

Attachment II

2.18 Definitions - R

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

RCRR TCC: A zone-to-zone TCC created when a Transmission Owner with a RCRR exercises its right to convert the RCRR into a TCC pursuant to Section 19.5.4 of Attachment M of the ISO OATT.

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

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

Real-Time Bid: A Bid submitted into the Real-Time Commitment 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; “RTC₀₀,” “RTC₁₅,” “RTC₃₀,” and “RTC₄₅” 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. RTC₁₅ will also establish hourly External Transaction schedules, while all RTC runs may establish 15 minute External Transaction schedules at Variably Scheduled Proxy Generator Buses. Additional information about RTC’s functions is provided in Section 4.4.2 of this ISO Services Tariff.

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

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

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

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

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

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

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

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

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

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

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

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 ten (10), used with the Regulation Movement Bids, to schedule Regulation Service providers in both the Day-Ahead and Real-Time Energy markets. The ISO calculates the Regulation Movement Multiplier based on the historical relationship between the number of MW of Regulation Capacity that the ISO seeks to maintain in each hour and the number of Regulation Movement MW instructed by AGC in each hour.

Regulation Movement Response Rate: The amount of Regulation Movement a Regulation Service provider is capable of delivering in six seconds which shall not be less than, but can be equal to or greater than, the Regulation Capacity Response Rate equivalent. **Regulation Service:** The Ancillary Service defined by the Commission as “frequency regulation” and that is instructed as Regulation Capacity in the Day-Ahead Market and as Regulation Capacity and Regulation Movement in the Real-Time Market as is further described in Section 15.3 of the Services Tariff. Day-Ahead and Real-Time Bids to provide Regulation Service shall include a Bid for Regulation Capacity and a Bid for Regulation Movement. The Regulation Service requirement or target level shall be for MW of Regulation Capacity.

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

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

Regulation Revenue Adjustment Payment (“RRAP”): A payment that will be made to certain Generators that are providing Regulation Service under Section 15.3.6 of Rate Schedule 3 to this ISO Services Tariff.

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

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

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

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

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

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

$$\text{Residual Transmission Capacity} = \text{TTC} - \text{TRM} - \text{CBM} - \text{GTR} - \text{GTCC} - \text{ETCNL}$$

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

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

GTR is the transmission capacity associated with Grandfathered Rights.

GTCC is the transmission capacity associated with Grandfathered TCCs.

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

TRM is the Transmission Reliability Margin.

CBM is the Capacity Benefit Margin.

Resource: An Energy Limited Resource, Generator, Installed Capacity Marketer, Special Case Resource, Intermittent Power Resource, Limited Control Run of River Hydro Resource, municipally-owned generation, System Resource, Demand Side Resource or Control Area System Resource.

Responsible Interface Party: 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.

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.

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

By 5 a.m., on the day prior to the Dispatch Day (or by 4:50 a.m. for Customers or Transmission Customers seeking to schedule External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line): (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:

4.2.1.1.1 Bids to supply Energy, including Bids to supply Energy in Virtual Transactions;

4.2.1.1.2 Bids to supply Ancillary Services;

4.2.1.1.3 Requests for Bilateral Transaction schedules;

4.2.1.1.4 Bids to purchase Energy, including Bids to purchase Energy in Virtual Transactions; and

4.2.1.1.5 Demand Reduction Bids.

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 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 Supplier may resubmit a complete Day-Ahead Bid, provided that the new Bid is timely. See Section 4.2.1.9 for bidding requirements for Demand Side Resources offering Energy in the Day-Ahead Market.

Suppliers other than Demand Side Resources entering a Bid into the Day-Ahead Market may also enter Day-Ahead Bids for each of the next nine (9) Dispatch Days. If not subsequently modified or withdrawn, these offers for subsequent Dispatch Days may be used by the ISO as offers from these Suppliers in the Day-Ahead Market for these subsequent Dispatch Days. For Suppliers that are providing Unforced Capacity in the ISO-administered ICAP Market for the month in which the Dispatch Day and the nine-day advance bidding period are encompassed, the

ISO may enter the eighth day offer as the Bid for that Supplier's ninth day, if there is, otherwise no ninth-day Bid.

4.2.1.3.2 Bid Parameters

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

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

4.2.1.3.3 Upper Operating Limits and Response Rates

All Bids to supply Energy and Ancillary Services must specify a UOL_N and a UOL_E for each hour. A Resource's UOL_E may not be lower than its UOL_N .

Bids from Suppliers for Generators supplying Energy and Ancillary Services must specify a normal response rate and may provide up to three normal response rates provided the minimum normal response rate may be no less than one percent (1%) of the Generator's

Operating Capacity per minute. All Bids from Suppliers for Generators supplying Energy and Ancillary Services must also specify an emergency response rate which shall be equal to or greater than the maximum normal response rate of the Generator.

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

4.2.1.4 Offers to Supply Energy from Self-Committed Fixed Generators

Self-Committed Fixed Generators shall provide the ISO with a schedule of their expected Energy output for each hour. Self-Committed Fixed Generators are responsible for ensuring that any hourly changes in output are consistent with their response rates. Self-Committed Fixed Generators shall also submit UOL_{NS} , UOL_{ES} and variable Energy Bids for possible use by the ISO in the event that RTD-CAM initiates a maximum generation pickup, as described in Section 4.4.3 of this ISO Services Tariff.

4.2.1.5 Bids to Supply Energy in Virtual Transactions

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

4.2.1.6 Bids to Purchase Energy in Virtual Transactions

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

4.2.1.7 Bilateral Transactions

Transmission Customers requesting Bilateral Transaction schedules shall identify hourly Transaction quantities (in MW) by Point of Injection and Point of Withdrawal, minimum run times associated with Firm Point-to-Point Transmission Service, if any, and shall provide other information (as described in ISO Procedures).

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

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

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

Demand Reduction Providers and DSASP Providers offering Energy from Demand Side Resources shall: (i) bid in whole megawatts and (ii) identify the amount of demand in megawatts, that is available for commitment in the Day-Ahead Market (for every hour of the dispatch day) and (iii) identify the prices at which the Demand Reduction Provider 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. Following the posting of the Monthly Net Benefit Offer Floor, the ISO shall monitor the gas prices utilized in the Net Benefits Test and recalculate the Monthly Net Benefit Offer Floor in the event that such prices vary by more than \$0.75/mmBTU, as measured on the last gas trading day that is no less than 4 business days prior to the first day of the Study Month. The ISO shall post any recalculated Monthly Net Benefit Offer Floor to its website in accordance with ISO Procedures.

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

4.2.2 ISO Responsibility to Establish a Statewide Load Forecast

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

4.2.3 Security Constrained Unit Commitment (“SCUC”)

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

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

The schedule will include commitment of sufficient Generators and/or Demand Side Resources to provide for the safe and reliable operation of the NYS Power System. Pursuant to ISO Procedures, the ISO may schedule any Resource to run above its UOL_N up to the level of its UOL_E . In cases in which the sum of all Bilateral Schedules, excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load within the NYCA in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO will commit Resources in addition to the Operating Reserves it normally maintains to enable it to respond to contingencies. The purpose of these additional resources is to ensure that sufficient Capacity is available to the ISO in real-time to enable it to meet its Load forecast (including associated Ancillary Services). In considering which additional Resources to schedule to meet the ISO's Load forecast, the ISO will evaluate unscheduled Imports, and will not schedule those Transactions if its evaluation determines the cost of those Transactions would effectively exceed a Bid Price cap in the hours in which the Energy provided by those Transactions is required. In addition to all Reliability Rules, the ISO shall consider the following information when developing the SCUC schedule: (i) Load forecasts; (ii) Ancillary Service requirements as determined by the ISO given the Regulation Service Demand Curve and Operating Reserve Demand Curves referenced above; (iii) Bilateral Transaction schedules excluding Bilateral Schedules for Transactions with Trading Hubs as their POWs; (iv) price Bids and operating Constraints submitted for Generators or for Demand Side Resources; (v) price

Bids for Ancillary Services; (vi) Decremental Bids and Sink Price Cap Bids for External Transactions; and (vii) Bids to purchase or sell Energy from or to the Day-Ahead Market. External Transactions with minimum run times greater than one hour will only be scheduled at the requested Bid for the full minimum run time. External Transactions with identical Bids and minimum run times greater than one hour will not be prorated. The SCUC schedule shall list the hourly injections and withdrawals for: (a) each Customer whose Bid the ISO accepts for the Dispatch Day; and (b) each Bilateral Transaction scheduled Day-Ahead excluding Bilateral Transactions with Trading Hubs as their POWs.

In the development of its SCUC schedule, the ISO may commit and de-commit Generators and Demand Side Resources, based upon any flexible Bids, including Minimum Generation Bids, Start-Up Bids, Curtailment Initiation Cost Bids, Energy, and Incremental Energy Bids and Decremental Bids received by the ISO provided however that the ISO shall commit zero megawatts of Energy for Demand Side Resources committed to provide Operating Reserves and Regulation Service.

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

4.2.3.1 Reliability Forecast for the Dispatch Day

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

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

A Transmission Owner may request commitment of additional Generators for a Dispatch Day following the close of the Day-Ahead Market to meet changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to ensure the reliability of its local system. The ISO will use SRE to fulfill a Transmission Owner's request for additional units.

All Generator commitments made in the Day-Ahead Market pursuant to this Section 4.2.3.1 shall be posted on the ISO website following the close of the Day-Ahead Market, in accordance with ISO procedures. In addition, the ISO shall post on its website a non-binding, advisory notification of a request, or any modifications thereto, made pursuant to this Section 4.2.3.1 in the Day-Ahead Market by a Transmission Owner to commit a Generator that is located within a Constrained Area, as defined in Attachment H of this Services Tariff. The advisory notification shall be provided upon receipt of the request and in accordance with ISO procedures.

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

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

4.2.4 Reliability Forecast for the Six Days Following the Dispatch Day

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

the start-up sequence, the ISO will perform an SRE to determine if long start-up time Generators will still be needed as previously forecasted. If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start-up sequence.

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

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

The ISO shall perform the SRE as follows: (1) The ISO shall develop a forecast of daily system peak Load for days two (2) through seven (7) in this seven (7)-day period and add the appropriate reserve margin; (2) the ISO shall then forecast its available Generators for the day in question by summing the Operating Capacity for all Generators currently in operation that are available for the commitment cycle, the Operating Capacity of all other Generators capable of starting on subsequent days to be available on the day in question, and an estimate of the net Imports from External Bilateral Transactions; (3) if the forecasted peak Load plus reserves exceeds the ISO's forecast of available Generators for the day in question, then the ISO shall commit additional Generators capable of starting prior to the day in question (*e.g.*, start-up period of two (2) days when looking at day three (3)) to assure system reliability; (4) in choosing among Generators with comparable start-up periods, the ISO shall schedule Generators to

minimize Minimum Generation Bid and Start-Up Bid costs of meeting forecasted peak Load plus Ancillary Services consistent with the Reliability Rules; (5) in determining the appropriate reserve margin for days two (2) through seven (7), the ISO will supplement the normal reserve requirements to allow for forced outages of the short start-up period units (*e.g.*, gas turbines) assumed to be operating at maximum output in the unit commitment analysis for reliability.

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

4.2.5 Post the Day-Ahead Schedule

By 11 a.m. on the day prior to the Dispatch Day, the ISO shall close the Day-Ahead scheduling process and post on the Bid/Post System the Day-Ahead schedule for each entity that submits a Bid or Bilateral Transaction schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the statewide aggregate resources (Day-Ahead Energy schedules and total operating capability forecast), Day-Ahead scheduled Load, forecast Load for each Load Zone, and the Day-Ahead LBMP prices (including the Congestion Component and the Marginal Losses

Component) for each Load Zone in each hour of the upcoming Dispatch Day. The ISO shall conduct the Day-Ahead Settlement based upon the Day-Ahead schedule determined in accordance with this section and Attachment B to this Services Tariff. The ISO will provide the Transmission Owner with the Load forecast (for seven (7) days) as well as the ISO security evaluation data to enable local area reliability to be assessed.

4.2.6 Day-Ahead LBMP Market Settlements

The ISO shall calculate the Day-Ahead LBMPs for each Load Zone and at each Generator bus and Demand Reduction Bus as described in Attachment B. Each Supplier that bids a Generator into the ISO Day-Ahead Market and is scheduled in the SCUC to sell Energy in the Day-Ahead Market will be paid the product of: (a) the Day-Ahead hourly LBMP at the applicable Generator bus; and (b) the hourly Energy schedule. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to sell Energy into the Day-Ahead LBMP Market will be paid the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. For each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in SCUC to provide Energy from the Demand Reduction, the LSE providing Energy service to the Demand Side Resource that accounts for the Demand Reduction shall be paid the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction Bus; and (b) the hourly demand reduction scheduled Day-Ahead (in MW). In addition, each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in the SCUC to provide Energy through Demand Reduction shall receive a Demand Reduction Incentive Payment from the ISO equal to the product of: (a) the Day-Ahead hourly LBMP at the Demand Reduction bus; and (b) the lesser of the verified actual hourly Demand Reduction or the

scheduled hourly Demand Reduction (in MW). Each Customer that bids into the Day-Ahead Market, including each Customer that submits a Bid for a Virtual Transaction, and has a schedule accepted by the ISO to purchase Energy in the Day-Ahead Market will pay the product of: (a) the Day-Ahead hourly Zonal LBMP at each Point of Withdrawal; and (b) the scheduled Energy at each Point of Withdrawal. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to buy Energy from the Day-Ahead LBMP Market will pay the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. Each Customer that submits a Virtual Transaction bid into the ISO Day-Ahead Market and has a schedule accepted by the ISO to sell Energy in a Load Zone in the Day-Ahead Market will receive a payment equal to the product of (a) the Day-Ahead hourly zonal LBMP for that Load Zone; and (b) the hourly scheduled Energy for the Customer in that Load Zone. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POI and has its schedule accepted by the ISO will pay the product of: (a) the Day-Ahead hourly zonal LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POW and has its schedule accepted by the ISO will be paid the product of: (a) the Day-Ahead hourly zonal LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

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

4.4 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 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.

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

Intermittent Power Resources that depend on wind as their fuel submitting new or revised offers to supply Energy shall bid as ISO-Committed Flexible and shall submit a Minimum

Generation Bid of zero MW and zero cost and a Start-Up Bid at zero cost. Eligible Customers may submit new or revised Bids to supply Energy, Operating Reserves and/or Regulation Service. Customers that submit such Bids may specify different Bid parameters in real-time than they did Day-Ahead. Incremental Energy Bids 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 submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, if not otherwise prohibited pursuant to other provisions of the tariff. Minimum Generation Bids, Start-Up Bids, 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, Start-up 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.

Suppliers bidding on behalf of Generators that did not receive a Day-Ahead schedule for a given hour may offer their Generators, for those hours, using the ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed bid mode or, with ISO approval, the ISO-Committed Fixed bid modes in real-time. 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 that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator for the Real-Time Market for that hour provided, however, that Generators that were scheduled Day-Ahead in Self-Committed Fixed mode may switch, with ISO approval, to ISO-Committed Fixed bidding mode in real-time. Generators that were scheduled Day-Ahead in ISO-Committed Fixed mode will be scheduled as Self-Committed Fixed in the Real-Time Market unless, with ISO approval, they change their bidding mode to ISO-Committed Fixed.

A Generator with a real time physical operating problem that makes it impossible for it to operate in the bidding mode in which it was scheduled Day-Ahead should notify the NYISO.

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

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

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

Except as provided in this section, External Transaction Bids may not vary over the course of an hour. Each such Bid must offer to import, export or wheel the same amount of Energy at the same price at each point in time within that hour. However, 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, export Energy to, or wheel Energy to or from Proxy Generator Buses that are authorized to schedule transactions on an intra-hour basis shall indicate whether the ISO may vary schedules associated with those Bids within each hour. Transmission Customers scheduling External Bilateral Transactions shall also be subject to the provisions of Section 16, Attachment J of the ISO OATT.

4.4.1.2.3 Self-Commitment Requests

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

4.4.1.2.4 ISO-Committed Fixed

The ability to use the ISO-Committed Fixed bidding mode in the Real-Time Market shall be subject to ISO approval pursuant to procedures, which shall be published by the ISO. Generators that have exclusively used the Self-Committed Fixed or ISO-Committed Fixed bid modes in the Day-Ahead Market or that do not have the communications systems, operational control mechanisms or hardware to be able to respond to five-minute dispatch basepoints are

eligible to bid using the ISO-Committed Fixed bid mode in the Real-Time Market. Real-Time Bids by Generators using the ISO-Committed Fixed bid mode in the Real-Time Market shall provide variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, Minimum Generation Bids, hourly Start-Up Bids and other information pursuant to ISO Procedures.

RTC shall schedule ISO-Committed Fixed Generators.

4.4.1.3 External Transaction Scheduling

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

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

Except as specifically noted in Section 4.4.2, 4.4.3 and 4.4.4 of this ISO Services Tariff, RTC will make all Resource commitment and de-commitment decisions. RTC will make all economic commitment/de-commitment decisions based upon available offers assuming

Suppliers internal to the NYCA have a one-hour minimum run time; provided however, Real-Time Minimum Run Qualified Gas Turbines shall be assumed to have a two-hour minimum run time.

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.

RTC₁₅ 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 RTC₁₅ run, RTC will:

- (i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;
- (ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;
- (iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time;
- (iv) Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information;
- (v) Schedule economic hourly External Transactions for the next hour;

- (vi) Schedule economic 15 minute External Transactions for the quarter hour, for which the results of the RTC run following 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.*, RTC₃₀, RTC₄₅, and RTC₀₀ will begin executing at fifteen minutes before their designated posting times (for example, RTC₃₀ 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 RTC run following the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;
- (vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and
- (viii) Schedule ISO-Committed Fixed Resources.

4.4.1.5 External Transaction Settlements

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

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

4.4.2 Real-Time Dispatch

4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and Demand Side Resources, produce schedules for intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Real-Time Market Prices for Regulation

Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions, except as specifically provided in Section 4.4.2.3 below. Each Real-Time Dispatch run will co-optimize to solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon (which may be fifty, fifty-five, or sixty minutes long depending on where the run falls in the hour.) In addition to producing a binding schedule for the next five minutes, each Real-Time Dispatch run will produce advisory schedules for the remaining four time steps of its bid-optimization horizon (which may be five, ten, or fifteen minutes long depending on where the run falls in the hour). An advisory schedule may become binding in the absence of a subsequent Real-Time Dispatch run. RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

4.4.2.2 External Transaction Scheduling

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

4.4.2.3 Calculating Real-Time Market LBMPs and Advisory Prices

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

4.4.2.4 Real-Time Pricing Rules for Scheduling Ten Minute Resources

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

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

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

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

Special Case Resource Capacity that has been scheduled in the Day-Ahead Market to provide Operating Reserves, Regulation Service or Energy and that has been instructed as a Special Case Resource to reduce demand shall be considered, for the purpose of applying Real-Time special scarcity pricing rules described in Attachment B of this Services Tariff, to be a Special Case Resource.

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

4.4.2.6 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 applying Real-Time special scarcity pricing rules described in Attachment B of this Services Tariff, to be a Emergency Demand Response Program Resource.

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

4.4.2.7 Real-Time Scarcity Pricing Rules Applicable to Regulation Service and Operating Reserves During EDRP and/or SCR Activations

Under Section 17.1.2.2 of Attachment B to this ISO Services Tariff, the ISO will use special scarcity pricing rules to calculate Real-Time LBMPs during intervals when it has activated the EDRP and/or SCRs in identified Load Zones due to a reliability need. During these intervals, the ISO will also implement special scarcity pricing rules for real-time Regulation Capacity and Operating Reserves. These rules are set forth in Rate Schedule 15.3 and Rate Schedule 15.4 of this ISO Services Tariff.

4.4.2.8 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, 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, East of Central East and/or NYCA-wide. RTD-CAM will produce schedules directing all Generators located in a targeted location to increase production at their emergency response rate up to their UOL_E level and to stay at that level until instructed otherwise. Security constraints will be obeyed to the extent possible. The ISO will continue to optimize for Energy and Operating

Reserves, will recognize locational Operating Reserve requirements, but will set all Regulation Service schedules to zero.

4.4.3.1.3 Base Points ASAP -- No Commitments

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

4.4.3.1.4 Base Points ASAP -- Commit As Needed

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

4.4.3.1.5 Re-Sequencing Mode

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

4.4.3.2 Calculating Real-Time LBMPs

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

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

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

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	CTS Enabled Proxy Generator Bus	Non-Competitive	Available Scheduling Frequencies		
						Hourly Scheduled	Variably Scheduled	Dynamically Scheduled
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					✓	✓	
PJM_LOAD_KEystone	55857					✓	✓	
PJM_GEN_NEPTUNE_PROXY	323594	Neptune Scheduled Line	✓			✓	✓	
PJM_LOAD_NEPTUNE_PROXY	355615	Neptune Scheduled Line	✓			✓	✓	
PJM_GEN_VFT_PROXY	323633	Linden VFT Scheduled Line	✓			✓	✓	
PJM_LOAD_VFT_PROXY	355723	Linden VFT Scheduled Line	✓			✓	✓	
PJM_HTP_GEN	323702	HTP Scheduled Line	✓			✓	✓	
HUDSONTP_345KV_HTP_LOAD	355839	HTP Scheduled Line	✓			✓	✓	
ISO New England								
N.E._GEN_SANDY_POND	24062					✓		
NE_LOAD_SANDY_PD	55858					✓		
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					✓		

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 only hourly 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.

4.5 Real-Time Market Settlements

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

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

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

- (ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 499 MW of such units.

This procedure shall not apply to a Generator for those hours it has used the ISO-Committed Flexible or Self-Committed Flexible bid mode.

In Sections 4.5.1, 4.5.2, 4.5.3, 4.5.4, 4.5.5 and 4.5.6 of this Tariff, references to “scheduled” Energy injections and withdrawals shall encompass injections and withdrawals that are scheduled Day-Ahead, as well as injections and withdrawals that occur in connection with real-time Bilateral Transactions. In Sections 4.5.1, 4.5.3, 4.5.4 and 4.5.6 of this Tariff, references to Energy Withdrawals and Energy Injections shall not include Energy Withdrawals or Energy Injections in Virtual Transactions, or Energy Withdrawals or Energy Injections at Trading Hubs. Generators, including Limited Energy Storage Resources, that are providing Regulation Service shall not be subject to the real-time Energy market settlement provisions set forth in this Section, but shall instead be subject to the Energy settlement rules set forth in Rate Schedule 15.3 of this ISO Services Tariff.

4.5.1 Settlement When Actual Energy Withdrawals Exceed Scheduled Energy Withdrawals Other Than Scheduled or Actual Withdrawals in Virtual Transactions

When the Actual Energy Withdrawals by a Customer over an RTD interval exceed the Energy withdrawals scheduled over that RTD interval, the ISO shall charge the Real-Time

LBMP for Energy equal to the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the Actual Energy Withdrawals and the scheduled Energy withdrawals at that Load Zone.

4.5.2 Settlement for Customers Scheduled To Sell Energy in Virtual Transactions in Load Zones

The Actual Energy Injection in a Load Zone by a Customer scheduled Day-Ahead to sell Energy in a Virtual Transaction is zero and the Customer shall pay a charge for the Energy imbalance equal to the product of: (a) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Injection of the Customer for that Hour in that Load Zone.

4.5.3 Settlement When Actual Energy Injections are Less Than Scheduled Energy Injections or Actual Demand Reductions are Less Than Scheduled Demand Reductions

4.5.3.1 General Rule

When the Actual Energy Injections by a Supplier over an RTD interval are less than the Energy injections scheduled Day-Ahead over that RTD interval, the Supplier shall pay a charge for the Energy imbalance equal to the product of: (a) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus; and (b) the difference between the scheduled Day-Ahead Energy injections and the lesser of: (i) the Actual Energy Injections at that bus; or (ii) the Supplier's Real-Time Scheduled Energy Injection plus any Compensable Overgeneration. If the Energy injections by a Supplier over an RTD interval are less than the Energy injections scheduled for the Supplier Day-Ahead, and if the Supplier reduced its Energy injections in response to instructions by the ISO or a Transmission Owner that were issued in order to

maintain a secure and reliable dispatch, the Supplier may be entitled to a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

4.5.3.2 Failed Transactions

If an Energy injection scheduled by RTC at a Proxy Generator Bus fails in the ISO's checkout process, the Supplier or Transmission Customer that was scheduled to make the injection will pay the Energy imbalance charge described above in Section 4.5.3.1. In addition, if the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Mitigation and Analysis Department will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control.

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

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this section and the Financial Impact Charge described below in Section 4.5.4.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 1 of this ISO Services Tariff. In the event that the Energy injections for an Import scheduled by RTC or RTD, at a Proxy Generator Bus is Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or

equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible to receive an Import Curtailment Guarantee Payment for its curtailed Import pursuant to Attachment J of this ISO Services Tariff.

4.5.3.3 Capacity Limited Resources and Energy Limited Resources

For any hour in which: (i) a Capacity Limited Resource is scheduled to supply Energy, Operating Reserves, or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in upper operating limit; (iii) the Capacity Limited Resource requests a reduction for Capacity limitation reasons; and (iv) the ISO reduces the Capacity Limited Resource's upper operating limit to a level equal to, or greater than, its bid-in upper operating limit; the imbalance charge for Energy, Operating Reserve Service or Regulation Service imposed on that Capacity Limited Resource for that hour for its Day-Ahead Market obligations above its Capacity limited upper operating limit shall be equal to the product of: (a) the Real-Time price for Energy, Operating Reserve Service and Regulation Capacity; and (b) the Capacity Limited Resource's Day-Ahead schedule for each of these services minus the amount of these services that it has an obligation to supply pursuant to its ISO-approved schedule. When a Capacity Limited Resource's Day-Ahead obligation above its Capacity limited upper operating limit is balanced as described above, any real-time variation from its obligation pursuant to its Capacity limited schedules shall be settled pursuant to the methodology set forth in Section 4.5.3.1.

For any day in which: (i) an Energy Limited Resource is scheduled to supply Energy, Operating Reserves or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in Normal Upper Operating Limit; (iii) the Energy

Limited Resource requests a reduction for Energy limitation reasons; and (iv) the ISO reduces the Energy Limited Resource's Day-Ahead Emergency Upper Operating Limit to a limit no lower than the Normal Upper Operating Limit; the Resource may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

4.5.3.4 Demand Reductions

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

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

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

4.5.4 Settlement When Actual Energy Withdrawals are Less Than Scheduled Energy Withdrawals Other Than Actual or Scheduled Withdrawals in Virtual Transactions

4.5.4.1 General Rules

When a Customer's Actual Energy Withdrawals over an RTD interval are less than its Energy withdrawals scheduled Day-Ahead over that RTD interval, the Customer shall be paid the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the scheduled Energy withdrawals and the Actual Energy Withdrawals in that Load Zone. In addition, a Customer LSE providing Energy service to a Demand Reduction Provider's Demand Side Resource in a Load Zone shall be charged the product of: (a) the Real-Time hourly LBMP for that Load Zone; and (b) the actual Demand Reduction at the Demand Reduction Bus in that Load Zone.

