

## **17.1 LBMP Calculation**

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 the Real-Time Dispatch (“RTD”) program 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”). LBMPs calculated by SCUC and RTD will incorporate the incremental dispatch costs of Dispatchable Resources that would be scheduled to meet an increment of Load. For pricing purposes, the incremental dispatch costs of Fast-Start Resources that Bid ISO-Committed Flexible shall be adjusted to include start-up costs and minimum generation costs based on the Start-Up Bids and Minimum Generation Bids or mitigated Start-Up Bids and Minimum Generation Bids of each such Resource, as described in Section 17.1.1.2 below.

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 increment of Load, given those tradeoffs, at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) 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 set forth in Rate Schedule 3 of this ISO Services Tariff and Operating Reserve Demand Curves and Scarcity Reserve Demand Curve set forth in Rate Schedule 4 of this ISO Services Tariff. For the purposes of calculating LBMPs under this

Services Tariff Section 17, Energy withdrawals by Withdrawal-Eligible Generators are treated as negative generation, and can set price.

Additionally, for the purpose of calculating Real-Time LBMPs when RTD is committing and dispatching Resources meeting Minimum Generation Levels and capable of starting in ten minutes pursuant to Section 4.4.2.4 of this ISO Services Tariff, RTD shall include in the incremental dispatch cost of each such Resource a start-up cost based on the Start-Up Bid of each such Resource and shall assume for each such Resource a zero downward response rate.

#### 17.1.1 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:

$\gamma_i$	=	LBMP at bus $i$ in \$/MWh
$\lambda^R$	=	the system marginal price at the Reference Bus
$\gamma_i^L$	=	Marginal Losses Component of the LBMP at bus $i$ which is the marginal cost of losses at bus $i$ relative to the Reference Bus
$\gamma_i^C$	=	Congestion Component of the LBMP at bus $i$ which is the marginal cost of Congestion at bus $i$ relative to the Reference Bus

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

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

Where:

$DF_i$	=	delivery factor for bus $i$ to the system Reference Bus and:
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$$DF_i = \left(1 - \frac{\partial L}{\partial P_i}\right)$$

Where:

$L$  = NYCA 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 Constraints;

$GF_{ik}$  = 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

$\mu_k$  = the Shadow Price of Constraint  $k$  expressed in \$/MWh, provided however, this Shadow Price shall not exceed the Transmission Shortage Cost.

Substituting the equations for  $\gamma_i^L$  and  $\gamma_i^c$  into the first equation yields:

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

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.

#### **17.1.1.1 Determining Shift Factors and Incremental System Losses**

For the purposes of pricing and scheduling, Shift Factors,  $GF_{ik}$ , and loss delivery factors,  $DF_i$ , will reflect expected power flows, including expected unscheduled power flows. When determining prices and schedules, SCUC, RTC and RTD shall include both the expected power flows resulting from NYISO interchange schedules (*see* Section 17.1.1.1.2), and expected unscheduled power flows (*see* Section 17.1.1.1.1). All NYCA Resource, NYCA Load and Proxy Generator Bus Shift Factors and loss delivery factors will incorporate internal and coordinated external transmission facility outages, power flows due to schedules, and expected unscheduled power flows.

##### **17.1.1.1.1 Determining Expected Unscheduled Power Flows**

In the Day-Ahead Market, expected unscheduled power flows will ordinarily be determined based on historical, rolling 30-day on-peak and off-peak averages. To ensure expected unscheduled power flows accurately reflect anticipated conditions, the frequency and/or period used to determine the historical average may be modified by the NYISO to address market rule, system topology, operational, or other changes that would be expected to significantly impact unscheduled power flows. The NYISO will publicly post the Day-Ahead on-peak and off-peak unscheduled power flows on its web site.

In the Real-Time Market, expected unscheduled power flows will ordinarily be determined based on current power flows, modified to reflect expected changes over the real-time scheduling horizon.

#### **17.1.1.1.2 Determining Expected Power Flows Resulting from NYISO Interchange Schedules**

In the Day-Ahead Market, for purposes of scheduling and pricing, SCUC will establish expected power flows for the ABC interface, JK interface and Hopatcong-Ramapo interconnection based on the following:

- a. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the Hopatcong-Ramapo interconnection;
  - 1) The expected flow over the Hopatcong-Ramapo interconnection may also be adjusted by a MW offset to reflect expected operational conditions;
- b. The percentage of PJM-NYISO scheduled interchange that is expected to flow over the ABC interface;
  - 1) The expected flow over the ABC interface will include an additional Operational Base Flow as described in Attachment CC to the OATT;
- c. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to flow over the JK interface;
  - 1) The expected flow over the JK interface will include an additional Operational Base Flow as described in Attachment CC to the OATT.

