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I. LBMP CALCULATION METHOD

The Locational Based Marginal Prices ("LBMPs" or "prices") for Suppliers and Loads in the Real-Time Market will be based on the system marginal costs produced by either the Real-Time Dispatch program, or during intervals when it is activated, the RTD-CAM program (together "RTD"), or, with respect to External Transactions, and during intervals when certain conditions exist at Proxy Generator Buses, the Real-Time Commitment ("RTC") program. LBMPs for Suppliers and Loads in the Day-Ahead Market will be based on the system marginal costs produced by the Security Constrained Unit Commitment ("SCUC") program. LBMPs calculated by SCUC and RTD will incorporate the incremental dispatch costs of Resources that would be scheduled to meet an incremental of Load and, to the extent that tradeoffs exist between scheduling providers to produce Energy or reduce demand, and scheduling them to provide Regulation Service or Operating Reserves, LBMPs shall reflect the effect of meeting an incremental of Load at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Availability Bids for Regulation Service or Operating Reserves; or (ii) shortage costs associated with the inability to meet a Regulation Service or Operating Reserves requirement under the Regulation Service Demand Curve and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively of the ISO Services Tariff.

A. Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Section I.A.1(a)-(e) to calculate Real-Time LBMPs, the Marginal Losses Component, and the Congestion Component at each Load Zone and Generator bus in the table below, the ISO shall employ the special scarcity pricing rules described in Sections I.A.2.a and 2.b. Procedures governing the calculation of LBMPs at External locations are set forth below in Section E.

SCR/EDRP NYCA Called and Needed	SCR/EDRP East Called and Needed	Scarcity Pricing Rule to be Used in the West	Scarcity Pricing Rule to be Used in the East
NO	NO	NONE	NONE
	YES	NONE	B
YES	NO	a	A
		A	A

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SCR/EDRP NYCA, Called and Needed	Is "YES" if the ISO has called SCR/EDRP resources and determined that, but for the Expected Load Reduction, the Available Reserves would have been less than the NYCA requirement for total 30-Minute Reserves; or is "NO" otherwise.
SCR/EDRP East, Called and Needed	Is "YES" if the ISO has called SCR/EDRP from resources located East of Central-East and determined that, but for the Expected Load Reduction, the Available Reserves located East of Central-East would have been less than the requirement for 10-Minute Reserves located East of Central-East; or is "NO" otherwise.
Scarcity Pricing Rule to be Used in the West	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Zones located West of Central-East, including the Reference Bus.
Scarcity Pricing Rule to be Used in the East	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Zones located East of Central-East.

1.   General Procedures

a.   Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes or each Real-Time Dispatch run, except as noted below in Section I.A.1.c. A new Real-Time Dispatch run will begin every five minutes and each run will produce prices and schedules for five points in time. Only the prices and schedules determined for the first point in time of a Real-Time Dispatch run will be binding. Prices and schedules for the other four points in time shall be advisory only.

Each Real-Time Dispatch run shall, depending on when it occurs during the hour, have a bid

optimization horizon of fifty, fifty-five, or sixty minutes beyond the first point in time that it addresses.

The first and second points of time in each Real-Time Dispatch run will be five minutes apart. The

remaining points in time in each run can be either five, ten, or fifteen minutes apart depending on when

the run begins within the hour. The points in time in each RTD run are arranged so that they parallel as

closely as possible RTC's fifteen minute evaluations.

For example, the RTD run that posts its results at the beginning of an hour ("RTD_0") will

initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five

minute optimization period. RTD_0 will produce binding prices and schedules for the RTD interval

beginning when it posts its results (*i.e.* at the beginning of the hour) and ending at the first time point in its

optimization period (*i.e.,* five minutes after the hour.) It will produce advisory prices and schedules for

its second time point, which is ten minutes after the first time point in its optimization period, and

advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen

minutes apart. The RTD run that posts its results at five minutes after the beginning of the hour

("RTD_5") will initialize at the beginning of the hour and produce prices over a fifty minute optimization

period. RTD_5 will produce binding prices and schedules for the RTD interval beginning when it posts its

results (*i.e*., at five minutes after the hour) and ending at the first time point in its optimization period

(*i.e.,* ten minutes after the

hour.) It will produce advisory prices and schedules for its second time point (which is five minutes after

the first time point), and advisory prices and schedules for its third, fourth and fifth time points, each of

which would be fifteen minutes apart. The RTD run that posts its results at ten minutes after the

beginning of the hour ("RTD_{10}") will initialize at five minutes after the beginning of the hour and produce

prices over a sixty minute optimization period. RTD_{10} will produce binding prices and schedules for the

interval beginning when it posts its results (*i.e.* at ten minutes after the hour) and ending at the first time

point in its optimization period (*i.e.,* fifteen minutes after the hour.) It will produce advisory prices and

schedules for its second, third, fourth, and fifth time points, each of which would be fifteen minutes after

the preceding time point.

b.   Description of the Real-Time Dispatch Process

(i)   The First Pass

The first Real-Time Dispatch pass consists of a least bid cost, multi-period co-optimized

dispatch for Energy, Regulation Service and Operating Reserves that treats all Fixed Block Units that

are committed by RTC, or are otherwise instructed to remain online by the ISO as if they were blocked

on at their UOL_N or UOL_E, whichever is applicable. The first pass establishes "physical base points"

(*i.e.,* real-time Energy schedules) and real-time schedules for Regulation Service and Operating

Reserves for the first time point of the run. Physical base points and

schedules established for the first time point shall be binding and shall remain in effect until the results of

the next run are posted. Physical base points and schedules established for all subsequent time points

shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point

Signals that the ISO sends to Suppliers.