4.5.4.2 Failed Transactions

If an Energy withdrawal at a Proxy Generator Bus scheduled by RTC fails in the ISO's checkout process, the Supplier or Transmission Customer that was scheduled to make the withdrawal will pay or be paid the energy imbalance charge described above in Section 4.5.4.1. In addition, if the checkout failure occurred for the reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Mitigation and Analysis Department will determine whether the Transaction associated with a withdrawal failed for reasons within a Supplier's or Transmission Customer's control.

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

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

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 15.1 of this ISO Services Tariff.

4.5.5 Settlement for Customers Scheduled To Purchase Energy in Virtual Transactions in Load Zones

The Actual Energy Withdrawal in a Load Zone by a Customer scheduled Day-Ahead to purchase Energy in a Virtual Transaction is zero and the Customer shall be paid the product of: (1) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Withdrawal of the Customer for that Hour in that Load Zone.

4.5.6 Settlement When Actual Energy Injections Exceed Scheduled Energy Injections

When Actual Energy Injections from a Generator over an RTD interval exceed the Energy injections scheduled Day-Ahead over the RTD interval the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the lesser of (i) the Supplier's Actual Energy Injection or (ii) its Real-Time Scheduled Energy Injection for that RTD interval, plus any Compensable Overgeneration and the Supplier's Day-Ahead scheduled Energy injection over the RTD

interval, unless the payment that the Supplier would receive for such injections would be negative (i.e., unless the LBMP calculated in that RTD interval at the applicable Generator's bus is negative) in which case the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the Supplier's Actual Energy Injection for that RTD interval and the Supplier's Day-Ahead scheduled Energy injection over that RTD interval. A Generator that is not following Base Point Signals shall not be compensated for Energy in excess of its Real-Time Scheduled Energy Injection if its applicable upper operating limit has been reduced below its bid-in upper operating limit by the ISO in order to reconcile the ISO's dispatch with the Generator's actual output, or to address reliability concerns. Suppliers shall not be compensated for Energy in excess of their Real-Time Scheduled Energy Injections, except: (i) for Compensable Overgeneration; (ii) when the ISO initiates a large event reserve pickup or a maximum generation pickup under RTD-CAM; or (iii) when a Transmission Owner initiates a reserve pickup in accordance with a Reliability Rule, including a Local Reliability Rule. When there is no large event reserve pickup or maximum generation pickup, or when there is such an instruction but a Supplier is not located in the area affected by the maximum generation pickup, that Supplier shall not be compensated for Energy in excess of its Real-Time Scheduled Energy Injection plus any Compensable Overgeneration. When there is a reserve pickup, or when there is a maximum generation pickup and a Supplier is located in the area affected by it, and the Supplier was either scheduled to operate in RTD or subsequently was directed to operate by the ISO, that Supplier shall be paid based on the product of: (1) the Real-Time LBMP calculated in that RTD Interval for the applicable Generator bus; and (2) the Actual Energy Injection minus the Energy injection scheduled Day-Ahead.

4.5.7 Settlement for Trading Hub Energy Owner when POI is a Trading Hub

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

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

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

4.5.9 Performance Tracking

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

4.6 Payments

4.6.1 Payments to Suppliers of Regulation Service

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

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

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

4.6.3 Payments to Suppliers for Operating Reserves

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

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

4.6.4 Payments to Generators for Black Start Capability

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

4.6.5 Day-Ahead Margin Assurance Payments

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

4.6.6 Bid Production Cost Guarantee Payments

4.6.6.1 Day-Ahead BPCG for Generators

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

4.6.6.2 Day-Ahead BPCG for Imports

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

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

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

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

4.6.6.4 BPCG for Generators for Supplemental Event Intervals

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

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

4.6.6.5 Real-Time BPCG for Imports

The ISO shall determine if a Supplier supplying an Import and eligible under Section 18.6.1 of Attachment C of this ISO Services Tariff for a real-time Bid Production Cost guarantee payment will not recover its real-time Decremental Bid through real-time LBMP revenue and real-time Imputed LBMP Revenue. Such determination shall be made for an entire Dispatch Day. Such determination shall be made separately for each Import transaction. On the basis of such determination, the ISO shall pay a real-time Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.6 of Attachment C of this ISO Services Tariff.

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

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

made separately for each long start-up time Generator. On the basis of such determination, the ISO shall pay a Bid Production Cost guarantee payment to the Supplier pursuant to Section 18.7 of Attachment C of this ISO Services Tariff.

4.6.6.7 BPCG for Demand Reduction in the Day-Ahead Market

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

4.6.6.8 BPCG for Special Case Resources

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

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

The ISO shall determine if a Supplier that bids Demand Side Resources committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service in the Day-Ahead Market will not recover its Day-Ahead synchronized Operating Reserves Bid to provide the amount of synchronized Operating Reserves that it was scheduled to provide, and/or its Day-Ahead Regulation Capacity Bid to provide the amount of Regulation Capacity that it was scheduled to provide. Such supplier shall be eligible under Section 18.10.1 of Attachment C to this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment. Such determination shall be made for an entire Day-Ahead Market day, and such determination shall be made separately for each Demand Side Resource. On the basis of such determination, the ISO shall make a Bid Production Cost guarantee payment to the Customer pursuant to Section 18.10 of Attachment C of this ISO Services Tariff.

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

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

determination, the ISO shall make a Bid Production Cost guarantee payment to the Customer pursuant to Section 18.11 of Attachment C of this ISO Services Tariff.

15.3 Rate Schedule 3 - Payments for Regulation Service

This Rate Schedule applies to Suppliers that provide Regulation Service to the ISO.

Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

15.3.1 Obligations of the ISO and Suppliers

15.3.1.1 The ISO shall:

- (a) Establish Regulation Service criteria and requirements in the ISO Procedures to ensure that Suppliers follow changes in Load consistent with the Reliability Rules;
- (b) Provide RTD Base Point Signals and AGC Base Point Signals to Suppliers providing Regulation Service to direct their output;
- (c) Establish criteria in the ISO Procedures that Suppliers must meet to qualify, or re-qualify, to supply Regulation Service;
- (d) Establish minimum metering requirements and telecommunication capability required for a Supplier to be able to respond to AGC Base Point Signals and RTD Base Point Signals sent by the ISO;
- (e) Select Suppliers to provide Regulation Service in the Day-Ahead Market and Real-Time Market 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; and
- (g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 15.3.3 of this Rate Schedule.

15.3.1.2 Each Supplier shall:

- (a) Register with the ISO the Regulation Capacity its resources are qualified to bid in the Regulation Services market;
- (b) Provide the ISO with the Resource's Regulation Capacity Response Rate and the Resource's Regulation Movement Response Rate;
- (c) Offer only Resources that are; (i) ISO-Committed Flexible or Self-Committed Flexible, provided however that Demand Side Resources shall be offered as ISO-Committed Flexible; within the dispatchable portion of their operating range, and; (ii) able to respond to AGC Base Point Signals sent by the ISO pursuant to the ISO Procedures, to provide Regulation Service;
- (d) Not use, contract to provide, or otherwise commit Regulation Capacity that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to any party other than the ISO;
- (e) Pay any charges imposed under this Rate Schedule;
- (f) Ensure that all of its Resources that are selected to provide Regulation Service comply with Base Point Signals issued by the ISO at all times pursuant to the ISO Procedures; and ensure that all of its Resources that are selected to provide Regulation Service comply with all criteria and ISO Procedures that apply to providing Regulation Service.

15.3.2 Selection of Suppliers in the Day-Ahead Market and the Real-Time Market

- (a) The ISO shall select Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day and in the Real-Time Market

to provide Regulation Service for each interval in the Dispatch Day, from those that have Bid to provide Regulation Service from Resources and that meet the qualification standards and criteria established in Section 15.3.1 of this Rate Schedule and in the ISO Procedures.

- (b) In order to schedule Suppliers in the Day-Ahead Market to provide Regulation Service for each hour in the following Dispatch Day, the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Day-Ahead Regulation Capacity Bid Price and b) the product of the Supplier's Day-Ahead Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.
- (c) In order to schedule Suppliers in the Real-Time Market to provide Regulation Service for each interval in the Dispatch Day the ISO shall use, as each Supplier's Regulation Service Bid price, the sum of: a) the Supplier's Real-Time Regulation Capacity Bid Price and b) the product of the Supplier's Real-Time Regulation Movement Bid Price and the applicable Regulation Movement Multiplier.
- (d) The ISO shall establish separate Regulation Capacity Market Prices in the Day-Ahead Market and the Real-Time Market under Sections 15.3.4, 15.3.5 and 15.3.7 of this Rate Schedule and shall establish a Real-Time Regulation Movement Market Price under Section 15.3.5.1 of this Rate Schedule. The ISO shall also compute Regulation Revenue Adjustment Payments and Regulation Revenue Adjustment Charges under Section 15.3.6 of this Rate Schedule.

15.3.2.1 Bidding Process

- (a) A Supplier may submit a Bid in the Day- Ahead Market or the Real-Time Market to provide Regulation Service from eligible Resources, provided, however, that Bids submitted by Suppliers that are attempting to re-qualify to provide Regulation Service, after being disqualified pursuant to Section 15.3.3 of this Rate Schedule 3, may be limited by the ISO pursuant to ISO Procedures.
- (b) Bids rejected by the ISO may be modified and resubmitted by the Supplier to the ISO in accordance with the terms of the ISO Tariff.
- (c) Each Bid shall contain the following information: (i) the maximum amount of capability (in MW) that the Resource is willing to provide as Regulation Capacity; (ii) the Supplier's Bid Price (in \$/MW) for Regulation Capacity; (iii) the Suppliers Bid Price (in \$/MW) for Regulation Movement; and (iv) the physical location and name or designation of the Resource.
- (d) Regulation Service Offers from Limited Energy Storage Resources: The ISO may reduce the real-time Regulation Service offer (in MWs) from a Limited Energy Storage Resource to account for the Energy storage capacity of such Resource.

15.3.3 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

- (a) The ISO shall establish (i) Resource performance measurement criteria; (ii) procedures to disqualify Suppliers whose Resources consistently fail to meet those criteria; and (iii) procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.
- (b) The ISO shall establish and implement a Performance Tracking System to monitor the performance of Suppliers that provide Regulation Service. The ISO

shall develop performance indices, which may vary with Control Performance, as part of the ISO Procedures. The ISO shall use the values provided by the Performance Tracking System to adjust settlements for real-time Regulation Movement pursuant to Section 15.3.5.5.1 and to compute a performance charge to apply to real-time Regulation Service providers pursuant to Section 15.3.5.5.2 of this Rate Schedule. (c) Resources that consistently fail to perform adequately may be disqualified by the ISO, pursuant to ISO Procedures.

15.3.4 Regulation Service Settlements - Day-Ahead Market

15.3.4.1 Calculation of Day-Ahead Market Prices

The ISO shall calculate a Day-Ahead Regulation Capacity Market Price for each hour of the following day. The Day-Ahead Regulation Capacity Market Price for each hour shall equal the Day-Ahead Shadow Price of the ISO's Regulation Service constraint for that hour, which shall be established under the ISO Procedures, minus the product of i) the Day-Ahead Regulation Movement Bid Price of the marginal Resource selected to provide Regulation Service; and ii) the applicable Regulation Movement Multiplier. Day-Ahead Shadow Prices will be calculated by the ISO's SCUC. Each hourly Day-Ahead Shadow Price shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that hour, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price shall include the Day-Ahead Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale of Energy or Operating Reserves in the Day-Ahead Market that the Resource would forego if scheduling it to provide

additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions). Shadow Prices consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Regulation Service Demand Curve.

Each Supplier that is scheduled Day-Ahead to provide Regulation Service shall be paid the Day-Ahead Regulation Capacity Market Price in each hour, multiplied by the amount of Regulation Capacity that it is scheduled Day-Ahead to provide in that hour.

15.3.4.2 Other Day-Ahead Payments

A Supplier that bids on behalf of a Generator that provides Regulation Service may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the ISO in the Day-Ahead Market, except to the extent that a Supplier is directed to provide the excess amount by the ISO.

15.3.5 Regulation Service Settlements - Real-Time Market

15.3.5.1 Calculation of Real-Time Market Prices

The ISO shall calculate a Real-Time Regulation Capacity Market Price and a Real-Time Regulation Movement Market Price for every RTD interval, except as noted in Section 15.3.8 of this Rate Schedule. Except when the circumstances described below in Section 15.3.5.2 apply, the Real-Time Regulation Capacity Market Price for each interval shall equal the real-time Shadow Price for the ISO's Regulation Service constraint for that RTD interval, which shall be established under the ISO Procedures, minus the product of: i) the real-time Regulation

Movement Bid of the marginal Resource selected to provide Real-Time Regulation Service; and

ii) the applicable Regulation Movement Multiplier. Real-time Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that interval, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that interval. As a result, the Shadow Price shall include the Real-Time Regulation Service Bids of the marginal Resource selected to provide Regulation Service, plus any margins on the sale of Energy or Operating Reserves in the Real-Time Market that Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves (or the applicable price on the Regulation Service Demand Curve during shortage conditions) provided however, if the marginal Resource selected to provide Regulation Service for the interval is in a Load Zone for which certain scarcity conditions apply but the ISO has not applied the pricing rule described in Section 15.4.6.2.1, the margins on the sale of Energy or Operating Reserves in the Real-Time Market that the marginal Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves, would be as calculated by RTD for that interval. 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 Calculation of Real-Time Market Prices for Regulation Capacity During EDRP/SCR Activations

During any interval in which the ISO is using the scarcity pricing rule to calculate LBMPs under Section 17.1.2.2 of Attachment B to this ISO Services Tariff, and is also using the scarcity pricing rule in Section 15.4.6.2.1 to price Operating Reserves in that interval, the real-time Regulation Capacity Market Price may be recalculated in light of the Regulation Bids of Suppliers and Lost Opportunity Costs of Generators scheduled to provide Regulation Service in real-time.

Specifically, when the NYISO is using the scarcity pricing rule in Section 15.4.6.2.1 to calculate Operating Reserves prices in an interval, the real-time Regulation Capacity Market Price shall be set to the higher of: (i) the highest total Regulation Capacity Bid and Lost Opportunity Cost of any Regulation Service provider scheduled by RTD; and (ii) the Market Price calculated under Section 15.3.5.1 of this Rate Schedule.

15.3.5.3 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 15.3.5.5.1.
- (d) The ISO shall assess a performance charge, pursuant to Section 15.3.5.5.2 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.

15.3.5.4 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.

15.3.5.5 Performance-Based Adjustment to Payments for Regulation Service Providers and Performance Based Charges

15.3.5.5.1 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 15.3.5.3 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} is the performance factor derived from the Regulation Service Performance index for the Resource for interval i ; PI_i is 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 is the payment scaling factor, established pursuant to ISO Procedures. The PSF shall be set between 0 and the minimum performance index required for payment 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.

15.3.5.5.2 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.

$$\text{Performance Charge}_i = (((1 - K_{PLi}) * RTRincap_i * -1.1 * RTMPreg_i) + (((1 - K_{PLi}) * (RTRcap_i - RTRincap_i) * -1.1) * \text{Max} (DAMPreg_i, RTMPreg_i))) * (s_i / 3600)$$

$DAMPreg_i$ 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 ;

$RTRincap_i$ 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_{PLi} is the performance factor for the Resource for interval i as defined in Section 15.3.5.5.1.

15.3.6 Energy Settlement Rules for Generators Providing Regulation Service

15.3.6.1 Energy Settlements

- A. For any interval in which a Generator that is not a Limited Energy Storage Resource is providing Regulation Service, it shall receive a settlement payment for Energy consistent with a real-time Energy injection equal to the lower of its

actual generation or its AGC Base Point Signal. Demand Side Resources providing Regulation Service shall not receive a settlement payment for Energy.

- B. For any hour in which a Limited Energy Storage Resource has injected or withdrawn Energy, pursuant to an ISO schedule to do so, it shall receive a settlement payment (if the amount calculated below is positive) or charge (if the amount calculated below is negative) for Energy pursuant to the following formula:

$$\text{Energy Settlement}_h = \text{Net MWHR}_h * \text{LBMP}_h$$

Where:

Net MWHR_h = the amount of Energy injected by the Limited Energy Storage Resource in hour h minus the amount of Energy withdrawn by that Limited Energy Storage Resource in hour h

LBMP_h = the time-weighted average LBMP in hour h calculated for the location of that Limited Energy Storage Resource

15.3.6.2 Additional Payments/Charges

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that differs from its RTD Base Point Signal, it shall receive or pay a Regulation Revenue Adjustment Payment (“RRAP”) or Regulation Revenue Adjustment Charge (“RRAC”) calculated under the terms of this subsection, provided however no RRAP shall be payable and no RRAC shall be charged to a Limited Energy Storage Resource.

15.3.6.2.1 Additional Payments/Charges When AGC Base Point Signals Exceed RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a

Generator is higher than the LBMP at its location in that interval, the Generator shall receive a RRAP. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at its location at that interval, the Generator shall be assessed a RRAC. RRAPs and RRACs shall be calculated using the following formula:

$$\text{Payment/Charge} = \frac{\max(\text{RTD Base Point Signal}, \min(\text{AGC Base Point Signal}, \text{Actual Output}))}{\text{RTD Base Point Signal}} \int [\text{Bid} - \text{LBMP}] * s/3600$$

Where:

s is the number of seconds in the RTD interval;

If the result of the calculation is positive then the Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of applying this formula, whenever the Generator's actual Bid exceeds the applicable LBMP the "Bid" term shall be set at a level equal to the lesser of the Generator's actual Bid or its reference Bid plus \$100/MWh.

Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.

15.3.6.2.2 Additional Charges/Payments When AGC Base Point Signals Are Lower than RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is lower than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall be assessed a RRAC. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at its location in that interval, the Generator shall receive a RRAP. RRAPs and RRACs shall be calculated using the following formula:

$$\text{Payment/Charge} = \frac{\int_{\min(\text{RTD Base Point Signal}, \max(\text{AGC Base Point Signal}, \text{Actual Output}))}^{\text{RTD Base Point Signal}} - [\text{Bid} - \text{LBMP}] \, ds}{3600}$$

Where:

s is the number of seconds in the RTD interval;

If the result of the calculation is positive then the Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of this formula, whenever the Generator's actual Bid is lower than the applicable LBMP the "Bid" term shall be set at a level equal to the higher of the Generator's actual Bid or its reference Bid minus \$100/MWh. Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.

15.3.7 Regulation Service Demand Curve

The ISO shall establish a Regulation Service Demand Curve that will apply to both the Day-Ahead and real-time Regulation 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 \$400/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 \$180/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 \$80/MW.

For all other quantities, the price on the Regulation Service demand curve shall be \$0/MW. However, the ISO shall not schedule more Regulation Service than the target level for the requirement for that hour.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure Regulation Capacity at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will

consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Regulation Service Demand Curve the ISO, in consultation with its Advisor, shall conduct an initial review in accordance with the ISO Procedures. The scope of the review shall be upward or downward in order to optimize the economic efficiency of any, or all, the ISO-Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.3.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Regulation Service Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 3 to the Services Tariff are also addressed in Section 30.4.6.4.1 of Attachment O.

15.3.8 Temporary Suspension of Regulation Service Markets During Reserve Pickups and Maximum Generation

During any period in which the ISO has activated its RTD-CAM software and called for a "large event" or "small event" reserve or maximum generation pickup, as described in Article 4.4.4.1 of this ISO Services Tariff, the ISO will set all Regulation Service schedules to zero. The ISO will establish real-time Regulation Market Prices for Regulation Capacity and Regulation Movement of zero for settlement and balancing purposes. The ISO will restore real-time Regulation Service schedules as soon as possible after the end of the reserve or maximum generation pickup.

15.3A Rate Schedule “3-A” -Charges Applicable to Suppliers That Are Not Providing Regulation Service

15.3A.1 Persistent Undergeneration Charges

A Supplier, other than a Supplier included in Section 15.3A.3.3 of this Rate Schedule, that is not providing Regulation Service and that persistently operates at a level below its Energy schedule shall pay a persistent undergeneration charge to the ISO, unless its operation is within a tolerance described below, provided, however, no persistent undergeneration charges shall apply to a Fixed Block Unit that has reached a percentage of its Normal Upper Operating Limit, which percentage shall be set pursuant to ISO Procedures and shall be initially set at seventy percent (70%). Persistent undergeneration charges per interval shall be calculated as follows:

$$\text{Persistent undergeneration charge} = \text{Energy Difference} \times \text{Max} (\text{MPRC}_{\text{DAM}}, \text{MPRC}_{\text{RT}}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the actual Energy provided by the Supplier from its RTD Base Point Signal for the dispatch interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall initially be 3% of the Supplier’s Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes;

MPRC_{DAM} is the Regulation Capacity Market Price in the Day-Ahead Market; and

MPRC_{RT} is the Regulation Capacity Market Price in the Real-Time Market.

15.3A.1.1 Overgeneration Charges

An Intermittent Power Resource that depends on wind as its fuel, for which the ISO has imposed a Wind Output Limit after October 31, 2009, or after February 1, 2010 for an Intermittent Power Resource that depends on wind as its fuel in commercial operation before 2006 with nameplate capacity of 30 MWs or less, that operates at a level above its schedule shall pay an overgeneration charge to the ISO, unless its operation is within a tolerance described below.

Overgeneration charges per interval shall be calculated as follows:

$$\text{Overgeneration charge} = \text{Energy Difference} \times \text{Max} (\text{MPRC}_{\text{DAM}}, \text{MPRC}_{\text{RT}}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the RTD Base Point Signal for the dispatch interval from the actual Energy provided by the Intermittent Power Resource for the same interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, which shall initially be set at 3% of the Supplier's Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable;

MPRC_{DAM} is the Regulation Capacity Market Price in the Day-Ahead Market; and

MPRC_{RT} is the Regulation Capacity Market Price in the Real-Time Market

15.3A.3 Exemptions

The following types of Generator shall not be subject to persistent undergeneration charges:

- 15.3A.3.1 Generators providing Energy under contracts (including PURPA contracts), executed and effective on or before November 18, 1999, in which the power purchaser does not control the operation of the supply source but would be responsible for payment of the persistent undergeneration or performance charge;
- 15.3A.3.2 Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 499 MW of such units;
- 15.3A.3.3 Intermittent Power Resources that depend on wind as their fuel and Limited Control Run of River Hydro Resources within the NYCA in operation on or before November 18, 1999, plus up to an additional 3300 MW of such Generators;
- 15.3A.3.4 Intermittent Power Resources that depend on landfill gas or solar energy as their fuel;
- 15.3A.3.5 Capacity Limited Resources and Energy Limited Resources to the extent that their real-time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their Real-Time Scheduled Energy Injections;
- 15.3A.3.6 Generators operating in their Start-Up Period or their Shutdown Period and, for Generators comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, each of the grouped generating units when one of the grouped generating units is operating in its Start-Up or Shutdown Period; and

15.3A.3.7 Generators operating during a Testing Period.

For Generators and Resources described in Sections 15.3A.3.1, 15.3A.3.2, 15.3A.3.3, and 15.3A.3.4 above, this exemption shall not apply in an hour if the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible.

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 and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively of this ISO Services Tariff.

Additionally, for the purpose of calculating Real-Time LBMPs when RTD is committing and dispatching Resources meeting Minimum Generation Levels and capable of starting in ten minutes pursuant to Section 4.4.3.3 of this ISO Services Tariff, RTD shall include in the incremental dispatch cost of each such Resource a start-up cost based on the Start-Up Bid of each such Resource and shall assume for each such Resource a zero downward response rate.

17.1.1 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:

$$DF_i = \left(1 - \frac{\mathcal{L}}{\mathcal{P}_i} \right)$$

Where:

- \mathcal{L} = NYCA losses; and
- \mathcal{P}_i = injection at bus i

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

$$\gamma_i^c = - \left(\sum_{k \in K}^n GF_{ik} \mu_k \right), \text{ except as noted in Sections 17.1.2.2.1 and 17.1.2.3.1 of this Attachment B}$$

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. 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. In addition, when certain scarcity conditions exist, as defined below, the ISO shall employ the special scarcity pricing rules described in Section 17.1.2.2. The NYISO shall use the scarcity pricing rule described in 17.1.2.2 for each interval in which EDRP/SCR Resources have been called in one or more Load Zones due to a reliability need and the aggregate of Available Reserves in the Load Zone(s) in which the reliability need was identified are less than the number of EDRP/SCR MW called for that event.

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 17.1.1.1.3. 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 ("RTD₀") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD₀ 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 (“RTD₅”) will initialize at the beginning of the hour and produce prices over a fifty minute optimization period. RTD₅ 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 (“RTD₁₀”) will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD₁₀ will produce binding prices and schedules for the interval beginning when it posts its results (i.e., at ten minutes after the hour) and ending at the first time point in its optimization period (i.e., fifteen minutes after the hour.) It will produce advisory prices and schedules for its second, third, fourth and fifth time points, each of which would be fifteen minutes after the preceding time point.

17.1.2.1.2 Description of the Real-Time Dispatch Process

17.1.2.1.2.1 The First Pass

The first RTD pass consists of a least bid cost, multi-period co-optimized dispatch for Energy, Regulation Service and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO as if they were blocked on at their UOL_N or UOL_E, whichever is applicable. Resources meeting Minimum Generation Levels and capable of being started in ten minutes that have not been committed by RTC are treated as flexible (i.e. able to be dispatched anywhere between zero (0)

MW and their UOL_N or UOL_E , whichever is applicable). The first pass establishes “physical base points” (i.e., real-time Energy schedules) and real-time schedules for Regulation Service and Operating Reserves for the first time point of the optimization period. Physical base points and schedules established for the first time point shall be binding and shall remain in effect until the results of the next run are posted. Physical base points and schedules established for all subsequent time points shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point Signals that the ISO sends to Suppliers.

When establishing physical base points, the ISO shall assume that each Generator will move toward the physical base point established during the first pass of the prior RTD run at its specified response rate.

17.1.2.1.2.1.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind as Their Fuel

When setting physical base points for a Dispatchable Resource at the first time point, the ISO shall ensure that they do not fall outside of the bounds established by the Dispatchable Resource’s lower and upper dispatch limits. A Dispatchable Resource’s dispatch limits shall be determined based on whether it was feasible for it to reach the physical base point calculated by the last RTD run given its: (A) metered output level at the time that the RTD run was initialized; (B) response rate; (C) minimum generation level; and (D) UOL_N or UOL_E , whichever is applicable. If it was feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E , as applicable, and starting from its previous base point. If it was not feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could

achieve over the next RTD interval, given its UOL_N or UOL_E , as applicable, but instead starting from the feasible output level closest to its previous base point.