The terms “ABC interface” and “JK interface” have the meaning ascribed to them in Attachment CC to the OATT.

The NYISO shall post the interchange percentage and Operational Base Flow values it is currently using to establish Day-Ahead and real-time expected Hopatcong-Ramapo interconnection, ABC interface and JK interface flows for purposes of scheduling and pricing on its web site. If the NYISO determines it is necessary to change the posted Hopatcong-Ramapo,

ABC or JK interchange percentage or Operational Base Flow values, it will provide notice to its Market Participants as far in advance of the change as is practicable under the circumstances.

In the Day-Ahead Market, scheduled interchange that is not expected to flow over the ABC interface, JK interface or Hopatcong-Ramapo interconnection (or on Scheduled Lines) will be expected to flow over the NYISO's other interconnections. Expected flows over the NYISO's other interconnections will be determined consistent with the expected impacts of scheduled interchange and consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

For pricing purposes, flows in the Real-Time Market will be established for the ABC interface, JK interface, and Hopatcong-Ramapo interconnection based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon in a manner that is consistent with the method used to establish Day-Ahead power flows over these facilities. Expected flows over the NYISO's other interconnections will be determined based on the current flow, modified to reflect the expected incremental impacts of changes to interchange schedules over the forward scheduling horizon, and shall be consistent with shift factors and delivery factors calculated in accordance with Section 17.1.1.1, above.

#### **17.1.1.1.3 Scheduled Lines and Chateauguay Interconnection with Hydro Quebec**

For purposes of scheduling and pricing, the NYISO expects that power flows will ordinarily match the interchange schedule at Scheduled Lines, and at the NYCA's Chateauguay interconnection with Hydro Quebec, in both the Day-Ahead and Real-Time Markets.

#### **17.1.1.2 Incremental Dispatch Costs for Pricing Fast-Start Resources**

For the purpose of calculating LBMPs for the Day-Ahead and Real-Time Markets, the incremental dispatch costs of Fast-Start Resources that Bid ISO-Committed Flexible shall be adjusted to include start-up costs and minimum generation costs based on the Start-Up Bids and Minimum Generation Bids or mitigated Start-Up Bids and Minimum Generation Bids of each such Resource (“Adjusted Dispatch Costs”). For start-up costs, the ISO will use a Fast-Start Resource’s single point Start-Up Bid if one is submitted (or the mitigated Bid, where appropriate). If a Fast-Start Resource does not submit a single point Start-Up Bid in the Real-Time Market, the ISO will use the point on the Fast-Start Resource’s multi-point Start-Up Bid curve (or its mitigated multi-point Start-Up Bid curve, where appropriate) that corresponds to the shortest specified down time.

The ISO will use the following procedure to determine a Fast-Start Resource’s Adjusted Dispatch Costs for each pricing interval in the Day-Ahead and Real-Time Markets. The ISO will determine the “cost-minimizing output level” that minimizes the average as-Bid operating cost (“minimum average cost”) for that Fast-Start Resource in each hour of the Day-Ahead Market and in each RTD interval of the Real-Time Market. The average as-Bid operating cost for a Fast-Start Resource at a given operating level shall include the Fast-Start Resource’s minimum generation costs and incremental energy costs to provide Energy at that operating level, based on the Resource’s Bids, or mitigated Bids as appropriate. The average as-Bid operating cost may also include some or all of the Fast-Start Resource’s start-up costs based on the Resource’s Bids, or mitigated Bids as appropriate, in a given hour, to be determined as follows: (1) for the Day-Ahead Market, a Fast-Start Resource’s average as-Bid operating cost to operate in a given hour will include start-up costs for the hour the Resource is scheduled to start; or (2) for the Real-Time Market, a Fast-Start Resource’s average as-Bid operating cost to operate in a given RTD

interval will include the start-up costs for approximately the first fifteen minutes, among consecutive operating intervals, after the Resource is scheduled to start, *i.e.*, for each RTD interval that starts within the first fifteen minutes after the Resource is scheduled to start, the average as-Bid operating cost to operate in that interval will include start-up costs.

For all output levels less than or equal to the cost-minimizing output level, the ISO will set the Adjusted Dispatch Cost equal to the minimum average cost. For all output levels greater than the cost-minimizing output level, the ISO will set the Adjusted Dispatch Cost equal to the price on the Resource's Bid curve. The ISO will calculate Adjusted Dispatch Costs for each output level between the Fast-Start Resource's minimum operating level and its  $UOL_N$  or  $UOL_E$  (whichever is applicable).

