

Attachment I

4.4 Real-Time Markets and Schedules

4.4.1 Real-Time Commitment (“RTC”)

4.4.1.1 Overview

RTC will make binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of Resources that can respond in ten minutes) and thirty minutes (in the case of Resources that can respond in thirty minutes) after the scheduled posting time of each RTC run, will provide advisory commitment information for the remainder of the two and a half hour optimization period, and will produce binding schedules for External Transactions to begin at the start of each quarter hour. RTC will treat a Behind-the-Meter Net Generation Resource as already being committed and available to be scheduled. RTC will co-optimize to solve simultaneously for all Load, Operating Reserves and Regulation Service and to minimize the total as-bid production costs over its optimization timeframe. RTC will consider SCUC’s Resource commitment for the day, load forecasts that RTC itself will produce each quarter hour, binding transmission constraints, and all Real-Time Bids and Bid parameters submitted pursuant to Section 4.4.1.2 below.

4.4.1.2 Bids and Other Requests

After the Day-Ahead schedule is published and before the close of the Real-Time Scheduling Window for each hour, Customers may submit Real-Time Bids into the Real-Time Market for real-time evaluation by providing all information required to permit real-time evaluation pursuant to ISO Procedures. If the Supplier elects to participate in the Real-Time Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not exclusively consist of Station Power) at a single PTID, it can only participate in the Real-Time Market as a Behind-the-Meter Net

Generation Resource. If a Behind-the-Meter Net Generation Resource submits Bids into the Real-Time Market for real-time evaluation, such Bids shall provide the forecasted Host Load for each hour for which Bids are submitted.

4.4.1.2.1 Real-Time Bids to Supply Energy and Ancillary Services, other than External Transactions

Intermittent Power Resources that depend on wind as their fuel submitting new or revised offers to supply Energy shall bid as ISO-Committed Flexible and shall submit a Minimum Generation Bid of zero MW and zero cost and a Start-Up Bid at zero cost. Eligible Customers may submit new or revised Bids to supply Energy, Operating Reserves and/or Regulation Service. Customers that submit such Bids may specify different Bid parameters in real-time than they did Day-Ahead. Incremental Energy Bids may be submitted by Suppliers bidding Resources using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, if not otherwise prohibited pursuant to other provisions of the tariff. Minimum Generation Bids, Start-Up Bids, Regulation Service Bids for any hour in which such Resources received a Day-Ahead Energy schedule or a Regulation Service schedule, as appropriate, may not exceed the Minimum Generation Bids, Start-up Bids, or Regulation Service Bids, as appropriate, submitted for those Resources in the Day-Ahead Market. Additionally, Real-Time Minimum Run Qualified Gas Turbine Customers shall not increase their previously submitted Real-Time Incremental Energy Bids, Minimum Generation Bids, or Start-Up Bids within 135 minutes of the dispatch hour. Bids to supply Energy or Ancillary Services shall be subject to the rules set forth in Section 4.2.1 of this ISO Services Tariff. For Behind-the-Meter Net Generation Resources, the ISO will consider only

those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

Suppliers bidding on behalf of Generators that did not receive a Day-Ahead schedule for a given hour may offer their Generators, for those hours, using the ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed bid mode or, with ISO approval, the ISO-Committed Fixed bid modes in real-time. For Behind-the-Meter Net Generation Resources, the ISO will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit. Suppliers bidding on behalf of Demand Side Resources that did not receive a Day-Ahead schedule to provide Operating Reserves or Regulation Service for a given hour may offer to provide Operating Reserves or Regulation Service using the ISO-Committed Flexible bid mode for that hour in the Real-Time Market provided, however, that the Demand Side Resource shall have an Energy price Bid no lower than the Monthly Net Benefit Offer Floor. A Supplier bidding on behalf of a Generator that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator for the Real-Time Market for that hour provided, however, that Generators that were scheduled Day-Ahead in Self-Committed Fixed mode may switch, with ISO approval, to ISO-Committed Fixed bidding mode in real-time. Generators that were scheduled Day-Ahead in ISO-Committed Fixed mode will be scheduled as Self-Committed Fixed in the Real-Time Market unless, with ISO approval, they change their bidding mode to ISO-Committed Fixed.

A Generator with a real time physical operating problem that makes it impossible for it to operate in the bidding mode in which it was scheduled Day-Ahead should notify the NYISO. Additionally, if the Host Load of a Behind-the-Meter Net Generation Resource is greater in real-

time than was forecasted Day-Ahead such that it cannot meet its Day-Ahead schedule, it must notify the NYISO.

Generators and Demand Side Resources may not submit separate Operating Reserves Availability Bids in real-time and will instead automatically be assigned a real-time Operating Reserves Availability Bid of zero for the amount of Operating Reserves they are capable of providing in light of their response rate (as determined under Rate Schedule 4).

4.4.1.2.2 Real-Time Bids Associated with Internal and External Bilateral Transactions

Customers may use Real-Time Bids to seek to modify Bilateral Transactions that were previously scheduled Day-Ahead or propose new Bilateral Transactions, including External Transactions, for economic evaluation by RTC, provided however, that Bilateral Transactions with Trading Hubs as their POWs that were previously scheduled Day-Ahead may not be modified. Bids associated with Internal Bilateral Transactions shall be subject to the rules set forth above in Section 4.2.1.7.

Except as provided in this section, External Transaction Bids may not vary over the course of an hour. Each such Bid must offer to import, export or wheel the same amount of Energy at the same price at each point in time within that hour. At Variably Scheduled Proxy Generator Buses the ISO shall permit the submission of Bids to import or export Energy that vary the amount of Energy, and vary the price, for each quarter hour evaluation period.

The ISO may vary External Transaction Schedules at Proxy Generator Buses that are authorized to schedule transactions on an intra-hour basis if the party submitting the Bid for such a Transaction elects to permit variable scheduling. The ISO may also vary External Transaction Schedules at CTS Enabled Proxy Generator Buses. External Transaction Bids submitted to import Energy from, or export Energy to Proxy Generator Buses that are authorized to schedule

transactions on either an intra-hour or hourly basis shall indicate whether the ISO may vary schedules associated with those Bids within each hour. Transmission Customers scheduling External Bilateral Transactions shall also be subject to the provisions of Section 16, Attachment J of the ISO OATT.

