26 Attachment T – Cost Allocation Methodology for Schedule 1 Bid Production Guarantees for Additional Generating Units Committed to Meet Forecast Load

The Day-Ahead commitment of generating units includes sufficient Resources to provide for the safe and reliable operation of the NYS Power System. In cases in which the sum of all Day-Ahead Bilateral Schedules, and all Day-Ahead purchases of energy to serve Load within the NYCA is less than the ISO's Day-Ahead forecast of Load, the ISO may commit Resources in addition to the reserves it normally maintains ("Additional Resources"). Payments for Bid Production Cost guarantees ("BPCG") made to such Additional Resources are to be allocated pursuant to the methodology set forth below and recovered under Rate Schedule 1 of the OATT. Any BPCG payments made to Additional Resources that are not allocated pursuant to this methodology shall be allocated to Transmission Customers according to the provisions of Section 6.1.7.2, of Rate Schedule 1 of the OATT

For purposes of this Attachment T, "Eligible Transmission Customers" are Transmission Customers that are scheduled to sell Energy at a Load bus specified for Virtual Transactions in the Day-Ahead Market and Transmission Customers purchasing Energy to serve load in the real-time market at a Load bus that is not a Load bus specified for Virtual Transactions and not a Proxy Generator Bus. Load Zones and composite Load Zones used in the allocation of Bid Production Cost guarantee payments made to Additional Resources are initially set as: (i) Load Zones A-E, (ii) Load Zones F-I, (iii) Load Zone J, and (iv) Load Zone K and may be adjusted by the ISO to reflect the most frequently constrained transmission interfaces in the NYCA.

BPCG payments made to Additional Resources shall be allocated to each Eligible Transmission Customer as follows:

$$BPCG_c = BPCG_{NYCA} \times \sum_{L \in NYCA} \left(K_L^{fe} \times K_L^{loc} \times K_{c,L}^{customer} \right)$$

Where:

$BPCG_c$	Obligation of Transmission Customer “c” for the Bid Production Cost guarantees for Additional Resources for the day.
$BPCG_{NYCA}$	Total Bid Production Cost guarantees paid to Additional Resources in the NYCA for the day.
c	An Eligible Transmission Customer.
J	Index for Load Zones or Composite Load Zones in the set NYCA
D	Index for eligible transmission customers in the NYCA
E	Set of all eligible transmission customers
L	Load Zone or Composite Load Zone
K^{fe}_{L}	A scale factor calculated for each Load Zone or Composite Load Zone that determines the portion of BPCG to Additional Resources that will be allocated through the procedures described in this attachment.
K^{loc}_{L}	A scale factor calculated for each Load Zone or Composite Load Zone “L” that determines the share of BPCG to Additional Resources that shall be allocated to that Load Zone or Composite Load Zone. The scale factor is based on the ratio of Energy purchases in the real-time market by Eligible Transmission Customers in load zone or composite load zone “L” in each hour, summe~~r~~d over the hours of the day in which these purchases are positive, to all Energy purchases in the real-time market by Eligible Transmission Customers in each Load Zone or Composite Load Zone in each hour, summed over the hours of the day in which these purchases in a given Load Zone or Composite Load Zone are positive, and summed over all Load Zones or Composite Load Zones.
$K^{customer}_{c,L}$	A scale factor calculated for Eligible Transmission Customer “c” in Load Zone or Composite Load Zone “L” which determines the portion of the BPCG to Additional Resources allocated to that Load Zone or Composite Load Zone that shall be allocated to that Eligible Transmission Customer “c.”
RTP^{act}_{L}	Net Energy purchases from the Real-Time market in Load Zone or Composite Load Zone “L” by all Eligible Transmission Customers in each hour, summed over the hours of the day in which these purchases are positive.
$RTP^{act}_{c,L}$	Energy purchases from the Real-Time market in Load Zone or Composite Load Zone “L” by an Eligible Transmission Customer “c” in each hour

	summed over hours of the day in which these purchases are positive.
RTP^{fcst}_{L}	The sum of (1) Day-Ahead sales for each hour of the day in the Day-Ahead market at the Load bus specified for Virtual Transactions in Load Zone or Composite Load Zone "L" by Eligible Transmission Customers; and (2) the ISO's Day-Ahead forecast Load requirement for Load Zone or Composite Load Zone "L" for that hour of the day less the sum of Energy purchases from the Day-Ahead market at Load buses including Load buses specified for Virtual Transactions but not Proxy Generator Buses and Bilateral Transactions with POWs that are Load Buses other than those specified for Virtual Transactions and other than Proxy Generator Buses for that hour; summed over the hours of the day in which the sum of (1) and (2) is positive.