For the purpose of calculating LBMPs for the Day-Ahead and Real-Time Markets, all Fast-Start Resources that Bid ISO-Committed Flexible are treated as flexible and able to be dispatched anywhere between zero (0) MW and their  $UOL_N$  or  $UOL_E$  (whichever is applicable). The dispatch for Fast-Start Resources, including Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits.

Additional rules for Fixed Block Units are set forth below in Section 17.1.2.1.2.

### **17.1.2 Real-Time LBMP Calculation Procedures**

For each RTD interval, the ISO shall use the procedures described below in Sections 17.1.2.1-17.1.2.1.4 to calculate Real-Time LBMPs at each Load Zone, Generator bus and Transmission Node. The LBMP bus and zonal calculation procedures are described in Sections 17.1.1 and 17.1.5 of this Attachment B, respectively. Procedures governing the calculation of LBMPs at Proxy Generator Buses are set forth below in Section 17.1.6 of this Attachment B.



### **17.1.2.1 General Procedures**

#### **17.1.2.1.1 Overview**

The ISO shall calculate Real-Time Market LBMPs using the three passes of each RTD run, except as noted below in Section 17.1.2.1.3. A new RTD run will initialize every five minutes and each run will produce prices and schedules for five points in time (the optimization period). Only the prices and schedules determined for the first time point of the optimization period will be binding. Prices and schedules for the other four time points of the optimization period are advisory.

Each RTD 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, or binding, point in time that it addresses. The posting time and the first time point in each RTD run, which establishes binding prices and schedules, will be five minutes apart. The remaining points in time in each optimization period 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 optimization period 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<sub>0</sub>") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD<sub>0</sub> 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<sub>5</sub>") 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.

#### **17.1.2.1.2 Description of the Real-Time Dispatch Process**

##### **17.1.2.1.2.1 The First Pass**

The first RTD 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 be online or remain online by the ISO as if they were blocked on at their  $UOL_N$  or  $UOL_E$ , whichever is applicable. Fixed Block Units that do not participate in a Co-located Storage Resource, are capable of being started and meeting Minimum Generation Levels in ten minutes or less, and that have not been committed by RTC, are treated as flexible (i.e. able to be dispatched anywhere between zero (0) MW and 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 optimization period. 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.

RTD will consider CSR Scheduling Limits when setting physical base points for Generators that participate as Co-located Storage Resources.

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When establishing physical base points, the ISO shall assume that each Generator and Aggregation will move toward the physical base point established during the first pass of the prior RTD run at its specified response rate.

**17.1.2.1.2.1.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel**

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 Dispatchable Resource's lower and upper dispatch limits. A Dispatchable 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 and metered Energy Level (if applicable) at the time that the RTD run was initialized; (B) response rate; (C) minimum generation level/LOL; (D) USL and LSL (if applicable); and (E)  $UOL_N$  or  $UOL_E$ , whichever is applicable. If it was feasible for the Dispatchable 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 starting from its previous base point, subject to factors (A) through (E) specified above.

If it was not feasible for the Dispatchable 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, subject to factors (A) through (E) specified above, 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 level/LOL; (D) Energy Level, USL and LSL (if applicable); and (E)  $UOL_N$  or  $UOL_E$ , whichever is applicable.

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting 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, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level/LOL considering applicable Energy Level limitations for ISO-Managed ESRs, or 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.

#### **17.1.2.1.2.1.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel**

For all time points of the optimization period, the Lower Dispatch Limit shall be the higher of (a) an Intermittent Power Resource's metered output level at the time that the RTD run

was initialized reduced by its response rate, or (b) zero. The Upper Dispatch Limit shall be the Wind and Solar Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind and Solar Energy Forecast.

**17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators and Aggregations**

When setting physical base points for Self-Committed Fixed Generators and Aggregations 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.

When setting physical base points for ISO-Committed Fixed Generators and Aggregations in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels scheduled for it by RTC 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 Self-Committed Fixed Generators and Aggregations shall follow the quarter hour operating schedules that those Generators and Aggregations submitted in their real-time self-commitment requests.

The RTD Base Point Signals sent to ISO-Committed Fixed Generators shall follow the quarter hour operating schedules established for those Generators by RTC, 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 a Self-Committed Fixed Generator's or Aggregation'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.