4.4.1.2.3 Self-Commitment Requests

Self-Committed Flexible Resources must provide the ISO with schedules of their expected minimum operating points in quarter hour increments. Self-Committed Fixed Resources must provide their expected actual operating points in quarter hour increments or, with ISO approval, bid as an ISO-Committed Fixed Generator.

4.4.1.2.4 ISO-Committed Fixed

The ability to use the ISO-Committed Fixed bidding mode in the Real-Time Market shall be subject to ISO approval pursuant to procedures, which shall be published by the ISO. Generators that have exclusively used the Self-Committed Fixed or ISO-Committed Fixed bid modes in the Day-Ahead Market or that do not have the communications systems, operational control mechanisms or hardware to be able to respond to five-minute dispatch basepoints are eligible to bid using the ISO-Committed Fixed bid mode in the Real-Time Market. Real-Time Bids by Generators using the ISO-Committed Fixed bid mode in the Real-Time Market shall provide variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, Minimum Generation Bids, hourly Start-Up Bids and other information pursuant to ISO Procedures.

RTC shall schedule ISO-Committed Fixed Generators.

4.4.1.3 External Transaction Scheduling

RTC15 will schedule External Transactions on an hourly basis as part of its development of a co-optimized least-bid cost Real-Time Commitment. For External Transactions that are scheduled on a 15 minute basis, the amount of Energy scheduled to be imported, exported or wheeled in association with that External Transaction may change on the quarter hour. All RTC runs will schedule intra-hour External Transactions on a 15 minute basis at Variably Scheduled Proxy Generator Buses. RTC will alert the ISO when it appears that scheduled External Transactions need to be reduced for reliability reasons but will not automatically Curtail them. Curtailment decisions will be made by the ISO, guided by the information that RTC provides, pursuant to the rules established by Attachment B of this ISO Services Tariff and the ISO Procedures. External Bilateral Transaction schedules are also governed by the provisions of Section 16, Attachment J of the OATT.

4.4.1.4 Posting Commitment/De-Commitment and External Transaction Scheduling Decisions

Except as specifically noted in Section 4.4.2, 4.4.3 and 4.4.4 of this ISO Services Tariff, RTC will make all Resource commitment and de-commitment decisions. RTC will make all economic commitment/de-commitment decisions based upon available offers assuming Suppliers internal to the NYCA have a one-hour minimum run time; provided however, Real-Time Minimum Run Qualified Gas Turbines shall be assumed to have a two-hour minimum run time. For Behind-the-Meter Net Generation Resources, RTC will consider only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

RTC will produce advisory commitment information and advisory real-time prices. RTC will make decisions and post information in a series of fifteen-minute “runs” which are described below.

RTC₁₅ will begin at the start of the first hour of the RTC co-optimization period and will post its commitment, de-commitment, and External Transaction scheduling decisions no later than fifteen minutes after the start of that hour. During the RTC₁₅ run, RTC will:

- (i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;
- (ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;
- (iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time;
- (iv) Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information;
- (v) Schedule economic hourly External Transactions for the next hour;
- (vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;

- (vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and
- (viii) Schedule ISO-Committed Fixed Resources.

All subsequent RTC runs in the hour, *i.e.*, RTC_{30} , RTC_{45} , and RTC_{00} will begin executing at fifteen minutes before their designated posting times (for example, RTC_{30} will begin in the fifteenth minute of the hour), and will take the following steps:

- (i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at that time;
- (ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at that time;
- (iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected at that time;
- (iv) Issue advisory commitment, de-commitment, and dispatching guidance for the period from thirty minutes in the future until the end of the RTC co-optimization period;
- (v) Either reaffirm that the External Transactions scheduled by previous RTC runs should continue to flow in the next hour, or inform the ISO that External Transactions may need to be reduced;

- (vi) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus;
- (vii) Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and
- (viii) Schedule ISO-Committed Fixed Resources.

4.4.1.5 External Transaction Settlements

Settlements for External Transactions in the LBMP Market are described in Sections 4.2.6 and 4.5 of this ISO Services Tariff. Settlements for External Bilateral Transactions are also described in Section 16, Attachment J and Rate Schedules 7 and 8 of the OATT.

The calculation of Real-Time LBMPs at Proxy Generator Buses and CTS Enabled Interfaces is described in Section 17, Attachment B to this ISO Services Tariff.

4.4.2 Real-Time Dispatch

4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and Demand Side Resources, produce schedules for intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Real-Time Market Prices for Regulation Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions, except as specifically provided in Section 4.4.2.4 below. Each Real-Time Dispatch run will co-optimize to

solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon (which may be fifty, fifty-five, or sixty minutes long depending on where the run falls in the hour.) In addition to producing a binding schedule for the next five minutes, each Real-Time Dispatch run will produce advisory schedules for the remaining four time steps of its bid-optimization horizon (which may be five, ten, or fifteen minutes long depending on where the run falls in the hour). An advisory schedule may become binding in the absence of a subsequent Real-Time Dispatch run. RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

4.4.2.2 External Transaction Scheduling

All RTD runs will schedule External Transactions on a 5 minute basis at Dynamically Scheduled Proxy Generator Buses. For External Transactions that are scheduled on a 5 minute basis, the amount of Energy scheduled to be imported, exported or wheeled in association with that External Transaction may change every 5 minutes. External Bilateral Transaction Schedules are also governed by the provisions of Attachment J of the OATT.

4.4.2.3 Calculating Real-Time Market LBMPs and Advisory Prices

RTD shall calculate *ex ante* Real-Time LBMPs at each Generator bus, and for each Load Zone in each RTD cycle, in accordance with the procedures set forth in Attachment B to this ISO Services Tariff. RTD will also calculate and post advisory Real-Time LBMPs for the next four quarter hours in accordance with the procedures set forth in Attachment B.

4.4.2.4 Real-Time Pricing Rules for Scheduling Ten Minute Resources

RTD may commit and dispatch, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting within ten minutes (“eligible Resources”) when

necessary to meet load. Eligible Resources committed and dispatched by RTD for pricing purposes may be physically started through normal ISO operating processes. In the RTD cycle in which RTD commits and dispatches an eligible Resource, RTD will consider the Resource's start-up and incremental energy costs and will assume the Resource has a zero downward response rate for purposes of calculating *ex ante* Real-Time LBMPs pursuant to Section 17, Attachment B to this ISO Services Tariff.