K^{fe}_{L} shall be calculated as shown below except that the value one shall be used if the expression yields a number greater than one.

$$K_L^{fe} = \frac{RTP_L^{act}}{RTP_L^{fcst}}$$

K^{loc}_{L} shall be calculated as shown below.

$$K_L^{loc} = \frac{RTP_L^{act}}{\sum_{j \in NYCA} RTP_j^{act}},$$

$K^{customer}_{c,L}$ shall be calculated as shown below.

$$K_{c,L}^{customer} = \frac{RTP_{c,L}^{act}}{\sum_{d \in E} RTP_{d,L}^{act}},$$

The residual BPCG payments not allocated to such Additional Resources according to the methodology described above shall be allocated to all Transmission Customers using the methods described in Section 6.1.7.2., of Rate Schedule 1 of the OATT. The residual is determined according to:

$$BPCG_{NYCA} - \sum_{c \in E} BPCG_c.$$

15.3 Rate Schedule 3 - Payments for Regulation Service

This Rate Schedule applies to Suppliers that provide Regulation Service to the ISO. Transmission Customers will purchase Regulation Service from the ISO under the ISO OATT.

15.3.1 Obligations of the ISO and Suppliers

15.3.1.1 The ISO shall:

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

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

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

(d) Establish minimum metering requirements and telecommunication capability required for a Supplier to be able to respond to AGC Base Point Signals and RTD Base Point Signals sent by the ISO;

(e) Select Suppliers to provide Regulation Service in the Day-Ahead Market and Real-Time Market, as described in Section 15.3.2 of this Rate Schedule;

(f) Pay Suppliers for providing Regulation Service as described in Sections 15.3.4, 15.3.5, 15.3.6 and 15.3.7 of this Rate Schedule; and

(g) Monitor Suppliers' performance to ensure that they provide Regulation Service as required, as described in Section 15.3.3 of this Rate Schedule.

15.3.1.2 Each Supplier shall:

(a) Register with the ISO the capacity its resources are qualified to bid in the Regulation Services market;

(b) Offer only Resources that are; (i) ISO-Committed Flexible or Self-Committed Flexible, provided however that Demand Side Resources shall be offered as ISO-Committed Flexible; within the dispatchable portion of their operating range, and; (ii) able to respond to AGC Base Point Signals sent by the ISO pursuant to the ISO Procedures, to provide Regulation Service;

(c) Not use, contract to provide, or otherwise commit Capability that is selected by the ISO to provide Regulation Service to provide Energy or Operating Reserves to any party other than the ISO;

(d) Pay any charges imposed under this Rate Schedule including, if they are re-instituted the charges described in Section 15.3.8 of this Rate Schedule;

(e) Ensure that all of its Resources that are selected to provide Regulation Service comply with Base Point Signals issued by the ISO at all times pursuant to the ISO Procedures; and ensure that all of its Resources that are selected to provide Regulation Service comply with all criteria and ISO Procedures that apply to providing Regulation Service.

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

(a) The ISO shall select Suppliers, in the Day-Ahead Market, to provide Regulation Service for each hour in the following Dispatch Day, from those that have Bid to provide Regulation Service from Resources that meet the qualification standards and criteria established in Section 15.3.1 of this Rate Schedule and in the ISO Procedures.

(b) Real-Time Market: The ISO shall establish a Real-Time Market for Regulation Service and will establish a real-time Regulation Service market clearing price in each interval. During any period when the ISO suspends Resources' obligation to follow the AGC Base Point Signals sent to Regulation Service providers, pursuant to Section 15.3.9 of this Rate Schedule, the Real-Time Market clearing price for Regulation Service shall automatically be set at zero, which shall be the price used for real-time balancing and settlement purposes. The ISO shall select Suppliers for Regulation Service from those that have Bid to provide Regulation Service from Resources that meet the qualification standards and criteria established in the ISO Procedures.

