BPCG, DAMAP and Related Tariff Provisions
January 6, 2010
BIC

BPCG and Related Tariff Provisions[1]

Definitions (Services Tariff)
These will also be added, amended in the OATT

Eighth Revised Sheet No. 28

~~**2.15b Bid Production Cost Guarantee (“BPCG”)**~~
~~A payment made in accordance with Section 4.10 and Attachment C of this ISO Services Tariff.~~

Seventh Revised Sheet No. 33A

2.36a Day-Ahead Margin
That portion of Day-Ahead LBMP, Operating Reserves settlement or Regulation Services settlement for an hour that represents the difference between the Supplier’s accepted Day-Ahead offer price and the Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for that hour.

2.36b Day-Ahead Margin Assurance Payment
A supplemental payment made to an eligible Supplier that buys out of a Day-Ahead Energy, Regulation Service, or Operating Reserves schedule such that an hourly balancing payment obligation offsets its Day-Ahead Margin. Rules for calculating these payments, and for determining Suppliers’ eligibility to receive them, are set forth in Attachment J of this ISO Services Tariff.

Fifth Revised Sheet No. 35

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

2.46 Economic Operating Point

The megawatt quantity at a point on the eleven constant cost steps that comprise a Supplier’s Incremental Energy Bid for a Resource which megawatt quantity is a function of: i) the Real-Time LBMP at the Resource bus; and ii) the Supplier’s real-time Incremental Energy Bid for the Resource such that the price associated with reducing that megawatt quantity must be less than or equal to the real-time LBMP at that Resource bus and the price associated with increasing that megawatt quantity must be greater than or equal to the real-time LBMP at the Resource bus. When the Real-Time LBMP at the Resource bus is equal to the Incremental Energy Bid for the Resource, the Economic Operating Point is the Resource’s Real-Time Scheduled Energy Injection.

Import Curtailment Guarantee Payment

A payment made in accordance with Section 4.5.C(2) and Attachment J of this ISO Services Tariff to compensate a Supplier whose Import is Curtailed by the ISO.

Sixth Revised Sheet No. 58

2.137 Performance Tracking System

A system designed to report metrics for Generators and Loads which include but are not limited to actual output and schedules. This system is used by the ISO to measure compliance with criteria associated with the provision of Energy and Ancillary Services.

Supplemental Event Interval

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

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

Services Tariff Body

(Excluding Section 4.10 of the Services Tariff)

Original Sheet No. 91B

4.2.5 Reliability Forecast for the Six Days Following the Dispatch Day

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the ISO must ensure that there will be

First Revised Sheet No. 92

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 4.2.5, may be eligible for a Bid Production Cost guarantee pursuant to the provisions of Section 4.10 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

Sixth Revised Sheet No. 99A

A. RTD-CAM Modes

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

First Revised Sheet No. 99A.01

necessary de-commit, Resources capable of starting or stopping within 10-minutes. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements, but will suspend Regulation Service requirements. If Resources are committed or de-committed in this RTD-CAM mode the schedules for them will be passed to RTC and the Real-Time Dispatch for their next execution.

The ISO will have discretion to classify a reserve pickup as a "large event" or a "small event." In a small event the ISO will have discretion to reduce Base Point Signals in order to reduce transmission line loadings. The ISO will not have this discretion in large event. The distinction also has significance with respect to a Supplier's eligibility to receive Bid Production Cost guarantee payment in accordance with Section 4.10 and Attachment C of this ISO Services Tariff.

2. Maximum Generation Pickup

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

First Revised Sheet No. 99A.03

B. Calculating Real-Time LBMPs

When RTD-CAM is activated, except when it is in reserve pickup mode, *ex ante* Real-Time LBMPs will be calculated at each Generator bus, and for each Load Zone, every five minutes, in accordance with the procedures set forth above in Section 4.4.3B. When it is in reserve pickup mode, *ex ante* Real-Time LBMPs will be calculated every ten minutes, but RTD-CAM shall otherwise follow the procedures set forth above in Section 4.4.3B. In addition, when RTD-CAM is activated, Suppliers may be eligible for Bid Production Cost guarantee payments during large event, but not small event, reserve pickups and during maximum generation pickups in accordance with Section 4.10 and Attachment C of this ISO Services Tariff.

C. Posting Commitment Decisions

To the extent that RTD-CAM makes commitment and de-commitment decisions they will be posted at the same time as Real-Time LBMPs.

Section 4.5 (Services Tariff)

First Revised Sheet No. 102.00

subsection C(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 Monitoring and Performance Unit will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control.

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

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

Second Revised Sheet No. 102.01.01

scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible to receive an Import Curtailment Guarantee Payment for its curtailed Import pursuant to Attachment J of this ISO Services Tariff.[2]

Second Revised Sheet No. 102.01

limited upper operating limit shall be equal to the product of: (a) the Real-Time price for Energy, Operating Reserve Service and Regulation Service; and (b) the Capacity Limited Resource's Day-Ahead schedule for each of these services minus the amount of these services that it has an obligation to supply pursuant to its ISO-approved schedule. When a Capacity Limited

[2] The substance of this provision has been relocated to Attachment J of the ISO Services Tariff.

Resource's Day-Ahead obligation above its Capacity limited upper operating limit is balanced as described above, any real-time variation from its obligation pursuant to its Capacity limited schedules shall be settled pursuant to the methodology set forth in the first paragraph of this subsection C.

