts_d * \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Local\ Reliability\ BPCG\ Charge_{c,d}$ = The amount, in $, for which Transmission Customer c is responsible for day d for the relevant Subzone.

$BPCGCosts_d$ = The Bid Production Cost guarantee payments, in $, made to Suppliers for Resources for day d in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone, except for the Bid Production Cost guarantee payments made to Suppliers for Special Case Resources.

$SZWithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.2~~3~~.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ BPCG\ Charge_{c,d} = \frac{BPCGCosts_d}{SZTotalWithdrawalUnits_d} * SZStationPower_{c,d}$$

Where:

$SZStationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* in day *d* in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.3.1 above,

6.1.12.2~~3~~.3 Local Reliability BPCG Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.2~~3~~.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Local\ Reliability\ BPCG\ Credit_{c,d} = LocRelBPCGCharge_d * \frac{SZWithdrawalUnits_{c,d}}{SZWithdrawalUnits_{c,d}}$$

Where:

$Local\ Reliability\ BPCG\ Credit_{c,d}$ = The amount, in $, that Transmission Customer *c* will receive for day *d* for the relevant Subzone.

$LocRelBPCGCharge_d$ = The sum of charges, in $, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.12.2~~3~~.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.2~~3~~.1 above.

6.1.12.3~~4~~ Cost of BPCGs for Special Case Resources Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.3~~4~~, the ISO shall recover the costs of Bid Production Cost guarantee payments incurred to compensate Special Case Resources called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Special Case Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$Local\ Reliability\ SCR\ BPCG\ Charge_{c,d} = BPCGCosts_d * \frac{SZWithdrawalUnits_{c,d}}{SZTotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Local\ Reliability\ SCR\ BPCG\ Charge_{c,d}$ = The amount, in $, for which Transmission Customer c is responsible for day d for the relevant Subzone.

$BPCGCosts_d$ = The Bid Production Cost guarantee payments, in $, made to Suppliers for Special Case Resources for day *d* in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone.

$SZWithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$SZTotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d* in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.4~~5~~ Cost of BPCG for Special Case Resources Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.12.4~~5~~, the ISO shall recover the costs for Bid Production Cost guarantee payments to compensate Special Case Resources called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used except for Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$NYCA\ Reliability\ SCR\ BPCG_{c,d} = BPCGCost_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$NYCA\ Reliability\ SCR\ BPCG\ Charge_{c,d}$ = The amount, in $, for which Transmission Customer *c* is responsible for day *d*.

$BPCGCosts_d$ = The Bid Production Cost guarantee payments, in $, made to Suppliers for Special Case Resources called to meet the reliability needs of the NYCA for day *d*.

$WithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d*, except for the Withdrawal Billing Units for Wheels Through, Exports or to supply Station Power as a third-party provider.

$TotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d*, except for the Withdrawal Billing Units for Wheels-Through, Exports or to supply Station Power as third-party providers.

6.1.12.5~~6~~ Costs of All Remaining BPCGs

Pursuant to this Section 6.1.12.5~~6~~, the ISO shall recover the costs of all Bid Production Cost guarantee payments not recovered through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, and 6.1.12.4~~, and 6.1.12.5~~ of this Rate Schedule 1, including the residual costs of Bid Production Cost guarantee payments for additional Resources not recovered through the methodology in Attachment T of this ISO OATT, from all Transmission Customers.

6.1.12.5~~6~~.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$Remaining\ BPCG\ Charge_{c,d} = RemainingBPCGCosts_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$Remaining\ BPCG\ Charge_{c,d}$ = The amount, in $, for which Transmission Customer *c* is responsible for day *d*.

$RemainingBPCGCosts_d$ = The BPCG costs, in $, for day *d* not recovered by the ISO through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, and 6.1.12.4~~, and 6.1.12.5~~ of this Rate Schedule 1.

$WithdrawalUnits_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer *c* in day *d*, except for the Withdrawal Billing Units to supply Station Power as a third-party provider and except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

$TotalWithdrawalUnits_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day *d*, except for the Withdrawal Billing Units to supply Station Power as third-party providers and except for Scheduled Energy Withdrawals at a

CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.12.5~~6~~.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Section 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$Remaining\ BPCG\ Charge_{c,d} = \frac{RemainingBPCGCosts_d}{TotalWithdrawalUnits_d} * StationPower_{c,d}$$

Where:

$StationPower_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer *c* used to supply Station Power as a third-party provider for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.5~~6~~.1 of this Rate Schedule 1 above.