(c) The ISO shall establish separate market clearing prices for Regulation Service in the Day-Ahead Market and the Real-Time Market under Sections 15.3.4, 15.3.5 and 15.3.7 of this Rate Schedule. The ISO shall also compute Regulation Revenue Adjustment Payments and Regulation Revenue Adjustment Charges under Section 15.3.6 of this Rate Schedule.

15.3.2.1 Bidding Process

(a) A Supplier may submit a Bid in the Day- Ahead Market or the Real-Time Market to provide Regulation Service from eligible Resources, provided, however, that Bids submitted by Suppliers that are attempting to re-qualify to provide Regulation Service, after being disqualified pursuant to Section 15.3.3 of this Rate Schedule 3, may be limited by the ISO pursuant to ISO Procedures.

(b) Bids rejected by the ISO may be modified and resubmitted by the Supplier to the ISO in accordance with the terms of the ISO Tariff.

(c) Each Bid shall contain the following information: (i) the maximum amount of Capability (in MW) that the Resource is willing to provide for Regulation Service; (ii) the Resource's regulation response rate (in MW/Minute) which must be sufficient to permit that Resource to provide the offered amount of Regulation Service within an RTD interval provided, however, that the regulation response rate for Demand Side Resources shall be at least equal to its energy response rate; (iii) the Supplier's Availability Bid Price (in $/MW); and (iv) the physical location and name or designation of the Resource.

(d) Regulation Service Offers from Limited Energy Storage Resources: The ISO may reduce the real-time Regulation Service offer (in MWs) from a Limited Energy Storage Resource to account for the Energy storage capacity of such Resource.

15.3.3 Monitoring Regulation Service Performance and Performance Related Payment Adjustments

(a) The ISO shall establish (i) Resource performance measurement criteria; (ii) procedures to disqualify Suppliers whose Resources consistently fail to meet those criteria; and (iii) procedures to re-qualify disqualified Suppliers, which may include a requirement to first demonstrate acceptable performance for a time.

(b) The ISO shall establish and implement a Performance Tracking System to monitor the performance of Suppliers that provide Regulation Service. The ISO shall develop performance indices, which may vary with Control Performance, as part of the ISO Procedures. The Performance Tracking System shall compute the difference between the Energy actually supplied and the Energy scheduled by the

ISO for all Suppliers serving Load within the NYCA as set forth in the ISO Procedures. The ISO shall use these values to reduce Regulation Service payments pursuant to Section 15.3.5.5 of this Rate Schedule.

(c) Resources that consistently fail to perform adequately may be disqualified by the ISO, pursuant to ISO Procedures.

15.3.4 Regulation Service Settlements - Day-Ahead Market

15.3.4.1 Calculation of Day-Ahead Market Clearing Prices

The ISO shall calculate a Day-Ahead Market clearing price for Regulation Service each hour of the following day. The Day-Ahead Market clearing price for each hour shall equal the Day-Ahead Shadow Price of the ISO's Regulation Service constraint for that hour, which shall be established under the ISO Procedures. Day-Ahead Shadow Prices will be calculated by the ISO's SCUC. Each hourly Day-Ahead Shadow Price shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that hour, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that hour,, as calculated during the fifth SCUC pass described in Section 17.1.2 of Attachment B to this ISO Services Tariff, and Section 16.1.2 of Attachment J to the ISO OATT. As a result, the Shadow Price shall include the Day-Ahead Regulation Service Bid of the marginal Resource selected to provide Regulation Service (or in the applicable price on the Regulation Service Demand Curve during shortage conditions), plus any margins on the sale of Energy or Operating Reserves in the Day-Ahead Market that the Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves. Shadow Prices shall also be consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule, which will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Regulation Service Demand Curve indicates should be paid. Each Supplier that is scheduled Day-Ahead to provide Regulation Service shall be paid the Day-Ahead Market clearing price in each hour, multiplied by the amount of Regulation Service that it is scheduled to provide in that hour.