4.4.2.5 Converting to Demand Reduction, Special Case Resource Capacity scheduled as Operating Reserves, Regulation or Energy in the Real-Time Market

The ISO shall convert to Demand Reductions, in hours in which the ISO requests that Responsible Interface Parties notify their Special Case Resources to reduce their demand pursuant to ISO Procedures, any Operating Reserves, Regulation Service or Energy scheduled in the Day-Ahead Market from Demand Side Resources that are also providing Special Case Resource Capacity. The ISO shall settle the Demand Reduction provided by that portion of the Special Case Resource Capacity that was scheduled Day-Ahead as Operating Reserves, Regulation Service or Energy as being provided by a Supplier of Operating Reserves, Regulation Service or Energy as appropriate. The ISO shall settle any remaining Demand Reductions provided beyond Capacity that was scheduled Day-Ahead as Ancillary Services or Energy as being provided by a Special Case Resource, provided such Demand Reduction is otherwise payable as a reduction by a Special Case Resource.

Operating Reserves or Regulation Service scheduled Day-Ahead and converted to Energy in real time pursuant to this Section 4.4.2.4, will be eligible for a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

Special Case Resource Capacity that has been scheduled in the Day-Ahead Market to provide Operating Reserves, Regulation Service or Energy and that has been instructed as a Special Case Resource to reduce demand shall be considered, for the purpose of determining a Scarcity Reserve Requirement pursuant to Rate Schedule 4 of this ISO Services Tariff, to be a Special Case Resource.

The ISO shall not accept offers of Operating Reserves or Regulation Service in the Real-Time Market from Demand Side Resources that are also providing Special Case Resource Capacity for any hour in which the ISO has requested Special Case Resources to reduce demand.

4.4.2.6 Converting to Demand Reduction Curtailment Services Provider Capacity scheduled as Operating Reserves, Regulation or Energy in the Real-Time Market

The ISO shall convert to Demand Reductions, in hours in which the ISO requests Demand Reductions from the Emergency Demand Response Program pursuant to ISO Procedures, any Operating Reserves, Regulation Service or Energy scheduled in the Day-Ahead Market by Demand Side Resources that are also providing Curtailment Services Provider Capacity. The ISO shall settle the Demand Reduction provided by that portion of the Curtailment Services Provider Capacity that was scheduled Day-Ahead as Operating Reserves, Regulation Service or Energy as being provided by a Supplier of Operating Reserves, Regulation Service or Energy as appropriate. The ISO shall settle Demand Reductions provided beyond Capacity that was scheduled Day-Ahead as ancillary services or Energy as being provided by a Curtailment Services Provider.

Operating Reserves or Regulation Service scheduled Day-Ahead and converted to Energy in real time pursuant to this Section 4.4.2.5, will be eligible for a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

Curtailment Services Provider Capacity that has been scheduled in the Day-Ahead Market as Operating Reserves, Regulation Service or Energy and that has been instructed to reduce demand shall be considered, for the purpose of determining a Scarcity Reserve Requirement pursuant to Rate Schedule 4 of this ISO Services Tariff, to be a Emergency Demand Response Program Resource.

The ISO shall not accept offers of Operating Reserves and Regulation Service in the Real-Time Market from Demand Side Resources that are also providing Curtailment Services Provider Capacity for any hour in which the ISO has requested participants in the Emergency Demand Response Program pursuant to ISO Procedures to reduce demand.

4.4.2.7 Post the Real-Time Schedule

Subsequent to the close of the Real-Time Scheduling Window, the ISO shall post the real-time schedule for each entity that submits a Bid or Bilateral Transaction schedule. All schedules shall be considered proprietary, with the posting only visible to the appropriate scheduling Customer, Transmission Customer and Transmission Owners subject to the applicable Code of Conduct (See Attachment F to the ISO OATT). The ISO will post on the OASIS the real-time Load for each Load Zone, and the Real-Time LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone for each hour of the Dispatch Day. The ISO shall conduct the real-time settlement based upon the real-time schedule determined in accordance with this Section.

4.4.3 Real-Time Dispatch - Corrective Action Mode

When the ISO needs to respond to system conditions that were not anticipated by RTC or the regular Real-Time Dispatch, *e.g.*, the unexpected loss of a major Generator or Transmission line, it will activate the specialized RTD-CAM program. RTD-CAM runs will be nominally

either five or ten minutes long, as is described below. Unlike the Real-Time Dispatch, RTD-CAM will have the ability to commit certain Resources, and schedule intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses. When RTD-CAM is activated, the ISO will have discretion to implement various measures to restore normal operating conditions. These RTD-CAM measures are described below.

The ISO shall have discretion to determine which specific RTD-CAM mode should be activated in particular situations. In addition, RTD-CAM may require Resources to run above their UOL_{NS} , up to the level of their UOL_{ES} as is described in the ISO Procedures. Self-Committed Fixed Resources will not be expected to move in response to RTD-CAM Base Point Signals except when a maximum generation pickup is activated.

Except as expressly noted in this section, RTD-CAM will dispatch the system in the same manner as the normal Real-Time Dispatch.

4.4.3.1 RTD-CAM Modes

4.4.3.1.1 Reserve Pickup

The ISO will enter this RTD-CAM mode when necessary to re-establish schedules when large area control errors occur. When in this mode, RTD-CAM will send 10-minute Base Point Signals and produce schedules for the next ten minutes. RTD-CAM may also commit, or if necessary de-commit, Resources capable of starting or stopping within 10-minutes. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements and Scarcity Reserve Requirements, but will set all Regulation Service schedules to zero. If Resources are committed or de-committed in this RTD-CAM mode the schedules for them will be passed to RTC and the Real-Time Dispatch for their next execution.

The ISO will have discretion to classify a reserve pickup as a “large event” or a “small event.” In a small event the ISO will have discretion to reduce Base Point Signals in order to reduce transmission line loadings. The ISO will not have this discretion in large events. The distinction also has significance with respect to a Supplier’s eligibility to receive Bid Production Cost guarantee payment in accordance with Section 4.6.6 and Attachment C of this ISO Services Tariff.

