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

18.1 ~~Supplemental Payments to Generators and Demand Resources~~Introduction

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Ten~~Three~~ Bid Production Cost Guarantee (BPCG) ~~supplemental~~ payments for eligible Suppliers~~Generators~~ are described in this attachment: (i) a Day-Ahead BPCG for Generators~~Bid Production Cost guarantees~~; (ii) a Day-Ahead BPCG for Imports; (iii) a ~~R~~real-time BPCG for Generators~~Bid Production guarantees for all~~ in RTD intervals other than Supplemental Event ~~i~~Intervals ~~except maximum generation pickups and large event reserve pickups~~; ~~and~~ (iv~~iii~~) a BPCG for Generators for Supplemental Event Intervals; ~~Real-time Bid Production Cost guarantees for maximum generation pickups and large event reserve pickups.~~ (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. ~~Generators~~ Suppliers shall be eligible for these payments in accordance with the eligibility requirements and formulas established in this Attachment C.~~under the circumstances described in Article 4 and Rate Schedule 15.4 of this ISO Services Tariff.~~

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.

~~Demand Side Resources that are committed to provide non-synchronized Operating Reserves shall be treated the same as Generators with respect to the determination of supplemental payments. Demand Reduction Providers that provide Demand Reductions in the Day-Ahead Market shall be eligible for supplemental payments under Section 18.2, but not this Section 18.1. Demand Side Resources committed in the Day-Ahead market to provide synchronized Operating Reserves shall be eligible for supplemental payments under Section 18.4.1. Demand Side Resources committed in the real-time market to provide synchronized Operating Reserves or Regulation Service shall be eligible for supplemental payments under Section 18.4.2.~~

18.~~1.1~~2 ~~Day-Ahead Bid Production Cost Guarantee Formulas~~Day-Ahead BPCG For Generators

18.2.1 Eligibility to Receive a Day-Ahead BPCG for Generators

18.2.1.1 Eligibility.

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

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

Notwithstanding Section 18.2.1.1:

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

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

18.2.2 Formulas for Determining Day-Ahead BPCG for Generators

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

Day-Ahead Bid Production Cost Guarantee for Generator g =

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$$\sum_{g \in G} \max\left[\sum_{h=1}^{24}\left(\int_{MGH_{gh}^{DA}}^{EH_{gh}^{DA}} C_{gh}^{DA} + MGC_{gh}^{DA}\, MGH_{gh}^{DA} + SUC_{gh}^{DA}\, NSUH_{gh}^{DA} - LBMP_{gh}^{DA}\, EH_{gh}^{DA} - NASR_{gh}^{DA}\right), 0\right]$$

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

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

~~Where:~~

~~G = set of Generators;~~

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

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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;

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

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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,

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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):

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$NSUH_{gh}^{DA}$ = 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 ~~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.

18.3 Day-Ahead BPCG For Imports

18.3.1 Eligibility to Receive a Day-Ahead BPCG for Imports

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

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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.

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18.3.3 Formula for Determining Day-Ahead BPCG for Imports

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

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

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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

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

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~~18.1.2~~18.4 Real-Time BPCG For Generators In RTD Intervals Other Than Supplemental Event Intervals ~~Bid Production Guarantee Formulas for All Imports and Real-Time Bid Production Guarantee Formulas for All Intervals With No Maximum Generation Pickups or Large Event Reserve Pickups for All Other Generators~~

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

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18.4.1.1 Eligibility.

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

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

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

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

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

Notwithstanding Section 18.4.1.1:

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

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

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

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Real-Time Bid Production Cost Guarantee for Generator g =

$$\sum_{g\in G}\max\left[\left\{\sum_{i=1}^{N}\left(\begin{array}{l}\left(\begin{array}{l}\int_{EI_{gi}^{DA}}^{EI_{gi}^{RT}} C_{gi}^{RT} + MGC_{gi}^{RT}\left(MGI_{gi}^{RT} - MGI_{gi}^{DA}\right)\\ - LBMP_{gi}^{RT}\left(EI_{gi}^{RT} - EI_{gi}^{DA}\right)\end{array}\right) * \frac{S_i}{3600}\\ \\ -\left(NASR_{gi}^{TOT} - NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}\end{array}\right) + \sum_{j=1}^{L}\left(SUC_{gj}^{RT}\left(NSUI_{gj}^{RT} - NSUI_{gj}^{DA}\right)\right)\right\}, 0\right]$$

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

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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~~.~~, 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