15.3.4.2 Other Day-Ahead Payments

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 Clearing Prices

The ISO shall calculate a Real-Time Market clearing price for Regulation Service for every RTD interval, except as noted in Section 15.3.9 of this Rate Schedule. Except when the circumstances described below in Section 15.3.5.2 apply, the Real-Time Market clearing price for each interval shall equal the real-time Shadow Price for the ISO's Regulation Service constraint for that RTD interval, which shall be established under the ISO Procedures. Real-time Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Regulation Service in that interval, including any impact on the Bid Production Cost of procuring Energy or Operating Reserves that would result from procuring an increment of Regulation Service in that interval, as calculated during the third RTD pass described in Section

17.1.1.1.2.3 of Attachment B to this ISO Services Tariff, and Section 16.1.1.1.2.3 of Attachment J to the ISO OATT. As a result, the Shadow Price shall include the Real-Time Regulation Service Bid of the marginal Resource selected to provide Regulation Service (or the applicable price on the Regulation Service Demand Curve during shortage conditions), plus any margins on the sale of Energy or Operating Reserves in the Real-Time Market that Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves. Shadow Prices shall also be consistent with the Regulation Service Demand Curves described in Section 15.3.7 of this Rate Schedule, which will ensure that Regulation Service is not scheduled by RTC at a cost greater than the Demand Curve indicates should be paid.

15.3.5.2 Calculation of Real-Time Market Clearing Prices for Regulation Service During EDRP/SCR Activations

During any interval in which the ISO is using scarcity pricing rule “A” or “B” to calculate LBMPs under Sections 17.1.1.2 or 17.1.1.3 of Attachment B to this ISO Services Tariff, and Sections 16.1.1.2 or 16.1.1.3 of Attachment J to the ISO OATT, the real-time Regulation Service market clearing price may be recalculated in light of the Availability Bids of Suppliers and Lost Opportunity Costs of Generators scheduled to provide Regulation Service in real-time.

Specifically, when either scarcity pricing rule is applicable, the real-time Regulation Service clearing price shall be set to the higher of: (i) the highest total Availability Bid and Lost Opportunity Cost of any Regulation Service provider scheduled by RTD; and (ii) the market clearing price calculated under Section 15.3.5.1 of this Rate Schedule.

15.3.5.3 Real-Time Regulation Service Balancing Payments

Any deviation from a Supplier's Day-Ahead schedule to provide Regulation Service shall be settled pursuant to the following rules.

(a) When the Supplier's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Market clearing price for Regulation Service; and (ii) the difference between the Supplier's Day-Ahead Regulation Service schedule and its real-time Regulation Service schedule (subject to possible adjustments pursuant to Section 15.3.5.5 of this Rate Schedule.)

(b) When the Supplier's real-time Regulation Service schedule is greater than its Day-Ahead Regulation Service schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time market clearing price for Regulation Service; and (ii) the difference between the Supplier's real-time Regulation Service schedule and its Day-Ahead Regulation Service schedule(subject to possible adjustments pursuant to Section 15.3.5.5 of this Rate Schedule.)

15.3.5.4 Other Real-Time Regulation Service Payments

A Supplier that bids on behalf of a Generator that provides Regulation Service 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 provides Regulation Service 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 Payments and Performance-Based Adjustments to Payments for Regulation Service Providers

Each Supplier that is scheduled in real-time to provide Regulation Service shall be paid in accordance with the following formula. The amount paid to each Supplier for providing Regulation Service in each RTD interval i shall be reduced to reflect the Supplier's performance:

$$\text{Total Payment} = \Sigma_i(\text{Total Payment}_i * (s_i/3600))$$

Where:

$\text{Total Payment}_i = (\text{DAMCPreg}_i \times \text{DARcap}_i) + ((\text{RTRcap}_i \times K_{-i}) - \text{DARcap}_i) \times \text{RTMCPreg}_i$

DAMCPreg_i is the applicable market clearing price for Regulation Service (in $/MW), in the Day-Ahead Market, as established by the ISO pursuant to Section 15.3.4.1 of this Rate Schedule for the hour that includes RTD interval i;