When setting physical base points for a Dispatchable Resource at later time points, the ISO shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper dispatch limits for that time point. A Resource's dispatch limits at later time points shall be based on its: (A) dispatch limits from the first time point; (B) response rate; (C) minimum generation; and (D) UOL_N or UOL_E , whichever is applicable.

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by increasing the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E , whichever is applicable. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by decreasing the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level or to a Demand Side Resource's Demand Reduction level.

The RTD Base Point Signals sent to Dispatchable Resources shall be the same as the physical base points determined above.

17.1.2.1.2.1.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind as Their Fuel

For all time points of the optimization period, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind Energy Forecast.

17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators

When setting physical base points for Self-Committed Fixed Generators in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels that it specified in its self-commitment request for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

When setting physical base points for ISO-Committed Fixed Generators in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels scheduled for it by RTC for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

The RTD Base Point Signals sent to Self-Committed Fixed Generators shall follow the quarter hour operating schedules that those Generators submitted in their real-time self-commitment requests

The RTD Base Point Signals sent to ISO-Committed Fixed Generators shall follow the quarter hour operating schedules established for those Generators by RTC, regardless of their actual performance. To the extent possible, the ISO shall honor the response rates specified by such Generators when establishing RTD Base Point Signals. If a Self-Committed Fixed Generator's operating schedule is not feasible based on its real-time self-commitment requests then its RTD Base Point Signals shall be determined using a response rate consistent with the operating schedule changes.

17.1.2.1.2.2 The Second Pass

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats all Fixed Block Units that are committed by RTC, all Resources meeting Minimum Generation Levels and capable of starting

in ten minutes that have not been committed by RTC and all units otherwise instructed to be online or remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E , whichever is applicable), regardless of their minimum run-time status. This pass shall establish “hybrid base points” (i.e., real-time Energy schedules) that are used in the third pass to determine whether minimum run-time constrained Fixed Block Units should be blocked on at their UOL_N or UOL_E , whichever is applicable, or dispatched flexibly. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Resources shall be the same as the physical base points calculated in the first pass.

17.1.2.1.2.2.1 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 the same as the second pass with three variations. First, the third pass treats Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO that received a non-zero physical base point in the first pass, and that received a hybrid base point of zero in the second pass, as blocked on at their UOL_N or UOL_E , whichever is applicable. Second, the third pass produces "pricing base points" instead of hybrid base points. Third, and finally, the third pass calculates real-time Energy prices and real-

time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Article 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this ISO Services Tariff respectively. The ISO shall not use schedules for Energy, Regulation Service and Operating Reserves that are established in the third pass to dispatch Resources.

17.1.2.1.3 Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 17.1.2.1.1 and 17.1.2.1.2 shall apply.

First, if the ISO enters reserve pickup mode: (i) the ISO will produce prices and schedules for a single ten minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments before executing the three RTD passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator to be set to the higher of the Generator's physical base point or its actual generation level.

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator within the affected area towards its UOL_E at its emergency response rate or set it at a level equal to its physical base point.

Third, if the ISO enters basepoints ASAP – no commitments mode it will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period).

Fourth, if the ISO enters basepoints ASAP – commit as needed mode: (i) the ISO will produce price and schedules for a single five minute interval (not for a multi-point co-optimization period); and (ii) the ISO may make additional commitments of Generators that are capable of starting within ten minutes before executing the three RTD passes.

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization period consisting of two five-minute time points.

17.1.2.1.4 The Real-Time Commitment (“RTC”) Process and Automated Mitigation

Attachment H of this Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are implemented they shall be incorporated into the RTC software through the establishment of a second, parallel, commitment evaluation that will assess the impact of the mitigation measures. The first evaluation, referred to as the “RTC evaluation,” will determine the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the “RT-AMP” evaluation, will determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow the rules governing RTC’s operation that are set forth in Article 4 and this Attachment B to this ISO Services Tariff.

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to

implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, RTC_{15} and $RT-AMP_{15}$ will perform Resource commitment evaluations simultaneously. $RT-AMP_{15}$ will then apply the mitigation “impact” test, account for reference bid levels as appropriate and determine which Resources are actually to be mitigated. This information will then be conveyed to RTC_{30} which will make Resource commitments consistent with the application of the mitigation measures (and will thus indirectly be incorporated into future RTD runs).

17.1.2.2 Scarcity Pricing Rule

The ISO shall implement the following price calculation procedures for intervals when certain scarcity conditions exist as described in Section 17.1.2.

17.1.2.2.1 Except as noted in 17.1.2.2.2 below:

- The system marginal price at the Reference Bus shall be set pursuant to Section 17.1.2.1 of this Attachment B if the identified reliability need is not in Load Zone E. If the reliability need is in Load Zone E or in a set of Load Zones that includes Load Zone E, the system marginal price at the Reference Bus shall be the maximum Minimum Payment Nomination.
- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the system marginal price at the Reference Bus produced by RTD and a quantity equal to the delivery factor produced by RTD for that location minus one as defined in Section 17.1.1 of this Attachment.
- The Congestion Component of the LBMP at each location in a Load Zone(s) in which the reliability need was identified shall be set to the maximum Minimum Payment

Nomination minus the system marginal price at the Reference Bus calculated pursuant to this Section 17.1.2.2.1.

- The Congestion Component of the LBMP at all other locations shall be set equal to Congestion Component for that location produced by RTD, minus the result of subtracting: i) the system marginal price at the Reference Bus produced by RTD from ii) the system marginal price at the Reference Bus calculated pursuant to this Section 17.1.2.2.1.
- The LBMP at each location shall be as defined in Section 17.1.1 of this Attachment: the sum of the Marginal Losses Component of the LBMP at that location, plus the Congestion Component of the LBMP at that location, plus the LBMP at the Reference Bus.

17.1.2.2.2 However, the ISO shall not use the pricing rules of Section 17.1.2.2.1 to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section 17.1.2.1, above. In cases in which the pricing in Section 17.1.2.2.1 above would cause this rule to be violated:

- The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location pursuant to Section 17.1.2.1 of this Attachment B; or the LBMP calculated for that location using the scarcity pricing rule established in Section 17.1.2.2.1.
- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the system marginal price at the Reference Bus produced by RTD and a quantity equal to the delivery factor produced by RTD for that location minus one.

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

17.1.3 Day-Ahead LBMP Calculation Procedures

LBMPs in the Day-Ahead Market are calculated using five passes. The first two passes are commitment and dispatch passes; the last three are dispatch only passes.

Pass 1 consists of a least cost commitment and dispatch to meet Bid Load and reliable operation of the NYS Power System that includes Day-Ahead Reliability Units.

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment (“SCUC”) to meet Bid Load. At the end of this step, committed Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units are dispatched to meet Bid Load with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure (“AMP”) activation.

If AMP is activated, Step 1B tests to determine if the AMP will be triggered by mitigating offer prices subject to mitigation that exceed the conduct threshold to their respective reference prices. These mitigated offer prices together with all originally submitted offer prices not subject to automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This step is another iteration of the SCUC process. At the end of Step 1B, committed Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources, and non-Fixed Block Units are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are

again calculated from this dispatch. The LBMPs determined at the end of Step 1B are compared to the LBMPs determined at the end of Step 1A to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the SCUC process. At the end of Step 1C, committed Fixed Block Units, Imports, Exports, virtual supply, virtual load, Demand Side Resources, and non-Fixed Block Units are again dispatched to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are again calculated from this dispatch.

All Demand Side Resources and non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of and the AMP) are blocked on at least to minimum load in Passes 4 through 6. The resources required to meet local system reliability are determined in Pass 1.

Pass 2 consists of a least cost commitment and dispatch of Fixed Block Units, Imports, Exports, Demand Side Resources and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load, considering the Wind Energy Forecast, that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fixed Block Units are dispatchable on a flexible basis. Incremental Import Capacity needed to meet forecast Load requirements is determined in Pass 2. Fixed Block Units committed in this pass are not included

in the least cost dispatches of Passes 5 or 6. Demand Side Resources and non-Fixed Block Units committed in this step are blocked on at least to minimum Load in Passes 4 through 6.

Intermittent Power Resources that depend on wind as their fuel committed in this pass as a result of the consideration of the Wind Energy Forecast are not blocked in Passes 5 or 6.

Pass 3 is reserved for future use.

Pass 4 consists of a least cost dispatch to forecast Load. It is not used to set schedules or prices. It is used for operational purposes and provides a dispatch of Fixed Block Units, Imports, Exports, Demand Side Resources and non-Fixed Block Units committed in Passes 1 or 2. Incremental Import Capacity committed in Pass 2 is re-evaluated and may be reduced if no longer required.

Pass 5 consists of a least cost dispatch of Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units committed to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fixed Block Units are treated as dispatchable on a flexible basis. LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

Pass 6 consists of a least cost dispatch of all Day-Ahead committed Resources, Imports, Exports, Virtual Supply, Virtual Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units committed in the final step of Pass 1 blocked

on at maximum Capacity. Final schedules for Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

17.1.4 Determination of Transmission Shortage Cost

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

The ISO may periodically evaluate the Transmission Shortage Cost to determine whether it is necessary to modify the Transmission Shortage Cost to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this evaluation. If the ISO determines that it is necessary to modify the Transmission Shortage Cost in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to ninety days, provided however the NYISO shall file such change with the Commission pursuant to Section 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change.

The responsibilities of the ISO and the Market Monitoring Unit in evaluating and modifying the Transmission Shortage Cost, as necessary are addressed in Attachment O, Section 30.4.6.8.1 of this Market Services Tariff (“Market Monitoring Plan”).

17.1.5 Zonal LBMP Calculation Method

The computation described in Section 17.1.1 of this Attachment B is at the bus level. An eleven (11) zone model will be used for the LBMP billing related to Loads. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the Load Zone. The Load weights which will sum to unity will be calculated from the load bus MW distribution. Each component of the LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone j can be written as:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

where:

$$\gamma_j^Z = \text{LBMP for zone } j,$$

$$\gamma_j^{L,Z} = \sum_{i=1}^n W_i \gamma_i^L \quad \text{is the Marginal Losses Component of the LBMP for zone } j;$$

$$\gamma_j^{C,Z} = \sum W_i \gamma_i^C \quad \text{is the Congestion Component of the LBMP for zone } j;$$

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
H Q	61844	HQ_GEN_WHEEL	23651
NPX	61845	N.E._GEN_SANDY_P OND	24062
O H	61846	O.H._GEN_BRUCE	24063
PJM	61847	PJM_GEN_KEYSTON E	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 Available 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).

Proxy Generator Bus Constraint Cost (PConstraint): The product of: i) that portion of the Congestion Component that is associated with a Proxy Generator Bus Constraint and ii) a factor, between zero and 1, calculated pursuant to ISO Procedures.

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 four tables below.

17.1.6.2.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses, excluding CTS Enabled Proxy Generator Buses.

The pricing rules for Dynamically Scheduled Proxy Generator Buses, excluding CTS Enabled 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	RTD used to schedule External Transactions in a given 5-minute interval is subject to a Proxy Generator Bus Constraint, and RTC_{15} was not subject to that Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a = RTD$ $LBMP_a$

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)
3	RTD used to schedule External Transactions in a given 5-minute interval is subject to a Proxy Generator Bus Constraint, and RTC_{15} was not subject to that Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = RTD$ $LBMP_a$
4	RTC_{15} and RTD are subject to the same Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(RTC_{15} LBMP_a, RTD LBMP_a)$
5	RTC_{15} and RTD are subject to the same Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(RTC_{15} LBMP_a, RTD LBMP_a)$

17.1.6.2.2 Pricing rules for Variably Scheduled Proxy Generator Buses, excluding CTS Enabled Proxy Generator Buses

The pricing rules for Variably Scheduled Proxy Generator Buses, excluding CTS Enabled 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)
6	Unconstrained in RTC_{15} , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD$ $LBMP_a$
7	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint, and RTC_{15} was not subject to that Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Rolling RTC } LBMP_a$
8	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint, and RTC_{15} was not subject to that Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Rolling RTC } LBMP_a$
9	RTC_{15} and the Rolling RTC are subject to the same Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(RTC_{15} LBMP_a, \text{Rolling RTC } LBMP_a)$

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)
10	RTC ₁₅ and the Rolling RTC are subject to the same Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time LBMP _a = Min(RTC ₁₅ LBMP _a , Rolling RTC LBMP _a)

17.1.6.2.3 Pricing rules for Proxy Generator Buses not designated as Dynamically Scheduled or Variably Scheduled or CTS Enabled Proxy Generator Buses

The pricing rules for Proxy Generator Buses not designated as Dynamically Scheduled or Variably Scheduled or CTS Enabled 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)
11	Unconstrained in RTC ₁₅ , Rolling RTC and RTD	N/A	Real-Time LBMP _a = RTD LBMP _a
12	RTC ₁₅ is subject to a Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time LBMP _a = RTC ₁₅ LBMP _a
13	RTC ₁₅ is subject to a Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time LBMP _a = RTC ₁₅ LBMP _a

17.1.6.2.4 Pricing rules for CTS Enabled Proxy Generator Buses

The pricing rules for CTS Enabled 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)
50	Unconstrained in Rolling RTC	N/A	Real-Time LBMP _a = RTD LBMP _a

51	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC } PConstraint_a$
52	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC } PConstraint_a$

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 three 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 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)
14	RTD used to schedule External Transactions in a given 5-minute interval is subject to a Interface ATC or Interface Ramp Constraint, and RTC_{15} was not subject to that Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(RTD\ LBMP_a, \text{Min}(\text{Unconstrained } RTD\ LBMP_a, 0))$
15	RTD used to schedule External Transactions in a given 5-minute interval is subject to a Interface ATC or Interface Ramp Constraint, and RTC_{15} was not subject to that Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(RTD\ LBMP_a, \text{Max}(\text{Unconstrained } RTD\ LBMP_a, SCUC\ LBMP_a))$

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)
16	RTD used to schedule External Transactions in a given 5-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Into NYCA (Import)	$\text{Real-Time LBMP}_a = \text{Max}(\text{RTD LBMP}_a, \text{Min}(\text{Unconstrained RTD LBMP}_a, 0))$
17	RTD used to schedule External Transactions in a given 5-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Out of NYCA (Export)	$\text{Real-Time LBMP}_a = \text{Min}(\text{RTD LBMP}_a, \text{Max}(\text{Unconstrained RTD LBMP}_a, \text{SCUC LBMP}_a))$
18	RTC_{15} and RTD are subject to the same Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	$\text{Real-Time LBMP}_a = \text{Max}(RTC_{15} \text{ LBMP}_a, \text{RTD LBMP}_a, \text{Min}(\text{Unconstrained RTD LBMP}_a, 0))$
19	RTC_{15} and RTD are subject to the same Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	$\text{Real-Time LBMP}_a = \text{Min}(RTC_{15} \text{ LBMP}_a, \text{RTD LBMP}_a, \text{Max}(\text{Unconstrained RTD LBMP}_a, \text{SCUC LBMP}_a))$
20	RTC_{15} and RTD are subject to the same NYCA Ramp Constraint	Into NYCA (Import)	$\text{Real-Time LBMP}_a = \text{Max}(RTC_{15} \text{ LBMP}_a, \text{RTD LBMP}_a, \text{Min}(\text{Unconstrained RTD LBMP}_a, 0))$
21	RTC_{15} and RTD are subject to the same NYCA Ramp Constraint	Out of NYCA (Export)	$\text{Real-Time LBMP}_a = \text{Min}(RTC_{15} \text{ LBMP}_a, \text{RTD LBMP}_a, \text{Max}(\text{Unconstrained RTD LBMP}_a, \text{SCUC LBMP}_a))$

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)
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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)
22	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Interface ATC or Interface Ramp Constraint, and RTC_{15} was not subject to that Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(\text{Rolling RTC } LBMP_a, \text{Min}(\text{RTD } LBMP_a, 0))$
23	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Interface ATC or Interface Ramp Constraint, and RTC_{15} was not subject to that Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(\text{Rolling RTC } LBMP_a, \text{Max}(\text{RTD } LBMP_a, \text{SCUC } LBMP_a))$
24	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(\text{Rolling RTC } LBMP_a, \text{Min}(\text{RTD } LBMP_a, 0))$
25	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(\text{Rolling RTC } LBMP_a, \text{Max}(\text{RTD } LBMP_a, \text{SCUC } LBMP_a))$
26	RTC_{15} and the Rolling RTC are subject to the same Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(RTC_{15} LBMP_a, \text{Rolling RTC } LBMP_a, \text{Min}(\text{RTD } LBMP_a, 0))$
27	RTC_{15} and the Rolling RTC are subject to the same Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(RTC_{15} LBMP_a, \text{Rolling RTC } LBMP_a, \text{Max}(\text{RTD } LBMP_a, \text{SCUC } LBMP_a))$
28	RTC_{15} and the Rolling RTC are subject to the same NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(RTC_{15} LBMP_a, \text{Rolling RTC } LBMP_a, \text{Min}(\text{RTD } LBMP_a, 0))$
29	RTC_{15} and the Rolling RTC are subject to the same NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(RTC_{15} LBMP_a, \text{Rolling RTC } LBMP_a, \text{Max}(\text{RTD } LBMP_a, \text{SCUC } LBMP_a))$

17.1.6.3.3 Pricing rules for Non-Competitive Proxy Generator Buses, not Designated as Either Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive Proxy Generator Buses not designated as either 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)
30	RTC ₁₅ is subject to a Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	Real-Time LBMP _a = Max(RTC ₁₅ LBMP _a , Min(RTD LBMP _a , 0))
31	RTC ₁₅ is subject to a Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	Real-Time LBMP _a = Min(RTC ₁₅ LBMP _a , Max(RTD LBMP _a , SCUC LBMP _a))

At all other times, the Real-Time LBMP shall be calculated as specified in Section 17.1.6.2 above.

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 three 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 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)
32	RTD used to schedule External Transactions in a given 5-minute interval is subject to an Interface ATC Constraint, and RTC_{15} was not subject to that Interface ATC Constraint	Into NYCA (Import)	$\text{Real-Time LBMP}_a = \text{Max}(\text{RTD LBMP}_a, \text{Min}(\text{Unconstrained RTD LBMP}_a, 0))$
33	RTD used to schedule External Transactions in a given 5-minute interval is subject to an Interface ATC Constraint, and RTC_{15} was not subject to that Interface ATC Constraint	Out of NYCA (Export)	$\text{Real-Time LBMP}_a = \text{Min}(\text{RTD LBMP}_a, \text{Max}(\text{Unconstrained RTD LBMP}_a, \text{SCUC LBMP}_a))$
34	RTD used to schedule External Transactions in a given 5-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Into NYCA (Import)	$\text{Real-Time LBMP}_a = \text{Max}(\text{RTD LBMP}_a, \text{Min}(\text{Unconstrained RTD LBMP}_a, 0))$
35	RTD used to schedule External Transactions in a given 5-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Out of NYCA (Export)	$\text{Real-Time LBMP}_a = \text{Min}(\text{RTD LBMP}_a, \text{Max}(\text{Unconstrained RTD LBMP}_a, \text{SCUC LBMP}_a))$
36	RTC_{15} and RTD are subject to the same Interface ATC Constraint	Into NYCA (Import)	$\text{Real-Time LBMP}_a = \text{Max}(RTC_{15} \text{ LBMP}_a, \text{RTD LBMP}_a, \text{Min}(\text{Unconstrained RTD LBMP}_a, 0))$
37	RTC_{15} and RTD are subject to the same Interface ATC Constraint	Out of NYCA (Export)	$\text{Real-Time LBMP}_a = \text{Min}(RTC_{15} \text{ LBMP}_a, \text{RTD LBMP}_a, \text{Max}(\text{Unconstrained RTD LBMP}_a, \text{SCUC LBMP}_a))$
38	RTC_{15} and RTD are subject to the same NYCA Ramp Constraint	Into NYCA (Import)	$\text{Real-Time LBMP}_a = \text{Max}(RTC_{15} \text{ LBMP}_a, \text{RTD LBMP}_a, \text{Min}(\text{Unconstrained RTD LBMP}_a, 0))$
39	RTC_{15} and RTD are subject to the same NYCA Ramp Constraint	Out of NYCA (Export)	$\text{Real-Time LBMP}_a = \text{Min}(RTC_{15} \text{ LBMP}_a, \text{RTD LBMP}_a, \text{Max}(\text{Unconstrained RTD LBMP}_a, \text{SCUC LBMP}_a))$

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)
40	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint, and RTC_{15} was not subject to that Interface ATC Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(\text{Rolling RTC } LBMP_a, \text{Min}(\text{RTD } LBMP_a, 0))$
41	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint, and RTC_{15} was not subject to that Interface ATC Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(\text{Rolling RTC } LBMP_a, \text{Max}(\text{RTD } LBMP_a, \text{SCUC } LBMP_a))$
42	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(\text{Rolling RTC } LBMP_a, \text{Min}(\text{RTD } LBMP_a, 0))$
43	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(\text{Rolling RTC } LBMP_a, \text{Max}(\text{RTD } LBMP_a, \text{SCUC } LBMP_a))$
44	RTC_{15} and the Rolling RTC are subject to the same Interface ATC Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(RTC_{15} LBMP_a, \text{Rolling RTC } LBMP_a, \text{Min}(\text{RTD } LBMP_a, 0))$
45	RTC_{15} and the Rolling RTC are subject to the same Interface ATC Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(RTC_{15} LBMP_a, \text{Rolling RTC } LBMP_a, \text{Max}(\text{RTD } LBMP_a, \text{SCUC } LBMP_a))$
46	RTC_{15} and the Rolling RTC are subject to the same NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a = \text{Max}(RTC_{15} LBMP_a, \text{Rolling RTC } LBMP_a, \text{Min}(\text{RTD } LBMP_a, 0))$
47	RTC_{15} and the Rolling RTC are subject to the same NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a = \text{Min}(RTC_{15} LBMP_a, \text{Rolling RTC } LBMP_a, \text{Max}(\text{RTD } LBMP_a, \text{SCUC } LBMP_a))$

17.1.6.4.3 Pricing rules for Proxy Generator Buses that are associated with Designated Scheduled Lines that are not Designated as 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 designated as 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)
48	RTC ₁₅ is subject to a Interface ATC Constraint	Into NYCA (Import)	Real-Time LBMP _a = Max(RTC ₁₅ LBMP _a , Min(RTD LBMP _a , 0))
49	RTC ₁₅ is subject to a Interface ATC Constraint	Out of NYCA (Export)	Real-Time LBMP _a = Min(RTC ₁₅ LBMP _a , Max(RTD LBMP _a , SCUC LBMP _a))

At all other times, the Real-Time LBMP shall be calculated as specified in Section 17.1.6.2 above.

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-Time LBMP = LOSSES_{RTC PROXY GENERATOR BUS};

and

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

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

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

and

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

where:

Energy_{RTC REF BUS} = (1) At Proxy Generator Buses that are authorized to schedule transactions hourly only, the marginal Bid cost of providing Energy at the reference Bus, as calculated by RTC₁₅ for the hour; (2) At Variably Scheduled Proxy Generator Buses, the marginal Bid cost of providing Energy at the reference Bus, as calculated by the Rolling RTC used to schedule External Transactions for that 15-minute interval; (3) At Dynamically Scheduled Proxy Generator Buses, the marginal Bid cost of providing Energy at the reference Bus, as calculated by RTD used to schedule External Transactions for that 5-minute interval;

Losses_{RTC PROXY GENERATOR BUS} = (1) At Proxy Generator Buses that are authorized to schedule transactions hourly only, the Marginal Losses Component of the LBMP as calculated by RTC₁₅ at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line for the hour; (2) At Variably Scheduled Proxy Generator Buses, the Marginal Losses Component of the LBMP as calculated by the Rolling RTC used to schedule External Transactions for that 15-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line; (3) At Dynamically Scheduled Proxy Generator Buses, the Marginal Losses Component of the LBMP as calculated by RTD used to schedule External Transactions for that 5-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line; and

Day-Ahead LBMP_{PROXY GENERATOR BUS} = Day-Ahead LBMP as calculated by SCUC for the Non-Competitive Proxy Generator Bus or Proxy

Generator Bus associated with a designated Scheduled Line for the hour.

**18 Attachment C -Formulas For Determining Bid Production Cost Guarantee
Payments**

18.1 Introduction

Ten Bid Production Cost Guarantee (BPCG) payments for eligible Suppliers are described in this attachment: (i) a Day-Ahead BPCG for Generators; (ii) a Day-Ahead BPCG for Imports; (iii) a real-time BPCG for Generators in RTD intervals other than Supplemental Event Intervals ; (iv) a BPCG for Generators for Supplemental Event Intervals; (v) a real-time BPCG for Imports; (vi) a BPCG for long start-up time Generators (i.e., Generators that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) whose start is aborted by the ISO prior to their dispatch; (vii) a BPCG for Demand Reduction in the Day-Ahead Market; (viii) a Special Case Resources BPCG; (ix) a BPCG for Demand Side Resources providing synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market; and (x) a BPCG for Demand Side Resources providing synchronized Operating Reserves and / or Regulation Service in the Real-Time Market. Suppliers shall be eligible for these payments in accordance with the eligibility requirements and formulas established in this Attachment C.

The Bid Production Cost guarantee payments described in this Attachment C are each calculated and paid independently from each other. A Customer's eligibility to receive one type of Bid Production Cost guarantee payment shall have no impact on the Customer's eligibility to be considered to receive another type of Bid Production Cost guarantee payment, in accordance with the rule set forth in this Attachment C.

18.2 Day-Ahead BPCG For Generators

18.2.1 Eligibility to Receive a Day-Ahead BPCG for Generators

18.2.1.1 Eligibility.

A Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO Committed Flexible Generator that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment.

18.2.1.2 Non-Eligibility (includes both partial and complete exclusions).

Notwithstanding Section 18.2.1.1,

a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator that is committed by the ISO in the Day-Ahead Market shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment if that Generator has been committed in the Day-Ahead Market for any other hour of the day as a result of a Self-Committed Fixed or Self-Committed Flexible bid.

18.2.2 Formulas for Determining Day-Ahead BPCG for Generators

18.2.2.1 Applicable Formula. A Supplier's BPCG for a Generator "g" shall be as follows:

Day-Ahead Bid Production Cost Guarantee for Generator g =

$$\max \left[\sum_{h=1}^N \left(\begin{aligned} &EH_{gh}^{DA} \\ &\int C_{gh}^{DA} + MGC_{gh}^{DA} MGH_{gh}^{DA} + SUC_{gh}^{DA} NSUH_{gh}^{DA} \\ &MGH_{gh}^{DA} \\ &- LBMP_{gh}^{DA} EH_{gh}^{DA} - NASR_{gh}^{DA} \end{aligned} \right), 0 \right]$$

18.2.2.2 Variable Definitions. The terms used in this Section 18.2.2 shall be defined as follows:

- N = number of hours in the Day-Ahead Market day;
- EH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by Generator g in hour h expressed in terms of MWh;
- MGH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by the minimum generation segment of Generator g in hour h expressed in terms of MWh;
- C_{gh}^{DA} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost curve for Generator g, in the Day-Ahead Market for hour h expressed in terms of \$/MWh;
- MGC_{gh}^{DA} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, for hour h in the Day-Ahead Market, expressed in terms of \$/MWh.

