Attachment II

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

18.1 Introduction

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

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

18.2 Day-Ahead BPCG For Generators

18.2.1 Eligibility to Receive a Day-Ahead BPCG for Generators

18.2.1.1 Eligibility.

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

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

Notwithstanding Section 18.2.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator that is committed by the ISO in the Day-Ahead Market shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment if that Generator has been committed in the Day-Ahead Market for any other hour of the day as a result of a Self-Committed Fixed or Self-Committed Flexible bid.

18.2.2 Formulas for Determining Day-Ahead BPCG for Generators

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

Day-Ahead Bid Production Cost Guarantee for Generator g =

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

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

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

EH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by Generator g in hour h expressed in terms of MWh;

MGH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by the minimum generation segment of Generator g in hour h expressed in terms of MWh;

C_{gh}^{DA} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost curve for Generator g, in the Day-Ahead Market for hour h expressed in terms of $/MWh;

MGC_{gh}^{DA} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, for hour h in the Day-Ahead Market, expressed in terms of $/MWh.

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

SUC_{gh}^{DA} = Start-Up Bid by Generator g in hour h, or when applicable the mitigated Start-Up Bid for Generator g, in hour h in the Day-Ahead Market expressed in terms of $/start; *provided*, *however*, that the Start-Up Bid for Generator g in hour h or, when applicable, the mitigated Start-Up Bid, for Generator g in hour h, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled, and to operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator g's Day-Ahead or SRE schedule.

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

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

$NSUH_{gh}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in hour h;

$LBMP_{gh}^{DA}$ = Day-Ahead LBMP at Generator g's bus in hour h expressed in $/MWh;

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

18.3 Day-Ahead BPCG For Imports

18.3.1 Eligibility to Receive a Day-Ahead BPCG for Imports

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

18.3.2 BPCG Calculated by Transaction ID

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

18.3.3 Formula for Determining Day-Ahead BPCG for Imports

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

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

Where;

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

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

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

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

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

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

18.4.1.1 Eligibility.

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

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

18.4.1.1.2 a Self-Committed Flexible Generator if the Generator's minimum ~~generation MW~~operating level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; or

18.4.1.1.3 a Generator committed via SRE, or committed or dispatched by the ISO as Out-of-Merit generation to ensure NYCA or local system reliability for the hours of the day that it is committed via SRE or is committed or dispatched by the ISO as Out-of-Merit generation to meet NYCA or local system reliability without regard to the Bid mode(s) employed during the Dispatch Day, except as provided in Sections 18.4.2 and 18.12, below.

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

Notwithstanding Section 18.4.1.1, a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator that is committed by the ISO in the real-time market shall not be eligible to receive a real-time Bid Production Cost guarantee payment if that Generator has been committed in real-time, in any other hour of the day, as the result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule, *provided however*, a Generator that has been committed in real time as a result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule will not be precluded from receiving a real-time Bid Production Cost guarantee payment for other hours of the Dispatch Day, in which it is otherwise eligible, due to these Self-Committed mode Bids if such bid mode was used for: (i) an ISO authorized Start-Up, Shutdown or Testing Period, or (ii) for hours in which such Generator was committed via SRE or committed or dispatched by the ISO as Out-of-Merit to meet NYCA or local system reliability.

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

Real-Time Bid Production Cost Guarantee for Generator g =

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

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 including through an adjustment to the Resource's self-commitment schedule, or (ii) in order to reconcile the ISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

MGI_{gi}^{RT}	=	metered Energy produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;
MGI_{gi}^{DA}	=	Energy scheduled Day-Ahead to be produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;
MGC_{gi}^{RT}	=	Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, in the Real-Time Market for the hour that includes RTD interval i, expressed in terms of \$/MWh, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8; If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), *then* Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Real-Time Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;
SUC_{gj}^{RT}	=	Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, for hour j into RTD expressed in terms of \$/start, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8; provided, however, (i) the Start-Up Bid shall be deemed to be zero for (1) Self-Committed Fixed and Self-Committed Flexible Generators, (2) Generators that are economically committed by RTC or RTD that have 10-minute start-up times that are not synchronized and producing Energy within 20 minutes after their scheduled start time, and (3) Generators that are economically committed by RTC that have greater than 10-minute start-up times that are not synchronized and producing Energy within 45 minutes after their scheduled start time; (ii) if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time commitment that did not

result from a Day-Ahead commitment, the Generator's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be the Start-Up Bid submitted in response to the SRE request (subject to mitigation, where appropriate);