$\text{DAR}cap_i$ is the Regulation Service Capability (in MW) offered by the Resource and selected by the ISO in the Day-Ahead Market in the hour that includes RTD interval i;

RTMCPreg_i is the applicable market clearing price for Regulation Service (in $/MW), in the Real-Time Market as established by the ISO under Section 15.3.5.1 of this Rate Schedule in RTD interval i;

RTRcap_i is the Regulation Service Capability (in MW) offered by the Resource and selected by the ISO in the Real-Time Market in RTD interval i;

s_i is the number of seconds in interval i; and

K_i is a factor, with a value between 0.0 and 1.0 inclusive, derived from each Supplier's Regulation Service performance, as measured by the performance indices set forth in the ISO Procedures and determined pursuant to the following equation:

$$K_i = (PI_i - PSF) / (1-PSF)$$

Where:
PI_i is the performance index of the Resource for interval i; and

PSF is the payment scaling factor, established pursuant to ISO Procedures. The PSF shall be set between 0 and the minimum performance index required for payment of Availability payments.

The PSF is established to reflect the extent of ISO compliance with the standards established by NERC, NPCC or Good Utility Practice for Control Performance and System Security. The PSF is set initially at zero. Should the ISO's compliance with these measures deteriorate, in a manner that can be improved if regulation performance improves, the PSF will be increased. Resources providing Regulation Service will be required to increase their performance index to obtain the same total Regulation Service payment as they received during periods of good ISO performance, as measured by these standards. The factor K_{PI} shall initially be set at 1.0 for Limited Energy Storage Resources. 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.

15.3.6 Energy Settlement Rules for Generators Providing Regulation Service

15.3.6.1 Energy Settlements

A. For any interval in which a Generator is providing Regulation Service, it shall receive a settlement payment for Energy consistent with a real-time Energy injection equal to the lower of its actual generation or its AGC Base Point Signal. Demand Side Resources providing Regulation Service shall not receive a settlement payment for Energy.

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

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

Where:

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

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

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

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it shall receive or pay a Regulation Revenue Adjustment Payment ("RRAP") or Regulation Revenue Adjustment Charge ("RRAC") calculated under the terms of this subsection, provided however no RRAP shall be payable and no RRAC shall be charged to a Limited Energy Storage Resource. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall receive a RRAP. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at is location at that interval, the Generator shall be assessed a RRAC. RRAPs and RRACs shall be calculated using the following formula:

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

Where:

s is the number of seconds in the RTD interval;

If the result of the calculation is positive then the Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of applying this formula, whenever the Generator’s actual Bid exceeds the applicable LBMP the “Bid” term shall be set at a level equal to the lesser of the Generator’s actual Bid or its reference Bid plus $100/MWh. Demand Side Resources providing Regulation Service shall not be eligible for a RRAP and not liable for an RRAC.

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

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

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

Where:

s is the number of seconds in the RTD interval;

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

15.3.7 Regulation Service Demand Curve

The ISO shall establish a Regulation Service Demand Curve that will apply to both the Day-Ahead and real-time Regulation Service markets. The market clearing prices for Regulation Service calculated pursuant to Sections 15.3.4.1 and 15.3.5.1 of this Rate Schedule shall take account of the demand curve established in this Section so that Regulation Service is not purchased by SCUC or RTC at a cost higher than the demand curve indicates should be paid in the relevant market.

The ISO shall establish and post a target level of Regulation Service for each hour, which will be the number of MW of Regulation Service that the ISO would seek to maintain in that hour. The ISO will then define a Regulation Service demand curve for that hour as follows:

For quantities of Regulation Service that are less than or equal to the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be $300/MW.

For quantities of Regulation Service that are less than or equal to the target level of Regulation Service but that exceed the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be $250/MW.