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation (“SRE”), on the day prior to the Dispatch Day and Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), then Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Day-Ahead Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

- SUC_{gh}^{DA} = Start-Up Bid by Generator g in hour h, or when applicable the mitigated Start-Up Bid for Generator g, in hour h in the Day-Ahead Market expressed in terms of \$/start; *provided, however*, that the Start-Up Bid for Generator g in hour h or, when applicable, the mitigated Start-Up Bid, for

Generator g in hour h , may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled, and to operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g 's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator g 's Day-Ahead or SRE schedule.

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* Generator g shall have its Start-Up Bid set to zero for purposes of calculating a Day-Ahead Bid Production Cost guarantee.

For a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the ISO and runs in real-time, the Start-Up Bid for Generator g in hour h shall be the Generator's Start-Up Bid, or when applicable the mitigated Start-Up Bid for Generator g , for the hour (as determined at the point in time in which the ISO provided notice of the request for start-up):

$NSUH_{gh}^{DA}$	=	number of times Generator g is scheduled Day-Ahead to start up in hour h ;
$LBMP_{gh}^{DA}$	=	Day-Ahead LBMP at Generator g 's bus in hour h expressed in \$/MWh;
$NASR_{gh}^{DA}$	=	Net Ancillary Services revenue, expressed in terms of \$, paid to Generator g as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that hour, if it is not a Supplier of Installed Capacity and has been scheduled to operate in that hour; (2) Regulation Service payments made to that Generator for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less that Generator's Day-Ahead Regulation Capacity Bid to provide that amount of Regulation Service in that hour; and (3) payments made to that Generator for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less that Generator's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.3 Day-Ahead BPCG For Imports

18.3.1 Eligibility to Receive a Day-Ahead BPCG for Imports

A Supplier that bids an Import that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment.

18.3.2 BPCG Calculated by Transaction ID

For purposes of calculating a Day-Ahead Bid Production Cost guarantee payment for an Import under this Section 18.3, the ISO shall treat the Import as being from a single Resource for all hours of the Day-Ahead Market day in which the same Transaction ID is used, and the ISO shall treat the Import as being from a different Resource for all hours of the Day-Ahead Market day in which a different Transaction ID is used.

18.3.3 Formula for Determining Day-Ahead BPCG for Imports

Day-Ahead Bid Production Cost guarantee for Import t by Supplier =

$$\max \left[\sum_{h=1}^N \left(\text{DecBid}_{th}^{\text{DA}} - \text{LBMP}_{th}^{\text{DA}} \right) \bullet \text{SchImport}_{th}^{\text{DA}}, 0 \right]$$

Where;

N = number of hours in the Day-Ahead Market day;

$\text{DecBid}_{th}^{\text{DA}}$ = Decremental Bid, in \$/MWh, supplied for Import t for hour h;

$\text{LBMP}_{th}^{\text{DA}}$ = Day-Ahead LBMP, in \$/MWh, for hour h at the Proxy Generator Bus that is the source of the Import t and

$\text{SchImport}_{th}^{\text{DA}}$ = total Day-Ahead schedule, in MWh, for Import t in hour h.

18.4 Real-Time BPCG For Generators In RTD Intervals Other Than Supplemental Event Intervals

18.4.1 Eligibility for Receiving Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event Intervals

18.4.1.1 Eligibility.

A Supplier shall be eligible to receive a real-time Bid Production Cost guarantee payment for intervals (excluding Supplemental Event Intervals) if it bids on behalf of:

18.4.1.1.1 an ISO-Committed Flexible Generator or an ISO-Committed Fixed

Generator that is committed by the ISO in the Real-Time Market; or

18.4.1.1.2 a Self-Committed Flexible Generator if the Generator's minimum

generation MW level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; or

18.4.1.1.3 a Generator committed via SRE, or committed or dispatched by the ISO as

Out-of-Merit generation to ensure NYCA or local system reliability for the hours

of the day that it is committed via SRE or is committed or dispatched by the ISO

as Out-of-Merit generation to meet NYCA or local system reliability without

regard to the Bid mode(s) employed during the Dispatch Day, except as provided

in Sections 18.4.2 and 18.12, below.

18.4.1.2 Non-Eligibility (includes both partial and complete exclusions).

Notwithstanding Section 18.4.1.1,

a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-

Committed Flexible Generator that is committed by the ISO in the real-time

market shall not be eligible to receive a real-time Bid Production Cost guarantee

payment if that Generator has been committed in real-time, in any other hour of

the day, as the result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule, *provided however*, a Generator that has been committed in real time as a result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule will not be precluded from receiving a real-time Bid Production Cost guarantee payment for other hours of the Dispatch Day, in which it is otherwise eligible, due to these Self-Committed mode Bids if such bid mode was used for: (i) an ISO authorized Start-Up, Shutdown or Testing Period, or (ii) for hours in which such Generator was committed via SRE or committed or dispatched by the ISO as Out-of-Merit to meet NYCA or local system reliability.

18.4.2 Formula for Determining Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee for Generator g =

$$\max \left[\sum_{i \in M} \left(\left(\frac{\int_{\max(EI_{gi}^{DA}, MGI_{gi}^{RT})}^{\max(EI_{gi}^{RT}, MGI_{gi}^{RT})} C_{gi}^{RT} + MGC_{gi}^{RT} \cdot (MGI_{gi}^{RT} - MGI_{gi}^{DA})}{3600} - LBMP_{gi}^{RT} \cdot (EI_{gi}^{RT} - EI_{gi}^{DA}) \right) \cdot \frac{s_i}{3600} \right) - (NASR_{gi}^{TOT} - NASR_{gi}^{DA}) - RRAP_{gi} + RRAC_{gi} + \sum_{j \in L} SUC_{gj}^{RT} \cdot (NSUI_{gj}^{RT} - NSUI_{gj}^{DA}) \right], 0 \right]$$

where:

s_i = number of seconds in RTD interval i;

C_{gi}^{RT} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost for Generator g, in the RTD for the hour that includes RTD interval i

expressed in terms of \$/MWh, except in intervals in which the dispatch of the Generator is constrained by its downward ramp rate for that interval, unless that Generator was scheduled to provide Regulation Service in that interval and its RTD basepoint was less than its AGC basepoint, and except in hours in which the NYISO has increased Generator g's minimum operating level, either (i) at the Generator's request, or (ii) in order to reconcile the ISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

MGI_{gi}^{RT} = metered Energy produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;

MGI_{gi}^{DA} = Energy scheduled Day-Ahead to be produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;

MGC_{gi}^{RT} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, in the Real-Time Market for the hour that includes RTD interval i, expressed in terms of \$/MWh, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), *then* Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Real-Time Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gj}^{RT} = Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, for hour j into RTD expressed in terms of \$/start, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

provided, however,

(i) the Start-Up Bid shall be deemed to be zero for (1) Self-Committed Fixed and Self-Committed Flexible Generators, (2) Generators that are economically committed by RTC or RTD that have 10-minute start-up times that are not synchronized and producing Energy within 20 minutes after their scheduled start time, and (3) Generators that are economically committed by RTC that have greater than 10-minute start-up times that are

not synchronized and producing Energy within 45 minutes after their scheduled start time;

(ii) if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time commitment that did not result from a Day-Ahead commitment, the Generator's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be the Start-Up Bid submitted in response to the SRE request (subject to mitigation, where appropriate);

(iii) if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time schedule that resulted from a Day-Ahead commitment, then the Generator's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be set to zero;

(iv) the real-time Start-Up Bid for Generator g for hour j or, when applicable, the mitigated real-time Start-Up Bid, for Generator g for hour j , may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled and operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g 's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator g 's Day-Ahead or SRE schedule; and

(v) if Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* Generator g shall have its Start-Up Bid set to zero for purposes of calculating a Real-Time Bid Production Cost guarantee.

$NSUI_{gj}^{RT}$ = number of times Generator g started up in hour j ;

$NSUI_{gj}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in hour j ;

$LBMP_{gi}^{RT}$ = Real-Time LBMP at Generator g 's bus in RTD interval i expressed in terms of \$/MWh;

M = the set of eligible RTD intervals in the Dispatch Day consisting of all of the RTD intervals in the Dispatch Day except:

(i) Supplemental Event Intervals (which are addressed separately in Section 18.5 below);

(ii) intervals during authorized Start-Up Periods, Shutdown Periods, or Testing Periods for Generator g;

L = the set of all hours in the Dispatch Day

EI_{gi}^{RT} = either, as the case may be:

(i) if $EOP_{ig} > AEI_{ig}$ then $\min(\max(AEI_{ig}, RTSen_{ig}), EOP_{ig})$; or

(ii) if otherwise, then $\max(\min(AEI_{ig}, RTSen_{ig}), EOP_{ig})$.

EI_{gi}^{DA} = Energy scheduled in the Day-Ahead Market to be produced by Generator g in the hour that includes RTD interval i expressed in terms of MW;

$RTSen_{ig}$ = Real-time Energy scheduled for Generator g in interval i, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Generator g during the course of interval i expressed in terms of MW;

AEI_{ig} = average Actual Energy Injection by Generator g in interval i but not more than $RTSen_{ig}$ plus any Compensable Overgeneration expressed in terms of MW;

EOP_{ig} = the Economic Operating Point of Generator g in interval i expressed in terms of MW;

$NASR_{gi}^{TOT}$ = Net Ancillary Services revenue, expressed in terms of \$, paid to Generator g as a result of either having been committed Day-Ahead to operate in the hour that includes RTD interval i or having operated in interval i which is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that RTD interval, if it is not a Supplier of Installed Capacity; (2) Regulation Service payments that would be made to that Generator for that hour based on a Performance Index of 1, less the Regulation Capacity and Regulation Movement Bids placed by that Generator to provide Regulation Service in that hour at the time it was committed to produce Energy for the LBMP Market and/or Ancillary Services to do so; (3) payments made to that Generator for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by that Generator to provide such reserves in that hour at the time it was scheduled to do so; and (4) Lost Opportunity Cost payments made to that Generator in that hour as a result of reducing that Generator's output in order for it to provide Voltage Support Service.

$NASR_{gi}^{DA}$	=	The proportion of the Day-Ahead net Ancillary Services revenue, expressed in terms of \$, that is applicable to interval i calculated by multiplying the $NASR_{gh}^{DA}$ for the hour that includes interval i by $s_i/3600$.
$RRAP_{gi}$	=	Regulation Revenue Adjustment Payment for Generator g in RTD interval i expressed in terms of \$.
$RRAC_{gi}$	=	Regulation Revenue Adjustment Charge for Generator g in RTD interval i expressed in terms of \$.

18.4.3 Bids Used For Intervals at the End of the Hour

For RTD intervals in an hour that start 55 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour in accordance with ISO Procedures. For RTD-CAM intervals in an hour that start 50 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour, in accordance with ISO Procedures.

18.5 BPCG For Generators In Supplemental Event Intervals

18.5.1 Eligibility for BPCG for Generators in Supplemental Event Intervals

18.5.1.1 Eligibility

For intervals in which the ISO has called a large event reserve pick-up, as described in Section 4.4.4.1.1 of this ISO Services Tariff, or an emergency under Section 4.4.4.1.2 of this ISO Services Tariff, any Supplier who meets the eligibility requirements for a real-time Bid Production Cost guarantee payment described in subsection 18.4.1.1 of this Attachment C, shall be eligible to receive a BPCG under this Section 18.5.

18.5.1.2 Non-Eligibility

Notwithstanding subsection 18.5.1.1, a Supplier shall not be eligible to receive a Bid Production Cost guarantee payment for Supplemental Event Intervals if the Supplier is not eligible for a real-time Bid Production Cost guarantee payment for the reasons described in Section 18.4.1.2 of this Attachment C.

18.5.1.3 Additional Eligibility

Notwithstanding Section 18.5.1.2, a Supplier shall be eligible to receive a Bid Production Cost guarantee payment for a Generator producing energy during Supplemental Event Intervals occurring as a result of an ISO emergency under Section 4.4.4.1.2 of this ISO Services Tariff regardless of bid mode used for the day.

18.5.2 Formula for Determining BPCG for Generators in Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee Payment for Generator g =

$$\sum_{i \in P} \left(\max \left(\begin{aligned} & \int_{\max(EI_{gi}^{DA}, MGI_{gi}^{RT})}^{\max(EI_{gi}^{RT}, MGI_{gi}^{RT})} C_{gi}^{RT} + MGC_{gi}^{RT} \cdot (MGI_{gi}^{RT} - MGI_{gi}^{DA}) \\ & - LBMP_{gi}^{RT} \cdot (EI_{gi}^{RT} - EI_{gi}^{DA}) \\ & - (NASR_{gi}^{TOT} - NASR_{gi}^{DA}) - RRAP_{gi} + RRAC_{gi} \end{aligned} \right) \cdot \frac{s_i}{3600}, 0 \right)$$

where:

P = the set of Supplemental Event Intervals in the Dispatch Day but excluding any intervals in which there are maximum generation pickups or large event reserve pickups where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA} ; and

EI_{gi}^{RT} = (i) for any intervals in which there are maximum generation pickups, and the three intervals following, for Generators in the location for which the maximum generation pickup has been called -- the average Actual Energy Injections, expressed in MWh, for Generator g in interval i , and for all other Generators EI_{gi}^{RT} is as defined in Section 18.4.2 above.

(ii) for any intervals in which there are large event reserve pickups and the three intervals following, EI_{gi}^{RT} is as defined in Section 18.4.2 above.

C_{gi}^{RT} = Bid cost submitted by Generator g , or when applicable the mitigated Bid cost for Generator g , in the RTD for the hour that includes RTD interval i expressed in terms of \$/MWh, except in hours in which the NYISO has increased Generator g 's minimum operating level, either (i) at the Generator's request, or (ii) in order to reconcile the ISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

The definition of all other variables is identical to those defined in Section 18.4 above.

In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 15.3.8 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

18.6 Real-Time BPCG For Imports

18.6.1 Eligibility for Receiving Real-Time BPCG for Imports

18.6.1.1 Eligibility.

A Supplier that bids an Import that is committed by the ISO in the Real-Time Market shall be eligible to receive a real-time Bid Production Cost guarantee payment for all intervals.

18.6.1.2 Non-Eligibility.

Notwithstanding Section 18.6.1.1:

18.6.1.2.1 Customers that schedule hourly Import Transactions at either Variably Scheduled Proxy Generator Buses or Dynamically Scheduled Proxy Generator Buses will not be eligible for Real-Time Bid Production Cost Guarantee payments for those Transactions for the day;

18.6.1.2.2 when a Non-Competitive Proxy Generator Bus or the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located is export constrained due to limits on available Interface Capacity or Ramp Capacity limits for that Interface in an hour, Customers scheduling an Import at such Non-Competitive Proxy Generator Bus in that hour shall not be eligible for a real-time Bid Production Cost Guarantee payment for this Transaction;

18.6.1.2.3 when a Proxy Generator Bus that is associated with a designated Scheduled Line is export constrained due to limits on available Interface Capacity in an hour, Customers scheduling an Import at such Proxy Generator Bus in that hour will not be eligible for a real-time Bid Production Cost guarantee payment for this Transaction;

18.6.1.2.4 when the Rolling RTC is export constrained due to limits on NYCA Ramp

Capacity in an hour, Customers scheduling Imports at Proxy Generator Buses associated with designated Scheduled Lines and Non-Competitive Proxy Generator Buses in that hour will not be eligible for Bid Production Cost Guarantee payments for those Transactions, and

18.6.1.2.5 Customers that schedule Import Transactions at CTS Enabled Proxy Generator Buses will not be eligible for Bid Production Cost Guarantee payments for those Transactions.

18.6.2 BPCG Calculated by Transaction ID

For purposes of calculating a real-time Bid Production Cost guarantee payment for an Import under this Section 18.6, the ISO shall treat the Import as being from a single Resource for all hours of the Dispatch 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 Dispatch Day in which a different Transaction ID is used.

18.6.3 Formula for Determining Real-Time BPCG for Imports

Real-Time Bid Production Cost Guarantee for Import t by a Supplier =

$$\text{Max} \left(\sum_{i=1}^Q \left[(\text{DecBid}_{ti}^{\text{RT}} - \text{LBMP}_{ti}^{\text{RT}}) \cdot \max(\text{SchImport}_{ti}^{\text{RT}} - \text{SchImport}_{ti}^{\text{DA}}, 0) \cdot S_i / 3600 \right], 0 \right)$$

Where:

Q = number of intervals in the Dispatch Day;

$\text{DecBid}_{ti}^{\text{RT}}$ = Decremental Bid, in \$/MWh, supplied for Import t for interval i;

$\text{LBMP}_{ti}^{\text{RT}}$ = real-time LBMP, in \$/MWh, for interval i at Proxy Generator Bus-p which is the source of the Import t;

$SchImport_{ti}^{RT}$ = total real-time schedule, in MW, for Import t in interval i; and

$SchImport_{ti}^{DA}$ = total Day-Ahead schedule, in MW, for Import t in hour that contains interval i.

S_i = number of seconds in RTD interval i.

18.7. BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their dispatch

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

A Supplier that bids on behalf of a long start-up time Generator (i.e., a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) that is committed by the ISO for reliability purposes as a result of a Supplemental Resource Evaluation and whose start is aborted by the ISO prior to its dispatch, as described in Section 4.2.5 of the ISO Services Tariff, shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.7.

18.7.2 Methodology for Determining BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their Dispatch

A Supplier whose long start-up time Generator's start-up is aborted shall receive a prorated portion of its Start-Up Bid submitted for the hour in which the ISO requested that the Generator begin its start-up sequence, based on the portion of the start-up sequence that it has completed prior to the signal to abort the start-up (*e.g.*, if a long start-up time Generator with a seventy-two (72) hour start-up time has its start-up sequence aborted after forty-eight (48) hours, it would receive two-thirds ($2/3$) of its Start-Up Bid).

18.8 BPCG For Demand Reduction In The Day-Ahead Market

18.8.1 Eligibility for BPCG for Demand Reduction in the Day-Ahead Market

A Demand Reduction Provider that bids a Demand Side Resource that is committed by the ISO in the Day-Ahead Market to provide Demand Reduction shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.8.

18.8.2 Formula for Determining BPCG for Demand Reduction in the Day-Ahead Market

Day-Ahead BPCG for Demand Reduction Provider d =

$$\text{Max} \left[\sum_{h=1}^N (\text{MinCurCost}_d^h + \text{IncrCurCost}_d^h - \text{CurRev}_d^h) + \text{CurInitCost}_d, 0 \right]$$

where:

$$\text{CurInitCost}_d = \left(\sum_{h=1}^N (\text{Min}(\text{ActCur}_d^h, \text{SchdCur}_d^h)) / \left(\sum_{h=1}^N \text{SchdCur}_d^h \right) \right) * \text{CurCost}_d$$

$$\text{MinCurCost}_d^h = \text{Min} [(\text{max}(\text{ActCur}_d^h, 0), \text{MinCur}_d^h)] * \text{MinCurBid}_d^h$$

$$\text{IncrCurCost}_d^h = \int_{\text{MinCur}_d^h}^{\text{max}(\text{MinCur}_d^h, \text{min}(\text{SchdCur}_d^h, \text{ActCur}_d^h))} \text{IncrCurBid}_d^h$$

$$\text{CurRev}_d^h = \text{LBMP}_{dh}^{\text{DA}} * \text{min}(\text{max}(\text{ActCur}_d^h, 0), \text{SchdCur}_d^h)$$

N = number of hours in the Day-Ahead Market day.

CurInitCost_d = daily Curtailment Initiation Cost credit for Day-Ahead Demand Reduction Provider d;

MinCurCost_d^h	=	minimum Curtailment cost credit for Day-Ahead Demand Reduction Provider d in hour h;
IncrCurCost_d^h	=	incremental Curtailment cost credit for Day-Ahead Demand Reduction Provider d for hour h;
CurCost_d	=	total bid Curtailment Initiation Costs for Day-Ahead Demand Reduction Provider d for the day;
CurRev_d^h	=	actual revenue for Day-Ahead Demand Reduction Provider d in hour h;
ActCur_d^h	=	actual Energy curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;
SchdCur_d^h	=	Energy scheduled Day-Ahead to be curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;
MinCurBid_d^h	=	minimum Curtailment initiation Bid submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of \$/MWh;
IncrCurBid_d^h	=	Bid cost submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of \$/MWh;
MinCur_d^h	=	Energy scheduled Day-Ahead to be produced by the minimum Curtailment segment of Day-Ahead Demand Reduction Provider d for hour h expressed in terms of MWh; and
$\text{LBMP}_{dh}^{\text{DA}}$	=	Day-Ahead LBMP for Day-Ahead Demand Reduction Provider d for hour h expressed in \$/MWh.

18.9 BPCG For Special Case Resources

18.9.1 Eligibility for Special Case Resources BPCG

Any Supplier that bids a Special Case Resource that is committed by the ISO for an event in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.9. Suppliers shall not be eligible for a Special Case Resource Bid Production Cost guarantee payment for the period over which a Special Case Resource is performing a test.

18.9.2 Methodology for Determining Special Case Resources BPCG

A Special Case Resource Bid Production Cost guarantee payment shall be made when the Minimum Payment Nomination for any Special Case Resource committed by the ISO over the period of requested performance or four (4) hours, whichever is greater, exceeds the LBMP revenue received for performance by that Special Case Resource; provided, however, that the ISO shall set to zero the Minimum Payment Nomination for Special Case Resource Capacity in each interval in which such capacity was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy.

18.10 BPCG For Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service In The Day-Ahead Market

18.10.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service in the Day-Ahead Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.10.

18.10.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Day-Ahead Market

A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves and/or Regulation Service schedule in the Day-Ahead Market shall be calculated as follows:

BPCG for Demand Side Resource d Providing synchronized Operating Reserves and/or Regulation Service Day-Ahead =

$$\max \left[\left(- \sum_{h=1}^N NASR_{dh}^{DA} \right), 0 \right]$$

where:

N = number of hours in the Day-Ahead Market day.

$NASR_{dh}^{DA}$ = Net Ancillary Services revenue, in \$, paid to Demand Side Resource d as a result of having been committed to provide Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Regulation Service payments made to that Demand Side Resource for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less Demand Side Resource d's Day-Ahead Regulation Capacity Bid to provide that amount of Regulation Service in that hour; and (2) payments made to Demand Side Resource d for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less Demand Side Resource d's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.11 BPCG For Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service In The Real-Time Market

18.11.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Real-Time Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves and/or Regulation Service in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.11.

18.11.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves and / or Regulation Service in the Real-Time Market

A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves and/or Regulation Service schedule in the real-time Market shall be calculated as follows:

BPCG for Demand Side Resource d Providing synchronized Operating Reserves and/or Regulation Service in Real-Time =

$$\max \left[- \sum_{i \in L} \langle NASR_{di}^{TOT} - NASR_{di}^{DA} \rangle, 0 \right]$$

where:

L = set of RTD intervals in the Dispatch Day;

$NASR_{di}^{TOT}$ = Net Ancillary Services revenue, in \$, paid to Demand Side Resource d as a result of either having been scheduled Day-Ahead in the hour that includes RTD interval i or having been scheduled in real-time interval i which is computed by summing the following: (1) Regulation Service payments that would be made to Demand Side Resource d for that hour based on a Performance Index of 1, less the Regulation Capacity and Regulation Movement Bids placed by Demand Side Resource d to provide Regulation Service in that hour at the time it was committed to provide Ancillary Services; and (2) payments made to Demand Side Resource d for providing Spinning Reserve or synchronized 30-Minute Reserve in that

hour, less the Bid placed by Demand Side Resource d to provide such reserves in that hour at the time it was scheduled to do so; and

$NASR_{di}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, in \$, that is applicable to interval i calculated by multiplying the $NASR_{dh}^{DA}$ for the hour that includes interval i by the quotient of the number of seconds in RTD interval i divided by 3600.

18.12 Proration Of Start-Up Bid For Generators That Are Committed In The Day-Ahead Market, Or Via Supplemental Resource Evaluation

18.12.1 Eligibility to Recover Operating Costs and Resulting Obligations

Generators committed in the Day-Ahead Market or via SRE that are not able to complete their minimum run time within the Dispatch Day in which they are committed are eligible to include in their Start-Up Bid expected net costs of operating on the day following the dispatch day at the minimum operating level specified for the hour in which the Generator is committed, for the hours necessary to complete the Generator's minimum run time.

Generators that receive Day-Ahead or SRE schedules that are not scheduled to operate in real-time, or that do not operate in real-time, at the MW level included in the Minimum Generation Bid for the first hour of the Generator's Day-Ahead or SRE schedule, for the longer of (a) the duration of the Generator's Day-Ahead or SRE schedule, or (b) the minimum run time specified in the Bid that was accepted for the first hour of the Generator's Day-Ahead or SRE schedule, will have the start-up cost component of the Bid Production Cost guarantee calculation prorated in accordance with the formula specified in Section 18.12.2, below. The rules for prorating the start-up cost component of the Bid Production Cost guarantee calculation apply both to operation within the Dispatch Day and to operation on the day following the Dispatch Day to satisfy the minimum run time specified for the hour in which the Generator was scheduled to start-up on the Dispatch Day.

Rules for calculating the reference level that the NYISO uses to test Start-Up Bids for possible mitigation are included in the Market Power Mitigation Measures that are set forth in Attachment H to the ISO Services Tariff. Proration of the start-up cost component of a Generator's Bid Production Cost guarantee based on the Generator's operation in real-time is different/distinct from the mitigation of a Start-Up Bid.

18.12.2 Proration of Eligible Start-Up Cost when a Generator Is Not Scheduled, or Does Not Operate to Meet the Schedule Specified in the Accepted Day-Ahead or SRE Start-Up Bid.

The start-up costs included in the Bid Production Cost guarantee calculation may be reduced *pro rata* based on a comparison of the actual MWs delivered in real-time to an hourly minimum MW requirement. The hourly MWh requirement is determined based on the MW component of the Minimum Generation Bid submitted for the Generator's accepted start hour (as mitigated, where appropriate).