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

Second Revised Sheet No. 102.02

be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

Section 4.9 (Services Tariff)

Seventh Revised Sheet No. 105

4.9 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.[3]

Fourth Revised Sheet No. 140A

The ISO shall pay Suppliers that schedule Special Case Resources that cause a verified Load reduction, in response to an ISO request to perform due to a Forecast Reserve Shortage, an ISO declared Major Emergency State, or in response to an ISO request to perform made in response to a request for assistance for Load relief purposes or as a result of a Local Reliability Rule, for such Load reduction, in accordance with ISO Procedures. Subject to performance verification Suppliers that schedule Special Case Resources shall be paid the zonal Real-Time LBMP for the period of requested performance or four (4) hours, whichever is greater, in accordance with ISO Procedures, provided, however, Special Case Resource Capacity shall settle Demand Reductions, in the interval and for the capacity for which Special Case Resource Capacity has been scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy, as being provided by a Supplier of Operating Reserves, Regulation Service or Energy.

A Supplier that bids a Special Case Resource may be eligible for a Bid Production Cost guarantee payment pursuant to Section 4.10 and Attachment C of this ISO Services Tariff.

Original Sheet No. 140B

[3] The substance of the deleted portion is addressed in Attachment J of the ISO Services Tariff.

Transmission Owners that require assistance from distributed Generators larger than 100 kW and Loads capable of being interrupted upon

Section 4.10 (Services Tariff)

Seventh Revised Sheet No. 105

4.10 Bid Production Cost Guarantee Payments

4.10.1 Day-Ahead BPCG for Generators

The ISO shall determine if a Supplier eligible under Section 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 Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid to produce Energy in the Day-Ahead Market through Day-Ahead LBMP revenues 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, the ISO shall pay a Day-Ahead BPCG to the Supplier pursuant to Section 2.0 of Attachment C of this ISO Services Tariff.

4.10.2 Day-Ahead BPCG for Imports

The ISO shall determine if a Supplier supplying an Import Sale to the LBMP Market and eligible under Section 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 revenues. 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 3.0 of Attachment C of this ISO Services Tariff.

Eight Revised Sheet No. 106

First Revised Sheet No. 106.00

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

Eight Revised Sheet No. 106.01

First Revised Sheet No. 106.02

The ISO shall determine if a Supplier eligible under Section 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 Minimum Generation Bid, Start-Up Bid, and Incremental Energy Bid to produce

Energy that was not scheduled in the Day-Ahead Market through real-time LBMP revenues 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, the ISO shall pay a real-time Bid Production Cost guarantee payment to the Supplier pursuant to Section 4.0 of Attachment C of this ISO Services Tariff.

4.10.4 BPCG for Generators for Supplemental Event Intervals

The ISO shall determine if a Supplier eligible under Section 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 Minimum Generation Bid and Incremental Energy Bid to produce Energy that was not scheduled Day-Ahead through real-time LBMP revenues 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 5.0 of Attachment C of this ISO Services Tariff.

4.10.5 Real-Time BPCG for Imports

The ISO shall determine if a Supplier supplying an Import sale to the LBMP Market and eligible under Section 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 revenues. 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 6.0 of Attachment C of this ISO Services Tariff.

4.10.6 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 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 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 7.0 of Attachment C of this ISO Services Tariff.

Eighth Revised Sheet No. 106A

4.10.7 BPCG for Demand Reduction in the Day-Ahead Market

The ISO shall determine if a Demand Reduction Provider eligible under Section 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 8.0 of Attachment C of this ISO Services Tariff.

4.10.8 BPCG for Special Case Resources

The ISO shall determine if a Supplier eligible under Section 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 9.0 of Attachment C of this ISO Services Tariff.

Sixth Revised Sheet No. 106B

4.10.9 Day-Ahead BPCG for Demand Side Resources Scheduled to Provide Synchronized Operating Reserves

The ISO shall determine if a Supplier that bids Demand Side Resources committed by the ISO to provide synchronized Operating Reserves 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. Such Supplier shall be eligible under Section 10.1 of Attachment C to this ISO Services Tariff for a Day-Ahead Bid Production Cost guarantee payment.[4] 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 10.0 of Attachment C of this ISO Services Tariff.

[4] This sentence was originally located in Section 4.10 of this ISO Services Tariff (Tariff Sheet 106).

4.10.10 Real-Time BPCG for Demand Side Resources Scheduled to Provide Synchronized Operating Reserves

The ISO shall determine if a Supplier that bids Demand Side Resources committed by the ISO to provide synchronized Operating Reserves will not recover its real-time synchronized Operating Reserves Bid to provide the amount of synchronized Operating Reserves that it was scheduled to provide. Such Supplier shall be eligible under Section 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 11.0 of Attachment C of this ISO Services Tariff.

<u>Second Revised Sheet No. 276.02</u>

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 4.10 and Attachment C of this ISO Services Tariff.

<no changes to end of page>

<u>Third Revised Sheet No. 276.05</u>

5.3 Other Real-Time Regulation Service Payments

A Supplier that bids on behalf of a Generator that provides Regulation Service may be eligible for a Bid Production Cost guarantee payment pursuant to Section 4.10 and Attachment C of this ISO Services Tariff.

<u>Third Revised Sheet No. 276.06</u>

A Supplier that provides Regulation Service may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.9 and Attachment J of this ISO Services Tariff.

<u>Fourth Revised Sheet No. 276A</u>

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Fourth Revised Sheet No. 276B

5.4 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.

$$\text{TotalPayment} = \sum_i \left(\text{TotalPayment}_i \bullet \left(S_i / 3600\right)\right)$$

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 4.1 of this Rate Schedule for the hour that includes RTD interval i;

$DARcap_i$ 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 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_i shall initially be set at 1.0 for Limited Energy Storage Resources.

No payments shall be made to any Supplier providing Regulation Service for any excess amount of Regulation Service beyond that 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.