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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, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

provided, however, ~~except that~~

(i) ~~SUC_{gj}^{RT}~~ the Start-Up Bid shall be deemed to be zero ~~in the cases of~~ for (1~~i~~) Self-Committed Fixed and Self-Committed Flexible Generators, (2~~ii~~) 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~~iii~~) 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;~~.~~ ~~Rules addressing the handling of Start-Up Bids submitted by Generators that are committed via SRE under particular factual circumstances are set forth below;~~

(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

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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 ~~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~~hour j;

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

~~N~~M = ~~except for imports,~~ the set of ~~number of~~ eligible RTD intervals in the Dispatch ~~d~~Day consisting of all of the RTD intervals in the Dispatch Day except:

(i) ~~excluding~~Supplemental Event ~~I~~intervals ~~in which there are any maximum generation pickups or large event reserve pickups and the three RTD intervals following the termination of the large event reserve pickup or maximum generation pickup~~ (which are addressed separately in ~~subs~~Section 18.5~~1.3~~ below);

(ii) ~~and excluding any RTD intervals where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA}; *provided, however*, for imports, the variable N is the number of eligible RTD intervals in the day excluding any RTD intervals where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA}~~; intervals during authorized Start-Up Periods, Shutdown Periods, or Testing Periods for Generator g;

L = the set of all hours~~intervals~~ in the Dispatch ~~d~~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 ~~and~~

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

EI_{gi}^{DA} = Energy scheduled in the Day-Ahead Market to be produced by

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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 ~~scheduled~~ 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 $.

~~Time periods including reserve pickups, and time periods following a reserve pickup in which the dispatch of a given Generator is constrained by its downward ramp rate, will not be included in the above calculation of supplemental payments for that Generator.~~

~~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). 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.~~

~~Supplemental payments to Generators that trip before completing their minimum run-time (for Generators that were not scheduled to run Day-Ahead) or before running for the number of hours they were scheduled to operate (for Generators scheduled to run Day-Ahead) may be reduced by the ISO, per ISO Procedures.~~

~~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.~~

18.4.3 Bids Used For Intervals at the End of the Hour

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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.~~1.3~~5 BPCG For Generators In Supplemental Event Intervals ~~Real-Time Bid Production Cost Guarantees for Intervals With Maximum Generation Pickups or Large Event Reserve Pickups~~

18.5.1 Eligibility for BPCG for Generators in Supplemental Event Intervals

18.5.1.1 Eligibility

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

18.5.1.2 Non-Eligibility

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

18.5.1.3 Additional Eligibility

Notwithstanding Section 18.5.1.2, a Supplier shall be eligible to receive a Bid Production Cost guarantee payment for a Generator, not a Limited Energy Storage Resource, producing energy during Supplemental Event Intervals occurring as a result of an ISO emergency under Section 4.4.4.1.2 of this ISO Services Tariff regardless of bid mode used for the day.

18.5.2 Formula for Determining BPCG for Generators in Supplemental Event Intervals

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

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$$\sum_{i\in P}\left(\max\left(\left(\int_{\max\left(EI^{DA}_{gi},MGI^{RT}_{gi}\right)}^{\max\left(EI^{RT}_{gi},MGI^{RT}_{gi}\right)} C^{RT}_{gi} + MGC^{RT}_{gi}\cdot\left(MGI^{RT}_{gi}-MGI^{DA}_{gi}\right) - LBMP^{RT}_{gi}\cdot\left(EI^{RT}_{gi}-EI^{DA}_{gi}\right)\right)\cdot\frac{s_i}{3600} - \left(NASR^{TOT}_{gi}-NASR^{DA}_{gi}\right) - RRAP_{gi} + RRAC_{gi}\right),0\right)$$

$$\sum_{g\in G}\left[\sum_{i=1}^{M}\max\left(\left(\int_{EI^{DA}_{gi}}^{EI^{RT}_{gi}} C^{RT}_{gi} + MGC^{RT}_{gi}\left(MGI^{RT}_{gi}-MGI^{DA}_{gi}\right) - LBMP^{RT}_{gi}\left(EI^{RT}_{gi}-EI^{DA}_{gi}\right)\right)*\frac{s_i}{3600} - \left(NASR^{TOT}_{gi}-NASR^{DA}_{gi}\right) - RRAP_{gi} + RRAC_{gi},0\right)\right]$$

where:

~~M~~P = ~~number~~ the set of Supplemental Event ~~i~~Intervals ~~in which there are maximum generation pickups or large event reserve pickups in the 24 hour day and the three RTD intervals following the termination of the large event reserve pickup or maximum generation pickup,~~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

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The definition of all other variables is identical to those defined in Section 18.4~~1.2~~ 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.