18.12.2.1 Total Energy Required to be Provided in Order to Avoid Proration of a Generator's Start-Up Costs

$$\text{TotMWReq}_{g,s} = \text{MinOpMW}_{g,s} * n_{g,s},$$

Where:

$\text{TotMWReq}_{g,s}$ = Total amount of Energy that Generator g, when started in hour s, must provide for its start-up costs not to be prorated

$\text{MinOpMW}_{g,s}$ = 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:

$$n_{g,s} = \max(\text{LastHrDASched}_{g,s}, \text{LastMinRunHr}_{g,s})$$

Where:

$\text{LastHrDASched}_{g,s}$ = 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

$\text{LastMinRunHr}_{g,s}$ = The last date/hour in a contiguous set of hours in which Generator g would need to operate to complete its minimum run time if it starts in hour s

18.12.2.2 Calculation of Prorated Start-Up Cost

$$ProratedSUC_{g,s} = SubmittedSUC_{g,s} \cdot \frac{\sum_{h=s}^{n_{g,s}} MinOpEnergy_{g,h,s}}{TotalMWReq_{g,s}},$$

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:

$$MinOpEnergy_{g,h,s} = \min(MetActEnergy_{g,h}, MinOpMW_{g,s}),$$

Where:

$MetActEnergy_{g,h}$ = the metered amount of Energy produced by Generator g during hour h

18.12.2.3 Additional Rules/Clarifications that Apply to the Calculation of Prorated Start-Up Cost

- a. For any hour that a Generator is derated below the minimum operating level specified in its accepted Start-Up Bid for reliability, either by the ISO or at the request of a Transmission Owner, the Generator will receive credit for that hour as if the Generator had produced metered actual MWh equal to its $MinOpMW_{g,s}$.
- b. A Generator must be scheduled and operate in real-time to produce Energy consistent with the $MinOpMW_{g,s}$ specified in the accepted Start-Up Bid for each hour that it is expected to run. *See* Section 18.12.2.1, above. These rules do not specify or require any particular bidding construct that must be used to achieve the desired commitment.

However, submitting a self-committed Bid may preclude a Generator from receiving a BPCG. *See, e.g.,* Sections 18.2.1.2.2 and 18.4.1.2.3 of this Attachment C.

21 Attachment F - Bid Restrictions

21.1 Definitions

Except as noted below, all capitalized terms used in Attachment F shall have the meanings specified in Article 2 of the ISO Services Tariff, or in Section 1 of the ISO OATT. In addition, the following terms, which are not defined in the ISO Tariffs, shall have the meanings specified below.

“Bid Restriction” shall mean the maximum or minimum Bid Price that may be submitted in connection with certain Bids, as specified in Section 21.5 of this Attachment F.

“Emergency External Purchases” shall mean the purchase, by the ISO, of Capability or Energy from External Suppliers for the purpose of eliminating an Operating Reserve deficiency, as described in the ISO Procedures.

“Price Cap Load Bid” a Bid identifying the maximum price above which an Internal Load is not willing to be scheduled in the Day-Ahead Market.

21.2 Supremacy of Attachment F

During the period that this Attachment F is in effect, the provisions set forth herein shall be deemed incorporated by reference into every provision of the ISO Services Tariff affected by this Attachment F, including each of the ISO Services Tariff's Rate Schedules and Attachments. In the event of a conflict between the terms of this Attachment F and the terms of any other provision of the ISO Services Tariff, the terms of Attachment F shall prevail.

21.3 Effective Date

Attachment F shall become effective on July 25, 2000 for Suppliers submitting Day-Ahead Bids to sell Energy in the July 26, 2000 Day-Ahead Market, and on July 26, 2000 for all other Suppliers and for any Demand Reduction Providers that submit Bids which are subject to Section 21.5 below.

21.4 Establishment of Bid Restrictions

During the period that Attachment F is in effect, the Bid Restriction for all Bids referenced in Section 21.5.1 below shall be \pm \$1,000/MWh. If a Bid exceeds an applicable maximum Bid Restriction or is less than an applicable minimum Bid Restriction, the Bid shall be automatically rejected by the ISO.

21.5 Applicability of Bid Restrictions

21.5.1 The Bid Restriction established in Section 21.4 shall apply to Day-Ahead and real-time Energy Bids, Minimum Generation Bids, Decremental Bids, Price Cap Load Bids, Sink Price Cap Bids and real-time CTS Interface Bids , as applicable. All Suppliers and Demand Side Resources, whether External or Internal to the NYCA, shall be subject to a Bid Restriction for all Bids specified herein.

21.5.2. The Bid Restriction established in Section 21.4 shall not apply to Ancillary Services Bids, Start-Up Bids or to any other Bid that is not specified in Section 21.5.1, provided however a Bid floor of \$0.00 shall apply to Regulation Capacity Bids and Regulation Movement Bids. This Attachment F does not supercede the reference level calculation rule or special mitigation procedures applicable to 10-Minute Non-Synchronized Reserve Bids under Sections 23.3.1.4.4 and 23.5.3 of Attachment H to this ISO Services Tariff.

21.5.3 Bid Restrictions shall not apply to Emergency External Purchases. Bids or Offers made in connection with External Emergency Purchases shall not establish market-clearing prices.

23.3 Criteria for Imposing Mitigation Measures

23.3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 23.2.4 above, which shall be detected through the use of indices and screens developed, adopted and made available as specified in Attachment O. The thresholds listed in Sections 23.3.1.1 to 23.3.1.3 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

23.3.1.1 Thresholds for Identifying Physical Withholding

23.3.1.1.1 The following initial thresholds will be employed by the ISO to identify physical withholding of a Generator or generation by a Market Party and its Affiliates:

23.3.1.1.1.1 Except for conduct addressed in Section 23.3.1.1.1.2: Withholding that exceeds (i) 10 percent of a Generator's capability, or (ii) 100 MW of a Generator's capability, or (iii) 5 percent of the total capability of a Market Party and its Affiliates, or (iv) 200 MW of the total capability of a Market Party and its Affiliates.

For a Generator or a Market Party in a Constrained Area for intervals in which an interface or facility into the area in which the Generator or generation is located has a Shadow Price greater than \$0.04/MWh, indicating an active constraint, withholding that exceeds (i) 10 percent of a Generator's capability, or (ii) 50 MW of a Generator's capability, or (iii) 5 percent of the total capability of a Market Party and its Affiliates, or (iv) 100 MW of the total capability of a Market Party and its Affiliates.

23.3.1.1.1.2 Operating a Generator or generation in real-time at a lower output level than would have been expected had the Market Party's and its Affiliate's Generator or generation followed the ISO's dispatch instructions, resulting in a difference in output that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator, or (iii) 200 MW of the total capability of a Market Party and its Affiliates. For a Generator or a Market Party in a Constrained Area for intervals in which an interface or facility into the area in which the generation is located has a Shadow Price greater than \$0.04/MWh, indicating an active constraint, operating a Generator or generation in real-time at a lower output level than would have been expected had the Market Party's and its Affiliate's Generator or generation followed the ISO's dispatch instructions, resulting in a difference in output that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 50 MW of a Generator's capability, or (iii) 100 MW of the total capability of a Market Party and its Affiliates.

23.3.1.1.2 The amounts of generating capacity considered withheld for purposes of applying the thresholds in this Section 23.3.1.1 shall include unjustified deratings, and the portions of a Generator's output that is not Bid or subject to economic withholding. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance

in accordance with an ISO maintenance schedule, subject to verification by the ISO as may be appropriate that an outage was forced.

23.3.1.1.3 A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes or contributes to transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule.

23.3.1.2 Thresholds for Identifying Economic Withholding

23.3.1.2.1 The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of a Generator in an area that is not a Constrained Area, or in a Constrained Area during periods not subject to transmission constraints affecting the Constrained Area, and shall be determined with respect to a reference level determined as specified in Section 23.3.1.4:

23.3.1.2.1.1 Incremental Energy and Minimum Generation Bids: An increase exceeding 300 percent or \$100 per MWh, whichever is lower; provided, however, that Incremental Energy or Minimum Generation Bids below \$25 per MWh shall be deemed not to constitute economic withholding.

23.3.1.2.1.2 Operating Reserves and Regulation Service Bids:

23.3.1.2.1.2.1 Operating Reserves and Regulation Capacity Bids: A 300 percent increase or an increase of \$50 per MW, whichever is lower; provided, however, that such Bids below \$5 per MW shall be deemed not to constitute economic withholding.

23.3.1.2.1.2.2 Regulation Movement Bids: A 300 percent increase.

23.3.1.2.1.3 Start-Up Bids: A 200 percent increase.

23.3.1.2.1.4 Time-based Bid parameters: An increase of 3 hours, or an increase of 6 hours in total for multiple time-based Bid parameters. Time-based Bid parameters include, but are not limited to, start-up times, minimum run times and minimum down times.

23.3.1.2.1.5 Bid parameters expressed in units other than time or dollars, including the MW component of a Minimum Generation Bid (also referred to as the “minimum operating level”): A 100 percent increase for parameters that are minimum values, or a 50 percent decrease for parameters that are maximum values (including but not limited to ramp rates and maximum stops).

23.3.1.2.2 The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of a Generator in an area that is a Constrained Area, and shall be determined with respect to a reference level determined as specified in Section 23.3.1.4:

23.3.1.2.2.1 For Energy and Minimum Generation Bids for the Real-Time Market: for intervals in which an interface or facility into the area in which a Generator is located has a Shadow Price greater than \$0.04/MWh, indicating an active constraint, the lower of the thresholds specified for areas that are not Constrained Areas or a threshold determined in accordance with the following formula:

$$\text{Threshold} = \frac{2 \% * \text{Average Price} * 8760}{\text{Constrained Hours}}$$

where:

Average Price = the average price in the Real-Time Market in the Constrained Area over the past 12 months, adjusted for fuel price changes, and adjusted for Out-of-Merit Generation dispatch as feasible and appropriate; and

Constrained Hours = the total number of minutes over the prior 12 months, converted to hours (retaining fractions of hours), in which the real-time Shadow Price has been greater than \$0.04/MWh, indicating an active constraint, on any interface or facility leading into the Constrained Area in which the Generator is located. For the In-City area, “Constrained Hours” shall also include the number of minutes that a Storm Watch is in effect. Determination of the number of Constrained Hours shall be subject to adjustment by the ISO to account for significant changes in system conditions.

23.3.1.2.2.2 For so long as the In-City area is a Constrained Area, the thresholds specified in subsection 23.3.1.2.2.1 shall also apply: (a) in intervals in which the transmission capacity serving the In-City area is subject to Storm Watch limitations; (b) to an In-City Generator that is operating as Out-of-Merit Generation; and (c) to a Generator dispatched as a result of a Supplemental Resource Evaluation.

23.3.1.2.2.3 For Energy and Minimum Generation Bids for the Day-Ahead Market: for all Constrained Hours for the Generator being Bid, a threshold determined in accordance with the formula specified in subsection 23.3.1.2.2.1 above, but where Average Price shall mean the average price in the Day-Ahead Market in the Constrained Area over the past twelve months, adjusted for fuel price changes, and where Constrained Hours shall mean the total number of hours over the prior 12 months in which the Shadow Price in the Day-Ahead Market has been greater than \$0.04/MWh, indicating an active constraint, on any interface or facility leading into the Constrained Area in which the Generator is located. Determination of the number of Constrained Hours shall be subject to adjustment by the ISO to account for significant changes in system conditions.

23.3.1.2.2.4 For Start-Up Bids; a 50% increase.

23.3.1.2.2.5 The thresholds listed in Sections 23.3.1.2.1.2 and 23.3.1.2.1.4 through 23.3.1.2.1.5.

23.3.1.2.3 The following thresholds shall be employed by the ISO to identify economic withholding that requires the mitigation of a Generator that is committed outside the ISO's economic evaluation process to protect NYCA or local area reliability in an area that is not a designated Constrained Area. Whether the thresholds specified in Sections 23.3.1.2.3.3(i) through 23.3.1.2.3.3(v) below have been exceeded shall be determined with respect to a reference level determined as specified in Section 23.3.1.4 of these Mitigation Measures.

If provisions 23.3.1.2.3.1 and 23.3.1.2.3.2 below are met for a Generator in the New York Control Area that is not located in a designated Constrained Area, the ISO shall substitute a reference level for each Bid, or component of a Bid, for which the applicable threshold specified in provisions 23.3.1.2.3.3(i) through 23.3.1.2.3.3(vi) below is exceeded. Where mitigation is determined to be appropriate, the mitigated results will be used in all aspects of the NYISO's settlement process.

23.3.1.2.3.1 The Generator was committed outside the ISO's economic merit order selection process to protect or maintain New York Control Area or local system reliability as a Day-Ahead Reliability Unit ("DARU") or via a Supplemental Resource Evaluation ("SRE"), or was committed as a DARU or via SRE and was

also dispatched Out-of-Merit above its minimum generation level to protect or maintain New York Control Area or local system reliability; and

23.3.1.2.3.2 One of the following three (i) – (iii) conditions in this Section 23.3.1.2.3.2 must be satisfied in order for mitigation to be applied:

- i the Market Party (including its Affiliates) that owns or offers the Generator is the only Market Party that could effectively solve the reliability need for which the Generator was committed or dispatched, or
- ii when evaluating an SRE that was issued to address a reliability need that multiple Market Parties' Generators are capable of solving, the NYISO only received Bids from one Market Party (including its Affiliates), or
- iii when evaluating a DARU, if the Market Party was notified of the need for the reliability commitment of its Generator prior to the close of the Day-Ahead Market.

23.3.1.2.3.3 The Bids or Bid components submitted for the Generator that were accepted outside the economic evaluation process to protect or maintain New York Control Area or local system reliability:

- i exceeded the Generator's Minimum Generation Bid reference level by the greater of 10% or \$10/MWh, or
- ii. exceeded the Generator's Incremental Energy Bid reference level by the greater of 10% or \$10/MWh, or
- iii. exceeded the Generator's Start-Up Bid reference level by 10%, or
- iv. exceeded the Generator's minimum run time, start-up time, and minimum down time reference levels by more than one hour in aggregate, or

- v. exceeded the Generator's minimum generation MW reference level by more than 10%, or
- vi. decreased the Generator's maximum number of stops per day below the Generator's reference level by more than one stop per day, or to one stop per day.

23.3.1.3 Thresholds for Identifying Uneconomic Production

23.3.1.3.1 The following threshold will be employed by the ISO to identify uneconomic production that may warrant the imposition of a mitigation measure:

23.3.1.3.1.1 Energy scheduled at an LBMP that is less than 20 percent of the applicable reference level and causes or contributes to transmission congestion; or

23.3.1.3.1.2 Real-time output from a Generator or generation resulting in real-time operation at a higher output level than would have been expected had the Market Party's and the Affiliate's Generator or generation followed the ISO's dispatch instructions, if such failure to follow ISO dispatch instructions in real-time causes or contributes to transmission congestion, and it results in an output difference that exceeds (i) 15 minutes times a Generator's stated response rate per minute at the output level that would have been expected had the Generator followed the ISO's dispatch instructions, or (ii) 100 MW for a Generator, or (iii) 200 MW of the total capability of a Market Party and its Affiliates.

23.3.1.4 Reference Levels

23.3.1.4.1 Except as provided in Sections 23.3.1.4.3 – 23.3.1.4.6 below, a reference level for each component of a Generator's Bid shall be calculated on the basis of the following methods, listed in the order of preference subject to the existence of sufficient data:

23.3.1.4.1.1 The lower of the mean or the median of a Generator's accepted Bids or Bid components, in hour beginning 6 to hour beginning 21 but excluding weekend and designated holiday hours, in competitive periods over the most recent 90 day period for which the necessary input data are available to the ISO's reference level calculation systems, adjusted for changes in fuel prices consistent with Section 23.3.1.4.7, below. To maintain appropriate reference levels (i) the ISO shall exclude all Incremental Energy and Minimum Generation Bids below \$15/MWh from its development of Bid-based reference levels, (ii) the ISO shall exclude Minimum Generation Bids submitted for a Generator that was committed on the day prior to the Dispatch Day for the hours during the Dispatch Day that the Generator needs to operate in order to complete the minimum run time specified in the Bid it submitted for the hour in which it was committed, and (iii) the ISO may exclude other Bids that would cause a reference level to deviate substantially from a Generator's marginal cost when developing Bid-based reference levels;

23.3.1.4.1.2 Calculate incremental energy and minimum generation reference levels for a Generator using the mean of the LBMP at the Generator's location during the lowest-priced 50 percent of the hours that the Generator was dispatched over the most recent 90 day period for which the necessary LBMP data are available to the ISO's reference level calculation systems, adjusted for changes in fuel prices consistent with Section 23.3.1.4.7, below. To maintain appropriate reference levels (i) the ISO shall exclude all LBMPs below \$15/MWh from its development of LBMP-based reference levels, (ii) the ISO shall exclude LBMPs during hours

when a Generator was scheduled as a Day-Ahead Reliability Unit or via a Supplemental Resource Evaluation or was Out-of-Merit Generation, from its development of that Generator's LBMP-based reference levels, (iii) for a Generator that was committed on the day prior to the Dispatch Day, the ISO shall exclude LBMPs for the hours during the Dispatch Day that the Generator needs to operate in order to complete the minimum run time specified in the Bid it submitted for the hour in which the Generator was committed from the ISO's development of that Generator's LBMP-based reference levels, and (iv) the ISO may exclude LBMPs that would cause a reference level to deviate substantially below a Generator's marginal cost when developing LBMP-based reference levels; or

23.3.1.4.1.3 A level determined in consultation with the Market Party submitting the Bid or Bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Party has provided data on a Generator's operating costs in accordance with specifications provided by the ISO.

The reference level for a Generator's Energy and Ancillary Service Bids are intended to reflect the Generator's marginal costs. The ISO's determination of a Generator's Energy marginal costs shall include an assessment of the Generator's incremental operating costs in accordance with the following formula:

$$((\text{heat rate} * \text{fuel costs}) + (\text{emissions rate} * \text{emissions allowance price}) + \text{other variable operating and maintenance costs}).$$

Reference levels shall also include such other factors or adjustments as the ISO shall reasonably determine to be appropriate based on such data as may be furnished by the Market Party or otherwise available to the ISO.

23.3.1.4.2 If sufficient data do not exist to calculate a reference level on the basis of either of the first two methods, or if the ISO determines that none of the three methods are applicable to a particular type of Bid component, or an attempt to determine a reference level in consultation with a Market Party has not been successful, or if the reference level produced does not reasonably approximate a Generator's marginal cost, the ISO shall determine a reference level on the basis of:

23.3.1.4.2.1 the ISO's estimate of the costs or physical parameters of an Electric Facility, taking into account available operating costs data, appropriate input from the Market Party, and the best information available to the ISO; or

23.3.1.4.2.2 an appropriate average of competitive bids of one or more similar Electric Facilities.

23.3.1.4.3 Notwithstanding the foregoing provisions, the reference level for Incremental Energy Bids for New Capacity for the three year and six month period following the New Capacity's first production of Energy while synchronously interconnected to the New York State Transmission System shall be the higher of (i) the amount determined in accordance with the provision of Section 23.3.1.4.1 or 23.3.1.4.2, or (ii) the average of the fuel price-adjusted peak LBMPs over the twelve months prior to the New Capacity's first production of Energy while synchronously interconnected to the New York State Transmission

System of the New Capacity in the Load Zone in which the New Capacity is located during hours when Generators with operating characteristics similar to the New Capacity would be expected to run. For entities owning or otherwise controlling the output of capacity in the New York Control Area other than New Capacity, the provisions of this Section 23.3.1.4.3 shall apply only to net additions of capacity during the applicable three year and six month period.

23.3.1.4.4 Notwithstanding the foregoing provisions, a reference level for a Generator's start-up costs Bid shall be calculated on the basis of the following methods, listed in the order of preference subject to the existence of sufficient data:

23.3.1.4.4.1 If sufficient bidding histories under the applicable bidding rules for a given Generator's start-up costs Bids have been accumulated, the lower of the mean or the median of the Generator's accepted start-up costs Bids in competitive periods over the previous 90 days for similar down times, adjusted for changes in fuel prices consistent with Section 23.3.1.4.7 below. However, accepted Start-Up Bids that incorporate anticipated costs of operating on the day after the Dispatch Day in which the Generator is committed in order to permit the Generator to satisfy its minimum run time shall not be used to develop Bid-based start-up reference levels;

23.3.1.4.4.2 A level determined in consultation with the Market Party submitting the Bid or Bids at issue and intended to reflect the costs incurred for a Generator to achieve its specified minimum operating level from an offline state, provided such consultation has occurred prior to the occurrence of the conduct being examined

by the ISO, and provided the Market Party has provided data on the Generator's operating costs in accordance with specifications provided by the ISO; or

23.3.1.4.4.3 Generators committed in the Day-Ahead Market or via Supplemental Resource Evaluation that are not able to complete their minimum run time within the Dispatch Day in which they are committed are eligible to include in their Start-Up Bid expected net costs of operating on the day following the dispatch day at the minimum operating level (in MW) specified in the Generator's Bid for the commitment hour, for the hours necessary to complete the Generator's minimum run time. The NYISO will calculate a start-up reference level that incorporates the net costs the Generator is expected to incur on the day following the Dispatch Day as follows:

23.3.1.4.4.3.1 Calculation of a start-up reference level that includes expected net costs of operating on the day following the Dispatch Day

The NYISO will use the following calculation to develop a reference level that incorporates the costs that a Generator is expected to incur on the day following the Dispatch Day.

$$LateDayAdjusted_{g,i} = StrtUpRef_g + \max\left(0, MinGenRef_{g,i} \cdot BidMinGen_{g,i} \cdot \sum_{h=0}^{Z_{g,i}-1} SR_{g,h,i}\right),$$

Where:

LateDayAdjusted_{g,i} = calculated start-up reference level for Generator g for hour i in \$ (reflects the applicable start-up reference level (StrtUpRef_g), plus the expected net cost of operating on the day following the Dispatch Day)

StrtUpRef_g = the start-up reference level for Generator g in \$ that is in effect at the time the calculation is performed (does not include the expected net cost of operating on the day following the Dispatch Day)

MinGenRef_{g,i} = the minimum generation cost reference level for Generator g for hour i in \$/MW that is in effect at the time the calculation is performed

$BidMinGen_{g,i}$ = Generator g 's Day-Ahead minimum operating level for hour i , in MW

$Z_{g,i}$ = the number of hours the Generator must operate during the day following the Dispatch Day in order to complete its minimum run time if it starts in hour i

$SR_{g,h,i}$ = shortfall ratio for Generator g that is bidding to start in hour i which must run during hour h in order to complete its minimum run time, calculated in accordance with Section 23.3.3.4.4.3.2, below

23.3.1.4.4.3.2 Calculation of the shortfall ratio for use in Section 23.3.1.4.4.3.1, above

$SR_{g,h,i}$ = the shortfall ratio calculated for Generator g that is bidding to start in hour i , and that must run during hour h to complete its minimum run time.

In all cases in which Generator g 's Day-Ahead minimum operating level deviates from the average of the previous seven days' Day-Ahead minimum operating levels for the same hour by less than 5 MW (*i.e.*, if $|AvgBidMinGen_{g,h,i} - BidMinGen_{g,i}| < 5$ MW) or by less than 10% (*i.e.*, if both $BidMinGen_{g,i} < 1.1 \times AvgBidMinGen_{g,h,i}$ and $BidMinGen_{g,i} > 0.9 \times AvgBidMinGen_{g,h,i}$),

Where:

$AvgBidMinGen_{g,h,i}$ = The average minimum operating level submitted in the Day-Ahead Market for hour h on the seven days preceding the day containing hour i , in MW, excluding any days for which a minimum operating level was not submitted in the Day-Ahead Market for Generator g , for hour h ; and

$BidMinGen_{g,i}$ = The minimum operating level submitted in the Day-Ahead Market for Generator g for hour i , in MW

and in all cases in which $AvgBidMinGen_{g,h,i}$ cannot be calculated because minimum operating levels were not submitted for Generator g in the Day-Ahead Market for hour h on any of the seven days preceding the day containing hour i , the $SR_{g,h,i}$ value will be calculated using the primary method. Otherwise, the $SR_{g,h,i}$ value will be calculated using the alternative method.

Primary Method of Calculating the Shortfall Ratio

$$SR_{g,h,i} = 1 - \frac{1}{7} \cdot \sum_{d=1}^7 \frac{LBMP_{g,h,i,d}}{MinGenRef_{g,h,i,d}},$$

Where:

$LBMP_{g,h,i,d}$ = Day ahead LBMP at the location of Generator g in hour h of the Day-Ahead Market for the Dispatch Day that precedes the day containing hour i by d days, and

$MinGenRef_{g,h,i,d}$ = minimum generation cost reference level for Generator g in hour h of the Day-Ahead Market for the Dispatch Day that precedes the day containing hour i by d days

Alternative Method of Calculating the Shortfall Ratio

$$SR_{g,h,i} = 1 - \frac{AvgLBMP_{g,h,i}}{\left(AvgRefRate_{g,h,i} \cdot \frac{RefRate2_{g,i}}{RefRate1_{g,h,i}} \right)}$$

Where:

$AvgLBMP_{g,h,i}$ = The average of the Day-Ahead LBMPs at the location of Generator g for hour h on the seven days preceding the day containing hour i, in \$/MWh, excluding any days for which a minimum operating level was not submitted in the Day-Ahead Market for Generator g for hour h

$AvgRefRate_{g,h,i}$ = The average of the minimum generation reference levels for Generator g in hour h on the seven days preceding the day containing hour i, in \$/MWh, excluding any days for which a minimum operating level was not submitted in the Day-Ahead Market for Generator g for hour h

$RefRate1_{g,h,i}$ = The minimum generation cost reference level in \$/MWh for Generator g for hour i, calculated using the most current reference data, and assuming that the minimum operating level submitted in the Day-Ahead Market for Generator g in hour i corresponds to the MWs reflected in the $AvgBidMinGen_{g,h,i}$

$RefRate2_{g,i}$ = The minimum generation cost reference level in \$/MWh for Generator g for hour i, calculated using the most current reference data, and incorporating the minimum operating level submitted in the Day-Ahead Market for Generator g in hour i that corresponds to the MWs reflected in the $BidMinGen_{g,i}$

Notwithstanding the above, in all cases where the denominator of the equation for calculating $SR_{g,h,i}$ is not greater than zero, $SR_{g,h,i}$ shall be set to zero, under both the primary and alternative methods.

23.3.1.4.4.4 The methods specified in Section 23.3.1.4.2.

23.3.1.4.5 Notwithstanding the foregoing provisions, the reference level for 10-Minute Non-Synchronized reserves shall be the lower of (i) the amount determined in accordance with the provisions of Section 23.3.1.4.1.1, or (ii) \$5.00 per MW.