4.4.3.1.2 Maximum Generation Pickup

The ISO will enter this RTD-CAM mode when an Emergency makes it necessary to maximize Energy production in one or more location(s), i.e., Long Island, New York City, Southeastern New York, East of Central East and/or NYCA-wide. RTD-CAM will produce schedules directing all Generators located in a targeted location to increase production at their emergency response rate up to their UOL_E level and to stay at that level until instructed otherwise. Security constraints will be obeyed to the extent possible. The ISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements and Scarcity Reserve Requirements, but will set all Regulation Service schedules to zero.

4.4.3.1.3 Base Points ASAP -- No Commitments

The ISO will enter this RTD-CAM mode when changed circumstances make it necessary to issue an updated set of Base Point Signals. Examples of changed circumstances that could necessitate taking this step include correcting line, contingency, or transfer overloads and/or voltage problems caused by unexpected system events. When operating in this mode, RTD-CAM will produce schedules and Base Point Signals for the next five minutes but will only

redispatch Generators that are capable of responding within five minutes. RTD-CAM will not commit or de-commit Resources in this mode.

4.4.3.1.4 Base Points ASAP -- Commit As Needed

This operating mode is identical to Base Points ASAP – No Commitments, except that it also allows the ISO to commit Generators that are capable of starting within 10 minutes when doing so is necessary to respond to changed system conditions.

4.4.3.1.5 Re-Sequencing Mode

When the ISO is ready to de-activate RTD-CAM, it will often need to transition back to normal Real-Time Dispatch operation. In this mode, RTD-CAM will calculate normal five-minute Base Point Signals and establish five minute schedules. Unlike the normal RTD-Dispatch, however, RTD-CAM will only look ahead 10-minutes. RTD-CAM re-sequencing will terminate as soon as the normal Real-Time Dispatch software is reactivated and is ready to produce Base Point signals for its entire optimization period.

4.4.3.2 Calculating Real-Time LBMPs

When RTD-CAM is activated, RTD shall calculate *ex ante* Real-Time LBMPs at each Generator bus, and for each Load Zone in accordance with the procedures set forth in Section 17, Attachment B of this ISO Services Tariff.

4.4.4 Identifying the Pricing and Scheduling Rules That Apply to External Transactions

LBMPs will be determined and External Transactions will be scheduled at external Proxy Generator Buses consistent with the table below.

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	Non-Competitive	CTS Enabled Proxy Generator Bus		Scheduling Frequencies		
					Requires CTS Bids	Permits CTS Bids	Hourly Scheduled	Variably Scheduled	Dynamically Scheduled (Not Presently Available)
Hydro Quebec									
HQ_GEN_IMPORT	323601			✓			✓	✓	
HQ_LOAD_EXPORT	355639			✓			✓	✓	
HQ_GEN_CEDARS_PROXY	323590	Dennison Scheduled Line		✓			✓		
HQ_LOAD_CEDARS_PROXY	355586	Dennison Scheduled Line		✓			✓		
HQ_GEN_WHEEL	23651			✓			✓		
HQ_LOAD_WHEEL	55856			✓			✓		
PJM									
PJM_GEN_KEYSTONE	24065					✓	✓* (See Notes)	✓	
PJM_LOAD_KEYSTONE	55857					✓	✓* (See Notes)	✓	
PJM_GEN_NEPTUNE_PROXY	323594	Neptune Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_LOAD_NEPTUNE_PROXY	355615	Neptune Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_GEN_VFT_PROXY	323633	Linden VFT Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_LOAD_VFT_PROXY	355723	Linden VFT Scheduled Line	✓			✓	✓* (See Notes)	✓	
PJM_HTP_GEN	323702	HTP Scheduled Line	✓			✓	✓* (See Notes)	✓	

Proxy Generator Bus	PTID	Scheduled Line	Designated Scheduled Line	Non-Competitive	CTS Enabled Proxy Generator Bus		Scheduling Frequencies		
					Requires CTS Bids	Permits CTS Bids	Hourly Scheduled	Variably Scheduled	Dynamically Scheduled (Not Presently Available)
HUDSONTP_345KV_HTP_LOAD	355839	HTP Scheduled Line	✓			✓	✓* (See Notes)	✓	
ISO New England									
N.E._GEN_SANDY_POND	24062				✓		✓** (See Notes)	✓	
NE_LOAD_SANDY_PD	55858				✓		✓** (See Notes)	✓	
NPX_GEN_CSC	323557	Cross Sound Scheduled Line	✓				✓		
NPX_LOAD_CSC	355535	Cross Sound Scheduled Line	✓				✓		
NPX_GEN_1385_PROXY	323591	Northport Norwalk Scheduled Line					✓		
NPX_LOAD_1385_PROXY	355589	Northport Norwalk Scheduled Line					✓		
Ontario									
O.H._GEN_BRUCE	24063						✓		
OH_LOAD_BRUCE	55859						✓		

Notes:

* At specifically identified Proxy Generator Buses (“* See Notes”), only Wheels Through (the NYCA) are scheduled on an hourly basis.

** At specifically identified Proxy Generator Buses (“** See Notes”), only wheels through the NYCA or a neighboring Control Area are scheduled on an hourly basis.

Pricing rules for Proxy Generator Buses are set forth in Section 17 of the Services Tariff.

The ISO may offer a more frequent scheduling option at a Proxy Generator Bus identified on the table. The ISO shall inform its Market Participants of the availability of such an option by providing notice at least two weeks in advance of the implementation of any such change. At the same time, the ISO shall update the above table to reflect the change in scheduling options by submitting a compliance filing in FERC Docket No. ER11-2547. Unless FERC acts on the ISO's compliance filing, the ISO shall effectuate the change in scheduling capability on the date it proposed in its compliance filing. The addition of new Proxy Generator Buses to the table, or changing the pricing rules that apply at a Proxy Generator Bus, may not be accomplished by submitting a compliance filing in Docket No. ER11-2547. The ISO may revert to establishing hourly Import and Export schedules using all available External Transaction Bids at a Proxy Generator Bus that is identified as a Dynamically or Variably Scheduled Proxy Generator Bus when the ISO or a neighboring Balancing Authority is not able to implement schedules as expected, or when necessary to ensure or preserve system reliability. When it reverts to hourly Import and Export schedules at a Dynamically or Variably Scheduled Proxy Generator Bus, the ISO shall apply the pricing rules for a corresponding Proxy Generator Bus that is not Dynamically Scheduled or Variably Scheduled. The ISO may cease evaluating CTS Interface Bids at CTS Enabled Proxy Generator Buses when the ISO or a neighboring Balancing Authority is not able to implement schedules as expected, or when necessary to ensure or preserve system reliability.