When establishing physical base points, the ISO shall assume that each Generator will move

toward the physical base point established during the first pass of the prior Real-Time Dispatch run at its

specified response rate.

When setting physical base points for a Dispatchable Resource at the first time point, the ISO

shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper

dispatch limits. A Resource's dispatch limits shall be determined based on whether it was feasible for it

to reach the physical base point calculated by the last RTD run given its: (A) metered output level at the

time that the Real-Time Dispatch run was initialized; (B) response rate; (C) minimum generation level;

and (D) UOL_N or UOL_E, whichever is applicable.   If it was feasible for the Resource to reach that base

point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could

achieve over the next RTD interval, given its UOL_N or UOL_E, as applicable, and starting from its

previous base point. If it was not feasible for the Resource to reach that base point, then its upper and

lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD

interval, given its UOL_N or UOL_E, as applicable, but instead starting from the feasible output level closest

to its previous base point.

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

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

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

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

The RTD Base Point Signals sent to ISO-Committed Fixed and Self-Committed Fixed

Generators shall follow the quarter hour operating schedules that those Generators submitted in their

real-time self-commitment requests, regardless of their actual performance. To the extent possible, the

ISO shall honor the response rates specified by such Generators when establishing RTD Base Point

Signals.   If such a Generator's operating schedule is not feasible based on its real-time self-commitment

requests then its RTD Base Point Signals shall be determined using a response rate consistent with the

operating schedule changes.

(ii)   The Second Pass

The second Real-Time Dispatch pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats all Fixed Block Units are committed by RTC, or that are otherwise instructed to remain online by the ISO, as flexible (*i.e.*, able to be dispatched anywhere between zero (0) MW and their UOL$_N$ or UOL$_E$, whichever is applicable), regardless of their minimum run-time status. This pass shall establish "hybrid base points" (*i.e.*, real-time Energy schedules) that are used in the third pass to determine whether minimum run-time constrained Fixed Block Units should be blocked on at their UOL$_n$ or UOL$_e$, whichever is applicable, or dispatched flexibly. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Resources, as well as for Dispatchable Generators scheduled to provide Regulation Service, shall be the same as the physical base points calculated in the first pass.

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource not scheduled to provide Regulation Service shall be the higher of: (A) its upper dispatch limit from the first pass; or (B) its "pricing base point" from the first time point of the prior RTD interval adjusted down within its Dispatchable range for any possible ramping since that pricing base point was issued.

The lower dispatch limit for the first time point of the second pass for a Dispatchable Resource not scheduled to provide Regulation Service shall be the lower of: (A) its upper dispatch limit from the first pass; or (ii) its pricing base point for the first time point of the prior RTD interval adjusted down within its Dispatchable range to account for any possible ramping since that pricing base point was issued.

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource that was not scheduled to provide Regulation Service in the first pass shall be determined by increasing its upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable. The lower dispatch limit for the later time points of the second pass for such a Resource shall be determined by decreasing its lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level

(iii)   The Third Pass

The third Real-Time Dispatch pass is the same as the second pass with three variations. First, the third pass treats Fixed Block Units that received a non-zero physical base point in the first pass, and that received a hybrid base point of zero in the second pass, as blocked on at their UOL_N or UOL_E, whichever is applicable. Second, the third pass produces "pricing base points" (*i.e.,* real-time Energy schedules) instead of hybrid base points. Third, and finally, the third pass calculates real-time Energy prices and real-time Shadow Prices for Regulation Service and

Operating Reserves that the ISO shall use for settlement purposes pursuant to Article 4, Rate Schedule

3, and Rate Schedule 4 of the ISO Services Tariff respectively. The ISO shall not use schedules for

Energy, Regulation Service and Operating Reserves that are established in the third pass to dispatch

Resources.

      c.   **Variations in RTD-CAM**

      When the ISO activates RTD-CAM, the following variations to the rules specified above in

Sections I.A.1.a and 1.b shall apply.

      First, if the ISO enters reserve pickup mode: (i) the ISO will produce prices and schedules for a

single ten minute interval (not for a multi-point co-optimization period); (ii) the Regulation Service

markets will be temporarily suspended as described in Rate Schedule 3 of the ISO Services Tariff; (iii)

the ISO will have discretion to make additional Generator commitments before executing the three

Real-Time Dispatch passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of

each Dispatchable Generator to be set to the higher of the Generator's physical base point or its actual

generation level.

      Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices

and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the

Regulation Service markets will be temporarily suspended as described in Rate Schedule 3 of the ISO

Services Tariff; (iii) the ISO will have discretion to make additional

Generator commitments in the affected area before executing the three Real-Time Dispatch passes; and

(iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator within the

affected area towards its UOL_E at its emergency response rate or set it at a level equal to its physical

base point.