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

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

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

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

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

15.3.8 Reinstating Performance Charges

The ISO will monitor, on a real-time hourly or daily basis, as appropriate, its compliance with the standards established by NERC and NPCC and with the standards of Good Utility

Practice for Control Performance, area control error, disturbance control standards, reserve pickup performance and system security. Should it appear to the ISO that degradation in performance threatens compliance with one or more of the established standards for these criteria or compromises reliability, and that reinstating the performance charges that were originally part of the ISO's market design, would assist in improving compliance with established standards for these criteria, or would assist in re-establishing reliability, the ISO may require Suppliers of Regulation Service, as well as Suppliers not providing Regulation Service, to pay a performance charge. Any reinstatement of Regulation penalties pursuant to this Section shall not override previous Commission-approved settlement agreements that exempt a particular unit from such penalties. The ISO shall provide notice of its decision to reinstate performance charges to the Commission, to each Customer and to the Operating Committee and the Business Issues Committee no less than seven days before it re-institutes the performance charges.

If the ISO determines that performance charges are necessary, Suppliers of Regulation Service shall pay a performance charge per interval to the ISO as follows:

Performance Charge = Energy Deviation x MCP_{reg} x (Length of Interval/60 minutes)

Where:

Energy Deviation (in MW) is the absolute difference between the actual Energy supplied by the Supplier and the Energy required by the AGC Base Point Signals, whether positive or negative, averaged over each RTD interval; and

MCP_{reg} is the market clearing price ($/MW) which applies to the RTD interval for this Service in the Real-Time Market or the Day-Ahead Market, if appropriate.

The method used by the ISO to calculate the Energy Deviation will permit Suppliers a certain period of time to respond to AGC Base Point Signals. Initially this time period will be thirty (30) seconds, although the ISO will have the authority to change its length. If the

Supplier's output at any point in time is between the largest and the smallest of the AGC Base Points sent to that Supplier within the preceding thirty (30) seconds (or such other time period length as the ISO may define), the Supplier's Energy Deviation at that point in time will be zero. Otherwise, the Supplier may have a positive Energy Deviation. However, in cases in which responding to the AGC Base Point within that time period would require a Supplier to change output at a rate exceeding the amount of Regulation it has been scheduled to provide, the Supplier will have a zero Energy Deviation if it changes output at the rate equal to the amount of Regulation it is scheduled to provide.

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

During any period in which the ISO has activated its RTD-CAM software and called for a "large event" or "small event" reserve or maximum generation pickup, as described in Article 4.4.4.1 of this ISO Services Tariff, the ISO will suspend Generators' obligation to follow the AGC Base Point Signals sent to Regulation Service providers, freeing them to provide Energy and will suspend the real-time Regulation Service market. The ISO will not procure any Regulation Service and will establish a real-time Regulation Service market clearing price of zero for settlement and balancing purposes. The ISO will resume sending AGC Base Point Signals and restore the real-time Regulation Service market as soon as possible after the end of the reserve or maximum generation pickup.

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) areal-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 Care Resources BPCG; (ix) a BPCG for Demand Side Resources providing synchronized Operating Reserves in the Day-Ahead Market; and (x) a BPCG for Demand Side Resources providing synchronized Operating Reserves 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:

18.2.1.2.1 a Supplier that bids on behalf of a Limited Energy Storage Resource shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment; and

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

18.2.2 Formulas for Determining Day-Ahead BPCG for Generators

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

Day-Ahead Bid Production Cost Guarantee for Generator g =

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

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

N	=	number of hours in the Day-Ahead Market day;
EH_{gh}^{DA}	=	Energy scheduled Day-Ahead to be produced by Generator g in hour h expressed in terms of MWh;
MGH_{gh}^{DA}	=	Energy scheduled Day-Ahead to be produced by the minimum generation segment of Generator g in hour h expressed in terms of MWh;
C_{gh}^{DA}	=	Bid cost submitted by Generator g, or when applicable the mitigated Bid cost curve for Generator g, in the Day-Ahead Market for hour h expressed in terms of \$/MWh;
MGC_{gh}^{DA}	=	Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, for hour h in the Day-Ahead Market, expressed in terms of \$/MWh. If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day and Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), then Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Day-Ahead Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gh}^{DA} = Start-Up Bid by Generator g in hour h, or when applicable the mitigated Start-Up Bid for Generator g, in hour h in~~to~~ 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 Bid to provide that amount of Regulation Service in that hour (unless the Bid exceeds the payments that Generator receives for providing Regulation Service that was committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead, in which case this component shall be zero); and (3) payments made to that Generator for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less that Generator's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.3 Day-Ahead BPCG For Imports