Within seven months of the date the \$5.00 per MW reference level maximum, referred to in the first paragraph of this Section, becomes effective, the Market Monitoring Unit shall independently evaluate the competitiveness of the 10-Minute Non-Synchronized reserves market and issue a recommendation to the ISO to either maintain the \$5.00 per MW reference level maximum, lower the \$5.00 per MW reference level maximum (but not lower than \$2.52 per MW), or raise the \$5.00 per MW reference level maximum to \$10.00 per MW. The Market Monitoring Unit shall present its recommendation to Market Participants for comment. The scope of the Market Monitoring Unit's evaluation shall include, but not be limited to, an analysis of: (i) the competitiveness of the 10-Minute Non-Synchronized reserves market and whether there is conduct that the ISO or the Market Monitoring Unit determine constitutes an abuse of market power; and (ii) how an adjustment to the reference level maximum is expected to impact the convergence of day-ahead and real-time 10-Minute Non-Synchronized reserves prices. The ISO will duly consider and, absent any material change in circumstances, implement the Market Monitoring Unit's recommendation in accordance with the schedule below. The ISO shall undertake best efforts to notice its Market Participants of its decision within two weeks after the Market Monitoring Unit presents its recommendation to Market Participants, but in no

event later than one month. The ISO shall also provide contemporaneous notice of its decision to the FERC which, if such notice is to revise the reference level maximum, shall be accompanied by an appropriately revised Section 23.3.1.4.5. The ISO shall provide such notices at least two weeks in advance of the implementation of any revision to the \$5.00 reference level maximum.

Within six months of the date of the Market Monitoring Unit's last recommendation, the Market Monitoring Unit shall again evaluate the competitiveness of the 10-Minute Non-Synchronized reserves market and issue a recommendation to the ISO to maintain or adjust the reference level maximum, which recommendation shall be presented to Market Participants for comment. The scope of the evaluation shall include, but not be limited to, an analysis of: (i) the competitiveness of the 10-Minute Non-Synchronized reserves market and whether there is conduct that the ISO or the Market Monitoring Unit determine constitutes an abuse of market power; and (ii) how an adjustment to the reference level maximum is expected to impact the convergence of day-ahead and real-time 10-Minute Non-Synchronized reserves prices.

The Market Monitoring Unit may recommend the then-effective reference level maximum be maintained, raised or lowered, or eliminated. The reference level maximum must be set at \$2.52 per MW, or \$5.00 per MW, or \$10.00 per MW, until it is eliminated. The responsibilities of the Market Monitoring Unit that are addressed in this Section of the Mitigation Measures are also addressed in Section 30.4.6.2.12 of Attachment O.

The ISO will duly consider and, absent any material change in circumstances, implement the Market Monitoring Unit's recommendation in accordance with the schedule below. The ISO shall undertake best efforts to notice its Market Participants of its decision within two weeks after the Market Monitoring Unit presents its recommendation to Market Participants, but in no event later than one month. The ISO shall also provide contemporaneous notice of its decision to the FERC which, if such notice is to revise the reference level maximum, shall be accompanied by an appropriately revised Section 23.3.1.4.5. The ISO shall provide such notices at least two weeks in advance of the implementation of any revision to the reference level maximum.

When the Market Monitoring Unit recommends, and the ISO implements, elimination of the reference level maximum, the ISO shall submit a compliance filing to the FERC, at least two weeks in advance of the implementation, that removes Section 23.3.1.4.5 from the Mitigation Measures and includes appropriate accompanying revisions to Section 30.4.6.2.12 of Attachment O.

23.3.1.4.6 The ISO is not required to calculate real-time reference levels for the three Operating Reserve products (Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves) because Generators that are capable of providing these products and that are submitting Bids into the Real-Time Market are automatically assigned a real-time Operating Reserves Availability Bid of zero for the amount of Operating Reserves they are capable of providing. The ISO shall calculate real-time reference levels for Regulation Capacity in accordance with Sections 23.3.1.4.1.1, 23.3.1.4.1.3 or 23.3.1.4.2 of these

Mitigation Measures. The ISO shall calculate real-time reference levels for Regulation Movement in accordance with Sections 23.3.1.4.1.3 or 23.3.1.4.2.1 of these Mitigation Measures and shall not calculate real-time Reference levels for Regulation Movement in accordance with Section 23.3.1.4.1.1.

The ISO shall calculate Day-Ahead reference levels for the three Operating Reserves products in accordance with Sections 23.3.1.4.1.1, 23.3.1.4.1.3 or 23.3.1.4.2 of these Mitigation Measures. The ISO shall calculate Day-Ahead reference levels for Regulation Capacity in accordance with Sections 23.3.1.4.1.1, 23.3.1.4.1.3 or 23.3.1.4.2 of these Mitigation Measures. The ISO shall calculate Day-Ahead reference levels for Regulation Movement in accordance with Sections 23.3.1.4.1.3 or 23.3.1.4.2.1 of these Mitigation Measures and shall not calculate Day-Ahead Reference levels for Regulation Movement in accordance with Section 23.3.1.4.1.1.

23.3.1.4.7 The ISO shall use the best information available to it to adjust reference levels to reflect appropriate fuel costs.

23.3.1.4.7.1 Market Parties shall monitor Generator reference levels and shall endeavor to timely (as that term is defined in Section 23.3.1.4.7.7 below) contact the ISO to request an adjustment to a Generator's reference level(s) when the Generator's fuel type or fuel price change.

23.3.1.4.7.2 Screening of fuel type and fuel price information. The ISO may use automated processes and/or require manual review of fuel type and fuel price information submitted by Market Parties to test the accuracy of the information

submitted in order to prevent market clearing prices and guarantee payments from being incorrectly calculated.

23.3.1.4.7.3 Consistent with the rules specified in this Section 23.3.1.4.7 of the Mitigation Measures and the procedures that the ISO develops to implement these rules, Market Parties shall notify the ISO of changes in fuel type or fuel price by (i) submitting revised fuel type or fuel price information to the ISO's Market Information System along with the Generator's Bid(s), or (ii) by directly contacting the ISO to request a reference level update consistent with ISO procedures, or (iii) by utilizing both of the available notification methods. Revised fuel type or fuel price information that exceeds, or is rejected based upon, the thresholds that the ISO uses to automatically screen fuel type or fuel price information that is submitted to the ISO's Market Information System along with a Generator's Bid(s) shall be submitted by directly contacting the ISO to request a reference level update, consistent with ISO procedures.

23.3.1.4.7.4 Following the completion of the ISO's automated and/or manual screening processes, the ISO shall use fuel type and fuel price information that Market Parties or their representatives submit to develop Generator reference levels unless (i) the information submitted is inaccurate, or (ii) the information was not timely submitted, and the Market Party's failure to timely submit the information is not excused by the ISO in accordance with Section 23.3.1.4.7.7 below, or (iii) consistent with Section 23.3.1.4.7.8 below.

23.3.1.4.7.5 The ISO may not always have sufficient time to complete its screening of proposed fuel type or fuel price changes prior to the relevant Day-Ahead Market

day or Real-Time Market hour. *If* fuel type or fuel price information (i) is timely submitted or, where untimely, the submission of fuel type or fuel price information is excused in accordance with Section 23.3.1.4.7.7 below, and (ii) the fuel type or fuel price information that the Market Party submitted is proven to have been accurate or to have understated the actual cost incurred for that component, and (iii) the Bid(s) were tested using reference levels that reflected outdated fuel type and/or fuel price information and the Bid(s) were mitigated or a sanction was imposed pursuant to Section 23.4.3 of these Mitigation Measures, *then* the ISO shall (a) re-perform any test(s) that resulted in a sanction being imposed pursuant to Section 23.4.3 of these Mitigation Measures, using the accurate fuel type and/or fuel price information and use the revised results to calculate the appropriate sanction (if any), and (b) determine if the Bids for the Generator would have failed the relevant conduct test(s) if accurate fuel type and/or fuel price information had been used to develop reference levels. The ISO shall then restore any original (as-submitted) Bid(s) that would not have failed the relevant conduct test(s) if accurate fuel type and/or fuel price information had been used to develop the Generator's reference levels, and use the restored Bid(s) to determine a settlement. Otherwise the ISO shall use the Generator's correct or corrected reference level(s) to determine a settlement.

23.3.1.4.7.6 The ISO shall publicly post the thresholds it employs to automatically screen fuel type and fuel price information that is submitted to the ISO's Market Information System for potentially inaccurate fuel type and fuel price data inputs.

23.3.1.4.7.7 For purposes of this Section 23.3.1.4.7, “timely” notice or submission to the Real-Time Market shall mean the submission of fuel type and/or fuel price information using the methods specified in Section 23.3.1.4.7.3 of these Mitigation Measures prior to market close for the relevant Real-Time Market hour. For purposes of this Section 23.3.1.4.7, “timely” notice or submission to the Day-Ahead Market shall mean the submission of fuel type and/or fuel price information using the methods specified in Section 23.3.1.4.7.3 of these Mitigation Measures prior to the close of the Day-Ahead Market. Market Parties are not expected to submit invoices or other supporting data with their Day-Ahead Market or Real-Time Market fuel type and fuel price information, but are expected to retain invoices and other supporting data consistent with the data retention requirements set forth in the Plan, and to be able to produce such information within a reasonable timeframe when asked to do so by the ISO or by its Market Monitoring Unit.

It may not always be possible for a Market Party to timely update a Generator’s fuel type or fuel price to reflect unexpected real-time changes or events in advance of the first affected market-hour. Upon a showing of extraordinary circumstances, the ISO may retroactively reflect in Real-Time Market reference levels fuel type or fuel price information that was not timely submitted by a Market Party. While it should ordinarily be possible for a Market Party to timely submit updated fuel type and fuel price information for use in developing a Generator’s Day-Ahead Market reference levels, the ISO may retroactively accept

and utilize late-submitted Day-Ahead Market fuel type or fuel price information upon a showing of extraordinary circumstances.

23.3.1.4.7.8 If (i) the ISO determines, following consultation with the Market Party and review by the Market Monitoring Unit, that the Market Party or its representative has, over a time period of at least one week, submitted inaccurate fuel type or fuel price information that was biased in the Market Party's favor, or (ii) if a Market Party is subject to a penalty or sanction under Section 23.4.3.3.3 of these Mitigation Measures for submitting inaccurate fuel price or fuel type information, *then* the ISO shall cease using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Generator's Bid(s) to develop reference levels for the affected Generator(s) in the relevant (Day-Ahead or real-time) market for the duration(s) set forth below.

23.3.1.4.7.8.1 The first time the ISO ceases using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Bid(s) for a Generator to develop Day-Ahead or real-time reference levels for that Generator, it shall do so for 60 days. The 60 day period shall start two business days after the date that the ISO provides written notice of its determination that the application of mitigation is required.

23.3.1.4.7.8.2 Any subsequent time the ISO ceases using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Bid(s) for a Generator to develop Day-Ahead or real-time reference levels for that Generator, it shall do so for 180 days. The 180 day period shall start two business

days after the date that the ISO provides written notice of its determination that the application of mitigation is required.

23.3.1.4.7.8.3 If the bidders of a Generator that has previously been mitigated under this Section 23.3.1.4.7.8 becomes and remains continuously eligible to submit fuel type and fuel price information in the Day-Ahead or Real-Time Market (as appropriate) for a period of one year or more, then the ISO shall apply the mitigation measure set forth in Section 23.3.1.4.7.8 of the Mitigation Measures as if the Generator had not previously been subject to the mitigation measure.

23.3.1.4.7.8.4 Market Parties that transfer, sell, assign, or grant to another Market Party the right or ability to Bid a Generator that is subject to the mitigation measure described in this Section 23.3.1.4.7.8 are required to inform the new Market Party that the Generator has been mitigated under this measure, and to inform the new Market Party of the expected duration of such mitigation.

23.3.1.4.7.8.5 For purposes of this Section 23.3.1.4.7.8, submitted fuel type information shall be considered biased in a Market Party's favor if (a) the fuel type that a Market Party submits for a Generator is not the most economic fuel type available to the Generator, taking into consideration fuel availability, operating conditions, and relevant regulatory or reliability requirements, and (b) as a result of the change(s) in fuel type, the fuel prices that the ISO uses to develop reference levels for a Generator exceeded the fuel price that the ISO would have used to develop reference levels for that Generator by greater than 10%, on average, over a seven-day period. For purposes of calculating the seven day average, only hours in which the Market Party changed the Generator's fuel type to a more expensive

fuel type will be considered. The Day-Ahead and Real-Time Markets shall be considered separately for purposes of this analysis.

23.3.1.4.7.8.6 For purposes of this Section 23.3.1.4.7.8, submitted fuel price information shall be considered biased in a Market Party's favor if the fuel price that the Market Party submitted to the ISO's Market Information System for use in developing reference levels for a Generator exceeded the greater of the actual fuel price (as substantiated by supplier quotes or invoices) or the ISO's indexed fuel price, by greater than 10%, on average, over a seven-day period. For purposes of calculating the seven-day average, only hours in which the fuel price submitted exceeds the ISO's indexed fuel price will be considered. The Day-Ahead and Real-Time Markets shall be considered separately for purposes of this analysis.

23.3.1.4.7.8.7 The responsibilities of the Market Monitoring Unit that are addressed in Section 23.3.1.4.7.8 of the Mitigation Measures are also addressed in Section 30.4.6.2.3 of the Plan.

23.3.1.4.7.9 In order to adjust (i) Bid-based incremental energy, minimum generation and start-up reference levels, and (ii) LBMP-based incremental energy and minimum generation reference levels to more accurately reflect fuel costs, the ISO may calculate distinct Bid- and LBMP-based reference levels for each fuel type or blend of fuel types that a Generator is capable of burning, and shall fuel index each of the distinct Bid- or LBMP-based reference levels that it calculates for fuel types that are amenable to fuel indexing. Where a Generator can draw on multiple natural gas sources that each have distinct, posted, market clearing

prices, the ISO may calculate distinct Bid-Based or LBMP-based reference levels for each such available supply source.

23.3.1.4.8 Except as otherwise authorized in accordance with Section 23.3.1.4.7.7 above, Market Parties shall timely report significant changes to the cost components used to develop their Generator's reference levels to the ISO in order to permit the revised costs to be timely reflected in the Generator reference levels. However, if the ISO uses published index prices to fuel index a Generator's reference level when that Generator is burning a fuel type that is amenable to fuel indexing (which may include a blend of two indexed fuel types), the Market Party is not required to report fuel prices that are less than the published index price that the ISO relies on.

23.3.2 Material Price Effects or Changes in Guarantee Payments

23.3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Administered Markets, Mitigation Measures shall not be imposed unless conduct identified as specified above (i) causes or contributes to a material change in one or more prices in an ISO Administered Market, or (ii) substantially increases guarantee payments to participants in the New York Electric Market. Initially, the thresholds to be used by the ISO to determine a material price effect or change in guarantee payments shall be:

23.3.2.1.1 an increase of 200 percent or \$100 per MWh, whichever is lower, in the hourly Day-Ahead or Real-Time Energy LBMP at any location, or of any other price in an ISO Administered Market; or

- 23.3.2.1.2 an increase of 200 percent, or 50 percent for Generators in a Constrained Area in Bid Production Cost guarantee payments to a Market Party for a Generator for a day; or
- 23.3.2.1.3 for a Constrained Area Generator subject to either a Real-Time Market or Day-Ahead Market conduct threshold, as specified above in Sections 23.3.1.1.1, 23.3.1.2.2.1, or 23.3.1.2.2.3: for all Constrained Hours (as defined in Section 23.3.1.2.2.1 for the Real-Time Market and in Section 23.3.1.2.2.3 for the Day-Ahead Market) for the unit being Bid, a threshold determined in accordance with the formula specified in Section 23.3.1.2.2.1 for the Real-Time Market or Section 23.3.1.2.2.3 for the Day-Ahead Market.

23.3.2.2 Price Impact Analysis

- 23.3.2.2.1 When it has the capability to do so, the ISO shall determine the effect on prices or guarantee payments of questioned conduct through the use of sensitivity analyses performed using the ISO's SCUC, RTC and RTD computer models, and such other computer modeling or analytic methods as the ISO shall deem appropriate following consultation with its Market Monitoring Unit. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.4 of Attachment O.
- 23.3.2.2.2 Pending development of the capability to use automated market models, the ISO, following consultation with its Market Monitoring Unit, shall determine the effect on prices or guarantee payments of questioned conduct using the best available data and such models and methods as they shall deem appropriate. The

responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.5 of Attachment O.

23.3.2.2.3 The ISO shall implement automated procedures within the SCUC for Constrained Areas, and within RTC for Constrained Areas. Such automated procedures will: (i) determine whether any Day-Ahead or Real-Time Energy Bids, including start-up costs Bids and Minimum Generation Bids but excluding Ancillary Services Bids, that have not been adequately justified to the ISO exceed the thresholds for economic withholding specified in Section 23.3.1.2 above; and, if so, (ii) determine whether such Bids would cause material price effects or changes in guarantee payments as specified in Section 23.3.2.1.

23.3.2.2.4 The ISO shall forgo performance of the additional SCUC and RTC passes necessary for automated mitigation of Bids in a given Day-Ahead Market or Real-Time Market if evaluation of unmitigated Bids results in prices at levels at which it is unlikely that the thresholds for Bid mitigation will be triggered.

23.3.2.3 Section 205 Filings

The ISO shall make a filing under § 205 with the Commission seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections 23.3.1.1 through 23.3.1.3 above if that conduct has a significant effect on market prices or guarantee payments as specified below, unless the ISO determines, from information provided by the Market Party or Parties (which may include a Demand Side Resource participating in the Operating Reserves or Regulation Service Markets) that would be

subject to mitigation, or from other information available to the ISO that the conduct and associated price or guarantee payment effect(s) are attributable to legitimate competitive market forces or incentives. For purposes of this section, conduct shall be deemed to have an effect on market prices or guarantee payments that is significant if it exceeds one of the following thresholds:

23.3.2.3.1 an increase of 100 percent in the hourly day-ahead or real-time energy

LBMP at any location, or of any other price in an ISO Administered Market; or

23.3.2.3.2 an increase of 100 percent in Bid Production Cost guarantee payments to a

Market Party for a Generator for a day, or an increase of 100 percent in any other

guarantee payment over the time period used by the ISO to calculate the

guarantee payment.

23.3.3 Consultation with a Market Party

23.3.3.1 Consultation Process

23.3.3.1.1 *Consultation initiated by the ISO to determine if mitigation is appropriate:*

Applies to Market-Party-specific and/or Generator-specific mitigation, but not to mitigation that is applied pursuant to Sections 23.3.1.2.3, 23.3.2.2.3, or 23.5.2 of these mitigation measures. If through the application of an appropriate index or screen or other monitoring of market conditions, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified above, on one or more prices or guarantee payments in an ISO Administered Market, the ISO shall, as and to the extent specified in Attachment O or in Section 23.3.3.2 of these Mitigation Measures, contact the Market Party engaging in the identified conduct to request an explanation of the conduct.

23.3.3.1.2 *Consultation initiated by a Market Party when it anticipates that its Generator's marginal costs or other Bid parameters may exceed the Generator's reference level(s) by more than the relevant threshold(s).* If a Market Party anticipates submitting Bids in a market administered by the ISO that will exceed the thresholds specified in Section 23.3.1 above for identifying conduct inconsistent with competition, the Market Party may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Party's Bids.

23.3.3.1.3 *Results of consultation process addressing Bids.* If a Market Party's explanation of the reasons for its bidding indicates to the satisfaction of the ISO that the questioned conduct is consistent with competitive behavior, no further action will be taken. A preliminary determination by the ISO shall be provided to the Market Monitoring Unit for its review and comment.

23.3.3.1.4 *Consultation initiated by a Market Party regarding reference levels.* Upon request, the ISO shall consult with a Market Party or its representative with respect to the information and analysis used to determine reference levels under Section 23.3.1.4 for that Market Party's Generator(s). If cost data or other information submitted by a Market Party's Generator(s) indicates to the satisfaction of the ISO that the reference levels for that Market Party should be changed, revised reference levels shall be proposed by the ISO, communicated to the Market Monitoring Unit for its review and comment and, following the ISO's consideration of any recommendations that the Market Monitoring Unit is able to timely provide, communicated to the Market Party, and implemented by the ISO as soon as practicable. Changes to the reference levels addressed pursuant to the terms of this Section 23.3.3.1.4 shall be implemented on a going-forward basis commencing no earlier than the date that the Market

Party's consultation request is received. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.6 of Attachment O.

23.3.3.1.5 *Information required to support consultation regarding Bids and reference levels.* Market Parties shall ensure that the information they submit to the ISO, including but not limited to fuel price and fuel type information, is accurate. Except as set forth in Section 23.3.1.4.7.7, the ISO may not retroactively revise a reference level to reflect additional fuel costs if a Market Party or its representative did not timely submit accurate fuel cost information. Unsupported speculation by a Market Party does not present a valid basis for the ISO to determine that Bids that a Market Party submitted are consistent with competitive behavior, or to determine that submitted costs are appropriate for inclusion in the ISO's development of reference levels. Consistent with Sections 30.6.2.2 and 30.6.3.2 of the Plan, the Market Party shall retain the documents and information supporting its Bids and the costs it proposes to include in reference levels.

23.3.3.2 Consultation Requirements

23.3.3.2.1 The ISO shall make a reasonable attempt to contact and consult with the relevant Market Party about the Market Party's reference level(s) before imposing conduct and impact mitigation, other than conduct and impact mitigation imposed through the automated procedures described in Section 23.3.2.2.3 of these Mitigation Measures. The ISO shall keep records documenting its efforts to contact and consult with the Market Party.

23.3.3.2.2 Consultation regarding both real-time guarantee payment mitigation and mitigation of Generators committed outside the economic evaluation process in

the Day-Ahead or Real-Time Markets to protect or preserve system reliability in accordance with Section 23.3.1.2.3 of these Mitigation Measures is addressed in Section 23.3.3.3, below. Consultation regarding Day-Ahead guarantee payment mitigation of Generators, other than mitigation imposed through the automated procedures described in Section 23.3.2.2.3 of these Mitigation Measures, shall be conducted in accordance with Sections 23.3.3.1 and 23.3.3.2 of these Mitigation Measures.

23.3.3.3 Consultation Rules for Real-Time Guarantee Payment Mitigation

23.3.3.3.1 Real-Time Guarantee Payment Consultation Process

23.3.3.3.1.1 For real-time guarantee payment mitigation determined pursuant to Sections 23.3.1.2.1 or 23.3.1.2.2, and 23.3.2.1.2 of these Mitigation Measures, the ISO shall electronically post settlement results informing Market Parties of Bid(s) that failed the real-time guarantee payment impact test. The settlement results posting shall include the adjustment to the guarantee payment and the mitigated Bid(s). The initial posting of settlement results ordinarily occurs two days after the relevant real-time market day.

23.3.3.3.1.2 For real-time guarantee payment mitigation determined pursuant to Sections 23.3.1.2.1 or 23.3.1.2.2, and 23.3.2.1.2 of these Mitigation Measures, no more than two business days after new or revised real-time guarantee payment impact test settlement results are posted, the ISO will send an e-mail or other notification to all potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures.

23.3.3.3.1.2.1 Although the ISO is authorized to take up to two business days to provide notification to all potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures, the ISO shall undertake reasonable efforts to provide notification to such Market Parties within one business day after new or revised real-time guarantee payment impact test settlement results are posted.

23.3.3.3.1.2.2 A Market Party that desires to receive notification from the ISO must provide one e-mail address to the ISO for real-time guarantee payment mitigation notices. Each Market Party is responsible for maintaining and monitoring the e-mail address it provides, and informing the ISO of any change(s) to that e-mail address in order to continue to receive e-mail notification. E-mail will be the ISOs primary method of providing notice to Market Parties.

23.3.3.3.1.2.3 Regardless of whether a Market Party chooses to receive notification from the ISO, each Market Party is responsible for reviewing its posted real-time guarantee payment impact test settlement results and for contacting the ISO to request a consultation if and when appropriate.

23.3.3.3.1.3 The following notice rules apply to guarantee payment mitigation determined pursuant to Section 23.3.1.2.3 of these Mitigation Measures.

23.3.3.3.1.3.1 For mitigation of a Generator's Minimum Generation Bid, Start-Up Bid or Incremental Energy Bid resulting from its DARU or SRE commitment, the ISO shall send an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures within ten business days after the relevant market day, and shall undertake

reasonable efforts to provide notification to such Market Parties within two business days after the relevant market day. The e-mail shall identify the date of the proposed mitigation and the Bid(s) or Bid components that the NYISO proposes to mitigate for all or part of the relevant market day.

As soon as it is able to do so, the NYISO will commence electronically posting settlement results informing Market Parties of Bid(s) that failed the Section 23.3.1.2.3 test and sending an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.1.2.2 of these Mitigation Measures. The settlement results posting shall include the mitigated bid(s). The posting of settlement results ordinarily occurs two days after the relevant real-time market day.

23.3.3.3.1.3.2 For mitigation of a Generator's Minimum Generation Bid, Start-Up Bid or Incremental Energy Bid resulting from an Out-of-Merit dispatch above the Generator's DARU or SRE commitment, the ISO shall send an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these Mitigation Measures within 10 business days after the relevant market day. The e-mail shall identify the date of the proposed mitigation and the bid(s) or bid components that the NYISO proposes to mitigate for all or part of the relevant market day.

23.3.3.3.1.3.3 For mitigation based on a Generator's minimum run time, start-up time, minimum down time, minimum generation MWs, or maximum number of stops per day, the ISO shall send an e-mail or other notification to potentially impacted Market Parties that comply with Section 23.3.3.3.1.2.2 of these

Mitigation Measures within 10 business days after the relevant market day. The e-mail shall identify the date of the proposed mitigation and the conduct failing Bid(s) or Bid components.

23.3.3.3.1.4 Market Parties that want to consult with the ISO regarding real-time guarantee payment impact test results, or regarding mitigation applied in accordance with Section 23.3.1.2.3 of these Mitigation Measures, for a particular market day must submit a written request to initiate the consultation process that specifies the market day and Bid(s) for which consultation is being requested (for purposes of this Section 23.3.3.3.1, a “Consultation Request”).

23.3.3.3.1.4.1 Consultation Requests must be received by the ISO’s customer relations department within 15 business days after the ISO (i) posts new or revised real-time guarantee payment impact test settlement results, or (ii) either posts new or revised real-time guarantee payment impact test settlement results or sends an e-mail informing a Market Party of the results of a test performed pursuant to Section 23.3.1.2.3 of these Mitigation Measures for the relevant market day. Consultation Requests received outside the 15 business day period shall be rejected by the ISO.

23.3.3.3.1.4.2 The ISO may send more than one notice informing a Market Party of the same instance of mitigation. Notices that identify real-time guarantee payment impact test or Section 23.3.1.2.3 mitigation settlement results that are not new (for which the Market Party has already received a notice from the ISO) and that do not reflect revised mitigation (for which the dollar impact of the real-time guarantee payment mitigation has not changed) shall not present an additional

opportunity, or temporally extend the opportunity, for the Market Party to initiate consultation.

