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 Resources that would be scheduled to meet an
increment 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 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 and Operating Reserve Demand
Curves set forth in Rate Schedules 3 and 4 respectively of this ISO Services Tariff.
 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 4.4.3.3 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 DayAhead and Real-Time LBMP bus prices using the following equations.
 The LBMP at bus i can be written as:

γi = λR + γLi + γCi

Where:

γi = LBMP at bus i in $/MWh

λR = the system marginal price at the Reference Bus

γ iL = Marginal Losses Component of the LBMP at bus i which is the marginal

cost of losses at bus i relative to the Reference Bus

γ Ci = 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:

γ L = (DFi - 1) λRi

Where:

DFi = delivery factor for bus i to the system Reference Bus and:

∂L

DFi = (1 - )

∂P i

Where:

L = NYCA losses; and

Pi = injection at bus i

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

c

n

γ

=−

GF

μ

i

Where:

∑

k∈K

ik k

, except as noted in Sections 17.1.2.2.1 and 17.1.2.3.1 of this Attachment B

K = the set of Constraints;

GFik = 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

µk = 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 γ

L and γ

i

C into the first equation yields:

i

γ i= λR+ (DFi- 1)λR - ∑ GFik µk

k Є K

LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the DayAhead 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, GFik, and loss delivery factors,
DFi, 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 realtime 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 Branchburg-Ramapo
interconnection based on the following:

a. Consolidated Edison Company of New York’s Day-Ahead Market hourly election

under OATT Attachment CC, Schedule C;

b. The percentage of PJM-NYISO scheduled interchange that is expected to flow

over the Branchburg-Ramapo interconnection. The expected flow may also be adjusted by a MW offset to reflect expected operational conditions;

c. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to

flow over the ABC interface; and

d. The percentage of PJM-NYISO scheduled interchange (if any) that is expected to

flow over the JK interface.

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

The NYISO shall post the percentage values it is currently using to establish Day-Ahead
and real-time expected Branchburg-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 Branchburg-Ramapo, ABC or JK percentage 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 Branchburg-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 Branchburg-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.

17.1.2 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 and Generator bus. 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. In addition, when certain scarcity
conditions exist, as defined below, the ISO shall employ the special scarcity pricing rules
described in Section 17.1.2.2. The NYISO shall use the scarcity pricing rule described in

17.1.2.2 for each interval in which EDRP/SCR Resources have been called in one or more Load
Zones due to a reliability need and the aggregate of Available Reserves in the Load Zone(s) in
which the reliability need was identified are less than the number of EDRP/SCR MW called for
that event.

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 17.1.1.1.3. 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 (“RTD0”) will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD0 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 (“RTD5”) will initialize at the beginning of the hour
and produce prices over a fifty minute optimization period. RTD5 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 (“RTD10”) will initialize at five minutes after the
beginning of the hour and produce prices over a sixty minute optimization period. RTD10 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 UOLN or UOLE, whichever is applicable. Resources meeting
Minimum Generation Levels and capable of being started in ten minutes that have not been
committed by RTC are treated as flexible (i.e. able to be dispatched anywhere between zero (0)

MW and their UOLN or UOLE, 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.

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 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 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 at the time that the RTD run was initialized;

(B) response rate; (C) minimum generation level; and (D) UOLN or UOLE, 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, given its UOLN or UOLE, as applicable, and starting from its
previous base point. 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, given its UOLN or UOLE, 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; and (D) UOLN or UOLE, 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 UOLN or UOLE, 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 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 as Their Fuel

For all time points of the optimization period, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall be the Wind 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 Energy Forecast.

17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators

When setting physical base points for Self-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.

When setting physical base points for ISO-Committed Fixed Generators 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 shall follow the quarter hour operating schedules that those Generators 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 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 all Fixed Block Units that are
committed by RTC, all Resources meeting Minimum Generation Levels and capable of starting

in ten minutes that have not been committed by RTC and all 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 UOLN or UOLE, whichever is applicable), regardless of their minimum runtime 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 UOLN or UOLE, 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 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 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; or (ii) zero.