#### **17.1.2.1.2.2 The Second Pass**

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats: (i) all Fast-Start Resources that are committed by RTC; (ii) Fixed Block Units that do not participate in a Co-located Storage Resource, are capable of starting and meeting Minimum Generation Levels in ten minutes, and have not been committed by RTC; and (iii) all Fixed Block Units otherwise instructed to be online or 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. The dispatch of Generators, including Fast-Start Resources and Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. The second 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 Section 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this ISO Services Tariff respectively. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

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The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Resources shall be the same as the physical base points calculated in the first pass.

##### **17.1.2.1.2.2.1 Upper and Lower Dispatch Limits for Dispatchable Resources Other Than Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel**

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource 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 up within its Dispatchable range for any possible ramping since that pricing base point was issued less the higher of: (i) the physical base point established during the first pass of the RTD immediately prior to the previous RTD minus the Resource’s metered output level at the time that the current RTD run was initialized, or (ii) zero.

The lower dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the lower of: (A) its lower 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 to account for any possible ramping since that pricing base point was issued plus the higher of: (i) the Resource’s metered output level at the time that the current RTD run was initialized minus the physical base point established during the first pass of the RTD immediately prior to the previous RTD, considering the metered Energy Level if applicable; or (ii) zero.

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource shall be determined by adjusting 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, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for the later time points of the second pass for a Dispatchable non-Fast-Start Resource shall be determined by adjusting its lower dispatch limit from the first time point at the Resource’s response rate, down to its minimum generation level/LOL, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for the later time points of the second pass for a Fast Start Resource shall be determined by decreasing its lower dispatch limit from the first time point at the Resource’s response rate, down to zero.

**17.1.2.1.2.2.2 Upper and Lower Dispatch Limits for Intermittent Power Resources That Depend on Wind or Solar Energy as Their Fuel**

For the first time point and later time points for Intermittent Power Resources that depend on wind or solar energy as their fuel, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind and Solar Energy Forecast for that Resource. For Intermittent Power Resources depending on wind as their fuel in commercial operation as of January 1, 2002 with a name plate capacity of 12 MWs or fewer, the Upper and Lower Dispatch Limits shall be the output level specified by the Wind and Solar Energy Forecast.

**17.1.2.1.2.3 The Third Pass**

The third RTD pass is reserved for future use.

**17.1.2.1.3 Variations in RTD-CAM**

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 17.1.2.1.1 and 17.1.2.1.2 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 ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator and Aggregations commitments before executing the three RTD passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator or Aggregation to be set to the higher of the Generator's or Aggregation's physical base point or its actual supply 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 ISO shall set Regulation Service schedules to zero as described in Rate Schedule



15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator and Aggregation commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator and Aggregation 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 and Aggregations that are capable of starting within ten minutes before executing the three RTD 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.

#### **17.1.2.1.4 The Real-Time Commitment (“RTC”) Process and Automated Mitigation**

Attachment H of this 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 Section 4 of and this Attachment B to this 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.  $RT-AMP_{15}$  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).

### **17.1.3 Day-Ahead LBMP Calculation Procedures**

LBMPs in the Day-Ahead Market are calculated using five passes. The first two passes are commitment and dispatch passes; the last three are dispatch only passes.

Pass 1 consists of a least cost commitment and dispatch to meet Bid Load and reliable operation of the NYS Power System that includes Day-Ahead Reliability Units.

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment ("SCUC") to meet Bid Load. At the end of this step, committed Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fast-Start Resources are dispatched to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable. For

mitigation purposes, LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure (“AMP”) activation.

If AMP is activated, Step 1B tests to determine if the AMP will be triggered by mitigating offer prices subject to mitigation 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 SCUC process. At the end of Step 1B, committed Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources, and non-Fast-Start Resources are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable. For mitigation purposes, LBMPs are again calculated from this dispatch. The LBMPs determined at the end of Step 1B are compared to the LBMPs determined at the end of Step 1A to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices subject to mitigation 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 SCUC process. At the end of Step 1C, committed Fast-Start Resources, Imports, Exports, virtual supply, virtual load, Demand Side Resources, and non- Fast-Start Resources are again dispatched to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable. The dispatch for Generators,

including Fast-Start Resources and Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. For mitigation purposes, LBMPs are again calculated from this dispatch.

All Demand Side and non-Fast-Start Resources committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at least to minimum generation level in Passes 4 through 6. All Energy Storage Resources, Hybrid Storage Resources and Aggregations dispatched in the final step of Pass 1 (which could be either Step 1A, 1B, or 1C depending on activation of the AMP) are blocked on at the dispatch that was determined in Pass 1 in Passes 2 through 4. The resources required to meet local system reliability are determined in Pass 1.