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

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

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

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

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

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

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

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

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

L = the set of all hours in the Dispatch Day

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

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

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

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

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

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

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

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

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

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

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

18.4.3 Bids Used For Intervals at the End of the Hour

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

18.5 BPCG For Generators In Supplemental Event Intervals

18.5.1 Eligibility for BPCG for Generators in Supplemental Event Intervals

18.5.1.1 Eligibility

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

18.5.1.2 Non-Eligibility

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

18.5.1.3 Additional Eligibility

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

18.5.2 Formula for Determining BPCG for Generators in Supplemental Event Intervals

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

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

where:

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

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

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

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

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

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

18.6 Real-Time BPCG For External Transactions

External Transactions are not eligible to receive Bid Production Cost guarantee payments in the Real-Time Market.

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

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

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

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

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

18.8 BPCG For Demand Reduction In The Day-Ahead Market

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

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

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

Day-Ahead BPCG for Demand Reduction Provider d =

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

where:

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

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

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

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

N	=	number of hours in the Day-Ahead Market day.
CurInitCost_d	=	daily Curtailment Initiation Cost credit for Day-Ahead Demand Reduction Provider d;
MinCurCost_d^h	=	minimum Curtailment cost credit for Day-Ahead Demand Reduction Provider d in hour h;

$IncrCurCost_d^h$ = incremental Curtailment cost credit for Day-Ahead Demand Reduction Provider d for hour h;

$CurCost_d$ = total bid Curtailment Initiation Costs for Day-Ahead Demand Reduction Provider d for the day;

$CurRev_d^h$ = actual revenue for Day-Ahead Demand Reduction Provider d in hour h;

$ActCur_d^h$ = actual Energy curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$SchdCur_d^h$ = Energy scheduled Day-Ahead to be curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$MinCurBid_d^h$ = minimum Curtailment initiation Bid submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of $/MWh;

$IncrCurBid_d^h$ = Bid cost submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of $/MWh;

$MinCur_d^h$ = Energy scheduled Day-Ahead to be produced by the minimum Curtailment segment of Day-Ahead Demand Reduction Provider d for hour h expressed in terms of MWh; and

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

18.9 BPCG For Special Case Resources

18.9.1 Eligibility for Special Case Resources BPCG

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

18.9.2 Methodology for Determining Special Case Resources BPCG

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

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

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

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

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

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

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

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

where:

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

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

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

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

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

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

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

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

where:

L = set of RTD intervals in the Dispatch Day;

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

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

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

18.12.1 Eligibility to Recover Operating Costs and Resulting Obligations

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

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

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

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

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

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

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

Where:

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

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

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

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

Where:

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

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

18.12.2.2 Calculation of Prorated Start-Up Cost

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

Where:

$ProratedSUC_{g,s}$ = the prorated start-up cost used to calculate the Bid Production Cost guarantee for Generator g that is scheduled to start in hour s

$SubmittedSUC_{g,s}$ = the Start-Up Bid submitted (as mitigated, where appropriate) for Generator g that is scheduled to start in hour s

$MinOpEnergy_{g,h,s}$ = the amount of Energy produced during hour h by Generator g during the time required to complete both its minimum run time and its Day-Ahead schedule, if that generator is started in hour s. $MinOpEnergy_{g,h,s}$ is calculated as follows:

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

Where:

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

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

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

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

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

25.1 Introduction

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

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

25.2 Eligibility for Receiving Day-Ahead Margin Assurance Payments

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

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

25.2.2 Exceptions

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

25.2.2.1 a Resource otherwise eligible for a Day-Ahead Margin Assurance Payment in hours in which the NYISO has increased the Resource's minimum operating level either: (i) at the Resource's request including through an adjustment to the Resource's self-commitment schedule; or (ii) in order to reconcile the ISO's dispatch with the Resource's actual output or to address reliability concerns that arise because the Resource is not following Base Point Signals; or (iii) an Intermittent Power Resource that depends on wind as its fuel.