Third, if the ISO enters basepoints ASAP – no commitments mode it will produce prices and

schedules for a single five minute interval (not for a multi-point co-optimization period).

Fourth, if the ISO enters basepoints ASAP – commit as needed mode: (i) the ISO will produce

price and schedules for a single five minute interval (not for a multi-point co-optimization period); and

(ii) the ISO may make additional commitments of Generators that are capable of starting within ten

minutes before executing the three Real-Time Dispatch passes.

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization

period consisting of two five-minute time points.

> **d.** **Calculating the Marginal Losses and Congestion Components**

The Marginal Losses Component of the price at each location shall be calculated as the product

of the price at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that

location minus one (1).

The Congestion Component of the price at each location shall be calculated as the price at that

location, minus the Marginal Losses Component of the price at that location, minus the price at the

Reference Bus.

e.   The Real-Time Commitment ("RTC") Process and Automated Mitigation

Attachment H of that ISO Services Tariff shall establish automated market power mitigation

measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are

implemented they shall be incorporated into the RTC software through the establishment of a second,

parallel, commitment evaluation that will assess the impact of the mitigation measures. The first

evaluation, referred to as the "RTC evaluation," will determine the schedules and prices that would

result using an original set of offers and Bids before any additional mitigation measures, the necessity for

which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the

"RT-AMP" evaluation, will determine the schedules and prices that would result from using the original

set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow

the rules governing RTC's operation that are set forth in Article 4 of the ISO Services Tariff, and this

Attachment J (as well as the corresponding provisions of Attachment B to the ISO Services Tariff).

In situations where Attachment H specifies that real-time automated mitigation measures be

utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement

mitigation measures one RTC run (*i.e.*, fifteen minutes) in the future. For example, RTC_{15} and RT-

AMP_{15} will perform Resource commitment evaluations simultaneously. $RT\text{-}AMP_{15}$ will then apply the

mitigation "impact" test, account for reference bid levels as

appropriate and determine which Resources are actually to be mitigated. This information will then be

conveyed to RTC_{30} which will make Resource commitments consistent with the application of the

mitigation measures (and will thus indirectly be incorporated into future RTD runs).

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  2a. **Scarcity Pricing Rule "A"**The ISO shall implement the following price calculation

procedures for intervals when scarcity pricing rule "A" is applicable.

  (i) Except as noted in Pricing Rule 2a(ii) below:

- The LBMP at the Reference Bus shall be determined by dividing the lowest offer price

  at which the quantity of Special Case Resources offered is equal to

$RREQ_{NYCA} - (RACT_{NYCA} - ELR_{NYCA})$, or \$500/MWh if the total quantity of Special

Case Resources offered is less than $RREQ_{NYCA} - (RACT_{NYCA} - ELR_{NYCA})$, by the

weighted average of the delivery factors produced by RTD that the ISO uses in its

calculation of prices for Load Zone J in that RTD interval,

where:

- $RACT_{NYCA}$ equals the quantity of Available Reserves in the RTD interval;

- $RREQ_{NYCA}$ equals the 30-Minute Reserve requirement set by the ISO for the NYCA;

  and

- ELR_{NYCA} equals the Expected Load Reduction in the NYCA from the Emergency

  Demand Response Program and Special Case Resources in that RTD interval.

- The Marginal Losses Component of the LBMP at each location shall be calculated as the

  product of the LBMP at the Reference Bus and a quantity equal to the delivery factor

  produced by RTD for that location minus one. The LBMP at each location shall be the sum

  of the Marginal Losses Component of the LBMP at that location, plus the LBMP at the

  Reference Bus.

- The Congestion Component of the LBMP at each location shall be set to zero.

(ii)   However, the ISO shall not use this procedure to set the LBMP for any location lower

than the LBMP for that Load Zone or Generator bus calculated pursuant to Section I.A.1 above. In

cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location pursuant to Section I.A.1; or the LBMP calculated for that location using the scarcity pricing rule "A" procedures.

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one.

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

2.b.   Scarcity Pricing Rule "B"

The ISO shall implement the following price calculation procedures in intervals when scarcity pricing rule "B" is applicable.

(i)   Except as noted in 2b(ii) below:

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section I.A.1) and a quantity equal to the delivery factor produced by RTD for that location minus one.

- The Congestion Component of the LBMP at each location shall be equal to the lowest offer price at which the quantity of Special Case Resources offered is equal

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to $RREQ_{East} - (RACT_{East} - ELR_{East})$, or \$500/MWh if the total quantity of Special Case

Resources offered is less than $RREQ_{East} - (RACT_{East} - ELR_{East})$, minus the LBMP

calculated for the Reference Bus (according to Section I.A.1), minus the Marginal

Losses Component of the LBMP for Load Zone J,

where:

- $RACT_{East}$ equals the quantity of Available Reserves located East of Central-East in

  that RTD interval;

- $RREQ_{East}$ equals the 10-Minute Reserve requirement set by the ISO for the portion

  of the NYCA located East of Central-East; and ELR_{East} equals the Expected Load

  Reduction East of Central-East from the Emergency Demand Response Program

  and Special Case Resources in that RTD interval.