Pass 2 consists of a least cost commitment and dispatch of Fast-Start Resources, Imports, Exports, Demand Side Resources and non-Fast-Start Resources to meet forecast Load requirements in excess of Bid Load, considering the Wind and Solar Energy Forecast, 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 Fast-Start Resources are dispatchable between zero MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable. The dispatch for Generators, including Fast-Start Resources, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. Incremental Import Capacity needed to meet forecast Load requirements is determined in Pass 2. Fixed Block Units committed in this pass are not included in the least cost dispatches of Passes 5 or 6. Demand Side Resources and non-Fast-Start Resources committed in this step are blocked on at least to minimum generation level in Passes 4 through 6. Intermittent Power Resources that depend on

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wind or solar energy as their fuel committed in this pass as a result of the consideration of the Wind and Solar Energy Forecast are not blocked in Passes 5 or 6.

Pass 3 is reserved for future use.

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 Fast-Start Resources, Imports, Exports, Demand Side Resources and non- Fast-Start Resources committed in Passes 1 or 2. Incremental Import Capacity committed in Pass 2 is re-evaluated and may be reduced if no longer required.

Pass 5 consists of a least cost dispatch of Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non- Fast-Start Resources committed to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fast-Start Resources are treated as dispatchable between zero MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable. 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 this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fast-Start Resources in the Day-Ahead Market are calculated from this dispatch.

Pass 6 consists of a least cost dispatch of all Day-Ahead committed Resources, Imports, Exports, Virtual Supply, Virtual Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units committed in the final step of Pass 1 blocked on at maximum Capacity. Final schedules for Fast-Start Resources in the Day-Ahead Market are calculated from this dispatch.

#### **17.1.4 Determination of Transmission Shortage Cost**

The applicable Transmission Shortage Cost depends on whether a particular transmission Constraint is associated with a transmission facility or Interface that includes a non-zero constraint reliability margin value. The ISO shall establish constraint reliability margin values for transmission facilities and Interfaces. Non-zero constraint reliability margin values established by the ISO are normally equal to 20 MW. The ISO assigns a non-zero constraint reliability margin value (normally equal to 5 MW) to certain transmission facilities accommodating power flows out of export constrained areas (or “generation pockets”) that, as further described below, are subject to a different Transmission Shortage Cost (for purposes of this Section 17.1.4, the aforementioned facilities are hereinafter referred to as “Identified Facilities”). The ISO shall post to its website a list of transmission facilities and Interfaces assigned a constraint reliability margin value other than 20 MW. The list posted by the ISO shall also include Identified Facilities and the applicable constraint reliability margin value assigned to each such facility.

Except for Identified Facilities, when evaluating transmission Constraints associated with transmission facilities and Interfaces assigned a non-zero constraint reliability margin value, SCUC, RTC, and RTD shall include consideration of a six-step demand curve consisting of the following components: (1) a MW value of additional available resource capacity equal to or less than 20% of the applicable constraint reliability margin value, at a cost of \$200/MWh; (2) a MW value of additional available resource capacity equal to or less than 40% of the applicable constraint reliability margin value, but greater than 20% of such value, at a cost of \$350/MWh; (3) a MW value of additional available resource capacity equal to or less than 60% of the applicable constraint reliability margin value, but greater than 40% of such value, at a cost of \$600/MWh; (4) a MW value of additional available resource capacity equal to or less than 80%

of the applicable constraint reliability margin value, but greater than 60% of such value, at a cost of \$1,500/MWh; (5) a MW value of additional available resource capacity equal to or less than 100% of the applicable constraint reliability margin value, but greater than 80% of such value, at a cost of \$2,500/MWh; and (6) any MW value of additional available resource capacity greater than the applicable constraint reliability margin value, at a cost of \$4,000/MWh.

When evaluating transmission Constraints associated with Identified Facilities, SCUC, RTC, and RTD shall include consideration of a two-step demand curve consisting of the following components: (1) a MW value of additional available resource capacity equal to or less than the applicable constraint reliability margin value, at a cost of \$100/MWh; and (2) any MW value of additional available resource capacity greater than the applicable constraint reliability margin value, at a cost of \$250/MWh.

For transmission facilities and Interfaces assigned a non-zero constraint reliability margin value, the applicable demand curve, as described above, shall be applied in a manner such that it is considered in resolving, collectively, all applicable transmission Constraints associated with a particular transmission facility or Interface rather than applying a distinct demand curve individually to each such transmission Constraint. In the event of redundant transmission Constraints on in-series transmission facilities or parallel transmission facilities, the most limiting of such redundant transmission Constraints shall be deemed binding and utilized for the purposes of determining the applicable Shadow Price for the redundant transmission Constraints at issue. The less limiting of such redundant transmission Constraints on in-series transmission facilities or parallel transmission facilities shall be deemed non-binding and assigned a zero value Shadow Price. The MW value of the additional available resource capacity associated

with each step of the applicable demand curve, as described above, shall be rounded to the nearest whole number.