25.2.2.2 a Generator, otherwise eligible for Day-Ahead Margin Assurance Payments, for (i) any hour in which the Incremental Energy Bids submitted in the real-time market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) in which the Incremental Energy Bids submitted in the real-time market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market.

25.3 Calculation of Day-Ahead Margin Assurance Payments

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

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

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

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

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

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

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

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

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

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

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:

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

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

$$\mathrm{CDMAPreg}_{\mathrm{iu}} = \left[\left(\mathrm{DASreg}_{\mathrm{hu}} - \mathrm{RTSreg}_{\mathrm{iu}}\right) \times \left(\mathrm{RTPreg}_{\mathrm{iu}} - \mathrm{DABreg}_{\mathrm{hu}}\right)\right] * \frac{\mathrm{Seconds}_{\mathrm{i}}}{3600} + [(-1 \times RTMreg_{iu}) \times max(0, RTPregm_{iu} - RTBregm_{iu})]$$

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

$$\mathrm{CDMAPreg}_{\mathrm{iu}} = \left[\left(\mathrm{DASreg}_{\mathrm{hu}} - \mathrm{RTSreg}_{\mathrm{iu}}\right) \times \mathrm{MAX}\left(\left(\mathrm{RTPreg}_{\mathrm{iu}} - \mathrm{RTBreg}_{\mathrm{iu}}\right), 0\right)\right] * \frac{\mathrm{Seconds}_{\mathrm{i}}}{3600} + [(-1 \times RTMreg_{iu}) \times max(0, RTPregm_{iu} - RTBregm_{iu})]$$

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

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

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

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

$$\mathrm{CDMAP_{iu}} = \sum_{p} \mathrm{CDMAPres_{iup}} + \mathrm{CDMAPreg_{iu}} \,,$$

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:

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

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:

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

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

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

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

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

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

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

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

Where:

RPI_{iu}	=	Reserve Performance Index in interval i for Demand Side Resource u;
UAGi	=	average actual Demand Reduction for interval i, represented as a positive generation value; and
ADGi	=	average scheduled Demand Reduction for interval i, represented as a positive generation base point.

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

Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources scheduled to provide Regulation Service shall be determined by applying the following equations to each Resource using the terms as defined in Section 25.3.4; *provided*, *however*, that a Day-Ahead Margin Assurance Payment is payable only for intervals in which the NYISO has reduced the real-time Regulation Service offer (in MWs) of a Limited Energy Storage Resource and the NYISO is not pursuing LESR Energy Management for such Resource for such interval, pursuant to ISO Procedures:

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

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

$$+ \left[(-1 \times RTMreg_{iu}) \times max(0, RTPregm_{iu} - RTBregm_{iu}) \right]$$

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

$$\mathrm{CDMAPreg}_{iu} = \left[\left(\mathrm{DASreg}_{hu} - \mathrm{RTSreg}_{iu} \right) * \left(\mathrm{RTPreg}_{iu} - \mathrm{DABreg}_{hu} \right) \right] * \frac{\mathrm{Seconds}_i}{3600}$$
$$+ \left[(-1 \times RTMreg_{iu}) \times max(0, RTPregm_{iu} - RTBregm_{iu}) \right]$$

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

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

$$+ \left[(-1 \times RTMreg_{iu}) \times max(0, RTPregm_{iu} - RTBregm_{iu}) \right]$$

25.3. 4 Terms Used in this Attachment J

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

h is the hour that includes interval *i*;