18.3.1 Eligibility to Receive a Day-Ahead BPCG for Imports

A Supplier that bids an Import sale to the LBMP Market 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 =

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

Where;

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

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

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

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

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

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

18.4.1.1 Eligibility.

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

18.4.1.1.1 an ISO-Committed Flexible Generator or an ISO-Committed Fixed Generator that is committed by the ISO in the Real-Time Market; or

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

18.4.1.2.1 a Supplier that bids on behalf of a Limited Energy Storage Resource shall not be eligible to receive a real-time Bid Production Cost guarantee payment;

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

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

Real-Time Bid Production Cost Guarantee for Generator g =

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

where:

s_i = number of seconds in RTD interval i;

C_{gi}^{RT} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost for Generator g, in the RTD for the hour that includes RTD interval i expressed in terms of $/MWh, except in intervals in which the dispatch of the Generator is constrained by its downward ramp rate for that interval, unless that Generator was scheduled to provide Regulation Service in that interval and its RTD basepoint was less than its AGC basepoint, and except in hours in which the NYISO has increased Generator g's minimum operating level, either (i) at the Generator's request, 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.

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;

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 ~~the hour that includes RTD interval~~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 Bid(s) placed by that Generator to provide Regulation Service in that hour at the time it was committed to produce Energy for the LBMP Market and/or Ancillary Services to do so (unless the Bid(s) exceeds the payments that Generator receives for providing Regulation

Service, in which case this component shall be zero); (3) payments made to that Generator for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by that Generator to provide such reserves in that hour at the time it was scheduled to do so; and (4) Lost Opportunity Cost payments made to that Generator in that hour as a result of reducing that Generator's output in order for it to provide Voltage Support Service.

$NASR_{gi}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, expressed in terms of $, that is applicable to interval i calculated by multiplying the $NASR_{gh}^{DA}$ for the hour that includes interval i by $_{Si}$/3600.

$RRAP_{gi}$ = Regulation Revenue Adjustment Payment for Generator g in RTD interval i expressed in terms of $.

$RRAC_{gi}$ = Regulation Revenue Adjustment Charge for Generator g in RTD interval i expressed in terms of $.

18.4.3 Bids Used For Intervals at the End of the Hour

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

18.5 BPCG For Generators In Supplemental Event Intervals

18.5.1 Eligibility for BPCG for Generators in Supplemental Event Intervals

18.5.1.1 Eligibility

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

18.5.1.2 Non-Eligibility

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

18.5.1.3 Additional Eligibility

Notwithstanding Section 18.5.1.2, a Supplier shall be eligible to receive a Bid Production Cost guarantee payment for a Generator, not a Limited Energy Storage Resource, 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.~~**18.5.1.3 Exception to Non-Eligibility**~~

~~Notwithstanding Sections 18.5.1.1 and 18.5.1.2, units using a Self-Committed fixed or Self-Committed Flexible bid mode shall be eligible to receive a Bid Production Cost guarantee payment under this section for intervals in which the ISO has called an emergency under Section 4.4.4.1.2 of this ISO Services Tariff.~~

18.5.2 Formula for Determining BPCG for Generators in Supplemental Event Intervals

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

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

where:

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

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

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

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

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

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

18.6 Real-Time BPCG For Imports

18.6.1 Eligibility for Receiving Real-Time BPCG for Imports

18.6.1.1 Eligibility.

A Supplier that bids an Import to sell Energy to the LBMP Market 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 when a Non-Competitive Proxy Generator Bus or the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located is export constrained due to limits on available Interface Capacity or Ramp Capacity limits for that Interface in an hour, External Generators and other Suppliers scheduling 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; and

18.6.1.2.2 when a Proxy Generator Bus that is associated with a designated Scheduled Line is export constrained due to limits on available Interface Capacity in an hour, External Generators and other Suppliers scheduling 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.