15.4 Rate Schedule 4 - Payments for Supplying Operating Reserves

This Rate Schedule applies to payments to Suppliers that provide Operating Reserves to the ISO. Transmission Customers will purchase Operating Reserves from the ISO under Rate Schedule 5 of the ISO OATT.

15.4.1 General Responsibilities and Requirements

15.4.1.1 ISO Responsibilities

The ISO shall procure on behalf of its Customers a sufficient quantity of Operating Reserve products to comply with the Reliability Rules and with other applicable reliability standards, as well as Scarcity Reserve Requirements. These quantities shall be established under Section 15.4.7 of this Rate Schedule for locational Operating Reserve requirements and Section 15.4.6.2 of this Rate Schedule for Scarcity Reserve Requirements. To the extent that the ISO enters into Operating Reserve sharing agreements with neighboring Control Areas its Operating Reserves requirements shall be adjusted as, and where, appropriate.

The ISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible, under Section 15.4.1.2 of this Rate Schedule, to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The ISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central-East, in Southeastern New York and on Long Island. In addition to being subject to the preceding limitations on Suppliers that can meet each of these requirements, the requirements for Operating Reserve located East of Central-East may only be met by eligible Suppliers that are located East of Central-East, requirements for Operating

Reserve located in Southeastern New York may only be met by eligible Suppliers that are located in Southeastern New York, and requirements for Operating Reserve located on Long Island may only be met by eligible Suppliers located on Long Island. Each of these Operating Reserve requirements shall be defined consistent with the Reliability Rules and other applicable reliability standards. The ISO shall also establish Scarcity Reserve Requirements in the Real-Time Market pursuant to Section 15.4.6.2 of this Rate Schedule, which may be met by Suppliers eligible to provide 30-Minute Reserve. Scarcity Reserve Requirements may only be met by eligible Suppliers that are located in the Scarcity Reserve Region associated with a given Scarcity Reserve Requirement. The ISO shall select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements and Scarcity Reserve Requirements, as part of its overall co-optimization process.

The ISO shall select Operating Reserves Suppliers that are properly located electrically so that all locational Operating Reserves requirements determined consistently with the requirements of Section 15.4.7 of this Rate Schedule and Scarcity Reserve Requirements determined consistently with the requirements of Section 15.4.6.2 of this Rate Schedule are satisfied, and so that transmission Constraints resulting from either the commitment or dispatch of Generators do not limit the ISO's ability to deliver Energy to Loads in the case of a Contingency. The ISO will ensure that Suppliers that are compensated for using Capacity to provide one Operating Reserve product are not simultaneously compensated for providing another Operating Reserve product, or Regulation Service, using the same Capacity (consistent with the additive market clearing price calculation formulae in Sections 15.4.5.1 and 15.4.6.1 of this Rate Schedule).

15.4.1.2 Supplier Eligibility Criteria

The ISO shall enforce the following criteria, which define which types of Suppliers are eligible to supply particular Operating Reserve products.

15.4.1.2.1 Spinning Reserve:

Suppliers that are ISO Committed Flexible or Self-Committed Flexible, are operating within the dispatchable portion of their operating range, are capable of responding to ISO instructions to change their output level within ten minutes, and that meet the criteria set forth in the ISO Procedures shall be eligible to supply Spinning Reserve (except for Demand Side Resources that are Local Generators and Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit).

15.4.1.2.2 10-Minute Non-Synchronized Reserve:

(i) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten (10) minutes, (ii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within ten (10) minutes, and (iii) Demand Side Resources that are capable of reducing their Energy usage within ten (10) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply 10-Minute Non-Synchronized Reserve.

15.4.1.2.3 30-Minute Reserve:

Generators, except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit, that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range and Demand Side Resources, that are not Local Generators, that are capable of

reducing their Energy usage within thirty (30) minutes shall be eligible to supply synchronized 30-Minute Reserves. (i) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes, (ii) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit that are capable of increasing their output level within thirty (30) minutes, and (iii) Demand Side Resources that are capable of reducing their Energy usage within thirty (30) minutes, that meet the criteria set forth in the ISO Procedures shall be eligible to supply non-synchronized 30-Minute Reserves.

15.4.1.2.4 Self-Committed Fixed and ISO-Committed Fixed Generators:

Shall not be eligible to provide any kind of Operating Reserve.

15.4.1.3 Other Supplier Requirements

All Suppliers of Operating Reserve must be located within the NYCA and must be under ISO Operational Control. Each Supplier bidding to supply Operating Reserve or reduce demand must be able to provide Energy or reduce demand consistent with the Reliability Rules and the ISO Procedures when called upon by the ISO.

All Suppliers that are selected to provide Operating Reserves shall ensure that their Resources maintain and deliver the appropriate quantity of Energy, or reduce the appropriate quantity of demand, when called upon by the ISO during any interval in which they have been selected.

Generators or Demand Side Resources that are selected to provide Operating Reserve in the Day-Ahead Market or any supplemental commitment may increase their Incremental Energy Bids or Demand Reduction Bids for portions of their Resources that have been scheduled through those processes; provided however, that they are not otherwise prohibited from doing so

pursuant to other provisions of the ISO's Tariffs. They may not, however, reduce their Day-Ahead Market or supplemental commitments in real-time except to the extent that they are directed to do so by the ISO. Generators and Demand Side Resources may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Operating Reserve.

15.4.2 General Day-Ahead Market Rules

15.4.2.1 Bidding and Bid Selection

Resources capable of providing Spinning Reserve, 10-Minute Non-Synchronized Reserve and/or 30-Minute Reserve in the Day-Ahead commitment may submit Availability Bids for each hour of the upcoming day. If a Supplier offers Resources that are capable, based on their indicated commitment status, of providing Operating Reserves but does not submit an Availability Bid, its Day-Ahead Bid will be rejected in its entirety. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new bid is timely.

The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the Resource's emergency response rate multiplied by ten; (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOLN or UOLE, whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid; and (iii) for synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by twenty.

However, the sum of the amount of Energy or Demand Reduction each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the

amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOLN or UOLE, whichever is applicable.