DMAPhu	=	the Day-Ahead Margin Assurance Payment attributable in any hour h to any Supplier u;
$CDMAP_{iu}$	=	the contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;
$CDMAPen_{iu}$	=	the Energy contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;
$CDMAPreg_{iu}$	=	the Regulation Service contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;
$CDMAPres_{iup}$	=	the Operating Reserve contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u* determined separately for each Operating Reserve product p;
$DASen_{hu}$	=	Day-Ahead Energy schedule for Supplier *u* in hour *h*;
$DASreg_{hu}$	=	Day-Ahead schedule for Regulation Service for Supplier *u* in hour *h*;
$DASres_{hup}$	=	Day-Ahead schedule for Operating Reserve product p, for Supplier *u* in hour *h*;
$DABen_{hu}$	=	Day-Ahead Energy bid curve for Supplier *u* in hour *h*;
$DABreg_{hu}$	=	Day-Ahead Regulation Capacity Bid price for Supplier *u* in hour *h*;
$DABres_{hup}$	=	Day-Ahead Availability Bid for Operating Reserve product p for Supplier *u* in hour *h*;
$RTSen_{iu}$	=	real-time Energy scheduled for Supplier *u* in interval *i*, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Supplier *u* during the course of interval *i*;
$RTSreg_{iu}$	=	real-time schedule for Regulation Service for Supplier *u* in interval *i*.
$RTSres_{iup}$	=	real-time schedule for Operating Reserve product p for Supplier *u* in interval *i*.
$RTBreg_{iu}$	=	real-time Regulation Capacity Bid price for Supplier *u* in interval *i*.
$RTBen_{iu}$	=	real-time Energy bid curve for Supplier *u* in interval *i*.
$RTBregm_{iu}$	=	real-time Regulation Movement Bid price for Supplier *u* in interval *i*.
$RTMreg_{iu}$	=	real-time Regulation Movement MWs for Supplier *u* in interval *i;*
AEI_{iu}	=	average Actual Energy Injection by Supplier u in interval *i* but not more than $RTSen_{iu}$ plus Compensable Overgeneration;
$RTPen_{iu}$	=	real-time price of Energy at the location of Supplier *u* in interval *i*;
$RTPreg_{iu}$	=	real-time price of Regulation Capacity at the location of Supplier *u* in interval *i*;
$RTPres_{iup}$	=	real-time price of Operating Reserve product p at the location of Supplier *u* in interval *i*;

$RTPregm_{iu}$ = real-time Regulation Movement Market Price at the location of Supplier *u* in interval *i;*

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

(a) if $RTSen_{iu} < EOP_{iu}$, 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 $RTSen_{iu} \square EOP_{iu} \square DASen_{hu}$, 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.

25.4 Exception for Generators Lagging Behind RTD Base Point Signals

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

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

25.5 Rules Applicable to Supplier Derates

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

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

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

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

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

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

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

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

where:

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

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

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

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

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

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

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

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

All other variables are as defined above.

25.6 Import Curtailment Guarantee Payments

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

In the event that the Energy injections for an Import scheduled by RTC or RTD at a Proxy Generator Bus, other than a CTS Enabled Proxy Generator Bus, are Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible for an Import Curtailment Guarantee Payment as determined in Section 25.6.2 of this Attachment J. Suppliers scheduling Imports at CTS Enabled Proxy Generator Buses shall not be eligible for Import Curtailment Guarantee payments for those Transactions.

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

A Supplier eligible under Section 25.6.1 of this Attachment J shall receive an Import Curtailment Guarantee Payment for its curtailed Energy injections that is equal to the daily sum of the hourly payments which, for each hour of Import t, is calculated as the greater of the interval payments determined for the hour or zero as seen in the formula below.

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

$$\sum_{h=1}^{N} \max\left(\sum_{i=1}^{H}\left(RTLBMP_{ti} - \max(DADecBid_{ti}, 0)\right) \cdot (DAen_{ti} - RTDen_{ti}) \cdot \frac{S_i}{3600}, 0\right)$$

Where

N = the number of hours in the Dispatch Day

H = the number of intervals in hour h

i = the relevant interval in hour h;

S_i = number of seconds in interval i;

$RTLBMP_{t,i}$ = the real-time LBMP, in $/MWh, for interval i at the Proxy Generator Bus which is the source of the Import t.

$DADecBid_{t\ i}$ = the Day Ahead Decremental Bid price associated with the Day-Ahead energy schedule, in $/MWh, for Import t in hour h containing interval i;

$DAen_{t,i}$ = the Day Ahead scheduled Energy injections, in MWh, for Import t in hour h containing interval i as determined by Security Constrained Unit Commitment (SCUC); and

$RTDen_{t,i}$ = the scheduled Energy injections, in MWh, for Import t in interval i as determined by Real-Time Dispatch (RTD).