- The LBMP at each location shall be the sum of the LBMP calculated for the

  Reference Bus (according to Section I.A.1) and the Marginal Loss Component and

  the Congestion Component for that location.

(ii)   However, the ISO shall not use this procedure to set the LBMP for any location lower

than the LBMP for that Load Zone or Generator bus calculated pursuant to Section I.A.1. In cases in

which the procedures described above would cause this rule to be violated:

- The LBMP at each such location shall be set to the LBMP calculated for that

  location pursuant to Section I.A.1.

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section I.A.1) and a quantity equal to the delivery factor produced by RTD for that location minus one.

- The Congestion Component of the LBMP at each such location shall be calculated as the LBMP at that location, minus the LBMP calculated for the Reference Bus (according to Section I.A.1), minus the Marginal Losses Component of the LBMP at that location.

B. Day-Ahead LBMP Calculation Procedures

LBMPs in the Day-Ahead Market are calculated using six passes. The first three passes are commitment and dispatch passes, Passes 4, 5 and 6 are dispatch only passes.

Pass 1 consists of a least cost commitment and ideal dispatch to meet Bid Load that assumes that all Fixed Block Units are dispatchable on a "flexible basis" (they can be dispatched anywhere between zero (0) MW and their maximum Capacity).

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It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment to meet Bid Load. At the end of this step, Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids and committed non-Fixed Block Units are dispatched to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis.

LBMPs are calculated from this dispatch. Following Step 1A SCUC tests for automated mitigation

procedure ("AMP") activation.

If AMP is activated, Step 1B applies the AMP impact test to determine if the AMP will be

triggered by mitigating offer prices that exceed the conduct threshold to their respective reference

prices. These mitigated offer prices together with all originally submitted offer prices not subject to

automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This

step is another iteration of the Security Constrained Unit Commitment process. At the end of Step 1B,

Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids, and committed non-

Fixed Block Units are again dispatched to meet Bid Load, using the same mitigated or unmitigated Bids

used to determine the commitment to meet Bid Load, with Fixed Block Units treated as dispatchable on

a flexible basis. LBMPs are calculated from this dispatch. The LBMPs determined at the end of Step

1B are compared to the LBMPs determined at the end of Step 1B to determine the hours and zones in

which the impact test is met.

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

All non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, 1C, or 1D depending on activation of the AMP) are blocked on at minimum load in Passes 4 through 6.

Pass 2 consists of a least cost commitment and dispatch of Fixed Block Units, Import offers, Export Bids, and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fixed Block Units are dispatchable on a flexible basis.

Pass 3 consists of a least cost commitment and dispatch of Fixed Block Units, Import offers, Export Bids, and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load that minimizes the cost of Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1 and assumes all Fixed Block Units are dispatchable on a flexible basis. Fixed Block Units dispatched in this Pass are not blocked on in Pass 6. Non-Fixed Block Units committed in this step are blocked on at minimum Load in Passes 4 through 6. The difference between Pass 2 and Pass 3 is the inclusion

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Pass 4 consists of a least cost dispatch to forecast Load. It is not used to set schedules or prices. It is used for operational purposes and provides a dispatch of Fixed Block Units, Import offers, Export Bids and the non-Fixed Block Units committed in Pass 3 (the "Day-Ahead committed resources") against forecast Loads.

Pass 5 consists of a least cost dispatch of Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids and day-ahead committed resources to meet Bid Load based, where appropriate on offer prices as mitigated in Pass 1. Fixed Block Units are treated as dispatchable on a flexible basis. LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of the ISO Services Tariff are also calculated from this dispatch.

Pass 6 consists of a least cost dispatch of Day-Ahead committed resources, Import offers, Export Bids, and virtual supply and demand Bids to meet Bid Load, based, where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units dispatched in the final step of Pass 1 or dispatched above zero in Pass 5 blocked on at maximum Capacity. The schedules of dispatchable units and Imports may be backed down, and Export schedules may be increased, to offset the additional Capacity scheduled on these Fixed Block Units. Final schedules for the Day-Ahead Market are calculated from this dispatch.

C.   LBMP Bus Calculation Method

System marginal costs will be utilized in an *ex ante* computation to produce Day-Ahead and Real-Time LBMP bus prices using the following equations.

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma_i^L + \gamma_i^C$$

Where:

γ_i =   LBMP at bus i in $/MWh

λ^R =   the system marginal price at the Reference Bus

The Marginal Losses Component of the LBMP at any bus i within the NYCA is calculated using the equation:

$$\gamma_i^L = \left(DF_i - 1\right)\lambda^R$$

Where:

$DF_i =$ delivery factor for bus i to the system Reference Bus
And:

$$DF_i = \left(1 - \frac{\partial L}{\partial P_i}\right)$$

Where:

$L =$ system losses; and

$P_i =$ injection at bus I

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

$$\gamma_i^C = -\left(\sum_{k \in K}^{n} GF_{ik}\,\mu_k\right)$$

Where:

$K =$ the set of thermal or Interface Constraints;

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GF_{ik} =   Shift Factor for bus i on Constraint k in the pre- or post- Contingency case which limits flows across that Constraint the Shift Factor measures the incremental change in flow on Constraint k, expressed in per unit, for an increment of injection at bus i and a corresponding withdrawal at the Reference Bus); and

$\boldsymbol{m}_k$ =   the reduction in system cost that results from an incremental relaxation of Constraint k expressed in $/MWh.