6.0 Energy Settlement Rules for Generators Providing Regulation Service

6.1 Energy Settlements

A. For any interval in which a Generator is providing Regulation

Rate Schedules 4 (Services Tariff)

Sixth revised Sheet No. 294

Original Sheet No. 294A

Fifth Revised Sheet No. 297

5.2 Other Day-Ahead Payments

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.10 and Attachment C of this ISO Services Tariff.

Seventh Revised Sheet No. 302

6.3. Other Real-Time Payments

The ISO shall pay Generators that are selected to provide Operating Reserves Day-

Ahead, but are directed to convert to Energy production in real-time, the applicable real-time LBMP for all Energy they are directed to produce in excess of their Day-Ahead Energy schedule.

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a Bid Production Cost guarantee payment pursuant to Section 4.10 and Attachment C of this ISO Services Tariff.

Fourth Revised Sheet No. 302A

A Supplier that provides Operating Reserves may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.9 and Attachment J of this ISO Services Tariff.

Attachment C (Services Tariff)

Fourth Revised Sheet No. 421

ATTACHMENT C

DETERMINING BID PRODUCTION COST GUARANTEE PAYMENTS

1.0 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 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, such that a Customer's eligibility to receive one type of Bid Production Cost guarantee payment shall have no impact on the Customer's eligibility to receive another type of Bid Production Cost guarantee payment.

[5]**Second Revised Sheet No. 421A**

2.0 DAY-AHEAD BPCG FOR GENERATORS

2.1 Eligibility to Receive a Day-Ahead BPCG for Generators

(a) *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.

(b) *Non-Eligibility*.

Notwithstanding Section 2.1(a):

[5] Non-synchronized Operating Reserves are not eligible to receive a BPCG.

(i) 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

(ii) a Supplier shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment under this Section 2.0 for an External Transaction.

(iii) 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.

2.2 Formulas for Determining Day-Ahead BPCG for Generators

(a) *Applicable Formula.* A Supplier's BPCG for a Generator g shall be as follows:

Day-Ahead Bid Production Cost guarantee for Generator g =

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

(b) *Variable Definitions.* The terms used in this Section 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;

SUC_{gh}^{DA} = Start-Up Bid by Generator g, 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:

(i) the Start-Up Bid for Generator g, or when applicable the mitigated Start-Up Bid for Generator g, in hour h shall be reduced pro rata if Generator g fails to run for the number of hours for which it was scheduled to run in the Day-Ahead Market, provided however, for purposes of this pro rata reduction, the ISO shall consider the Generator to have run in any hour (a) in which the ISO, in real-time, economically scheduled the Generator not to run;

(ii) 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); and

$NSUH_{gh}^{DA}$ = 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;

<u>Fourth Revised Sheet No. 422</u>

$NASR_{gh}^{DA}$ = Net Ancillary Services revenue, expressed in terms of $, paid to Generator g as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead ~~to operate~~ in hour h 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.

3.0 DAY-AHEAD BPCG FOR IMPORTS

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.

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 3.0, 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.

3.3 Formula for Determining Day-Ahead BPCG for Imports

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

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

Where;

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

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

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

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

4.0 REAL-TIME BPCG FOR GENERATORS IN RTD INTERVALS OTHER THAN SUPPLEMENTAL EVENT INTERVALS

4.1 <u>Eligibility for Receiving Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event Intervals</u>

(a) *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:

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

(ii) a Self-Committed Flexible Generator if the Generator's minimum generation level does not exceed its Day-Ahead schedule at any point during the Dispatch Day, or

(iii) 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 are committed or dispatched by the ISO as Out-of-Merit Generation to meet NYCA or local reliability without regard to the Bid mode(s) employed during the Dispatch Day;

(b) *Non-Eligibility*.

Notwithstanding Section 4.1(a):

(i) 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;

(ii) a Supplier shall not be eligible to receive a real-time Bid Production Cost guarantee payment under this Section 4.0 for an External Transaction;

(iii) 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 generation 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 generation 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 reliability.

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 =

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

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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;

SUC_{gj}^{RT} = Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, for the hour that includes interval j into RTD expressed in terms of \$/start;

provided, however, that:

(i) the Start-Up Bid shall be deemed to be zero in the cases of (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; and
(iv) if a Generator g has been committed via SRE, the Start-Up Bid by such Generator g, or when applicable the mitigated Start-Up Bid for such Generator g, for the hour that includes interval j shall be reduced pro rata if Generator g fails to complete the lesser of its SRE schedule or its minimum run time;

$NSUI_{gj}^{RT}$ = number of times Generator g started up in the hour that includes RTD interval j;

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

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

~~N~~ M = the set of 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 5.0 below); and

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

L = the set of all RTD intervals 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;

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$NASR_{gi}^{TOT}$ = 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 $.

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 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 4.2 will be the Bid for the next hour, in accordance with ISO Procedures.

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In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 8.0 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

5.0 BPCG FOR GENERATORS IN SUPPLEMENTAL EVENT INTERVALS

5.1 Eligibility for BPCG for Generators ~~for~~ in Supplemental Event Intervals

(a) *Eligibility*.

For intervals in which the ISO has called a large event reserve pick-up, as described in Section 4.4.4.A.1 of this ISO Services Tariff, or an emergency under Section 4.4.4.A.2 of this ISO Services Tariff, any Supplier who meets the eligibility requirements for a real-time Bid Production Cost guarantee payment described in Section 4.1(a) of this Attachment C, shall be eligible to receive a BPCG under this Section 5.0.

(b) *Non-Eligibility*.