For transmission facilities and Interfaces with a constraint reliability margin value of zero, the Shadow Price for transmission Constraints associated with such facilities and Interfaces shall not exceed \$4,000/MWh. SCUC, RTC, and RTD shall not include consideration of additional available resource capacity provided by a demand curve mechanism for such transmission Constraints.

In evaluating transmission Constraints for transmission facilities and Interfaces with a constraint reliability margin value of zero, the ISO will determine whether sufficient available resource capacity exists to solve each transmission Constraint at its applicable limit. If sufficient available resource capacity does not exist to solve the transmission Constraint at its otherwise applicable limit, the ISO shall increase the applicable limit for such transmission Constraint to an amount achievable by the available resource capacity plus 0.2 MW.

Notwithstanding anything to the contrary herein, in circumstances where the ISO is the “Non-Monitoring RTO” with respect to a transmission Constraint associated with a “Flowgate” subject to “M2M” coordination, the ISO’s evaluation of such transmission Constraint in the Real-Time Market shall be consistent with the rules and procedures specified in Section 35.23 of Attachment CC of the ISO OATT. For purposes of this Section 17.1.4, the terms “Non-Monitoring RTO,” “Flowgate,” and “M2M” shall have the meaning specified in Section 35.2.1 of Attachment CC of the ISO OATT.

The ISO may periodically evaluate the Transmission Shortage Cost to determine whether it is necessary to modify the Transmission Shortage Cost to avoid future operational or reliability problems. The ISO will consult with its Market Monitoring Unit after it conducts this



evaluation. If the ISO determines that it is necessary to modify the Transmission Shortage Cost in order to avoid future operational or reliability problems the resolution of which would otherwise require recurring operator intervention outside normal market scheduling procedures, in order to avoid among other reliability issues, a violation of NERC Interconnection Reliability Operating Limits or System Operating Limits, it may temporarily modify it for a period of up to ninety days, provided however the ISO shall file such change with the Commission pursuant to Section 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will: (i) consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change; and (ii) notify Market Participants of any temporary modification.

The responsibilities of the ISO and the Market Monitoring Unit in evaluating and modifying the Transmission Shortage Cost, as necessary are addressed in Attachment O, Section 30.4.6.8.1 of this Market Services Tariff ("Market Monitoring Plan").

#### **17.1.5 Zonal LBMP Calculation Method**

The computation described in Section 17.1.1 of this Attachment B is at the bus level. An eleven (11) zone model will be used for the LBMP billing related to Loads, except for Energy withdrawals by Eligible Generators for later injection onto the grid. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the Load Zone. The Load weights which will sum to unity will be calculated from the load bus MW distribution. 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:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

where:

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

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

$\gamma_j^{C,Z} = \sum W_i \gamma_i^L$  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 NYISO also calculates and posts zonal LBMP for four (4) external zones for informational purposes only. Settlements for External Transactions are determined using the Proxy Generator Bus LBMP. Each external zonal LBMP is equal to the LBMP of the Proxy Generator Bus associated with that external zone. The table below identifies which Proxy Generator Bus LBMP is used to determine each of the posted external zonal LBMPs.

External Zone	External Zone PTID	Proxy Generator Bus	Proxy Generator Bus PTID
HQ	61844	HQ_GEN_WHEEL	23651
NPX	61845	N.E._GEN_SANDY_POND	24062
OH	61846	O.H._GEN_PROXY	24063
PJM	61847	PJM_GEN_KEystone	24065

Consistent with the ISO Services Tariff, LBMPs at Proxy Generator Buses are determined using calculated bus prices as described in this Section 17.1.

## **17.1.6 Real Time LBMP Calculation Methods for Proxy Generator Buses, Non-Competitive Proxy Generator Buses and Proxy Generator Buses Associated with Designated Scheduled Lines**

### **17.1.6.1 Definitions**

**Interface ATC Constraint:** An Interface ATC Constraint exists when proposed economic transactions over an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed the transfer capability for the Interface or for an associated Proxy Generator Bus.

**Interface Ramp Constraint:** An Interface Ramp Constraint exists when proposed interchange schedule changes pertaining to an Interface between the NYCA and the Control Area with which one or more Proxy Generator Bus(es) are associated would exceed any Ramp Capacity limit imposed by the ISO for the Interface or for an associated Proxy Generator Bus.