Substituting the equations for $\boldsymbol{g}_i^L$ and $\boldsymbol{g}_i^C$ into the first equation yields:

$$\gamma_i = \lambda^R + \left(DF_i - 1 \right)\lambda^R - \sum_{k \in K} GF_{ik}\,\mu_k$$

LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the Day-Ahead

Market, the three components of the LBMP at each location will be calculated from the SCUC results

and posted for each of the twenty-four (24) hours of the next day. The Real- Time LBMPs will be

calculated and posted for each execution of RTD.

D.   Zonal LBMP Calculation Method

The computation described above is at the bus level. An eleven (11) zone model will be used

for the LBMP billing related to Loads. The LBMP for a zone will be a Load weighted average of the

Load bus LBMPs in the zone. The Load weights which will sum to unity will be predetermined by the

ISO. Each component of the LBMP for a zone will be calculated as a Load weighted average of the

Load bus LBMP components in the zone. The LBMP for a zone j can be written as:

where:

$\gamma_j^Z =$ LBMP for zone j,

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

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

n = number of Load buses in zone j for which LBMPs are calculated; and

$W_i =$ load weighting factor for bus i.

The zonal LBMPs will be a weighted average of the Load bus LBMPs in the zone. The weightings will be predetermined by the ISO.

E. LBMP Calculation Method

1. General Rules

External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. External Generators may arrange Bilateral Transactions with Internal or External Loads and External Loads may arrange Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of buses External to the NYCA. LBMPs will be calculated for each bus within this limited set. The three components of LBMP will be calculated from the results of

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RTD, or, in the case of a Proxy Generator Bus, from the results of RTC_{15} during periods in which

(1) proposed economic transactions over the Interface between the NYCA and the Control Area with

which that Proxy Generator Bus is associated would exceed the Available Transfer Capability for that

Interface, (2) proposed interchange schedule changes pertaining to the NYCA as a whole would

exceed any Ramp Capacity limits in place for the NYCA as a whole, or (3) proposed interchange

schedule changes pertaining to the Interface between the NYCA and the Control Area in which that

Proxy Generator Bus is associated would exceed any Ramp Capacity limit imposed by the ISO for that

Interface.

2.   Rules for Non-Competitive Proxy Generator Buses

Real-Time LBMPs for a Non-Competitive Proxy Generator Bus shall be determined as

follows.

When (i) proposed Real-Time Market economic net Import transactions into the NYCA from

the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the

Available Transfer Capability for the Interface between the NYCA and the Control Area in which the

Non-Competitive Proxy Generator Bus is located, or (ii) proposed interchange schedule changes

pertaining to increases in Real-Time Market net imports into the NYCA from the Control Area in which

the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed

by the ISO for the Interface between the NYCA and the Control Area in which the Non-Competitive

Proxy Generator Bus is located, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus

will be the higher of (i) the RTC-determined price at that

Non-Competitive Proxy Generator Bus or (ii) the lower of the LBMP determined by RTD for that

Non-Competitive Proxy Generator Bus or zero.

When (i) proposed Real-Time Market economic net Export Transactions from the NYCA to

the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the

Available Transfer Capability for the Interface between the NYCA and the Control Area in which the

Non-Competitive Proxy Generator Bus is located, or (ii) proposed interchange schedule changes

pertaining to increases in Real-Time Market net Exports from the NYCA to the Control Area in which

the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed

by the ISO for the Interface between the NYCA and the Control Area in which that Non-Competitive

Proxy Generator Bus is located, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus

will be the lower of (i) the RTC-determined price at the Non-Competitive Proxy Generator Bus or

(ii) the higher of the LBMP determined by RTD for the Non-Competitive Proxy Generator Bus or the

Day-Ahead LBMP determined by SCUC for the Non-Competitive Proxy Generator Bus. At all other

times, the Real-Time LBMP shall be calculated as specified in Section E.1, above.

Under the conditions specified below, the Marginal Losses Component and the Congestion

Component of the Real-Time LBMP, calculated pursuant to the preceding paragraph, shall be

constructed as follows:

When the Real-Time LBMP is set to zero and that zero price was not the result of using the RTD, RTC

or SCUC-determined LBMP;

Marginal Losses Component of the Real-Time LBMP = $\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$; and

Congestion Component of the Real-Time LBMP = - ($\text{Energy}_{\text{RTC REF BUS}}$ + $\text{Losses}_{\text{RTC PROXY}}$

$_{\text{GENERATOR BUS}}$).

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

Marginal Losses Component of the Real-Time LBMP = $\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$; and

Congestion Component of the Real-Time LBMP = Day-Ahead $\text{LBMP}_{\text{PROXY GENERATOR BUS}}$ -

($\text{Energy}_{\text{RTC REF BUS}}$ + $\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$).

where:

$\text{Energy}_{\text{RTC REF BUS}}$ = marginal Bid cost of providing Energy at the reference Bus, as calculated by RTC_{15} for the hour;

$\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$ = Marginal Losses Component of the LBMP as calculated by RTC_{15} at the Non-Competitive Proxy Generator Bus for the hour; and

$\text{Day-Ahead LBMP}_{\text{PROXY GENERATOR BUS}}$ = Day-Ahead LBMP as calculated by SCUC for the Non-Competitive Proxy Generator Bus for the hour.