23.3.3.3.1.4.3 If consultation was timely requested and completed addressing a particular set of real-time guarantee payment impact test results, or addressing a particular instance of mitigation applied in accordance with Section 23.3.1.2.3 of these Mitigation Measures, a Market Party may not again request consultation regarding the same real-time guarantee payment impact test results, or the same application of Section 23.3.1.2.3 mitigation, unless revised settlement results, that are not due to the previously completed consultation and that change the dollar impact of the relevant instance of mitigation, are posted.

23.3.3.3.1.5 The Consultation Request may include: (i) an explanation of the reason(s) why the Market Party believes some or all of the reference levels used by the ISO for the market day(s) in question are inappropriate, or why some or all of the Market Party's Bids on the market day(s) in question were otherwise consistent with competitive behavior; and (ii) supporting documents, data and other relevant information (collectively, for purposes of this Section 23.3.3.3.1, "Data"), including proof of any cost(s) claimed.

23.3.3.3.1.5.1 Market Parties shall ensure that the information they submit to the ISO, including but not limited to fuel price and fuel type information, is accurate. Except as set forth in Section 23.3.1.4.7.7, the ISO may not retroactively revise a reference level to reflect additional fuel costs if a Market Party or its representative did not timely submit accurate fuel cost information.

23.3.3.3.1.6 If the Market Party is not able to provide (i) an explanation of the reason(s) why the Market Party believes some or all of the reference levels used by the ISO for the market day(s) in question are inappropriate, or why some or all of the Market Party's Bids on the market day(s) in question were otherwise consistent with competitive behavior, or (ii) all supporting Data, at the time a Consultation Request is submitted, the Market Party should specifically identify any additional explanation or Data it intends to submit in support of its Consultation Request and provide an estimate of the date by which it will provide the additional explanation or Data to the ISO.

23.3.3.3.1.7 Following the submission of a Consultation Request that satisfies the timing and Bid identification requirements of Section 23.3.3.3.1.4, above, consultation shall be performed in accordance with Section 23.3.3.1 of these Mitigation Measures, as supplemented by the following rules:

23.3.3.3.1.7.1 The ISO shall consult with the Market Party to determine whether the information available to the ISO presents an appropriate basis for (i) modifying the reference levels used to perform real-time guarantee payment mitigation for the market day in question, or (ii) determining that the Market Party's Bid(s) on the market day in question were consistent with competitive behavior. The ISO shall only modify the reference levels used to perform mitigation, or determine that the Market Party's Bid(s) on the market day that is the subject of the Consultation Request were consistent with competitive behavior, if the ISO has in its possession Data that is sufficient to support such a decision.

23.3.3.3.1.7.2 A preliminary determination by the ISO shall be provided to the Market Monitoring Unit for its review and comment, and the ISO shall consider the Market Monitoring Unit's recommendations in reaching its decision. The ISO shall inform the Market Party of its decision, in writing, as soon as reasonably practicable, but in no event later than (i) 50 business days after the new or revised real-time guarantee payment impact test settlement results for the relevant market day were posted, or (ii) 50 business days after the earlier of the posting of new or revised Section 23.3.1.2.3 mitigation settlement results for the relevant market day, or the issuance of an e-mail in accordance with Section 23.3.3.3.1.3, above. If the ISO does not affirmatively determine that it is appropriate to modify the Bid(s) that are the subject of the Consultation Request within 50 business days, the Bid(s) shall remain mitigated. The responsibilities of the Market Monitoring Unit that are addressed in this section of the Mitigation Measures are also addressed in Section 30.4.6.2.7 of Attachment O.

23.3.3.3.1.7.3 The ISO may, as soon as practicable, but at any time within the consultation period, request Data from the Market Party. The Market Party is expected to undertake all reasonable efforts to provide the requested Data as promptly as possible, to inform the ISO of the date by which it expects to provide requested Data, and to promptly inform the ISO if the Market Party does not intend to, or cannot, provide Data that has been requested by the ISO.

23.3.3.3.1.8 This Section 23.3.3.3.1 addresses Consultation Requests. It is not intended to limit, alter or modify a Market Party's ability to submit or proceed

with a billing dispute pursuant to Section 7.4 of the ISO Services Tariff or Section 2.7.4.1 of the ISO OATT.

23.3.3.3.2 Revising Reference Levels of Certain Generators Committed Out-of-Merit or via Supplemental Resource Evaluation for Conducting Real-Time Guarantee Payment Conduct and Impact Tests and Applying Mitigation in Accordance with Section 23.3.1.2.3 of these Mitigation Measures

23.3.3.3.2.1 Consistent with and subject to all of the requirements of Section 23.3.3.3.1 of these Mitigation Measures, Generators that (i) are committed Out-of-Merit or via a Supplemental Resource Evaluation after the DAM has posted, and (ii) for which the NYISO has posted real-time guarantee payment impact test settlement results, or identified possible mitigation under Section 23.3.1.2.3 of these Mitigation Measures may contact the ISO within 15 business days after new or revised impact test settlement results are posted, or possible mitigation under Section 23.3.1.2.3 of these Mitigation Measures is identified, to request that the reference levels used to perform the testing and mitigation be adjusted to include any of the following verifiable costs:

23.3.3.3.2.1.1 procuring fuel at prices that exceed the index prices used to calculate the Generator's reference level;

23.3.3.3.2.1.2 burning a type of fuel or blend of fuels that is not reflected in the Generator's reference level;

23.3.3.3.2.1.3 gas balancing penalties;

23.3.3.3.2.1.4 compliance with operational flow orders; and

23.3.3.3.2.1.5 purchasing additional emissions allowances that are necessary to satisfy the Generator's Supplemental Resource Evaluation or Out-of-Merit schedule.

23.3.3.3.2.2 The five categories of verifiable costs specified above shall be used to modify the requesting Generator's reference level(s) subject to the following prerequisites:

23.3.3.3.2.2.1 the Generator must specifically and accurately identify and document the extraordinary costs it has incurred to operate during the hours of its Supplemental Resource Evaluation or Out-of-Merit commitment; and

23.3.3.3.2.2.2 the costs must not already be reflected in the Generator's reference levels or be recovered from the ISO through other means.

As soon as practicable after the Market Party demonstrates to the ISO's reasonable satisfaction that one or more of the five categories of extraordinary costs have been incurred, but in no event later than the deadline set forth in Section 23.3.3.3.1.7.2 of these Mitigation Measures, the ISO shall adjust the affected Generator's reference levels and re-perform the real-time guarantee payment conduct and impact tests, or the Section 23.3.1.2.3 test, as appropriate, for the affected day. Only the reference levels used to perform real-time guarantee payment mitigation and/or mitigation pursuant to Section 23.3.1.2.3 of these Mitigation Measures, will be adjusted.

23.3.3.3.2.3 If, at some point prior to the issuance of a Close-Out Settlement for the relevant service month, the ISO or the Commission determine that some or all of the costs claimed by the Market Party during the consultation process described above were not, in fact, incurred over the course of the Out-of-Merit or Supplemental Resource Evaluation commitment, or were recovered from the ISO through other means, the ISO shall re-perform the appropriate test(s) using reference levels that reflect the verifiable costs that the Generator incurred and

shall apply mitigation if the Generator's Bids fail conduct and impact, or the Section 23.3.1.2.3 test, at the corrected reference levels.

23.3.3.3.2.4 Generators may contact the ISO to request the inclusion of costs other than the five types identified above in their reference levels. The ISO shall consider such requests in accordance with Sections 23.3.1.4, or 23.3.3.3.1 of these Mitigation Measures, as appropriate.

**25 Attachment J – Determination of Day-Ahead Margin Assurance Payments and
Import Curtailment Guarantee Payments**

25.1 Introduction

If a Supplier that is eligible pursuant to Section 25.2 of this Attachment J buys out of a Day-Ahead Energy, Regulation Service or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin it shall receive a Day-Ahead Margin Assurance Payment, except as noted in Sections 25.4, and 25.5 of this Attachment J. The purpose of such payments is to protect Suppliers' Day-Ahead Margins associated with real-time reductions after accounting for: (I) any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve schedules; and (ii) any Supplier-requested real-time de-rate granted by the ISO.

In addition, a Supplier may be eligible to receive an Import Curtailment Guarantee Payment if its Import is curtailed at the request of the ISO as determined pursuant to Section 25.6 of this Attachment J.

25.2 Eligibility for Receiving Day-Ahead Margin Assurance Payments

25.2.1 General Eligibility Requirements for Suppliers to Receive Day-Ahead Margin Assurance Payments

Subject to Section 25.2.2 of this Attachment J, the following categories of Resources bid by Suppliers shall be eligible to receive Day-Ahead Margin Assurance Payments: (I) all Self-Committed Flexible and ISO-Committed Flexible Generators that are either online and dispatched by RTD or available for commitment by RTC; (ii) Demand Side Resources committed to provide Operating Reserves or Regulation Service; (iii) any Resource that is scheduled out of economic merit order by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; (iv) any Resource internal to the NYCA that is derated or decommitted by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; and (v) Energy Limited Resources with an ISO-approved real-time reduction in scheduled output from its Day-Ahead schedule.

25.2.2 Exceptions

Notwithstanding Section 25.2.1 of this Attachment J, no Day-Ahead Margin Assurance Payment shall be paid to:

25.2.2.1 a Resource otherwise eligible for a Day-Ahead Margin Assurance Payment in hours in which the NYISO has increased the Resource's minimum operating level either: (i) at the Resource's request; 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 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.

25.3 Calculation of Day-Ahead Margin Assurance Payments

25.3.1 Formula for Day-Ahead Margin Assurance Payments for Generators, Except for Limited Energy Storage Resources

Subject to Sections 25.4 and 25.5 of this Attachment J, Day-Ahead Margin Assurance Payments for Generators, except for Limited Energy Storage Resources, shall be determined by applying the following equations to each individual Generator using the terms as defined in Section 25.3.4:

$$DMAP_{hu} = \max\left(0, \sum_{i \in h} CDMAP_{iu}\right) \quad \text{where:}$$

$$CDMAP_{iu} = CDMAPen_{iu} + \sum_p CDMAPres_{iup} + CDMAPreg_{iu}$$

If the Generator's real-time Energy schedule is lower than its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = \left\{ \begin{array}{c} [DASen_{hu} - LL_{iu}] \times RTPen_{iu} \\ - \int_{LL_{iu}}^{DASen_{hu}} DABen_{hu} \end{array} \right\} * \frac{Seconds_i}{3600},$$

If the Generator's real-time Energy schedule is greater than or equal to its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = \text{MIN} \left(\left\{ \begin{array}{c} [DASen_{hu} - UL_{iu}] \times RTPen_{iu} \\ + \int_{DASen_{hu}}^{UL_{iu}} RTBen_{iu} \end{array} \right\} * \frac{Seconds_i}{3600}, 0 \right)$$

If the Generator's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = [(DASres_{hup} - RTSres_{iup}) \times (RTPres_{iup} - DABres_{hup})] * \frac{Seconds_i}{3600}$$

If the Generator's real-time schedule for a given Operating Reserve product, p , is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[(DASres_{hu} - RTSres_{iup}) \times (RTPres_{iup}) \right] * \frac{Seconds_i}{3600}$$

If the Generator's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) \times (RTPreg_{iu} - DABreg_{hu}) \right] * \frac{Seconds_i}{3600} \\ + [(-1 \times RTMreg_{iu}) \times \max(0, RTPreg_{iu} - RTBreg_{iu})]$$

If the Generator's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) \times \max((RTPreg_{iu} - RTBreg_{iu}), 0) \right] * \frac{Seconds_i}{3600} \\ + [(-1 \times RTMreg_{iu}) \times \max(0, RTPreg_{iu} - RTBreg_{iu})]$$

25.3.2 Formula for Day-Ahead Margin Assurance Payments for Demand Side Resources

25.3.2.1 Formula for Day-Ahead Margin Assurance Payment for Demand Side Resources

Subject to Section 25.5 of this Attachment J, Day-Ahead Margin Assurance Payments for Demand Side resources scheduled to provide Operating Reserves or Regulation Service shall be determined by applying the following equations to each individual Demand Side Resource using the terms as defined in Section 25.3.4, except for RPI_{iu} , which is defined in Section 25.3.2.2:

$$DMAP_{hu} = \max\left(0, \sum_{i \in h} CDMAP_{iu}\right) \text{ where:}$$

$$CDMAP_{iu} = \sum_p CDMAPres_{iup} + CDMAPreg_{iu},$$

If the Demand Side Resource's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[(DASres_{hup} - RTSres_{iup}) \times (RTPres_{iup} - DABres_{hup}) \right] * RPI_{iu} * \frac{Seconds_i}{3600}$$

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:

$$CDMAPres_{iup} = \left[(DASres_{hup} - RTSres_{iup}) \times (RTPres_{iup}) \right] * RPI_{iu} * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) \times (RTPreg_{iu} - DABreg_{hu}) \right] * \frac{Seconds_i}{3600} \\ + [(-1 \times RTMreg_{iu}) \times \max(0, RTPreg_{iu} - RTBreg_{iu})]$$

If the Demand Side Resource's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[(DASreg_{hu} - RTSreg_{iu}) \times \max((RTPreg_{iu} - RTBreg_{iu}), 0) \right] * \frac{Seconds_i}{3600} \\ + [(-1 \times RTMreg_{iu}) \times \max(0, RTPreg_{iu} - RTBreg_{iu})]$$

25.3.2.2 Reserve Performance Index for Demand Side Resource Suppliers of Operating Reserves

The ISO shall produce a Reserve Performance Index for purposes of calculating a Day Ahead Margin Assurance Payment for a Demand Side Resource providing Operating Reserves.

The Reserve Performance Index shall take account of the actual Demand Reduction achieved by the Supplier of Operating Reserves following the ISO's instruction to convert Operating Reserves to Demand Reduction.

The Reserve Performance Index shall be a factor with a value between 0.0 and 1.0 inclusive. For each interval in which the ISO has not instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction, the Reserve Performance Index shall have a value of one. For each interval in which the ISO has instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction the Reserve Performance Index shall be calculated pursuant to the following formula, provided however when UAGi is zero or less, the Reserve Performance Index shall be set to zero:

$$RPI_{iu} = \text{Min} [(UAGi / ADGi + .1), 1]$$

Where:

RPI_{iu} = Reserve Performance Index in interval i for Demand Side Resource u;

$UAGi$ = average actual Demand Reduction for interval i, represented as a positive generation value; and

$ADGi$ = average scheduled Demand Reduction for interval i, represented as a positive generation base point.

25.3.3 Formula for Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources

Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources scheduled to provide Regulation Service shall be determined by applying the following equations to each Resource using the terms as defined in Section 25.3.4; *provided, however*, that a Day-Ahead Margin Assurance Payment is payable only for intervals in which the NYISO has

reduced the real-time Regulation Service offer (in MWs) of a Limited Energy Storage Resource and the NYISO is not pursuing LESR Energy Management for such Resource for such interval, pursuant to ISO Procedures:

If the LESR's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule and the real-time Regulation Capacity Market Price is greater than the Day-Ahead Regulation Capacity Bid price then:

$$\begin{aligned} \text{CDMAPreg}_{iu} = & \left[\left(\text{DASreg}_{hu} - \text{RTSreg}_{iu} \right) * \left(\text{RTPreg}_{iu} - \text{DABreg}_{hu} \right) \right] * K_p * \frac{\text{Seconds}_i}{3600} \\ & + \left[(-1 \times \text{RTMreg}_{iu}) \times \max(0, \text{RTPreg}_{iu} - \text{RTBreg}_{iu}) \right] \end{aligned}$$

If the LESR's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule and the real-time Regulation Capacity Market price is less than or equal to the Day-Ahead Regulation Capacity Bid price then:

$$\begin{aligned} \text{CDMAPreg}_{iu} = & \left[\left(\text{DASreg}_{hu} - \text{RTSreg}_{iu} \right) * \left(\text{RTPreg}_{iu} - \text{DABreg}_{hu} \right) \right] * \frac{\text{Seconds}_i}{3600} \\ & + \left[(-1 \times \text{RTMreg}_{iu}) \times \max(0, \text{RTPreg}_{iu} - \text{RTBreg}_{iu}) \right] \end{aligned}$$

If the LESR's real-time Regulation Service schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$\begin{aligned} \text{CDMAPreg}_{iu} = & \left[\left(\text{DASreg}_{hu} - \text{RTSreg}_{iu} \right) \times \text{MAX}((\text{RTPreg}_{iu} - \text{RTBreg}_{iu}), 0) \right] * \frac{\text{Seconds}_i}{3600} \\ & + \left[(-1 \times \text{RTMreg}_{iu}) \times \max(0, \text{RTPreg}_{iu} - \text{RTBreg}_{iu}) \right] \end{aligned}$$

25.3.4 Terms Used in this Attachment J

The terms used in the formulas in this Attachment J shall be defined as follows:

h is the hour that includes interval i ;

$DMAP_{hu}$	=	the Day-Ahead Margin Assurance Payment attributable in any hour h to any Supplier u ;
$CDMAP_{iu}$	=	the contribution of RTD interval i to the Day-Ahead Margin Assurance Payment for Supplier u ;
$CDMAPen_{iu}$	=	the Energy contribution of RTD interval i to the Day-Ahead Margin Assurance Payment for Supplier u ;
$CDMAPreg_{iu}$	=	the Regulation Service contribution of RTD interval i to the Day-Ahead Margin Assurance Payment for Supplier u ;
$CDMAPres_{iup}$	=	the Operating Reserve contribution of RTD interval i to the Day-Ahead Margin Assurance Payment for Supplier u determined separately for each Operating Reserve product p ;
$DASen_{hu}$	=	Day-Ahead Energy schedule for Supplier u in hour h ;
$DASreg_{hu}$	=	Day-Ahead schedule for Regulation Service for Supplier u in hour h ;
$DASres_{hup}$	=	Day-Ahead schedule for Operating Reserve product p , for Supplier u in hour h ;
$DABen_{hu}$	=	Day-Ahead Energy bid curve for Supplier u in hour h ;
$DABreg_{hu}$	=	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 curve for Supplier u in interval i .
$RTBregm_{iu}$	=	real-time Regulation Movement Bid price for Supplier u in interval i .
$RTMreg_{iu}$	=	real-time Regulation Movement MWs for Supplier u in interval i ;
AEI_{iu}	=	average Actual Energy Injection by Supplier u in interval i but not more than $RTSen_{iu}$ plus Compensable Overgeneration;
$RTPen_{iu}$	=	real-time price of Energy at the location of Supplier u in interval i ;
$RTPreg_{iu}$	=	real-time price of Regulation Capacity at the location of Supplier u in interval i ;
$RTPres_{iup}$	=	real-time price of Operating Reserve product p at the location of Supplier u in interval i ;

$RT\text{Pregm}_{iu}$ = real-time Regulation Movement Market Price at the location of Supplier u in interval i ;

LL_{iu} = either, as the case may be:

(a) if $RT\text{Sen}_{iu} < EOP_{iu}$, then $LL_{iu} = \min(\max(RT\text{Sen}_{iu}, \min(AEI_{iu}, EOP_{iu})), DASen_{hu})$; or

(b) if $RT\text{Sen}_{iu} \geq EOP_{iu}$, then $LL_{iu} = \min(RT\text{Sen}_{iu}, \max(AEI_{iu}, EOP_{iu}), DASen_{hu})$,

UL_{iu} = either, as the case may be:

(a) if $RT\text{Sen}_{iu} \square EOP_{iu} \square DASen_{hu}$, then $UL_{iu} = \max(\min(RT\text{Sen}_{iu}, \max(AEI_{iu}, EOP_{iu})), DASen_{hu})$; or

(b) otherwise, then $UL_{iu} = \max(RT\text{Sen}_{iu}, \min(AEI_{iu}, EOP_{iu}), DASen_{hu})$;

EOP_{iu} = the Economic Operating Point of Supplier u in interval i calculated without regard to ramp rates;

Seconds_i = number of seconds in interval i

K_{PI} = the factor derived from the Regulation Service Performance index for Resource u for interval i as defined in Rate Schedule 3 of this Services Tariff.

25.4 Exception for Generators Lagging Behind RTD Base Point Signals

If an otherwise eligible Generator's average Actual Energy Injection in an RTD interval (*i.e.*, its Actual Energy Injections averaged over the RTD interval) is less than or equal to its penalty limit for under-generation value for that interval, as computed below, it shall not be eligible for Day-Ahead Margin Assurance Payments for that interval.

The penalty limit for under-generation value is the tolerance described in Section 15.3A.1 of Rate Schedule 3-A of this ISO Services Tariff, which is used in the calculation of the persistent under-generation charge applicable to Generators that are not providing Regulation Service.

25.5 Rules Applicable to Supplier Derates

Suppliers that request and are granted a derate of their real-time Operating Capacity, but that are otherwise eligible to receive Day-Ahead Margin Assurance Payments may receive a payment up to a Capacity level consistent with their revised Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable. The foregoing rule shall also apply to a Generator otherwise eligible for a Day-Ahead Margin Assurance Payment in hours in which the ISO has derated the Generator's Operating Capacity in order to reconcile the ISO's dispatch with the Generator's actual output, or to address reliability concerns that arise because the Generator is not following Base Point Signals. If a Supplier's derated real-time Operating Capacity is lower than the sum of its Day-Ahead Energy Regulation Services and Operating Reserve schedules then when the ISO conducts the calculations described in Section 25.3 above, the DASen, DASEg and DASres_p variables will be reduced by REDen, REDreg and REDres_p respectively. REDen, REDreg and REDres_p shall be calculated using the formulas below:

$$RED_{tot_{iu}} = \max(DASen_{hu} + DASEg_{hu} + \square_p DASres_{hup} - RTUOL_{iu}, 0)$$

$$POTREDen_{iu} = \max(DASen_{hu} - RTSen_{iu}, 0)$$

$$POTREDreg_{iu} = \max(DASEg_{hu} - RTSreg_{iu}, 0)$$

$$POTREDres_{iup} = \max(DASres_{hup} - RTSres_{iup}, 0)$$

$$REDen_{iu} = ((POTREDen_{iu} / (POTREDen_{iu} + POTREDreg_{iu} + \square_p POTREDres_{iup})) * RED_{tot_{iu}})$$

$$REDreg_{iu} = ((POTREDreg_{iu} / (POTREDen_{iu} + POTREDreg_{iu} + \square_p POTREDres_{iup})) * RED_{tot_{iu}})$$

$$REDres_{iup} = ((POTREDres_{iup} / (POTREDen_{iu} + POTREDreg_{iu} + \square_p POTREDres_{iup})) * RED_{tot_{iu}})$$

where:

$$RTUOL_{iu} = \text{The real-time Emergency Upper Operating Limit or Normal Upper Operating Limit whichever is applicable of Supplier } u \text{ in interval } i$$

- $RED_{tot_{iu}}$ = The total amount in MW that Day-Ahead schedules need to be reduced to account for the derate of Supplier u in interval i;
- $RED_{en_{iu}}$ = 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;
- $RED_{reg_{iu}}$ = 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;
- $RED_{res_{iup}}$ = 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;
- $POTRED_{en_{iu}}$ = 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;
- $POTRED_{reg_{iu}}$ = 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;
- $POTRED_{res_{iup}}$ = The potential amount in MW that Supplier u's Day-Ahead Operating Reserve Schedule for Operating Reserve product p could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier in interval;

All other variables are as defined above.

25.6 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 =

$$\sum_{k=1}^N \max \left(\sum_{i=1}^K (RTLBMP_u - \max(DADecBid_u, 0)) \cdot (DAen_u - RTDen_u) \cdot \frac{S_t}{3600}, 0 \right)$$

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 ;

$RTLBP_{t,i}$ = 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).

30.4 Market Monitoring Unit

30.4.1 Mission of the Market Monitoring Unit

The Market Monitoring Unit's goals are (1) to ensure that the markets administered by the ISO function efficiently and appropriately, and (2) to protect both consumers and participants in the markets administered by the ISO by identifying and reporting Market Violations, market design flaws and market power abuses to the Commission in accordance with Sections 30.4.5.3 and 30.4.5.4 below.

30.4.2 Retention and Oversight of the Market Monitoring Unit

The Board shall retain a consulting or other professional services firm, or other similar entity, to advise it on the matters encompassed by Attachment O and to carry out the responsibilities that are assigned to the Market Monitoring Unit in Attachment O. The Market Monitoring Unit selected by the Board shall have experience and expertise appropriate to the analysis of competitive conditions in markets for electric capacity, energy and ancillary services, and financial instruments such as TCCs, and to such other responsibilities as are assigned to the Market Monitoring Unit under Attachment O, and must also have sufficient resources and personnel to be able to perform the Core Functions and other assigned functions.

The Market Monitoring Unit shall be accountable to the non-management members of the Board, and shall serve at the pleasure of the non-management members of the Board.

30.4.3 Market Monitoring Unit Ethics Standards

The Market Monitoring Unit, including all persons employed thereby, shall comply at all times with the ethics standards set forth below. The Market Monitoring Unit ethics standards set forth below shall apply in place of the standards set forth in the ISO's OATT Attachment F Code

of Conduct, and/or the more general policies and standards that apply to consultants retained by the ISO.

30.4.3.1 The Market Monitoring Unit and its employees must have no material affiliation with any Market Party or Affiliate of any Market Party.

30.4.3.2 The Market Monitoring Unit and its employees must not serve as an officer, employee, or partner of a Market Party.

30.4.3.3 The Market Monitoring Unit and its employees must have no material financial interest in any Market Party or Affiliate of a Market Party. Ownership of mutual funds by Market Monitoring Units and their employees that contain investments in Market Parties or their Affiliates is permitted so long as: (a) the fund is publicly traded; (b) the fund's prospectus does not indicate the objective or practice of concentrating its investment in Market Parties or their Affiliates; and (c) the Market Monitoring Unit/Market Monitoring Unit employee does not exercise or have the ability to exercise control over the financial interests held by the fund.

30.4.3.4 The Market Monitoring Unit and its employees are prohibited from engaging in transactions in the markets administered by the ISO, other than in the performance of duties under the ISO's Tariffs. This provision shall not, however, prevent the Market Monitoring Unit, or its employees, from purchasing electricity, power and Energy as retail customers for their own account and consumption.

30.4.3.5 The Market Monitoring Unit and its employees must not be compensated, other than by the ISO, for any expert witness testimony or other commercial

services, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or to the markets that the ISO administers.

30.4.3.6 The Market Monitoring Unit and its employees may not accept anything that is of more than *de minimis* value from a Market Party.

30.4.3.7 The Market Monitoring Unit and its employees must advise the Board in the event they seek employment with a Market Party, and must disqualify themselves from participating in any matter that could have an effect on the financial interests of that Market Party until the outcome of the matter is determined.