Notwithstanding Section 5.1(a), 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 4.1(b) of this Attachment C.

5.2 <u>Formula for Determining BPCG for Generators for Supplemental Event Intervals</u>

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

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

where:

P = the set of Supplemental Event Intervals,[6] 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 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 4.2 above.[7]

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[6] The deleted language is included in the definition of the term "Supplemental Event Intervals."

[7] The current formula for real-time BPCGs for Generators for Supplemental Event Intervals does not account for the difference in the determination of Energy injections for the calculation of BPCGs for intervals in which there are maximum generation pickups and for intervals in which there are large event reserve pickups. This modification clarifies this distinction.

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 4.2 above.

In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 8.0 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

6.0 REAL-TIME BPCG FOR IMPORTS

6.1 Eligibility for Receiving Real-Time BPCG for Imports

(a) *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.

(b) *Non-Eligibility*.

Notwithstanding Section 6.1(a):

(i) 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

(ii) 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.

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 6.0, 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.

6.3 Formula for Determining Real-Time BPCG for Imports

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

$$Max\left(\sum_{i=1}^{Q}\left[\left(DecBid_{ti}^{RT} - LBMP_{ti}^{RT}\right) \bullet \max\left(SchImport_{ti}^{RT} - SchImport_{ti}^{DA}, 0\right) \bullet S_i / 3600\right], 0\right)$$

Where:

Q	= number of intervals in the Dispatch Day;
$DecBid_{ti}^{RT}$	= 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;
$SchImport_{ti}^{RT}$	= 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 ~~by Supplier s~~ in hour that contains interval i.
$S_{i,}$	= number of seconds in RTD interval i.

7.0 BPCG FOR LONG START-UP TIME GENERATORS WHOSE STARTS ARE ABORTED BY THE ISO PRIOR TO THEIR DISPATCH

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 7.0.

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 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 (*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).

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8.0 BPCG FOR DEMAND REDUCTION IN THE DAY-AHEAD MARKET

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 8.0.

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

Day-Ahead BPCG for Demand Reduction Provider d =

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

where:

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

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

$$\mathrm{IncrCurCost}_d^h = \int_{\mathrm{MinCur}_d^h}^{\max(\mathrm{MinCur}_d^h, \min(SchdCur_d^h, ActCur_d^h))} \mathrm{IncrCurBid}_d^h]$$

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

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.

9.0 BPCG FOR SPECIAL CASE RESOURCES

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 9.0. 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.

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,[8] 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.

10.0 BPCG FOR DEMAND SIDE RESOURCES PROVIDING SYNCHRONIZED OPERATING RESERVES IN THE DAY-AHEAD MARKET

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 10.0.

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

[8] The substance of this provision was originally located in Section 4.10 of the ISO Services Tariff (Tariff Sheets 106A and 140A).

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.

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11.0 BPCG FOR DEMAND SIDE RESOURCES PROVIDING SYNCHRONIZED OPERATING RESERVES IN THE REAL-TIME MARKET

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 11.0.

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 in 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.

Attachment J (Services Tariff)

Sixth Revised Sheet No. 486

ATTACHMENT J

DETERMINATION OF DAY-AHEAD MARGIN ASSURANCE PAYMENTS AND IMPORT CURTAILMENT GUARANTEE PAYMENTS

1.0 Introduction

If a Supplier that is eligible pursuant to Section 2.0 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 4.0 and 5.0 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 6.0 of this Attachment J.

2.0 Eligibility for Receiving Day-Ahead Margin Assurance Payments

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

Subject to Section 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 online and dispatched by RTD; (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

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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 t an ISO-approved real-time reduction in scheduled output from its Day-Ahead schedule.

2.2 Exceptions

Notwithstanding Section 2.1 of this Attachment J, no Day-Ahead Margin Assurance Payment shall be paid to

(i) 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: (a) at the Resource's request; or (b) 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

(ii) an Intermittent Power Resource that depends on wind as its fuel.

<u>Second Revised Sheet No. 486.00</u>

3.0 Calculation of Day-Ahead Margin Assurance Payments

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

Subject to Sections 4.0 and 5.0 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 3.4:

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

$$CDMAP_{iu} = CDMAPen_{iu} + \sum_{P} CDMA\Pr es_{iup} + CDMA\Pr eg_{iu}$$

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:

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

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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:

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

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

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) \times (RTPreg_{iu} - DABreg_{hu})] * \frac{Seconds_i}{3600}$$

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

$$CDMAPreg_{iu} = [(DASreg_{hu} - RTSreg_{iu}) \times MAX((RTPreg_{iu} - RTBreg_{iu}), 0)] * \frac{Seconds_i}{3600}.$$

3.2. Formula for Day-Ahead Margin Assurance Payments for Demand Side Resources

A. <u>Formula for Day-Ahead Margin Assurance Payment for Demand Side Resources</u>

Subject to Section 5.0 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 3.4, except for RPIiu, which is defined in Section 3.2.B.:

$$\mathrm{DMAP}_{hu} = \max\left(0, \sum_{i \in h} \mathrm{CDMAP}_{iu}\right) \text{where:}$$

$$\mathrm{CDMAP}_{iu} = \sum_{p} \mathrm{CDMAPres}_{iup} + \mathrm{CDMAPreg}_{iu}\ ,$$

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:

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$$\mathrm{CDMAPres}_{iup} = \left[\left(\mathrm{DASres}_{hup} - \mathrm{RTSres}_{iup}\right) \times \left(\mathrm{RTPres}_{iup} - \mathrm{DABres}_{hup}\right)\right] * \mathrm{RPIiu} * \frac{\mathrm{Seconds}_i}{3600}$$