The components of LBMP will be posted in the Day-Ahead and Real-Time Markets as described above, except that the Marginal Losses Component of LBMP will be calculated differently for Internal locations. The Marginal Losses Component of the LBMP at each bus, as described above, includes the difference between the marginal cost of losses at that bus and the Reference Bus. If this formulation were employed for an External bus, then the Marginal Losses Component would include the difference in the cost of Marginal Losses for a section of the transmission system External to the NYCA. Since the ISO will not charge for losses incurred Externally, the formulation will exclude these loss effects. To exclude these External loss effects, the Marginal Losses Component will be calculated from points on the boundary of the NYCA to the Reference Bus.

The Marginal Losses Component of the LBMP at the External bus will be a weighted average of the Marginal Losses Components of the LBMPs at the Interconnection Points. To derive the Marginal Losses Component of the LBMP at an External location, a Transaction will be assumed to be scheduled from the External bus to the Reference Bus. The Shift Factors for this Transaction on the tie lines into these Interconnection buses, which measure the per-unit effect of flows over each of those tie lines that results from the hypothetical transaction, will provide the weights for this calculation. Since all the power from this assumed Transaction crosses the NYCA boundary, the sum of these weights is unity.

1.1 Loss Matrix

The ISO's RTD software will use a power flow model and penalty factors to estimate

losses incurred in performing generation dispatch and billing functions for losses.

1.2 Residual Loss Payment

The ISO will determine the difference between the payments by Transmission Customers

for losses and the payments to Suppliers for losses associated with all Transactions (LBMP Market or

Transmission Service under Parts II, III, and IV of this Tariff) for both the Day-Ahead and Real-Time

Markets. The accounting for losses at the margin may result in the collection of more revenue than is

required to compensate the Generators for the Energy they produced to supply the actual losses in the

system. This over collection is termed residual loss payments. The ISO shall calculate residual loss

payments revenue on an hourly basis and will credit them against the ISO's Residual Adjustment (See

Rate Schedule 1 of the ISO OATT).

2.0 Computation of Residual Loss Payments

2.1 Marginal Losses Component LBMP

The ISO shall utilize the Marginal Losses Component of the LBMP on an Internal bus,

an External bus, or a zone basis for computing the marginal contribution of each Transaction to the

system losses. The computation of these quantities is described in this Attachment.

2.1.1　Marginal Losses Component Day-Ahead

The ISO shall utilize the Marginal Losses Component computed by for

computing the marginal contributions of each Transaction in the Day-Ahead Market.

2.1.2　Marginal Losses Component Real-Time

The ISO shall utilize the Marginal Losses Component calculated by the (i) RTD

programs in most cases; (ii) by RTC_{15}, for External Transactions; or (iii) during intervals when the

conditions specified in Part I of this Attachment J exist at Proxy Generator Buses, the RTC program, for

computing the Marginal Losses Component associated with each Transaction scheduled in the Real-

Time Market (or deviations from Transactions scheduled in the Day-Ahead Market). The

computations will be performed on an RTD-interval basis and aggregated to an hourly total.

2.2　Charges

Charges to reflect the impact of Energy consumed by each Load, or transmitted by

each Transmission Customer on Marginal Losses Component shall be determined as follows. Each of

these charges may be negative.

Day-Ahead Charges

As part of the LBMP charged to all LSEs scheduled Day-Ahead to purchase Energy

from the LBMP Market, the ISO shall charge each such LSE the product of: (a) the

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withdrawal scheduled Day-Ahead in each Load Zone by that LSE in each hour, in MWh; and (b) the

Marginal Losses Component of the Day-Ahead LBMP in that Load Zone, in $/MWh.

As part of the TUC charged to all Transmission Customers whose transmission service

has been scheduled Day-Ahead, the ISO shall charge each such Transmission Customer the product of

(a) the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in

each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of

Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn or the bus where Energy is

scheduled to be withdrawn under if Energy is scheduled to be withdrawn at a location outside the

NYCA), minus the Marginal Losses Component of the Day-Ahead LBMP at the Point of Receipt, in

$/MWh.

Real-Time Charges

As part of the LBMP charged to all LSEs that purchase Energy from the Real-Time

LBMP Market, the ISO shall charge each such LSE the product of (a) the Actual Energy Withdrawals

by that LSE in each Load Zone in each hour, minus the Energy withdrawal scheduled Day-Ahead in

that Load Zone by that LSE for that hour, in MWh; and (b) the Marginal Losses Component of the

Real-Time LBMP in that Load Zone, in $/MWh.

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As part of the TUC charged to all Transmission Customers whose transmission service was scheduled after the determination of the Day-Ahead schedule, or who schedule additional transmission service after the determination of the Day-Ahead schedule, the ISO shall charge each such Transmission Customer the product of (a) actual Energy Withdrawals by RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (i.e., the Load Zone in which Energy is scheduled to be withdrawn or the external bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Real-Time LBMP at the Point of Receipt, in $/MWh.