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource shall be determined by increasing its upper dispatch limit from the first time point at the Resource’s response rate, up to its UOLN or UOLE, 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.

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

For the first time point and later time points for Intermittent Power Resources that depend
on wind as their fuel, the Lower Dispatch Limit shall be zero and the Upper Dispatch Limit shall
be the Wind 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 Energy Forecast.

17.1.2.1.2.3 The Third Pass

The third RTD pass is the same as the second pass with three variations. First, the third
pass treats Fixed Block Units that are committed by RTC, or are otherwise instructed to be
online or remain online by the ISO 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 UOLN or
UOLE, whichever is applicable. Second, the third pass produces “pricing base points” 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 15.3, and Rate Schedule 15.4 of this
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.

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 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 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 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
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 within the affected
area towards its UOLE 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 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 Article 4 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,
RTC15 and RT-AMP15 will perform Resource commitment evaluations simultaneously. RT-
AMP15 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 RTC30 which will make Resource commitments consistent with the
application of the mitigation measures (and will thus indirectly be incorporated into future RTD
runs).

17.1.2.2 Scarcity Pricing Rule

The ISO shall implement the following price calculation procedures for intervals when certain scarcity conditions exist as described in Section 17.1.2.

17.1.2.2.1 Except as noted in 17.1.2.2.2 below:

• The system marginal price at the Reference Bus shall be set pursuant to Section 17.1.2.1
 of this Attachment B if the identified reliability need is not in Load Zone E. If the
 reliability need is in Load Zone E or in a set of Load Zones that includes Load Zone E,
 the system marginal price at the Reference Bus shall be the maximum Minimum
 Payment Nomination.

• The Marginal Losses Component of the LBMP at each location shall be calculated as the
 product of the system marginal price at the Reference Bus produced by RTD and a
 quantity equal to the delivery factor produced by RTD for that location minus one as
 defined in Section 17.1.1 of this Attachment.

• The Congestion Component of the LBMP at each location in a Load Zone(s) in which the
 reliability need was identified shall be set to the maximum Minimum Payment

Nomination minus the system marginal price at the Reference Bus calculated pursuant to this Section 17.1.2.2.1.

• The Congestion Component of the LBMP at all other locations shall be set equal to

Congestion Component for that location produced by RTD, minus the result of

subtracting: i) the system marginal price at the Reference Bus produced by RTD from ii) the system marginal price at the Reference Bus calculated pursuant to this Section

17.1.2.2.1.

• The LBMP at each location shall be as defined in Section 17.1.1 of this Attachment: the

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

Congestion Component of the LBMP at that location, plus the LBMP at the Reference
Bus.

17.1.2.2.2 However, the ISO shall not use the pricing rules of Section 17.1.2.2.1 to

set the LBMP for any location lower than the LBMP for that Load Zone or

Generator bus calculated pursuant to Section 17.1.2.1, above. In cases in which
the pricing in Section 17.1.2.2.1 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 17.1.2.1 of this Attachment B; or the LBMP calculated for that location using the scarcity pricing rule established in Section 17.1.2.2.1.

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

product of the system marginal price at the Reference Bus produced by RTD 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.

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 Fixed Block
Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed
Block Units are dispatched to meet Bid Load with Fixed Block Units treated as dispatchable on a
flexible basis. 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 Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side
Resources, and 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. 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 Fixed Block Units, Imports,
Exports, virtual supply, virtual load, Demand Side Resources, and non-Fixed Block Units are
again dispatched to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible
basis. For mitigation purposes, LBMPs are again calculated from this dispatch.
 All Demand Side Resources and non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of and the AMP) are blocked on at least to minimum load in Passes 4 through 6. The resources required to meet local system reliability are determined in Pass 1.