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:

$$\mathrm{CDMAPres}_{iup} = \left[\left(\mathrm{DASres}_{hup} - \mathrm{RTSres}_{iup}\right) \times \left(\mathrm{RTPres}_{iup}\right)\right] * \mathrm{RPI\ iu} * \frac{\mathrm{Seconds}_i}{3600}$$

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

$$\mathrm{CDMAPreg}_{iu} = \left[\left(\mathrm{DASreg}_{hu} - \mathrm{RTSreg}_{iu}\right) \times \left(\mathrm{RTPreg}_{iu} - \mathrm{DABreg}_{hu}\right)\right] * \frac{\mathrm{Seconds}_i}{3600}$$

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

$$\mathrm{CDMAPreg}_{iu} = \left[\left(\mathrm{DASreg}_{hu} - \mathrm{RTSreg}_{iu}\right) \times \mathrm{MAX}\left(\left(\mathrm{RTPreg}_{iu} - \mathrm{RTBreg}_{iu}\right), 0\right)\right] * \frac{\mathrm{Seconds}_i}{3600}\ .$$

B. 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:

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

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.

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 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 then:

$$CDMAPre_{iu} = \left[\left(DASre_{hu} - RTSre_{iu} \right) * \left(RTPre_{iu} - DABre_{hu} \right) \right] * K_{PI} * \frac{Seconds_i}{3600}$$

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

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

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*;

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$CDMAPres_{iup}$ = the Operating Reserve contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u* determined separately for each Operating Reserve product p;

$DASen_{hu}$ = Day-Ahead Energy schedule for Supplier *u* in hour *h*;

$DASreg_{hu}$ = Day-Ahead schedule for Regulation Service for Supplier *u* in hour *h*;

$DASres_{hup}$ = Day-Ahead schedule for Operating Reserve product p, for Supplier *u* in hour *h*;

$DABen_{hu}$ = Day-Ahead Energy bid curve for Supplier *u* in hour *h*;

$DABreg_{hu}$ = Day-Ahead Availability Bid for Regulation Service for Supplier *u* in hour *h*;

$DABres_{hup}$ = Day-Ahead Availability Bid for Operating Reserve product p for Supplier *u* in hour *h*;

$RTSen_{iu}$ = real-time Energy scheduled for Supplier *u* in interval *i*, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Supplier *u* during the course of interval *i*;

$RTSreg_{iu}$ = real-time schedule for Regulation Service for Supplier *u* in interval *i*.

$RTSres_{iup}$ = real-time schedule for Operating Reserve product p for Supplier *u* in interval *i*.

$RTBreg_{iu}$ = real-time Availability Bid for Regulation Service for Supplier *u* in interval *i*.

$RTBen_{iu}$ = real-time Energy bid curve for Supplier *u* in interval *i*.

AEI_{iu} = average Actual Energy Injection by Supplier u in interval *i* but not more than $RTSen_{iu}$ plus Compensable Overgeneration;

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

$RTPreg_{iu}$ = real-time price of Regulation Service at the location of Supplier *u* in interval *i*;

$RTPres_{iup}$ = real-time price of Operating Reserve product p at the location of Supplier *u* in interval *i*;

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

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

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

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

(a) if $RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}$, then $UL_{iu} = \max(\min(RTSen_{iu}, \max(AEI_{iu}, EOP_{iu})), DASen_{hu})$; or

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

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

$Seconds_i$ = number of seconds in interval *i*

K_{PI} = the factor derived from the Regulation Service Performance index for Resource u for interval i as defined in Rate Schedule 3 of this Services Tariff which shall initially be set at 1.0 for LESRs.

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4.0 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 1.0 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.

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5.0 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

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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 3.0 above, the DASen, DASeg and $DASres_p$ variables will be reduced by REDen, REDreg and $REDres_p$ respectively. REDen, REDreg and $REDres_p$ shall be calculated using the formulas below:

$$REDtot_{iu} = \max(DASen_{hu} + DASreg_{hu} + \Sigma_p DASres_{hup} - RTUOL_{iu},0)$$

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

$$POTREDreg_{iu} = \max(DASreg_{hu} – RTSreg_{iu}, 0)$$

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

$$REDen_{iu} = ((POTREDen_{iu}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$$

$$REDreg_{iu} = ((POTREDreg_{iu}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$$

$REDres_{iup} = ((POTREDres_{iup}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$

where:

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

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$REDtot_{iu}$ = The total amount in MW that Day-Ahead schedules need to be reduced to account for the derate of Supplier u in interval i;

$REDen_{iu}$ = The amount in MW that the Day-Ahead Energy schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier u in interval i;

$REDreg_{iu}$ = The amount in MW that Supplier u's Day-Ahead Regulation Service schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval i;

$REDres_{iup}$ = The amount in MW that Supplier u's Day-Ahead Operating Reserve schedule for Operating Reserves product p is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval i;

$POTREDen_{iu}$ = The potential amount in MW that Supplier u's Day-Ahead Energy schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier u in interval i;

$POTREDreg_{iu}$ = The potential amount in MW that Supplier u's Day-Ahead Regulation Service schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier u in interval i;

$POTREDres_{iup}$ = The potential amount in MW that Supplier u's Day-Ahead Operating Reserve Schedule for Operating Reserve product p could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier in interval;

All other variables are as defined above.

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6.0 IMPORT CURTAILMENT GUARANTEE PAYMENTS

6.1 Eligibility for an Import Curtailment Guarantee Payment for an Import Curtailed by the ISO

In the event that the Energy injections scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible for an Import Curtailment Guarantee Payment as determined in Section 6.2 of this Attachment J.