III. TRANSMISSION SERVICE, SCHEDULES AND CURTAILMENT

1.0 ISO's General Responsibilities

The ISO shall evaluate requests for transmission service submitted in the Day-Ahead scheduling process using Security Constrained Unit Commitment ("SCUC"), and will subsequently establish a Day-Ahead schedule. During the Dispatch Day, the ISO shall use the RTC_{15} to establish schedules for each hour of dispatch in that day.

The ISO shall use the information provided by RTC when making Curtailment decisions pursuant to the Curtailment rules described in Part III, Section 4.0 of this Attachment J.

2.0   Use of Decremental Bids to Dispatch Internal Generators

When dispatching Generators taking service under this Tariff to match changing conditions, the ISO shall treat Decremental Bids and Incremental Energy Bids simultaneously and identically as follows: (i) a generating facility selling energy in the LBMP Market may be dispatched downward if the LBMP at the Point of Receipt falls below the generating facility's Incremental Energy Bid; (ii) a Generator serving a transaction scheduled under this Tariff may be dispatched downward if the LBMP at the Generators's Point of Receipt falls below Decremental Bid for the Generator; (iii) a Supplier's Generator may be dispatched upward if the LBMP at the Generator's Point of Receipt rises above the Decremental or Incremental Energy Bid for the Generator regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a transaction scheduled under this Tariff.

2.1   Use of Decremental Bids to Dispatch External Generators

When determining the amount of Energy that External Generators taking service under this Tariff are scheduled an hour ahead to produce, the ISO shall treat Decremental Bids and Incremental Energy Bids simultaneously and identically as follows: (i) a generating facility selling

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Energy in the LBMP Market will have its hour-ahead schedule reduced if the LBMP forecasted for the

next hour by BME at the Point of Receipt falls below the generating facility's Incremental Energy Bid;

(ii) a Generator serving a Transaction scheduled under this Tariff will have its schedule reduced if the

LBMP forecasted for the next hour by RTC_{15} at the Generator's Point of Receipt falls below the

Decremental Bid for the Generator; (iii) a Supplier's Generator will have its schedule increased if the

LBMP forecasted for the next hour by RTC_{15} at the Generator's Point of Receipt rises above the

Decremental or Incremental Energy Bid for the Generator, regardless of whether the Generator is

supplying Energy to the LBMP Market or supporting a Transaction scheduled under this Tariff.

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3.0 Day-Ahead Schedules

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

In the Day-Ahead schedule, the ISO shall use the SCUC to determine Generator schedules, Transmission Service schedules and DNIs with adjacent Control Areas. The ISO shall not use Decremental Bids submitted by Transmission Customers for Generators associated with Non-Firm Point-to-Point Transmission Service in the determination of the Day-Ahead schedule.

4.0 Reduction and Curtailment

If a Transmission Customer's Firm Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Internal Bilateral Transaction, or an Import, the ISO shall not reduce the Transmission Service.

If the Transaction was scheduled in the Day-Ahead Market, and the Day-Ahead Schedule for the Generator designated as the Supplier of Energy for that Bilateral Transaction called for that Generator to produce less Energy than was scheduled Day-Ahead to be consumed in association with that Transaction, the ISO shall supply the Load or Transmission Customer in

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an Export with Energy from the Day-Ahead LBMP Market. The Transmission Customer shall continue

to pay the Day-Ahead TUC and in addition, the Transmission Customer, if it takes service under the

ISO Services Tariff, shall pay the Day-Ahead LBMP price, at the Point of Receipt for the Transaction,

for the replacement amount of Energy in (MWh) purchased in the LBMP Market. If the Transmission

Customer does not take service under the ISO Services Tariff, it shall pay the greater of 150 percent of

the Day-Ahead LBMP at the Point of Receipt for the Transaction or $100/MWh, for the replacement

amount of Energy, as specified in this Tariff. These procedures shall apply regardless of whether the

Generator designated to supply Energy in association with the Transaction was located inside or outside

the NYCA.

If the Transaction was scheduled following the Day-Ahead Market, or the schedule for

the Transaction was revised following the Day-Ahead Market, then the ISO shall supply the Load or

Transmission Customer in an Export with Energy from the Real-Time LBMP Market, at the Real-Time

LBMP, if necessary. If (1) the Generator designated to supply the Transaction is an Internal Generator,

and it has been dispatched to produce less than the amount of Energy that is scheduled hour-ahead to

be consumed in association with that Transaction; or (2) the Generator designated to supply the

Transaction is an External Generator, and the amount of

Energy it has been scheduled an hour ahead to produce (modified for any within-hour changes in DNI, if any) is less than the amount of Energy scheduled hour-ahead to be consumed in association with that Transaction; then the Transmission Customer shall pay the Real-Time TUC for the amount of Energy withdrawn in real-time in association with that Transaction minus the amount of Energy scheduled Day-Ahead to be withdrawn in association with that Transaction. In addition, to the extent that it has not purchased sufficient replacement Energy in the Day-Ahead Market, the Transmission Customer, if it takes service under the ISO Services Tariff, shall pay the Real-Time LBMP price, at the Point of Injection for the Transaction, for any additional replacement Energy (in MWh) necessary to serve the Load.