The ISO shall select Operating Reserve Suppliers for each hour of the upcoming day through a co-optimized Day-Ahead commitment process that minimizes the total bid cost of Energy, Operating Reserves and Regulation Service, using Bids submitted pursuant to Article 4.2 of, and Attachment D to, this ISO Services Tariff. As part of the co-optimization process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements specified above.

15.4.2.2 ISO Notice Requirement

The ISO shall notify each Operating Reserve Supplier that has been selected in the Day-Ahead Market of the amount of each Operating Reserve product that it has been scheduled to provide.

15.4.2.3 Real-Time Market Responsibilities of Suppliers Scheduled to Provide Operating Reserves in the Day-Ahead Market

Suppliers that are scheduled Day-Ahead to provide Operating Reserves shall either provide Operating Reserve, Energy or Demand Reductions in real-time when scheduled by the ISO in all hours for which they have been selected to provide Operating Reserve and are physically capable of doing so. However, Suppliers that are scheduled Day-Ahead to provide Operating Reserves and have startup periods of two hours or less may advise the ISO no later than three hours prior to the first hour of their Day-Ahead schedule that they will not be available to provide Operating Reserves or Energy in real-time under normal conditions. Such Suppliers will be required to settle their Day-Ahead schedule at real-time prices pursuant to Section 15.4.6.3 of this Rate Schedule. The only restriction on Suppliers' ability to exercise this option

is that all Suppliers with Day-Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the ISO for dispatch in the RTD if the ISO initiates a Supplemental Resource Evaluation.

15.4.3 General Real-Time Market Rules

15.4.3.1 Bid Selection

The ISO will automatically select Operating Reserves Suppliers in real-time from eligible Resources, that submit Real-Time Bids pursuant to Section 4.4 of, and Attachment D to, this ISO Services Tariff. Each Supplier will automatically be assigned a real-time Operating Reserves Availability bid of \$0/MW for the quantity of Capacity that it makes available to the ISO in its Real-Time Bid. The ISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels: (i) for Spinning Reserves, the Resource's emergency response rate multiplied by ten; (ii) for 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E , whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid); and (iii) for synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by twenty. However, the sum of the amount of Energy or Demand Reduction, that each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E , whichever is applicable.

Suppliers will thus be selected on the basis of their response rates, their applicable upper operating limits, and their Energy Bids (which will reflect their opportunity costs) through a co-optimized real-time commitment process that minimizes the total bid cost of Energy, or Demand

Reduction, Regulation Service, and Operating Reserves. As part of the process, the ISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements and Scarcity Reserve Requirements specified above.

15.4.3.2 ISO Notice Requirement

The ISO shall notify each Supplier of Operating Reserve that has been scheduled by RTD of the amount of Operating Reserve that it must provide.

15.4.3.3 Obligation to Make Resources Available to Provide Operating Reserves

Any Resource that is eligible to supply Operating Reserves and that is made available to ISO for dispatch in Real-Time must also make itself available to provide Operating Reserves.

15.4.3.4 Activation of Operating Reserves

All Resources that are selected by the ISO to provide Operating Reserves shall respond to the ISO's directions to activate in real-time.

15.4.3.5 Performance Tracking and Supplier Disqualifications

When a Supplier committed to supply Operating Reserves is activated, the ISO shall measure and track its actual Energy production or its Demand Reduction against its expected performance in real-time. The ISO may disqualify Suppliers that consistently fail to provide Energy or Demand Reduction when called upon to do so in real-time from providing Operating Reserves in the future. If a Resource has been disqualified, the ISO shall require it to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from it. Disqualification and re-qualification criteria shall be set forth in the ISO Procedures.

15.4.4 Operating Reserves Settlements - General Rules

15.4.4.1 Establishing Locational Reserve and Scarcity Reserve Requirement Prices

Except as noted below, the ISO shall calculate separate Day-Ahead Market and Real-Time Market prices for each of the products in four locations: (i) West of Central-East (“West” or “Western”); (ii) East of Central-East excluding Southeastern New York (“Eastern”); (iii) Southeastern New York excluding Long Island (“Southeastern”); and (iv) Long Island (“L.I.”). The ISO will thus calculate twelve different locational Operating Reserve prices in both the Day-Ahead Market and the Real-Time Market. The ISO will also calculate prices in the Real-Time Market for each of the products in a Scarcity Reserve Region, if applicable. Day-Ahead locational reserve prices shall be calculated pursuant to Section 15.4.5 of this Rate Schedule. Real-Time locational Operating Reserves prices and Scarcity Reserve Requirement prices shall be calculated pursuant to Section 15.4.6 of this Rate Schedule

15.4.4.2 Settlements Involving Suppliers of Operating Reserves Located on Long Island

Suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York, except in the case of a Scarcity Reserve Requirement for a Scarcity Reserve Region that includes Long Island in addition to one or more other Load Zones. In this instance, suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in Southeastern New York and in the applicable Scarcity Reserve Region. The ISO will calculate separate locational Long Island Operating Reserves prices and Long Island Scarcity Reserve Requirement prices for Scarcity Reserve Regions that include Long Island but will not post them or use them for settlement purposes.

15.4.4.3 “Cascading” of Operating Reserves

The ISO will deem Spinning Reserve to be the “highest quality” Operating Reserve, followed by 10-Minute Non-Synchronized Reserve and by 30-Minute Reserve. The ISO shall substitute higher quality Operating Reserves in place of lower quality Operating Reserves, when doing so lowers the total as-bid cost, *i.e.*, when the marginal cost for the higher quality Operating Reserve product is lower than the marginal cost for the lower quality Operating Reserve product, and the substitution of a higher quality for the lower quality product does not cause locational Operating Reserve requirements or Scarcity Reserve Requirements to be violated. To the extent, however, that reliability standards require the use of higher quality Operating Reserves, substitution cannot be made in the opposite direction.

The market clearing price of higher quality Operating Reserves will not be set at a price below the market clearing price of lower quality Operating Reserves in the same location or Scarcity Reserve Region. Thus, the market clearing price of Spinning Reserves will not be below the price for 10-Minute Non-Synchronized Reserves or 30-Minute Reserves and the market clearing price for 10-Minute Non-Synchronized Reserves will not be below the market clearing price for 30-Minute Reserves.