18.6.2 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 =

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

Where:

Q	= number of intervals in the Dispatch Day;
$\mathrm{DecBid}_{ti}^{RT}$	= Decremental Bid, in $/MWh, supplied for Import t for interval i;
LBMP_{ti}^{RT}	= real-time LBMP, in $/MWh, for interval i at Proxy Generator Bus ~~p~~ which is the source of the Import t;
$\mathrm{SchImport}_{ti}^{RT}$	= total real-time schedule, in MW, for Import t in interval i; and
$\mathrm{SchImport}_{ti}^{DA}$	= 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 =

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

where:

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

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

$$\text{IncrCurCost}_{d}^{h}=\int_{\text{MinCur}_{d}^{h}}^{\max(\text{MinCur}_{d}^{h},\min(SchdCur_{d}^{h},ActCur_{d}^{h}))}\text{IncrCurBid}_{d}^{h}]$$

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

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

$LBMP_{dh}^{DA}$ = Day-Ahead LBMP for Day-Ahead Demand Reduction Provider d for hour h expressed in $/MWh.

18.9 BPCG For Special Case Resources

18.9.1 Eligibility for Special Case Resources BPCG

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

18.9.2 Methodology for Determining Special Case Resources BPCG

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

18.10 BPCG For Demand Side Resources Providing Synchronized Operating Reserves In The Day-Ahead Market

18.10.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Day-Ahead Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves 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 in the Day-Ahead Market

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

BPCG for Demand Side Resource d Providing synchronized Operating Reserves 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 Bid to provide that amount of Regulation Service in that hour (unless the Bid exceeds the payments that the Demand Side Resource receives for providing Regulation Service that was committed to provide Ancillary Services Day-Ahead, in which case this component shall be zero); 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 In The Real-Time Market

18.11.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Real-Time Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves 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 in the Real-Time Market

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

BPCG for Demand Side Resource d Providing synchronized Operating Reserves in Real-Time =

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

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 Bid(s) placed by Demand Side Resource d to provide Regulation Service in that hour at the time it was committed to provide Ancillary Services (unless the Bid(s) exceeds the payments that Demand Side Resource d receives for providing Regulation Service, in which case this component shall be zero); and (2) payments made to Demand Side Resource d for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by Demand Side Resource d to provide such reserves in that hour at the time it was scheduled to do so; and

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

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

18.12.1 Eligibility to Recover Operating Costs and Resulting Obligations

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

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

Rules for calculating the reference level that the NYISO uses to test Start-Up Bids for possible mitigation are included in the Market Power Mitigation Measures that are set forth in Attachment H to the ISO Services Tariff. Proration of the start-up cost component of a

Generator's Bid Production Cost guarantee based on the Generator's operation in real-time is different/distinct from the mitigation of a Start-Up Bid.

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

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

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

$TotMWReq_{g,s} = MinOpMW_{g,s} * n_{g,s}$,

Where:

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

$MinOpMW_{g,s}$ = Minimum operating level (in MW) specified by Generator g in its hour s Bid

$n_{g,s}$ = The last hour that Generator g must operate when started in hour s to complete both its minimum run time and its Day-Ahead schedule. The variable $n_{g,s}$ is calculated as follows:

$$n_{g,s} = \max\left(LastHrDASched_{g,s}, LastMinRunHr_{g,s}\right),$$

Where:

$LastHrDASched_{g,s}$ = The last date/hour in a contiguous set of hours in the Dispatch Day, beginning with hour s, in which Generator g is scheduled to operate in the Day-Ahead Market

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

18.12.2.2 Calculation of Prorated Start-Up Cost

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

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:

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

Where:

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

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

a. For any hour that a Generator is derated below the minimum operating level specified in its accepted Start-Up Bid for reliability, either by the ISO or at the request of a Transmission Owner, the Generator will receive credit for that hour as if the Generator had produced metered actual MWh equal to its $MinOpMW_{g,s}$.

b. A Generator must be scheduled and operate in real-time to produce Energy consistent with the $MinOpMW_{g,s}$ specified in the accepted Start-Up Bid for each hour that it is expected to run. *See* Section 18.12.2.1, above. These rules do not specify or require any particular bidding construct that must be used to achieve the desired commitment. However, submitting a self-committed Bid may preclude a Generator from receiving a BPCG. *See, e.g.*, Sections 18.2.1.2.2 and 18.4.1.2.3 of this Attachment C.