6.2 Formula for an Import Curtailment Guarantee Payment for a Supplier Whose Import Was Curtailed by the ISO

A Supplier eligible under Section 6.1 of this Attachment J shall receive an Import Curtailment Guarantee Payment for its curtailed Energy injections that is equal to the sum for each hour of the interval payments determined in the formula below.

Import Curtailment Guarantee Payment to Supplier u in association with Import t=

$$\max\left[\left(RTLBMP_{ti} - \max\left(DecBid_{ti}, 0\right)\right) \cdot \left(RTCen_{ti} - RTDen_{ti}\right) \cdot \frac{S_i}{3600}, 0\right].$$

Where

i	=	the relevant interval;
S_i	=	number of seconds in interval i;
$RTLBMP_{t,i}$	=	the real-time LBMP, in $/MWh, for interval i at the Proxy Generator Bus which is the source of the Import t.
$DecBid_{t\ i}$	=	the Decremental Bid, in $/MWh, for Import t in hour h containing interval i;
$RTCen_{t,i}$	=	the scheduled Energy injections, in MWh, for Import t in hour h containing interval i as determined by Real-Time Commitment (RTC_{15}); and
$RTDen_{t,i}$	=	the scheduled Energy injections, in MWh, for Import t in interval i as determined by Real-Time Dispatch (RTD).

Cost Recovery and Miscellaneous Provisions

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Energy schedules for all Wheels Through and Exports. For the ISO Services Charge calculated pursuant to Sections 2.B.2, and 2.B.3, of this Rate Schedule, the Transmission Customer's billing units shall be based on the Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA, and hourly Energy schedules for all Wheels Through and Exports. For the ISO Services Charge calculated pursuant to Sections 2.B.4, 2.B.5, 2.B.6 and 2.B.7 of this Rate Schedule, the Transmission Customer's billing units shall be as described in the body of those Sections of this Rate Schedule. To the extent Schedule 1 charges are associated with meeting the reliability needs of a local system, the billing units for such charges will be based on the Actual Energy Withdrawals in the Subzone(s) where the Resource needed to meet the reliability need is located

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B. Computation of Rates

The ISO Services Charge for Scheduling, System Control and Dispatch Service shall consist of seven components and shall be recovered on a monthly basis (except for section 2.B.6 which shall be billed quarterly) in accordance with the following processes:

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for those taking services under Part IV of the OATT) as described in Section 2.A of this Rate Schedule. Charges to be paid by Transmission Customers for this service shall be aggregated to render a monthly charge.

b. Transmission Customers taking service under Part IV of the OATT to supply Station Power as third-party providers shall pay to the ISO a daily charge for this service equal to the product of (A) the sum of the daily bills for such facilities as described in subparagraph (a) above and (B) the ratio of the Transmission Customer's Station Power supplied under Part IV of the OATT for the day to the sum of all withdrawal billing units for the day.

c. The ISO shall credit charges paid for this service by Transmission Customers and LSEs taking service under Part IV of the OATT to supply

Station Power as third-party providers for the day on a Load Ratio Share basis to Transmission Customers serving Load in the NYCA for the day.

4. Residual Adjustment

The Residual Adjustment shall consist of four costs: Residual Costs pursuant to 2.B.4.a (1) and (2), of this Rate Schedule, Special Case Resource and Curtailment Service Provider costs pursuant to 2.B.4.b of this Rate Schedule, Day-Ahead Margin Assurance payments pursuant to 2.B.4.c of this Rate Schedule and Import Supplier Guarantee costs pursuant to 2.B.4.d of this Rate Schedule.

a.1. The ISO shall calculate, and Transmission Customers, other than Transmission Customers taking service under Part IV of the OATT to supply Station Power as third party providers, shall pay an hourly charge equal to the product of (A) the residual costs listed in Section 4.A of this Rate Schedule for each hour and (B) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the hour, and hourly Energy schedules for all Wheels Through and Exports, to

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(ii) the sum of all ISO Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the hour, and hourly Energy schedules for all Wheels Through and Exports.

a.2. The ISO shall calculate, and each Transmission Customer taking service under Part IV of the OATT to supply Station Power as a third party provider shall pay a daily charge equal to the product of (A) the residual costs listed in Section 4.A of this Rate Schedule for each day and (B) the ratio of (i) the withdrawal units of the Transmission Customer taking service under Part IV of the OATT to supply Station Power as a third party provider for that day to (ii) the sum of all ISO Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the day, and Energy schedules for the day for all Wheels Through and Exports. The ISO shall credit revenue collected by application of this charge, on a Load ratio share basis, to all ISO Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the day, and Energy schedules for all Wheels Through and Exports summed for the day.

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~~To the extent that the sum of all Bilateral Schedules and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load and the ISO commits Resources in addition to the reserves it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load, charges associated with the costs of Bid Production~~

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~~Cost Guarantees for the additional Resources committed Day-Ahead to meet the ISO's Day-Ahead forecast of Load shall be allocated to Transmission Customers who are not bidding as Suppliers according to the Methodology described in Attachment T.~~

b. The ISO shall calculate, and Transmission Customers, other than Transmission Customers taking service under Part IV of the OATT to supply Station Power as third party providers, shall pay an hourly charge for the costs of payments made for Special Case Resources and Curtailment Service Providers to meet the reliability needs of local systems and of the NYCA pursuant to Section 4.B. of this Rate Schedule.

c. The ISO shall calculate, and Transmission Customers shall pay an hourly charge for the costs of payments made for Day-Ahead Margin Assurance calculated pursuant to Section 5 of this Rate Schedule.

d. The ISO shall calculate, and Transmission Customers shall pay an hourly charge for the costs of payments made for Import Supplier Guarantees calculated pursuant to Section 6 of this Rate Schedule.