6.1.12.5~~6~~.3 Remaining BPCG Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.5~~6~~.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$Remaining\ BPCG\ Credit_{c,d} = RemainingBPCGCharge_d * \frac{WithdrawalUnits_{c,d}}{TotalWithdrawalUnits_{c,d}}$$

Where:

$Remaining\ BPCG\ Credit_{c,d}$ = The amount, in \$, that Transmission Customer *c* will receive for day *d*.

$RemainingBPCGCharge_d$ = The sum of charges, in \$, for all Transmission Customers as calculated in Section 6.1.12.5~~6~~.2 of this Rate Schedule 1 for day *d*.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.5~~6~~.1 of this Rate Schedule 1 above.

6.1.13 Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or charge in accordance with Section 6.1.13.1 of this Rate Schedule 1 for the distribution of funds received by the ISO or the recovery of funds incurred by the ISO in the settlement of a dispute.

6.1.13.1 Calculation of the Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or a dispute resolution charge for each Billing Period as calculated according to the following formula.

$$Dispute\ Resolution\ Payment/Charge_{c,P} = DisputeResolutionCosts_P * \frac{WithdrawalUnits_{c,P}}{TotalWithdrawalUnits_P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$Dispute\ Resolution\ Payment/Charge_{c,P}$ = The amount, in \$, for Billing Period P that (i) Transmission Customer c will receive if the ISO is distributing funds that it has collected in the settlement of a dispute, or (ii) Transmission Customer c will be responsible for if the ISO is recovering funds that it has incurred in the settlement of a dispute.

$DisputeResolutionCosts_P$ = The amount, in \$, for Billing Period P that (i) the ISO has collected in the settlement of a dispute or (ii) the ISO has incurred in the settlement of a dispute.

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

$TotalWithdrawalUnits_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in Billing Period P, except for Scheduled Energy Withdrawals at a CTS Enabled Interface with ISO New England resulting from Exports that are not associated with wheels through New England.

6.1.14 Credit for Financial Penalties

The ISO shall distribute to each Transmission Customer each Billing Period in accordance with the following formula any payments that it has collected from Transmission Customers to satisfy: (i) Financial Impact Charges issued pursuant to Sections 4.5.3.2 and 4.5.4.2 of the ISO Services Tariff; (ii) ICAP sanctions issued pursuant to Section 5.12.12 of the ISO Services Tariff; (iii) ICAP deficiency charges pursuant to Section 5.14.3.1 of the ISO Services Tariff, except as provided in Section 5.14.3.2 of the ISO Services Tariff; (iv) market power mitigation financial penalties pursuant to Section 23.4.3.6 of Attachment H of the ISO Services Tariff, except as provided in Section 23.4.4.3.2 of Attachment H of the ISO Services Tariff; and (v) any other financial penalties set forth in the ISO Services Tariff or this ISO OATT. The ISO will perform this calculation separately for the allocation of the revenue from each financial penalty.

$$Financial\ Penalties\ Credit_{c,P} = PenaltyRevenue_P * \frac{WithdrawalUnits_{c,P}}{TotalWithdrawalUnits_P}$$

Where:

c = Transmission Customer.

P = A given day in the relevant Billing Period.

$Financial\ Penalties\ Credit_{c,P}$ = The amount, in \$, that Transmission Customer c will receive for Billing Period P.

$PenaltyRevenue_P$ = The sum, in \$, of revenue that the ISO has collected for Billing Period P from a Transmission Customer for one of the financial penalties indicated in Section 6.1.14 of this Rate Schedule 1.

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

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

6.1.15 Calculation of FERC Fee Charges

As a public utility the transmission provider under this Tariff is subject to annual charges assessed by the Commission in accordance with Part 382 of the Commission's regulations (annual FERC fee). The ISO shall charge, and each Transmission Customer taking service under the ISO Tariffs shall pay, a charge for the recovery of the annual FERC fee, on the basis of its participation in physical market activity, and on the basis of its participation in non-physical market activity in accordance with Sections 6.1.15.1 and 6.1.15.2 respectively. The annual FERC fee shall be allocated ninety-four (94%) to physical market activity and six (6%) to non-physical market activity respectively. Pursuant to ISO Procedures, the six (6%) of the annual FERC fee allocated to non-physical market activity shall be further allocated approximately four percent (4%) to Transmission Congestion Contracts and approximately two percent (2%) to Virtual Transactions. The total charge to each Transmission Customer for recovery of the annual FERC fee shall be the sum of the Transmission Customer's Physical FERC Fee Charge and the Transmission Customer's Non-Physical FERC Fee Charge.