30.4.3.8 If the Market Monitoring Unit or any of its employees provide services to entities other than the ISO, the Market Monitoring Unit shall provide to the ISO's Board, and shall regularly update, a list of such entities and services. When the Market Monitoring Unit issues an opinion, report or recommendation to, for or addressing the ISO or the markets it administers that relates to, or could reasonably be expected to affect, an entity (other than the ISO) to which the Market Monitoring Unit or its employees provide services, the Market Monitoring Unit shall inform the ISO's Board of the opinion, report or recommendation it has issued, and that its opinion, report or recommendation relates to, or could reasonably be expected to affect, an entity to which the Market Monitoring Unit or its employees provide services.

30.4.4 Duties of the Market Monitoring Unit

The Market Monitoring Unit shall advise the Board, shall perform the Core Functions specified in Section 30.4.5 of Attachment O, and shall have such other duties and responsibilities

as are specified in Attachment O. The Market Monitoring Unit may, at any time, bring any matter to the attention of the Board that the Market Monitoring Unit may deem necessary or appropriate for achieving the purposes, objectives and effective implementation of Attachment O.

The Market Monitoring Unit shall not participate in the administration of the ISO's Tariffs, except for performing its duties under Attachment O. The Market Monitoring Unit shall not be responsible for performing purely administrative duties, such as enforcement of late fees or Market Party reporting obligations, that are not specified in Attachment O. The Market Monitoring Unit may (i) provide, or assist the ISO's efforts to develop, the inputs required to conduct mitigation, and (ii) assist the ISO's efforts to conduct "retrospective" mitigation (*see* Order 719 at PP. 369, 375) that does not change bids or offers (including physical bid or offer parameters) at or before the time such bids or offers (including physical bid or offer parameters) are considered in the ISO's market solution.

30.4.5 Core Market Monitoring Functions

The Market Monitoring Unit shall be responsible for performing the following Core Functions:

- 30.4.5.1 Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the ISO, to the Commission's Office of Energy Market Regulation staff, and to other interested entities, including the New York Public Service Commission, and participants in the ISO's stakeholder governance process. Provided that:
 - 30.4.5.1.1 The Market Monitoring Unit is not responsible for systematic review of every tariff and market rule; its role is monitoring, not audit.

30.4.5.1.2 The Market Monitoring Unit is not to effectuate its proposed market design itself.

30.4.5.1.3 The Market Monitoring Unit's role in recommending proposed rule and Tariff changes is advisory in nature, unless a Tariff provision specifically concerns actions to be undertaken by the Market Monitoring Unit itself.

30.4.5.1.4 The Market Monitoring Unit must limit distribution of issues or concerns it identifies, and its recommendations to the ISO and to Commission staff in the event it believes broader dissemination could lead to exploitation. Limited distributions should include an explanation of why further dissemination should be avoided at that time.

30.4.5.2 Review and report on the performance of the wholesale markets to the ISO, the Commission, and other interested entities such as the New York Public Service Commission and participants in its stakeholder governance process on at least a quarterly basis, and issue a more comprehensive annual state of the market report. The Market Monitoring Unit may issue additional reports as necessary.

30.4.5.2.1 In order to perform the Core Functions, the Market Monitoring Unit shall perform daily monitoring of the markets that the ISO administers. The Market Monitoring Unit's daily monitoring shall include monitoring of virtual bidding.

30.4.5.2.2 The Market Monitoring Unit shall submit drafts of each of its reports to the ISO for review and comment sufficiently in advance of the report's issuance to provide an effective opportunity for review and comment by the ISO. The Market Monitoring Unit may disregard any suggestions with which it disagrees.

The ISO may not alter the reports prepared by the Market Monitoring Unit, nor dictate the Market Monitoring Unit's conclusions.

30.4.5.3 Identify and notify the Commission staff of instances in which a Market Party's or the ISO's behavior may require investigation, including, but not limited to, suspected Market Violations.

30.4.5.3.1 Except as provided in Section 30.4.5.3.2 below, in compliance with § 35.28(g)(3)(iv) of the Commission's regulations (or any successor provisions thereto) the Market Monitoring Unit shall submit a non-public referral to the Commission in all instances where it has obtained sufficient credible information to believe a Market Violation has occurred. Once the Market Monitoring Unit has obtained sufficient credible information to warrant referral to the Commission, the Market Monitoring Unit shall immediately refer the matter to the Commission and desist from further investigation of independent action related to the alleged Market Violation, except at the express direction of the Commission or Commission staff. The Market Monitoring Unit may continue to monitor for repeated instances of the reported activity by the same or other entities and shall respond to requests from the Commission for additional information in connection with the alleged Market Violation it has referred.

30.4.5.3.2 The Market Monitoring Unit is not required to refer the actions (or failures to act) listed in this Section 30.4.5.3.2 to the Commission as Market Violations, because they have: (i) already been reported by the ISO as a Market Problem under Article 3.5.1 of the ISO Services Tariff; and/or (ii) because they pertain to actions or failures that: (a) are expressly set forth in the ISO's Tariffs;

(b) involve objectively identifiable behavior; and (c) trigger a sanction or other consequence that is expressly set forth in the ISO Tariffs and that is ultimately appealable to the Commission. The actions (or failures to act) that are exempt from mandatory referral to the Commission are:

- 30.4.5.3.2.1 failure to meet a Contract or Non-Contract CRIS MW Commitment pursuant to Sections 25.7.11.1.1 and 25.7.11.1.2 of Attachment S to the ISO OATT that results in a charge or other a sanction under Section 25.7.11.1.3 of Attachment S of the ISO OATT;
- 30.4.5.3.2.2 Black Start performance that results in reduction or forfeitures of payments under Rate Schedule 5 to the ISO Services Tariff;
- 30.4.5.3.2.3 any failure by the ISO to meet the deadlines for completing System Impact Studies, or any failure by a Transmission Owner to meet the deadlines for completing Facilities Studies, under Sections 3.7 and 4.5 of the ISO OATT that results in the filing of a notice and/or the imposition of sanctions under those provisions;
- 30.4.5.3.2.4 failure of a Market Party to comply with the ISO's creditworthiness requirements set forth in Attachment K of the ISO Services tariff, or other action, that triggers sanctions under Section 7.5 of the ISO Services Tariff or Section 2.7.5 of the ISO OATT, specifically: (i) failure of a Market Party to make timely payment under Section 7.2.2 of the ISO Services Tariff or Section 2.7.3.2 of the ISO OATT that triggers a sanction under Sections 7.5.3(i) or 7.5.3(iv) of the ISO Services Tariff, or Sections 2.7.5.3(i), 2.7.5.3(iv), or 2.7.5.4 of the ISO OATT; (ii) failure of a Market Party to comply with a demand for additional credit support

under Article 26.6 of Attachment K of the ISO Services Tariff that triggers a sanction under Section 7.5.3(i) of the ISO Services Tariff or Section 2.7.5.3(i) of the ISO OATT; (iii) failure of a Market Party to cure a default in another ISO/RTO market under Sections 7.5.3(iii) of the ISO Services Tariff, or Section 2.7.5.3(iii) of the ISO OATT that triggers a sanction under either of those tariff provisions; (iv) failure of a Market Party that has entered into a Prepayment Agreement with the ISO under Appendix K-1 to Attachment K to the ISO Services Tariff to make payment in accordance with the terms of the Prepayment Agreement that triggers a sanction under the Prepayment Agreement or 7.5.3(i) of the ISO Services Tariff; and (v) failure of a Market Party to make timely payment on two occasions within a rolling twelve month period under Section 7.5.3(iv) of the ISO Services Tariff, or Section 2.7.5.3(iv) of the ISO OATT that triggers a sanction under either of those provisions.

30.4.5.3.2.5 bidding in a manner that results in a penalty under Section 23.4.3.3.4 of the Market Mitigation Measures.

30.4.5.3.2.6 submission of inaccurate fuel type information into the Day-Ahead Market that results in a penalty under Section 23.4.3.3.3.3 of the Market Mitigation Measures.

30.4.5.3.2.7 submission of inaccurate fuel type and/or fuel price information into the Real-Time Market that results in a penalty under Section 23.4.3.3.3.4 of the Market Mitigation Measures.

To the extent the above list enumerates specific Tariff provisions, the exclusions specified above shall also apply to re-numbered and/or successor provisions thereto. The Market

Monitoring Unit is not precluded from referring any of the activities listed above to the Commission.

30.4.5.4 Identify and notify the Commission staff of perceived market design flaws that could be effectively remedied by rule or tariff changes.

30.4.5.4.1 In compliance with § 35.28(g)(3)(v) of the Commission's regulations (or any successor provisions thereto) the Market Monitoring Unit shall submit a referral to the Commission when the Market Monitoring Unit has reason to believe that a market design flaw exists, that the Market Monitoring Unit believes could effectively be remedied by rule or tariff changes.

30.4.5.4.1.1 If the Market Monitoring Unit believes broader dissemination of the possible market design flaw, and its recommendation could lead to exploitation, the Market Monitoring Unit shall limit distribution of its referral to the ISO and to the Commission. The referral shall explain why further dissemination should be avoided.

30.4.5.4.1.2 Following referral of a possible market design flaw, the Market Monitoring Unit shall continue to provide to the Commission additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the Market Monitoring Unit's proposed market rule or tariff change, any recommendations made by the Market Monitoring Unit to the ISO, its stakeholders, Market Parties or state public service commissions regarding the perceived market design flaw, and any actions taken by the ISO regarding the perceived market design flaw.

30.4.6 Market Monitoring Unit Responsibilities Set Forth Elsewhere in the ISO's Tariffs

30.4.6.1 Supremacy of (Attachment O)

Provisions addressing the Market Monitoring Unit, its responsibilities and its authority, have been centralized in Attachment O. However, provisions that address the Market Monitoring Unit can also be found in the Market Mitigation Measures that are set forth in Attachment H to the ISO Services Tariff, and elsewhere in the ISO's Tariffs. In the event of any inconsistency between the provisions of Attachment O and any other provision of the ISO OATT, the ISO Services Tariff, or any of their attachments and schedules, with regard to the Market Monitoring Unit, its responsibilities and its authority, the provisions of Attachment O shall control.

30.4.6.2 Market Monitoring Unit responsibilities set forth in the Market Mitigation Measures

30.4.6.2.1 The ISO and its Market Monitoring Unit shall monitor the markets the ISO administers for conduct that the ISO or the Market Monitoring Unit determine constitutes an abuse of market power but that does not trigger the thresholds specified in the Market Mitigation Measures for the imposition of mitigation measures by the ISO. If the ISO identifies or is made aware of any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified in Section 23.3.2.3 of the Market Mitigation Measures, it shall make a filing under § 205 of the Federal Power Act, 16 U.S.C. § 824d (1999) ("§ 205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation

measure for the conduct, shall incorporate or address the recommendation of its Market Monitoring Unit, and shall set forth the ISO's justification for imposing that mitigation measure. The Market Monitoring Unit's reporting obligations are specified in Sections 30.4.5.3 and 30.4.5.4 of Attachment O. *See* Market Mitigation Measures Section 23.1.2.

30.4.6.2.2 The ISO and the Market Monitoring Unit shall monitor the ISO Administered Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices or guarantee payments in an ISO Administered Market. *See* Market Mitigation Measures Section 23.2.4.4.

30.4.6.2.3 If (i) the ISO determines, following consultation with the Market Party and review by the Market Monitoring Unit, that the Market Party or its representative has, over a time period of at least one week, submitted inaccurate fuel type or fuel price information that was, taken as a whole, biased in the Market Party's favor, *then* the ISO shall cease using the fuel type and fuel price information submitted to the ISO's Market Information System along with the Generator's Bid(s) to develop reference levels for the affected Generator(s) in the relevant (Day-Ahead or real-time) market for the durations specified in Sections 23.1.4.7.8.1, 23.3.1.4.7.8.2, and 23.3.1.4.7.8.3 of the Mitigation Measures. *See* Section 23.3.1.4.7.8 of the Market Mitigation Measures

30.4.6.2.4 When it has the capability to do so, the ISO shall determine the effect on prices or guarantee payments of questioned conduct through the use of sensitivity analyses performed using the ISO's SCUC, RTC and RTD computer models, and

such other computer modeling or analytic methods as the ISO shall deem appropriate following consultation with its Market Monitoring Unit. *See* Market Mitigation Measures Section 23.3.2.2.1.

30.4.6.2.5 Pending development of the capability to use automated market models, the ISO, following consultation with its Market Monitoring Unit, shall determine the effect on prices or guarantee payments of questioned conduct using the best available data and such models and methods as they shall deem appropriate. *See* Market Mitigation Measures Section 23.3.2.2.2.

30.4.6.2.6 If through the application of an appropriate index or screen or other monitoring of market conditions, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified above, on one or more prices or guarantee payments in an ISO Administered Market, the ISO shall, as and to the extent specified in Attachment O or in Section 23.3.3.2 of the Market Mitigation Measures, contact the Market Party engaging in the identified conduct to request an explanation of the conduct. If a Market Party anticipates submitting bids in a market administered by the ISO that will exceed the thresholds specified in Section 23.3.1 of the Market Mitigation Measures for identifying conduct inconsistent with competition, the Market Party may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Party's bids. If a Market Party's explanation of the reasons for its bidding indicates to the satisfaction of the ISO that the questioned conduct is consistent with competitive behavior, no further action will be taken. Market Parties shall ensure that the information they submit to the ISO, including but not

limited to fuel price and fuel type information, is accurate. Except as set forth in Section 23.3.1.4.7.7 of the Market Mitigation Measures, the ISO may not retroactively revise a reference level to reflect additional fuel costs if a Market Party or its representative did not timely submit accurate fuel cost information. Unsupported speculation by a Market Party does not present a valid basis for the ISO to determine that Bids that a Market Party submitted are consistent with competitive behavior, or to determine that submitted costs are appropriate for inclusion in the ISO's development of reference levels. Consistent with Sections 30.6.2.2 and 30.6.3.2 of the Plan, the Market Party shall retain the documents and information supporting its Bids and the costs it proposes to include in reference levels. A preliminary determination by the ISO shall be provided to the Market Monitoring Unit for its review and comment, and the ISO shall consider the Market Monitoring Unit's recommendations before the ISO issues its decision or determination to the Market Party. Upon request, the ISO shall consult with a Market Party or its representative with respect to the information and analysis used to determine reference levels under Section 23.3.1.4 of the Market Mitigation Measures for that Market Party's Generator(s). If cost data or other information submitted by a Market Party indicates to the satisfaction of the ISO that the reference levels for that Market Party's Generator(s) should be changed, revised reference levels shall be proposed by the ISO, communicated to the Market Monitoring Unit for its review and comment and, following the ISO's consideration of any recommendation that the Market Monitoring Unit is able to timely provide, communicated to the Market Party, and implemented by the ISO

as soon as practicable. Changes to reference levels addressed pursuant to the terms of Section 23.3.3.1.4 of the Market Mitigation Measures shall be implemented on a going-forward basis commencing no earlier than the date that the Market Party's consultation request is received. *See* Market Mitigation Measures Sections 23.3.3.1.1 through 23.3.3.1.5.

30.4.6.2.7 With regard to a Market Party's request for consultation that satisfies the requirements of Sections 23.3.3.3.1.4 and 23.3.3.3.1.7 of the Market Mitigation Measures, and consistent with the duties assigned to the ISO in Section 23.3.3.3.1.7.1 of the Market Mitigation Measures, a preliminary determination by the ISO regarding the Market Party's consultation request shall be provided to the Market Monitoring Unit for its review and the ISO shall consider the Market Monitoring Unit's recommendations in reaching its decision. *See* Market Mitigation Measures Section 23.3.3.3.1.7.1 and 23.3.3.3.1.7.2.

30.4.6.2.8 Reasonably in advance of the deadline for submitting offers in an External Reconfiguration Market and in accordance with the deadlines specified in ISO Procedures, the Responsible Market Party for External Sale UCAP may request the ISO to provide a projection of ICAP Spot Auction clearing prices for a Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market. Prior to completing its projection of ICAP Spot Auction clearing prices for a Mitigated Capacity Zone over the Comparison Period for the External Reconfiguration Market, the ISO shall consult with the Market Monitoring Unit regarding such price projection. *See* Market Mitigation Measures Section 23.4.5.4.3.

30.4.6.2.9 Prior to reaching its decision regarding whether the presumption of control of Unforced Capacity has been rebutted, the ISO shall provide its preliminary determination to the Market Monitoring Unit for review and comment. *See* Market Mitigation Measures Section 23.4.5.5.

30.4.6.2.10 Any proposal or decision by a Market Participant to retire or otherwise remove an Installed Capacity Supplier from a Mitigated Capacity Zone Unforced Capacity market, or to de-rate the amount of Installed Capacity available from such supplier, may be subject to audit and review by the ISO if the ISO determines that such action could reasonably be expected to affect Market-Clearing Prices in one or more ICAP Spot Market Auctions for a Mitigated Capacity Zone subsequent to such action. Such an audit or review shall assess whether the proposal or decision has a legitimate economic justification or is based on an effort to withhold Installed Capacity physically in order to affect prices. The ISO shall provide the preliminary results of its audit or review to the Market Monitoring Unit for its review and comment. *See* Market Mitigation Measures Section 23.4.5.6.

30.4.6.2.11 When evaluating a request by a Developer or Interconnection Customer pursuant to Section 23.4.5.7 of the Market Mitigation Measures, the ISO shall seek comment from the Market Monitoring Unit on matters relating to the determination of price projections and cost calculations. As required by Section 23.4.5.7.8 of Attachment H to this Services Tariff, the Market Monitoring Unit shall prepare a written report confirming whether the ISO's Offer Floor and exemption determinations and calculations conducted pursuant to Section

23.4.5.7.2 of the Market Mitigation Measures were conducted in accordance with the terms of the Services Tariff, and if not, identifying the flaws inherent in the ISO's approach. This report shall be presented concurrent with the ISO's posting of its mitigation exemption determinations. Pursuant to Section 23.4.5.7.7 of the Market Mitigation Measures, the ISO shall also consult with the Market Monitoring Unit when evaluating whether any existing or proposed Generator or UDR project in a Mitigated Capacity Zone, except New York City, shall be exempted from an Offer Floor under that Section. Prior to the ISO making an exemption determination pursuant to Section 23.4.5.7.7, the Market Monitoring Unit shall provide the ISO a written opinion and recommendation. The Market Monitoring Unit shall also provide a public report on its assessment of an ISO determination that an existing or proposed Generator or UDR project is exempt from an Offer Floor under Section 23.4.5.7.7. *See* Market Mitigation Measures Section 23.4.5.7.

30.4.6.2.12 The ISO and its Market Monitoring Unit shall monitor the Spinning Reserves and 10-Minute Non-Synchronized reserves markets the ISO administers for competitiveness and for conduct that the ISO or the Market Monitoring Unit determine constitutes an abuse of market power. The Market Monitoring Unit shall evaluate and recommend adjustments to the reference level maximum used in Section 23.3.1.4.5 of the Market Mitigation Measures and to the Bid maximum used in Section 23.5.3.3 of the Market Mitigation Measures. The scope of the Market Monitoring Unit's evaluation shall include, but not be limited to, an analysis of: (i) the competitiveness of each reserves market and whether there is

conduct that the ISO or the Market Monitoring Unit determine constitutes an abuse of market power; and (ii) how an adjustment to the reference level maximum/Bid maximum is expected to impact the convergence of day-ahead and real-time prices. *See* Market Mitigation Measures Sections 23.3.1.4.5 and 23.5.3.3.

30.4.6.3 Market Monitoring Unit responsibilities set forth in the ISO Services Tariff

30.4.6.3.1 The ICAP Demand Curve periodic review schedule and procedures shall provide an opportunity for the Market Monitoring Unit to review and comment on the draft request for proposals, the independent consultant's report, and the ISO's proposed ICAP Demand Curves. *See* ISO Services Tariff Section 5.14.1.2.5.

30.4.6.3.2 The new capacity zone periodic review shall provide an opportunity for the Market Monitoring Unit to review and comment on the NCZ Study, and any proposed NCZ tariff revisions. *See* ISO Services Tariff Sections 5.16.1.3 and 5.16.4.

30.4.6.3.3 The Bid Restriction, specified in ISO Services Tariff Section 21.5.3.1, shall be the subject of a periodic, but no less frequent than annual, review by the Market Monitoring Unit, which review shall be presented to the ISO and to Market Participants. The review shall include, but not be limited to, an evaluation of whether an increase in the Bid Restriction, or its elimination, would provide incentives to raise offers for Regulation Movement substantially above levels that would be anticipated in an efficient market and whether the Bid Restriction prevents appropriate cost recovery. With its review, the Market Monitoring Unit

shall recommend continuation, adjustment or elimination of the Regulation Movement Bid Restriction. *See* ISO Services Tariff Section 21.5.3.

30.4.6.4 Market Monitoring Unit responsibilities set forth in the Rate Schedules to the ISO Services Tariff.

30.4.6.4.1 Responsibilities related to the Regulation Service Demand Curve

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure Regulation Service at a quantity and/or price point different than those specified in Section 15.3.7 of Rate Schedule 3 to the ISO Services Tariff. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to 90 days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

After the first year the Regulation Service Demand Curve is in place, the ISO shall perform periodic reviews, subject to the scope requirement specified in Section 15.3.7 of Rate Schedule 3 to the ISO Services Tariff, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Regulation Service Demand Curve. *See* Section 15.3.7 of Rate Schedule 3 to the ISO Services Tariff.

30.4.6.4.2 Responsibilities related to the Operating Reserves Demand Curves

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure any Operating Reserve product at a quantity and/or price point different than those specified in Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified in Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to 90 days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

After the first year the Operating Reserves Demand Curves are in place, the ISO shall perform periodic reviews, subject to the scope requirement specified in Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Operating Reserve Demand Curves. *See* Section 15.4.7 of Rate Schedule 4 to the ISO Services Tariff.

30.4.6.5 Market Monitoring Unit responsibilities set forth in the Attachments to the ISO Services Tariff (other than the Market Mitigation Measures).

30.4.6.5.1 Responsibilities related to Transmission Shortage Cost

The ISO may periodically evaluate the Transmission Shortage Cost to determine whether it is necessary to modify the Transmission Shortage Cost to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this evaluation.

If the ISO determines that it is necessary to modify the Transmission Shortage Cost in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to 90 days, provided however the ISO shall file such change with the Commission pursuant to § 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change. *See* Section 17.1.4 of Attachment B to the ISO Services Tariff.

30.4.6.5.2 Responsibilities under Appendix 4 to the Operating Protocol for the Implementation of Commission Opinion No. 476 (the “Operating Protocol”)

The ISO and PJM and their Market Monitoring Units shall, to the extent compatible with their respective tariffs and with any other market monitoring procedures that they have filed with the Commission:

- 30.4.6.5.2.1 Conduct such investigations as may be necessary to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the 600/400 MW contracts;
- 30.4.6.5.2.2 Conduct investigations that go into the region of the other ISO jointly with the ISO, PJM and both Market Monitoring Units;
- 30.4.6.5.2.3 Inform each other of any such investigations; and
- 30.4.6.5.2.4 Share information related to such investigations, as necessary to conduct joint investigations, subject to the requirements of Section C of Appendix 4 to the Operating Protocol and Section 30.6.6 of Attachment O.

See Section A of Appendix 4 to Attachment M-1 to the ISO Services Tariff.

30.4.6.6 Market Monitoring Unit responsibilities set forth in the ISO OATT

30.4.6.7 Market Monitoring Unit responsibilities set forth in the Rate Schedules to the ISO OATT

30.4.6.8 Market Monitoring Unit responsibilities set forth in the Attachments to the ISO OATT

30.4.6.8.1 Responsibilities related to implementing new scheduling path prohibitions

If the ISO, acting in consultation with its Market Monitoring Unit, identifies transmission scheduling paths that are being used to schedule External Transactions in a manner that is not consistent with the manner in which power is actually expected to flow, the ISO may submit a compliance filing in FERC Docket No. ER13-780 proposing to expand the list of prohibited scheduling paths included in Section 16.3.3.8 of the ISO OATT. The ISO's compliance filing will include, or be accompanied by, a discussion of the Market Monitoring Unit's position regarding the ISO's proposal to add a new prohibited scheduling path or new prohibited scheduling paths. The Market Monitoring Unit's position may be explained in the ISO's filing

letter, be set forth in an accompanying affidavit, or be submitted by the Market Monitoring Unit as a companion filing or as comments on the ISO's compliance filing in Docket No. ER13-780.

See Section 16.3.3.8 of Attachment J to the ISO OATT.

30.4.6.8.2 Responsibilities related to the draft Reliability Needs Assessment

Following the Management Committee vote, the draft Reliability Needs Assessment (RNA), with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft RNA will be provided to the Market Monitoring Unit for its review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets.

See Section 31.2.3.2 of Attachment Y to the ISO OATT.

30.4.6.8.3 Responsibilities related to the draft Comprehensive Reliability Plan

Following the Management Committee vote, the draft Comprehensive Reliability Plan (CRP), with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CRP will also be provided to the Market Monitoring Unit for its review and consideration of whether market rule changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. *See* Section 31.2.6.2 of Attachment Y to the ISO OATT.

30.4.6.8.4 Responsibilities related to the draft Congestion Analysis and Resource Integration Study

Following the Management Committee vote, the draft Congestion Analysis and Resource Integration Study (CARIS), with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CARIS will be provided to the Market Monitoring Unit for its review and consideration. *See* Section 31.3.2.2 of Attachment Y to the ISO OATT.

30.4.6.8.5 Responsibilities related to the draft report on transmission solutions for Public Policy Requirements

Following the Management Committee vote, the draft report on transmission solutions for Public Policy Requirements that drive the need for expansions or upgrades to BPTFs, with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft report will be provided to the Market Monitoring Unit for its review and consideration of any impact of such regulated transmission project on the ISO administered-markets. *See* Section 31.4.7 of Attachment Y to the ISO OATT.

30.4.6.9 Market Monitoring Unit responsibilities set forth in other documents that have been formally filed with the Commission.

30.4.7 Availability of Data and Resources to Market Monitoring Unit

30.4.7.1 The ISO shall ensure that the Market Monitoring Unit has sufficient access to ISO resources, personnel and market data to enable the Market Monitoring Unit to carry out its functions under Attachment O. Consistent with Section 30.6.1 of Attachment O, the Market Monitoring Unit shall have complete access to the ISO's databases of market information.

30.4.7.2 Any data created by the Market Monitoring Unit, including but not limited to reconfiguration of the ISO's data, will be kept within the exclusive control of the Market Monitoring Unit. The Market Monitoring Unit may share the data it creates, subject to the limitations on distribution of and obligation to protect the confidentiality of Protected Information that are contained in Attachment O, the ISO Services Tariff, and the ISO's Code of Conduct.

30.4.7.3 Where data outside the ISO's geographic footprint would be helpful to the Market Monitoring Unit in carrying out its duties, the Market Monitoring Unit should seek out that data (with assistance from the ISO, where appropriate).