**NYCA Ramp Constraint:** A NYCA Ramp Constraint exists when 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.

**Proxy Generator Bus Constraint:** Any of an Interface ATC Constraint, an Interface Ramp Constraint, or a NYCA Ramp Constraint (individually and collectively).

**External Interface Congestion:** The product of: (i) the portion of the Congestion Component of the LBMP at a Proxy Generator Bus that is associated with a Proxy Generator Bus Constraint and (ii) a factor, between zero and 1, calculated pursuant to ISO Procedures.

**Proxy Generator Bus Border LBMP:** The LBMP at a Proxy Generator Bus minus External Interface Congestion at that Proxy Generator Bus.

**Unconstrained RTD LBMP:** The LBMP as calculated by RTD less any congestion associated with a Proxy Generator Bus Constraint.

### **17.1.6.2 General Rules**

Transmission Customers and Customers with External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. Those with External Generators may arrange LBMP Market sales and/or Bilateral Transactions with Internal or External Loads and External Loads may arrange LBMP Market purchases and/or 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 Proxy Generator Buses. LBMPs will be calculated for each Proxy

Generator Bus within this limited set. When an Interface with multiple Proxy Generator Buses is constrained, the ISO will apply the constraint to all of the Proxy Generator Buses located at that Interface. Except as set forth in Sections 17.1.6.3 and 17.1.6.4, the NYISO will calculate the three components of LBMP for Transactions at a Proxy Generator Bus as provided in the tables below.

When determining the External Interface Congestion, if any, to apply to determine the LBMP for RTD intervals that bridge two RTC intervals, the NYISO shall use the External Interface Congestion associated with the second (later) RTC interval.

#### 17.1.6.2.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses

The pricing rules for Dynamically Scheduled Proxy Generator Buses are to be determined.

#### 17.1.6.2.2 Pricing rules for Variably Scheduled Proxy Generator Buses

The pricing rules for Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location <i>a</i>	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location <i>a</i> )
1	Unconstrained in RTC <sub>15</sub> , Rolling RTC and RTD	N/A	Real-Time LBMP <sub><i>a</i></sub> = RTD LBMP <sub><i>a</i></sub>
2	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time LBMP <sub><i>a</i></sub> = RTD LBMP <sub><i>a</i></sub> + Rolling RTC External Interface Congestion <sub><i>a</i></sub>

#### 17.1.6.2.3 Pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled

The pricing rules for Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location $a$	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location $a$ )
1	Unconstrained in $RTC_{15}$ , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$
3	$RTC_{15}$ is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time $LBMP_a = RTD\ LBMP_a + RTC_{15}\ \text{External Interface Congestion}_a$

### 17.1.6.3 Rules for Non-Competitive Proxy Generator Buses and Associated Interfaces

Real-Time LBMPs for an Interface that is associated with one or more Non-Competitive Proxy Generator Buses or for a Non-Competitive Proxy Generator Bus shall be determined as provided in the tables below. Non-Competitive Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

#### 17.1.6.3.1 Pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Dynamically Scheduled Proxy Generator Buses are to be determined.

#### 17.1.6.3.2 Pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive, Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location $a$	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location $a$ )
1	Unconstrained in $RTC_{15}$ , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$

4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface RampConstraint	Into NYCA (Import)	<p>If Rolling RTC Proxy Generator Bus <math>LBMP_a &gt; 0</math>, then Real-Time <math>LBMP_a = RTD LBMP_a + \text{Rolling RTC External Interface Congestion}_a</math></p> <p>Otherwise, Real-Time <math>LBMP_a = \text{Minimum of (i) } RTD LBMP_a \text{ and (ii) zero}</math></p>
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	<p>If Rolling RTC Proxy Generator Bus <math>LBMP_a &lt; 0</math>, then Real-Time <math>LBMP_a = RTD LBMP_a + \text{Rolling RTC External Interface Congestion}_a</math></p> <p>Otherwise, Real-Time <math>LBMP_a = RTD LBMP_a</math></p>