15.4.5 Operating Reserve Settlements – Day-Ahead Market

15.4.5.1 Calculation of Day-Ahead Market Clearing Prices

The ISO shall calculate hourly Day-Ahead Market clearing prices for each Operating Reserve product at each location. Each Day-Ahead Market clearing price shall equal the sum of the relevant Day-Ahead locational Shadow Prices for that product in that hour, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

The Day-Ahead Market clearing price for a particular Operating Reserve product in a particular location shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements, that a particular Operating Reserves product from a particular location may be used to satisfy in a given hour. The ISO shall calculate Day-Ahead Market clearing prices using the following formulae:

$$\text{Market clearing price for Western 30-Minute Reserves} = \text{SP1}$$

$$\text{Market clearing price for Western 10-Minute Non-Synchronized Reserves} = \text{SP1} + \text{SP2}$$

$$\text{Market clearing price for Western Spinning Reserves} = \text{SP1} + \text{SP2} + \text{SP3}$$

$$\text{Market clearing price for Eastern 30-Minute Reserves} = \text{SP1} + \text{SP4}$$

$$\begin{aligned} \text{Market clearing price for Eastern 10-Minute Non-Synchronized Reserves} = & \text{SP1} + \text{SP2} \\ & + \text{SP4} + \\ & \text{SP5} \end{aligned}$$

$$\begin{aligned} \text{Market clearing price for Eastern Spinning Reserves} = & \text{SP1} + \text{SP2} + \text{SP3} + \text{SP4} + \text{SP5} + \\ & \text{SP6} \end{aligned}$$

$$\text{Market clearing price for Southeastern 30-Minute Reserves} = \text{SP1} + \text{SP4} + \text{SP7}$$

$$\begin{aligned} \text{Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves} = & \text{SP1} + \\ & \text{SP2} + \text{SP4} + \text{SP5} + \text{SP7} + \text{SP8} \end{aligned}$$

$$\begin{aligned} \text{Market clearing price for Southeastern Spinning Reserves} = & \text{SP1} + \text{SP2} + \text{SP3} + \text{SP4} + \\ & \text{SP5} + \text{SP6} + \text{SP7} + \text{SP8} + \text{SP9} \end{aligned}$$

$$\text{Market clearing price for L.I. 30-Minute Reserves} = \text{SP1} + \text{SP4} + \text{SP7} + \text{SP10}$$

$$\begin{aligned} \text{Market clearing price for L.I. 10-Minute Non-Synchronized Reserves} = & \text{SP1} + \text{SP2} + \\ & \text{SP4} + \text{SP5} + \\ & \text{SP7} + \text{SP8} + \\ & \text{SP10} + \text{SP11} \end{aligned}$$

$$\begin{aligned} \text{Market clearing price for L.I. Spinning Reserves} = & \text{SP1} + \text{SP2} + \text{SP3} + \text{SP4} + \text{SP5} + \text{SP6} \\ & + \text{SP7} + \text{SP8} + \text{SP9} + \text{SP10} + \text{SP11} + \\ & \text{SP12} \end{aligned}$$

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint for the hour

- SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the hour
- SP3 = Shadow Price for total Spinning Reserve requirement constraint for the hour
- SP4 = Shadow Price for Eastern, Southeastern, or L.I. 30-Minute Reserve requirement constraint for the hour
- SP5 = Shadow Price for Eastern, Southeastern, or L.I. 10-Minute Reserve requirement constraint for the hour
- SP6 = Shadow Price for Eastern, Southeastern, or L.I. Spinning Reserve requirement constraint for the hour
- SP7 = Shadow Price for Southeastern, or L.I. 30-Minute Reserve requirement constraint for the hour
- SP8 = Shadow Price for Southeastern, or L.I. 10-Minute Reserve requirement constraint for the hour
- SP9 = Shadow Price for Southeastern, or L.I. Spinning Reserve requirement constraint for the hour
- SP10 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour
- SP11 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour
- SP12 = Shadow Price for Long Island Spinning Reserve requirement constraint for the hour

Day-Ahead locational Shadow Prices will be calculated by SCUC. Each hourly Day-Ahead Shadow Price for each Operating Reserves requirement shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that hour, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that hour, as calculated during the fifth SCUC pass described in Section 17.1.3 of Attachment B to this Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement shall include the Day-Ahead Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve for that

requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Day-Ahead Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by SCUC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If more Operating Reserve of a particular quality than is needed is scheduled to meet a particular locational Operating Reserve requirement, the Shadow Price for that Operating Reserve requirement constraint shall be set at zero.

Each Supplier that is scheduled Day-Ahead to provide Operating Reserve shall be paid the applicable Day-Ahead Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each hour.

15.4.5.2 Other Day-Ahead Payments

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a Day-Ahead Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

15.4.6 Operating Reserve Settlements – Real-Time Market

15.4.6.1 Calculation of Real-Time Market Clearing Prices

The ISO shall calculate Real-Time Market clearing prices for each Operating Reserve product for each location in every interval and Scarcity Reserve Region in each interval for

which a Scarcity Reserve Requirement is established by the ISO. Each real-time market-clearing price shall equal the sum of the relevant real-time locational Shadow Prices and Scarcity Reserve Requirement Shadow Prices for a given product, subject to the restriction described in Section 15.4.4.3 of this Rate Schedule.

The Real-Time Market clearing price for a particular Operating Reserve product for a particular location or Scarcity Reserve Region shall reflect the Shadow Prices associated with all of the ISO-defined Operating Reserve requirements, including locational requirements and Scarcity Reserve Requirements, that a particular Operating Reserves product from that location or Scarcity Reserve Region may be used to satisfy in a given interval. The ISO shall calculate the Real-Time Market clearing prices using the following formulae:

Market clearing price for Western 30-Minute Reserves = SP1

Market clearing price for Western 10-Minute Non-Synchronized Reserves = SP1 + SP2

Market clearing price for Western Spinning Reserves = SP1 + SP2 + SP3

Market clearing price for Eastern 30-Minute Reserves = SP1 + SP4

Market clearing price for Eastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5

Market clearing price for Eastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6

Market clearing price for Southeastern 30-Minute Reserves = SP1 + SP4 + SP7

Market clearing price for Southeastern 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8

Market clearing price for Southeastern Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9

Market clearing price for L.I. 30-Minute Reserves = SP1 + SP4 + SP7 + SP10

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves = SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11

Market clearing price for L.I. Spinning Reserves = SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 + SP12