5. Bid Production Cost guarantee payments

The ISO shall calculate, and each Transmission Customer shall pay, a daily charge for Bid Production Cost guarantees including the costs of supplemental payments and Demand Reduction Incentive Payments made to Demand Reduction Providers calculated pursuant to Section 7 of this Rate Schedule.

The balance of the page concerning NERC and Related Dues, Fees and Other Charges Component remains renumbered as Section 2.B.6.

Second revised Sheet No. 233A.01 remains with the exception that Section 6 dealing with Payments Made to Generators Pursuant to incremental

<u>Cost recovery for Units Responding to Local reliability Rule I-R3 and I-R5 is renumbered Section 2.B.7.</u>

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- Costs that the ISO incurs as a result of bad debt, including finance charges;
- Refunds, if any, ordered by the Commission to be paid by the ISO, at the conclusion of <u>Central Hudson Gas & Electric Corp.</u>, Docket Nos. ER97-1523- 011, OA97-470-010 and ER97-4234-008; and
- Regulatory fees.
- The ISO's share of the expenses of Northeast Power Coordinating Council, Inc. or its successor.

4. Residual Costs

A. Residual Costs

The ISO's payments from Transmission Customers will not equal the ISO's payments to Suppliers. That part of the difference, not otherwise allocated pursuant to provisions of this Rate Schedule, including Day-Ahead Congestion Rent, shall comprise the Residual Cost component of the Residual Adjustment. Significant components of the Residual Cost component, which is calculated below, include:

- The greater revenue the ISO collects for Marginal Losses from Transmission Customers, in contrast to payments for losses remitted to generation facilities;
- Costs or savings associated with the ISO redispatch of Generators resulting from a change in Transfer Capability between the Day-Ahead schedule and the real-time dispatch;

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The Residual Cost component for each month shall be the sum of the hourly Residual costs calculated as follows: (A) the ISO's receipts from Transmission Customers and Primary Holders of TCCs for services which equal the sum of: (i) payments for Energy scheduled in the LBMP Market in that hour in the Day-Ahead commitment; (ii) payments for Energy purchased in the Real-Time LBMP Market for that hour that was not scheduled Day-Ahead; (iii) payments for Energy by generating facilities that generated less Energy in the real- time dispatch for that hour than they were scheduled Day-Ahead to generate in that hour for the

LBMP Market; (iv) TUC payments made in accordance with Parts II, III and IV of this Tariff that were scheduled in that hour in the Day-Ahead commitment; and (v) real-time TUC payments in accordance with Parts II, III and IV of this Tariff that were not scheduled in that hour in the Day-Ahead commitment; (B) less the ISO's payments to generation facilities, Transmission Owners and Primary Holders of TCCs equal to the sum of the following: (i) payments for Energy to generation facilities that were scheduled to operate in the LBMP Market in that hour in the Day-Ahead commitment; (ii) payments to generation facilities for Energy provided to the ISO in the real-time dispatch for that hour that those generation facilities were not scheduled to generate in that hour in the Day-Ahead commitment; (iii) payments for Energy to LSEs that consumed less Energy in the real-time dispatch than those LSEs were scheduled Day-Ahead to consume in that hour;

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

B. Special Case Resources and Curtailment Service Providers Costs

1. Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of a Local System

The ISO shall allocate payments for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of a local system only to Transmission Customers, other than those taking service under Part IV of this OATT to supply station power as a third party provider, serving Load in the Subzone for which the reliability services of the Special Case Resources and Curtailment Service Providers were called. To do so, the ISO shall assess to each Transmission Customer an hourly charge for each Subzone equal to the product of:

(i) the payments made for that hour to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of a local system; and

(ii) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load for that hour in that sub-zone, excluding Wheels Through and Exports, to (ii) the sum of all Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load for that hour in that sub-zone excluding Wheels Through and Exports.

2. Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of the NYCA

The ISO shall allocate payments to Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA to Transmission Customers, other than those taking service under part IV of this OATT to supply station power as a third party provider, serving Load in the NYCA. To do so, the ISO shall assess to each Transmission Customer an hourly charge equal to the product of:

(i) the payments made for that hour to Suppliers for Special Case Resources and Curtailment Service Providers; and

(ii) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the hour, and hourly Energy schedules for all Wheels Through and Exports, to (ii) the sum of all Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the hour, and hourly Energy schedules for all Wheels Through and Exports.

5. Day-Ahead Margin Assurance Payment Costs

The ISO shall allocate, on an hourly basis, the costs related to Day-Ahead Margin Assurance Payments in the following manner:

A. Costs of DAMAPs Resulting from Meeting the Reliability Needs of a Local System

The ISO shall allocate the costs for DAMAPs incurred to compensate Resources for meeting the reliability needs of a local system only to Transmission Customers serving Load in the sub-zone where the Resource is located. To do so, the ISO shall assess to each Transmission Customer an hourly charge for each sub-zone equal to the product of:

(a) the DAMAP costs for that hour in that Subzone arising as a result of meeting the reliability needs of the local system; and

(b) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load for that hour in that sub-zone, excluding Wheels Through and Exports, to (ii) the sum of all Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load for that hour in that sub-zone excluding Wheels Through and Exports.

B. Costs of All Remaining DAMAPs

The ISO shall allocate the costs of all DAMAPs not recovered through Section 6.A of this Schedule 1 among all Transmission Customers. To do so, the ISO shall assess to each Transmission Customer an hourly charge equal to the product of:

(a) the remaining DAMAP costs for that hour not recovered by the ISO through Section 6.A; and

(b) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the hour, and hourly Energy schedules for all Wheels Through and Exports to (ii) the sum of all Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the hour, and hourly Energy schedules for all Wheels Through and Exports.