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18.6 Real-Time BPCG For Imports

18.6.1 Eligibility for Receiving Real-Time BPCG for Imports

18.6.1.1 Eligibility.

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

18.6.1.2 Non-Eligibility.

Notwithstanding Section 18.6.1.1:

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

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

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18.6.2 BPCG Calculated by Transaction ID

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

18.6.3 Formula for Determining Real-Time BPCG for Imports

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

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

Where:

Q = number of intervals in the Dispatch Day;

$DecBid_{ti}^{RT}$ = 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 in hour that contains interval i.

S_i = number of seconds in RTD interval i.

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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.

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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).

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18.8~~2~~ ~~Supplemental Payments for Curtailment Initiation Costs~~BPCG For Demand Reduction In The Day-Ahead Market

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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

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~~A supplemental payment for Curtailment Initiation Costs shall be made when the Curtailment Initiation Cost Bid and the Demand Reduction Bid price offered by a Demand Reduction Provider for any Demand Reduction committed by the ISO in the Day-Ahead market over the [twenty-four (24) hour] day exceeds Day-Ahead LBMP revenue, provided however that Supplemental payments made to Demand Reduction Providers that fail to complete their scheduled reductions may be reduced by the ISO, pursuant to ISO Procedures.~~

Day-Ahead BPCG for Demand Reduction Provider d =

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

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where:

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

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

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$$IncrCurCost_d^h = \int_{MinCur_d^h}^{max(MinCur_d^h, min(SchdCur_d^h, ActCur_d^h))} IncrCurBid_d^h]$$

$$CurRev_d^h = LBMP_{dh}^{DA} * min(max(ActCur_d^h, 0), SchdCur_d^h)$$

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.

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18.9~~3~~ ~~Supplemental Payments for Special Case Resources~~ 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 ~~supplemental payment for Minimum~~ Special Case Resource Bid Production Cost guarantee ~~P~~payment ~~Nominations~~ 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~~4 ~~Supplemental Payments for Demand Side Resources providing Synchronized Operating Reserves~~ BPCG For Demand Side Resources Providing Synchronized Operating Reserves In The Day-Ahead Market

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

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

18.10.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Day-Ahead Market

~~A.~~ A ~~supplemental~~ Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves ~~or Regulation Service~~ schedule in the Day-Ahead Market shall be calculated as follows:~~by setting to zero all terms provided in Section 18.1.1 of this Attachment C, with which Day-Ahead supplemental payments are calculated, with the exception of the term NASR~~ ~~$_{gh}^{DA}$~~ ~~which shall be calculated pursuant to its description.~~

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

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committed to provide Ancillary Services Day-Ahead, in which case this component shall be zero); and (2) payments made to Demand Side Resource d for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less Demand Side Resource d's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.11 BPCG For Demand Side Resources Providing Synchronized Operating Reserves In The Real-Time Market

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

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

18.11.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Real-Time Market

~~B.~~ A ~~supplemental~~ 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:~~by setting to zero all terms provided in Section 18.1.2 of this Attachment C, with which real-time supplemental payments are calculated, with the exception of the terms NASR$_{gi}^{DA}$ and NASR$_{gi}^{TOT}$, which shall be calculated pursuant to their descriptions.~~

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

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

where:

L = set of RTD intervals in the Dispatch Day;

NASR$_{di}^{TOT}$ = Net Ancillary Services revenue, in $, paid to Demand Side Resource d as a result of either having been scheduled Day-Ahead in the hour that includes RTD interval i or having been scheduled in real-time interval i which is computed by summing the following: (1) Regulation Service payments that would be made to Demand Side Resource d for that hour based on a Performance Index of 1, less the Bid(s) placed by Demand Side Resource d to provide Regulation Service in that hour at the time it was committed to provide Ancillary Services (unless the Bid(s) exceeds the payments that

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

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

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~~Generators with start-up times of greater than twenty-four (24) hours will have their start-up cost Bids equally prorated over the course of each day included in their start-up period. Consequently, units whose start-ups are aborted will receive a prorated portion of those payments, based on the portion of the start-up sequence they have completed (e.g., if a unit 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 cost Bid).~~

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

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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).

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

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

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:

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

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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

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

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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:

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

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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 $MinOpMW_{g,s}$.

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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

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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.