Pass 2 consists of a least cost commitment and dispatch of Fixed Block Units, Imports,

Exports, Demand Side Resources and non-Fixed Block Units to meet forecast Load requirements
in excess of Bid Load, considering the Wind 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 Fixed Block Units are
dispatchable on a flexible basis. 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-Fixed Block Units committed in this step are blocked on at least to minimum Load in Passes 4 through 6.
Intermittent Power Resources that depend on wind as their fuel committed in this pass as a result of the consideration of the Wind 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 Fixed Block Units, Imports,
Exports, Demand Side Resources and non-Fixed Block Units 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 Fixed Block Units, Imports, Exports, Virtual
Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units committed 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 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-Fixed Block Units in the DayAhead 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 Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

17.1.4 Determination of Transmission Shortage Cost

The Transmission Shortage Costs represent the limits on system costs associated with efficient dispatch to meet a particular Constraint. It is the maximum Shadow Price that will be used in calculating LBMPs under various levels of relaxation.

The ISO may periodically evaluate the Transmission Shortage Costs to determine

whether it is necessary to modify the Transmission Shortage Costs 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 Costs
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 NYISO 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 consult with those entities as soon as reasonably possible after
implementing a temporary modification and shall explain the reasons for the change.
 The responsibilities of the ISO and the Market Monitoring Unit in evaluating and
modifying the Transmission Shortage Costs, 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. 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:

γ Zj

where:

= λR + γ

L,Z
j + γ C,Zj

γ

γ

γ

Zj

L,Z
j

C,Zj

=

n

= ∑ Wi γ

i =1

=

∑ Wiγ

LBMP for zone j,

L is the Marginal Losses Component of the LBMP for zone j;

i

Ci is the Congestion Component of the LBMP for zone j;

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

Wi = 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 External

Zone Zone PTID

H Q 61844

NPX 61845

O H 61846
PJM 61847

Proxy Generator Bus Proxy Generator

Bus PTID

HQ\_GEN\_WHEEL 23651

N.E.\_GEN\_SANDY\_P 24062

OND

O.H.\_GEN\_BRUCE 24063

PJM\_GEN\_KEYSTON 24065
E

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 Available Transfer Capabilitytransfer 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 Proxy Generator Bus Constraint

No. affecting External Schedules at

location a

1 Unconstrained in RTC15, Rolling RTC

and RTD

2 The Rolling RTC used to schedule

External Transactions in a given 15-
minute interval is subject to a Proxy Generator Bus Constraint

Direction of Proxy Real-Time Pricing Rule

Generator Bus (for location a) Constraint

N/A Real-Time LBMPa = RTD

LBMPa

Into NYCA or out of Real-Time LBMPa = RTD

NYCA LBMPa + Rolling RTC External
(Import or Export) Interface Congestiona

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 Proxy Generator Bus Constraint

No. affecting External Schedules at

location a

1 Unconstrained in RTC15, Rolling RTC

and RTD

3 RTC15 is subject to a Proxy Generator

Bus Constraint

Direction of Proxy Real-Time Pricing Rule

Generator Bus (for location a) Constraint

N/A Real-Time LBMPa = RTD

LBMPa

Into NYCA or out of Real-Time LBMPa = RTD

NYCA LBMPa + RTC15 External
(Import or Export) Interface Congestiona

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 Proxy Generator Bus Constraint

No. affecting External Schedules at

location a

1 Unconstrained in RTC15, Rolling RTC

and RTD

4 The Rolling RTC used to schedule

External Transactions in a given 15-
minute interval is subject to an

Interface ATC or Interface RampConstraint

Direction of Proxy Real-Time Pricing Rule

Generator Bus (for location a) Constraint

N/A Real-Time LBMPa = RTD

LBMPa

Into NYCA If Rolling RTC Proxy Generator

(Import) Bus LBMPa > 0, then Real-Time

LBMPa = RTD LBMPa + Rolling RTC External Interface

Congestiona

Otherwise, Real-Time LBMPa =
Minimum of (i) RTD LBMPa and
(ii) zero

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 If Rolling RTC Proxy Generator