6. Import Curtailment Guarantee Payment Costs

The ISO shall allocate, on an hourly basis, the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers among all Transmission Customers. To do so, the ISO shall assess to each Transmission Customer an hourly charge equal to the product of:

(a) the costs for the Import Curtailment Guarantee Payments for that hour; and

(b) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the hour, and hourly Energy schedules for all Wheels Through and Exports to (ii) the sum of all Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the hour, and hourly Energy schedules for all Wheels Through and Exports

7. Bid Production Cost Guarantee Payment and Demand Reduction Incentive Payment Costs

The ISO shall allocate on a daily basis the costs related to Bid Production Cost guarantee payments in the following manner:

A. Costs of Demand Reduction BPCG and Demand Reduction Incentive Payments

After accounting for imbalance charges paid by Demand Reduction Providers, the ISO shall allocate the costs associated with Demand Reduction Bid Production Cost guarantee payments and Demand Reduction Incentive Payments to Transmission Customers pursuant to the methodology established in Attachment R of this ISO OATT.

B. Costs of BPCG for Additional Generating Units Committed to Meet Forecast Load

If the sum of all Bilateral Transaction schedules and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO may commit Resources in addition to the reserves that it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load. The ISO shall allocate a portion of the costs associated with Bid Production Cost guarantee payments for the additional Resources committed Day-Ahead to meet the Day-Ahead forecast of Load to Transmission Customers pursuant to the methodology established in Attachment T of this ISO OATT.[9] The ISO shall allocate the residual costs of such Bid Production Cost guarantee payments not recovered through the methodology in Attachment T of the ISO OATT pursuant to Section 7. F of this Schedule 1.

C. Costs of BPCGs Resulting from Meeting the Reliability Needs of a Local System

The ISO shall allocate the costs for Bid Production Cost guarantee payments incurred to compensate Suppliers for their Resources, other than Special Case Resources, that are committed or dispatched to meet the reliability needs of a local system, only to Transmission Customers serving Load in the Subzone where the Resource is located. To do so, the ISO shall assess to each Transmission Customer a daily charge for each Subzone equal to the product of:

(a) the Bid Production Cost guarantee payments made for that day to Suppliers for Resources in that sub-zone arising as a result of meeting the reliability needs of the local system; and

(b) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load for that day in that sub-zone, excluding Wheels Through and Exports, to (ii) the sum of all Transmission Customers'

[9] This sentence was originally located in Section 2A of this Rate Schedule 1.

Actual Energy Withdrawals for all Transmission Service to supply Load for that day in that sub-zone excluding Wheels Through and Exports.

D. Cost of BPCGs for Special Case Resources Called to Meet the Reliability Needs of a Local System

The ISO shall allocate the costs for Bid Production Cost guarantee payments incurred to compensate Special Case Resources called to meet the reliability needs of a local system only to Transmission Customers, other than those taking service under Part IV of this OATT to supply station power as a third party provider, serving Load in the Subzone where the Special Case Resource is located. To do so, the ISO shall assess to each Transmission Customer a daily charge for each Subzone equal to the product of:

(a) the BPCG payments made for that day to Suppliers for Special Case Resources called in that sub-zone to meet the reliability needs of the local system; and

(b) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load for that day in that sub-zone, excluding Wheels Through and Exports, to (ii) the sum of all Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load for that day in that sub-zone excluding Wheels Through and Exports

E. Cost of BPCG for Special Case Resources Called to Meet the Reliability Needs of the NYCA

The ISO shall allocate the costs for Bid Production Cost guarantee payments to compensate Special Case Resources called to meet the reliability needs of the NYCA to Transmission Customers, other than those taking service under Part IV of this OATT to supply station power as a third party provider, serving Load in the NYCA. To do so, the ISO shall assess to each Transmission Customer a daily charge for each Subzone equal to the product of:

(a) the BPCG payments made for that day to Suppliers for Special Case Resources called to meet the reliability needs of the NYCA; and

(b) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the day, and Energy schedules for the day for all Wheels Through and Exports to (ii) the sum of all Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the day, and Energy schedules for the day for all Wheels Through and Exports.

F. Costs of All Remaining BPCGs

The ISO shall allocate the costs of all Bid Production Cost guarantee payments not recovered through Sections 7.A, 7.B, 7.C, 7.D, and 7.E of this Schedule 1, including the residual costs of Bid Production Cost guarantee payments for additional Resources not recovered through the methodology in Attachment T of this ISO OATT, among all Transmission Customers. To do so, the ISO shall assess to each Transmission Customer a daily charge equal to the product of:

(a) the remaining BPCG costs for that day not recovered by the ISO through Sections 7.A, 7.B, 7.C, 7.D and 7.E of this Schedule; and

(b) the ratio of (i) the Transmission Customer's Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the day, and Energy schedules for the day for all Wheels Through and Exports to (ii) the sum of all Transmission Customers' Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA for the day, and Energy schedules for the day for all Wheels Through and Exports.

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, 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 guarantee("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 Rate Schedule 1, Section 7.B. 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, summed over the hours of the day in which these purchases are positive, to all Energy purchases in the real-time market by Eligible Transmission Customers in each Load Zone or Composite Load Zone in each hour, summed over the hours of the day in which these purchases in a given Load Zone or Composite Load Zone are positive, and summed over all Load Zones or Composite Load Zones..
$K^{customer}_{c,L}$	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 (i) 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 Schedule 1, Section7.B. The residual is determined according to:

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