#### 17.1.6.3.3 Pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses

The pricing rules for Non-Competitive Proxy Generator Buses that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location <i>a</i>	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location <i>a</i> )
1	Unconstrained in RTC <sub>15</sub> , Rolling RTC and RTD	N/A	Real-Time LBMP <sub><i>a</i></sub> = RTD LBMP <sub><i>a</i></sub>
6	RTC <sub>15</sub> is subject to an Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	If RTC <sub>15</sub> Proxy Generator Bus LBMP <sub><i>a</i></sub> > 0, then Real-Time LBMP <sub><i>a</i></sub> = RTD LBMP <sub><i>a</i></sub> + RTC <sub>15</sub> External Interface Congestion <sub><i>a</i></sub>  Otherwise, Real-Time LBMP <sub><i>a</i></sub> = Minimum of (i) RTD LBMP <sub><i>a</i></sub> and (ii) zero
7	RTC <sub>15</sub> is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If RTC <sub>15</sub> Proxy Generator Bus LBMP <sub><i>a</i></sub> < 0, then Real-Time LBMP <sub><i>a</i></sub> = RTD LBMP <sub><i>a</i></sub> + RTC <sub>15</sub> External Interface Congestion <sub><i>a</i></sub>  Otherwise, Real-Time LBMP <sub><i>a</i></sub> = RTD LBMP <sub><i>a</i></sub>

#### 17.1.6.4 Special Pricing Rules for Proxy Generator Buses Associated with Designated Scheduled Lines

Real-Time LBMPs for the Proxy Generator Buses associated with designated Scheduled Lines shall be determined as provided in the tables below. The Proxy Generator Buses that are associated with designated Scheduled Lines are identified in Section 4.4.4 of the Services Tariff.

##### 17.1.6.4.1 Pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Dynamically Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are to be determined.

##### 17.1.6.4.2 Pricing rules for Variably Scheduled Proxy Generator Buses that are associated with Designated Scheduled Lines

The pricing rules for Variably Scheduled Proxy Generator Buses that are associated with designated Scheduled Lines are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location $a$	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location $a$ )
1	Unconstrained in $RTC_{15}$ , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$
4	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Into NYCA (Import)	<p>If Rolling RTC Proxy Generator Bus <math>LBMP_a &gt; 0</math>, then Real-Time <math>LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a</math></p> <p>Otherwise, Real-Time <math>LBMP_a = \text{Minimum of (i) } RTD\ LBMP_a \text{ and (ii) zero}</math></p>
5	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint	Out of NYCA (Export)	<p>If Rolling RTC Proxy Generator Bus <math>LBMP_a &lt; 0</math>, then Real-Time <math>LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a</math></p> <p>Otherwise, Real-Time <math>LBMP_a = RTD\ LBMP_a</math> )</p>

**17.1.6.4.3 Pricing rules for Proxy Generator Buses that are associated with Designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses**

The pricing rules for Proxy Generator Buses that are associated with designated Scheduled Lines that are not Dynamically Scheduled or Variably Scheduled Proxy Generator Buses, are provided in the following table.

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location $a$	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location $a$ )
1	Unconstrained in $RTC_{15}$ , Rolling RTC and RTD	N/A	Real-Time $LBMP_a = RTD\ LBMP_a$
6	$RTC_{15}$ is subject to an Interface ATC Constraint	Into NYCA (Import)	<p>If <math>RTC_{15}</math> Proxy Generator Bus <math>LBMP_a &gt; 0</math>, then Real-Time <math>LBMP_a = RTD\ LBMP_a + RTC_{15} \text{ External Interface Congestion}_a</math></p> <p>Otherwise, Real-Time <math>LBMP_a = \text{Minimum of (i) } RTD\ LBMP_a \text{ and (ii) zero}</math></p>



Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location <i>a</i>	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location <i>a</i> )
7	RTC <sub>15</sub> is subject to an Interface ATC Constraint	Out of NYCA (Export)	<p>If RTC<sub>15</sub> Proxy Generator Bus LBMP<sub>a</sub> &lt; 0, then Real-Time LBMP<sub>a</sub> = RTD LBMP<sub>a</sub> + RTC<sub>15</sub> External Interface Congestion<sub>a</sub></p> <p>Otherwise, Real-Time LBMP<sub>a</sub> = RTD LBMP<sub>a</sub></p>

**17.1.6.5 Method of Calculating Marginal Loss and Congestion Components of Real-Time LBMP at Non-Competitive Proxy Generator Buses and Proxy Generator Buses that are Subject to the Special Pricing Rule for Designated Scheduled Lines**

Under the conditions specified below, the Marginal Losses Component and the Congestion Component of the Real-Time LBMP, calculated pursuant to the preceding paragraphs in Sections 17.1.6.3 and 17.1.6.4, 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;

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

and

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

where:

$\text{Energy}_{\text{RTD REF BUS}}$  = The marginal Bid cost of providing Energy at the reference Bus, as calculated by RTD for that 5-minute interval; and

$\text{Losses}_{\text{RTD PROXY GENERATOR BUS}}$  = The Marginal Losses Component of the LBMP as calculated by RTD for that 5-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line.