An estimated annual FERC fee shall be recovered over the twelve months of each federal fiscal year. The ISO will publish the estimated annual FERC fee for each federal fiscal year no less than one month in advance of the start of that federal fiscal year. Upon receiving the invoice for the annual FERC fee, the ISO will implement a true-up, a credit or charge, equal to the difference between the estimated annual FERC fee for the fiscal year and the invoiced amount, in the first Billing Period following receipt of the invoiced annual FERC fee, as is practicable. The ISO shall recover or refund the true-up amount over a six month period.

All funds collected by the ISO for the annual FERC fee shall be deposited in the annual FERC fee account. The annual FERC fee account shall be an interest-bearing account separate from all other accounts maintained by the ISO. The ISO shall disburse funds from the annual FERC fee account in order to pay the FERC any and all annual FERC fee charges assessed against the ISO.

6.1.15.1 Calculation of Physical FERC Fee Charge for Transmission Customers Participating in Physical Market Activity

The ISO shall charge, and each Transmission Customer that participates in physical market activity shall pay, a charge for the recovery of the annual FERC fee as calculated according to the following formula:

$$\begin{aligned} &Physical\ FERC\ Fee\ Charge_{c,P} \\ &= \left(Injection\ Units_{c,P} * \left(0.28 * PRatio * \frac{(Est\ FERC\ Fee_P + True\text{-}Up\ Costs_P)}{TotalInjectionUnits_P}\right)\right) \\ &+ \left(Withdrawal\ Units_{c,P} * \left(0.72 * PRatio * \frac{(Est\ FERC\ Fee_P + True\text{-}Up\ Costs_P)}{TotalWithdrawalUnits_P}\right)\right) \end{aligned}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$Physical\ FERC\ Fee\ Charge_{c,P}$ = The amount, in \$, of the annual FERC fee for which Transmission Customer c is responsible for Billing Period P.

$Injection\ Units_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P.

$PRatio$ = Ninety-four percent (94%).

$Est\ FERC\ Fee_P$ = Billing Period P's proportional allocation of the estimated annual FERC fee for the current FERC fiscal year.

$True\text{-}up\ Costs_P$ = Billing Period P's proportional allocation of the difference between the invoiced annual FERC fee and the estimated annual FERC fee.

$TotalInjectionUnits_P$ = The sum, in MWh, of Injection Billing Units for all Transmission Customers in Billing Period P.

$Withdrawal\ Units_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in the Billing Period P.

$TotalWithdrawalUnits_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in the Billing Period P.

6.1.15.2 Calculation of the FERC Fee Charge for Transmission Customers Participating in Non-Physical Market Activity

The ISO shall charge, and each Transmission Customer that has its virtual bids accepted and thereby engages in Virtual Transactions or that purchases Transmission Congestion Contracts shall pay, a charge for the recovery of the annual FERC fee as calculated according to the following formula: $Non\text{-}Physical\ FERC\ Fee\ Charge_{c,P} = \left(VTCleared_{c,P} * \left(\left(\frac{VTRatio * Est\ FERC\ Fee_P}{Total\ VT\ Cleared_P}\right) + \left(\frac{VTRatio * True\text{-}Up\ Costs_P}{Total\ VT\ Cleared_P}\right)\right)\right) + \left(TCC\ Settled_{c,P} * \left(\left(\frac{TCCRatio * Est\ FERC\ Fee_P}{Total\ TCC\ \ Settled_P}\right) + \left(\frac{TCCRatio * True\text{-}Up\ Costs_P}{Total\ TCC\ Settled_P}\right)\right)\right)$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$Non - Physical\ FERC\ Fee\ Charge_{c,P}$ = The amount, in \$, of the annual FERC fee for which Transmission Customer c is responsible for Billing Period P.

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

$Est\ FERC\ Fee_P$ = Billing Period P's proportional allocation of the estimated annual FERC fee for the current FERC fiscal year.

$True - up\ Costs_P$ = Billing Period P's proportional allocation of the difference between the invoiced annual FERC fee and the estimated annual FERC fee.

$VTRatio$ = Approximately two percent (2%).

$Total\ VT\ Cleared_P$ = The sum, in MWh, of cleared Virtual Transactions for all Transmission Customers in Billing Period P.

$TCCSettled_{c,P}$ = The total settled Transmission Congestion Contracts, in MWh, for Transmission Customer c in Billing Period P.

$TCCRatio$ = Approximately four percent (4%).

$Total\ TCC\ Settled_P$ = The sum of settled Transmission Congestion Contracts, in MWh, for all Transmission Customers in Billing Period P.