(Export) Bus LBMPa < 0, then Real-Time

LBMPa = RTD LBMPa + Rolling RTC External Interface

Congestiona

Otherwise, Real-Time LBMPa = RTD LBMPa

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 Proxy Generator Bus Constraint

No. affecting External Schedules at

location a

1 Unconstrained in RTC15, Rolling RTC

and RTD

6 RTC15 is subject to an Interface ATC

or Interface Ramp Constraint

7 RTC15 is subject to an Interface ATC

or Interface Ramp Constraint

Direction of Proxy Real-Time Pricing Rule

Generator Bus (for location a) Constraint

N/A Real-Time LBMPa = RTD

LBMPa

Into NYCA If RTC15 Proxy Generator Bus

(Import) LBMPa > 0, then Real-Time

LBMPa = RTD LBMPa + RTC15External Interface Congestiona

Otherwise, Real-Time LBMPa =
Minimum of (i) RTD LBMPa and
(ii) zero

Out of NYCA If RTC15 Proxy Generator Bus

(Export) LBMPa < 0, then Real-Time

LBMPa = RTD LBMPa + RTC15External Interface Congestiona

Otherwise, Real-Time LBMPa = RTD LBMPa

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 Proxy Generator Bus Constraint

No. affecting External Schedules at

location a

1 Unconstrained in RTC15, Rolling RTC

and RTD

4 The Rolling RTC used to schedule

External Transactions in a given 15-
minute interval is subject to an

Interface ATC Constraint

Direction of Proxy Real-Time Pricing Rule

Generator Bus (for location a) Constraint

N/A Real-Time LBMPa = RTD

LBMPa

Into NYCA If Rolling RTC Proxy Generator

(Import) Bus LBMPa > 0, then Real-Time

LBMPa = RTD LBMPa + Rolling RTC External Interface

Congestiona

Otherwise, Real-Time LBMPa =
Minimum of (i) RTD LBMPa and
(ii) zero

Rule Proxy Generator Bus Constraint

No. affecting External Schedules at

location a

5 The Rolling RTC used to schedule

External Transactions in a given 15-
minute interval is subject to an

Interface ATC Constraint

Direction of Proxy Real-Time Pricing Rule

Generator Bus (for location a) Constraint

Out of NYCA If Rolling RTC Proxy Generator

(Export) Bus LBMPa < 0, then Real-Time

LBMPa = RTD LBMPa + Rolling RTC External Interface

Congestiona

Otherwise, Real-Time LBMPa = RTD LBMPa )

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 Proxy Generator Bus Constraint Direction of Proxy Real-Time Pricing Rule

No. affecting External Schedules at Generator Bus (for location a)

location a Constraint

1 Unconstrained in RTC15, Rolling RTC N/A Real-Time LBMPa = RTD

and RTD LBMPa

6 RTC15 is subject to an Interface ATC Into NYCA If RTC15 Proxy Generator Bus

Constraint (Import) LBMPa > 0, then Real-Time

LBMPa = RTD LBMPa + RTC15External Interface Congestiona

Otherwise, Real-Time LBMPa =
Minimum of (i) RTD LBMPa and
(ii) zero

7 RTC15 is subject to an Interface ATC Out of NYCA If RTC15 Proxy Generator Bus

Constraint (Export) LBMPa < 0, then Real-Time

LBMPa = RTD LBMPa + RTC15External Interface Congestiona

Otherwise, Real-Time LBMPa = RTD LBMPa

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;

Marginal Losses Component of the Real-Time LBMP = Losses RTD PROXY GENERATOR BUS;

and

Congestion Component of the Real-Time LBMP = - (Energy RTD REF BUS+ Losses RTD

PROXY GENERATOR BUS).

where:

Energy RTD REF BUS

= The marginal Bid cost of providing Energy at the reference
 Bus, as calculated by RTD for that 5-minute interval; and

Losses 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.