If the Energy injections scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier of Transmission Customer whose transaction is Curtailed, in addition to paying the charge for replacement Energy necessary to serve the Load, shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of the Real-Time Bid price and zero; and (b) the scheduled Energy injection minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour. If the Transmission Customer does not take service under the ISO Services Tariff, it shall pay the greater of 150 percent of the Real-Time LBMP at the Point of Injection for the Transaction or $100/MWh for the replacement amount of Energy, as specified in this Tariff. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with that Transaction was located inside or outside the NYCA.

If the Transmission Customer was receiving Non-Firm Point-to-Point Transmission

Service, and its Transmission Service was Reduced or Curtailed, the replacement Energy may be

purchased in the Real-Time LBMP Market, at the Real-Time LBMP, by the Internal Load. An Internal

Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed may sell its

excess Energy in the Real-Time LBMP Market.

The ISO shall not automatically reinstate Non-Firm Point-to-Point Transmission Service

that was Reduced or Curtailed. Transmission Customers may submit new schedules to restore the Non-

Firm Point-to-Point Transmission Service in the next RTC_{15} execution.

If a security violation occurs or is anticipated to occur, the ISO shall attempt to relieve

the violation using the following procedures:

> (i)   Reduce Non-Firm Point-to-Point Transmission Service: Partially or fully
>
> physically Curtail External Non-Firm Transmission Service (Imports, Exports
>
> and Wheels Through) by changing DNI schedules to (1) Curtail those in the
>
> lowest NERC priority categories first; (2) Curtail within each NERC priority
>
> category, based on Decremental Bids; and Incremental Energy Bids for Imports
>
> and Wheel Throughs; and based on Sink Price Cap Bids for Exports and (3)
>
> prorate Curtailment of equal cost transactions within a priority category ;

(ii)   Curtail non-Firm Point-to-Point Transmission Service: Curtail (through changing

DNI) unscheduled non-Firm Transactions which contribute to the violation,

starting with the lowest NERC priority category;

(iii)   Dispatch Internal Generators, based on Incremental Energy Bids and

Decremental Bids, including committing additional resources, if necessary;

(iv)   Adjust the DNI associated with Transactions supplied by External Resources:

Curtail External Firm Transactions until the Constraint is relieved by (1)

Curtailing based on Incremental Energy Bids, Decremental Bids and Sink Price

Cap Bids; and (2) except for External Transactions with minimum run times,

prorating Curtailment of equal cost transactions;

(v)   Request Internal Generators to voluntarily operate in manual mode below

minimum or above maximum dispatchable levels. When operating in manual

mode, Generators will not be required to adhere minimum ramp rates, nor will

they be required to be respond to RTD Base Point Signals;

(vi)   In over generation conditions, decommit Internal Generators based on Minimum

Generation Bid rate in descending order; and

(vii)   Invoke other emergency procedures including involuntary load Curtailment, if

necessary.

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5.0 Scheduling Transmission Service for External Transactions

The amount of Firm Transmission Service scheduled Day-Ahead for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions Day-Ahead. The amount of Firm Transmission Service scheduled in the RTC_{15} for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions in the RTC_{15}. The DNI between the NYCA and adjoining Control Areas will be adjusted as necessary to reflect the effects of any Curtailments of Import or Export Transactions. Additionally, any Curtailment or Reductions of schedules for Export Transactions will cause the scheduled amount of Transmission Service to change.

The ISO shall use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy those Generators are scheduled Day-Ahead to produce in each hour. This in turn will determine the Firm Transmission Service scheduled Day-Ahead to support those Transactions. The ISO shall

also use Decremental Bids supplied by Transmission Customers using External Generators to supply

Wheels-Through to determine the amount of Energy these Generators are scheduled to produce in the

RTC_{15}, which, in turn, will determine the Transmission Service scheduled in the RTC to support those

Transactions.

The amount of Transmission Service scheduled hour-ahead in the RTC for Transactions

supplied by one of the following Generators shall retroactively be set equal to that Generator's actual

output in each RTD interval:

(i)   Generators providing Energy under existing contracts (including PURPA

contracts) in which the power purchaser does not control the operation of the

supply source but would be responsible for penalties for being off-schedule;

(ii)   Existing topping turbine Generators and extraction turbine Generators producing

electric Energy resulting from the supply of steam to the district steam system

located in New York City (LBMP Zone J) and/or topping or extraction turbine

Generators utilized in replacing or repowering existing steam supplies from such

units (in accordance with good engineering and economic design) that cannot

follow schedules, up to a maximum total of 365 MW of such units; and

(iii) Existing intermittent (i.e., non-schedulable) renewable resource Generators

within the NYCA, plus up to an additional 50 MW of such Generators.

This procedure shall not apply at times when the Generator supplying that Transaction

has been scheduled to provide Regulation Service or Operating Reserves.

The ISO will not schedule a Bilateral Transaction which crosses an Interface between

the NYCA and a neighboring Control Area if doing so would cause the DNI to exceed the Transfer

Capability of that Interface.

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