Where:

SP1 = Shadow Price for total 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP2 = Shadow Price for total 10-Minute Reserve requirement constraint for the interval

SP3 = Shadow Price for total Spinning Reserve requirement constraint for the interval

SP4 = Shadow Price for Eastern, Southeastern, or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP5 = Shadow Price for Eastern, Southeastern, or L.I. 10-Minute Reserve requirement constraint for the interval

SP6 = Shadow Price for Eastern, Southeastern, or L.I. Spinning Reserve requirement constraint for the interval

SP7 = Shadow Price for Southeastern, or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP8 = Shadow Price for Southeastern, or L.I. 10-Minute Reserve requirement constraint for the interval

SP9 = Shadow Price for Southeastern, or L.I. Spinning Reserve requirement constraint for the interval

SP10 = Shadow Price for Long Island 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP11 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP12 = Shadow Price for Long Island Spinning Reserve requirement constraint for the interval

Real-time locational and Scarcity Reserve Requirement Shadow Prices will be calculated by the ISO's RTD. Each Real-Time Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement

in that interval, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that interval, as calculated during the second RTD pass described in Section 17.1.2.1.2.2 of Attachment B to this ISO Services Tariff. As a result, the Shadow Price for each Operating Reserves requirement, including a Scarcity Reserve Requirement, shall include the Real-Time Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve or Scarcity Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Real-Time Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service. Shadow Prices will also be consistent with the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve described in Section 15.4.7 of this Rate Schedule, which will ensure that Operating Reserves are not scheduled by RTC at a cost greater than the relevant Operating Reserve Demand Curve or Scarcity Reserve Demand Curve indicates should be paid. If there is more Operating Reserve of the required quality than is needed to meet a particular locational Operating Reserve requirement or Scarcity Reserve Requirement then the Shadow Price for that Operating Reserve requirement or Scarcity Reserve Requirement constraint shall be zero.

Each Supplier that is scheduled in real-time to provide Operating Reserve shall be paid the applicable Real-Time Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each interval that was not scheduled Day-Ahead.

15.4.6.1.1 The Real-Time Market clearing price shall also reflect the Shadow Price for any Scarcity Reserve Requirement constraint as part of the applicable 30-Minute Reserve requirement constraint Shadow Price for the Load Zones included in the Scarcity Reserve Region. The inclusion of Scarcity Reserve Requirement constraint Shadow Prices in the calculation of Real-Time Market clearing prices is as set forth below:

- (a) When the Load Zones included in a Scarcity Reserve Region are identical to the Load Zones of an existing locational reserve region, the Scarcity Reserve Requirement will be added to the existing 30-Minute Reserve requirement for the locational reserve region and the Shadow Price for the Scarcity Reserve Requirement will be the Shadow Price for the revised 30-Minute Reserve requirement. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:
 - i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones A, B, C, D, E, F, G, H, I, J and K (*i.e.*, all Load Zones), then the Shadow Price for the Scarcity Reserve Requirement shall be SP1. SP1 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices;
 - ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones F, G, H, I, J and K (*i.e.*, all East of Central-East Load Zones), but does not include Load Zones A, B, C, D or E, then the Shadow Price for the Scarcity Reserve Requirement shall be SP4. SP4 shall be utilized in the

same manner as described in the formulae above in calculating Real-Time Market clearing prices;

- iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zones G, H, I, J and K (*i.e.*, all Southeastern New York Load Zones), but does not include Load Zones A, B, C, D, E or F, then the Shadow Price for the Scarcity Reserve Requirement shall be SP7. SP7 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices; or
 - iv. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zone K (*i.e.*, Long Island only), but does not include Load Zones A, B, C, D, E, F, G, H, I or J, then the Shadow Price for the Scarcity Reserve Requirement shall be SP10. SP10 shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices.
- (b) When the Load Zones included in the Scarcity Reserve Region are not identical to the Load Zones of an existing locational reserve region, the Shadow Price attributable to the Scarcity Reserve Requirement will be added to the applicable Shadow Price for the 30-Minute Reserve requirement for the existing locational reserve region to which all of the Load Zones included in the Scarcity Reserve Region belong. The inclusion of the Scarcity Reserve Requirement Shadow Prices shall apply only to the Load Zones included as part of a Scarcity Reserve Region. The use of Scarcity Reserve Requirement Shadow Prices in calculating Real-Time Market clearing in such circumstances is as follows:

- i. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones A, B, C, D or E and Section 15.4.6.1.1(a)(i) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP1 for each of the Load Zones included in the Scarcity Reserve Region. This SP1 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region;
- ii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least Load Zone F, but does not include Load Zones A, B, C, D or E and Section 15.4.6.1.1(a)(ii) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP4 for each of the Load Zones included in the Scarcity Reserve Region. This SP4 value shall be utilized in the same manner as described in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region; or
- iii. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes at least one or more of Load Zones G, H, I or J, but does not include Load Zones A, B, C, D, E or F and Section 15.4.6.1.1(a)(iii) of this Rate Schedule is not applicable, then the Shadow Price for the Scarcity Reserve Requirement shall be included in SP7 for each of the Load Zones included in the Scarcity Reserve Region. This SP7 value shall be utilized in the same manner as described

in the formulae above in calculating Real-Time Market clearing prices for each of the Load Zones included in the Scarcity Reserve Region.

15.4.6.2 Establishment of Scarcity Reserve Requirements in the Real-Time Market During EDRP/SCR Activations

The ISO will establish a Scarcity Reserve Requirement for each Scarcity Reserve Region when it has called upon the EDRP and/or SCRs in identified Load Zones to reduce Load to address a reliability need. The Scarcity Reserve Requirement will be applicable for all real-time intervals during which the ISO has activated EDRP and/or SCRs within the applicable Scarcity Reserve Region to provide Load reduction. The Scarcity Reserve Requirement for each affected real-time interval shall be an amount equal to the sum of the applicable values for the Expected EDRP/SCR MW for all of the Load Zones included in a Scarcity Reserve Region, less the Available Operating Capacity in the Scarcity Reserve Region; provided, however, that a Scarcity Reserve Requirement shall not have a value less than zero.

The applicable value of the Expected EDRP/SCR MW for each Load Zone included in a Scarcity Reserve Region to be used in calculating the Scarcity Reserve Requirement is dependent upon whether the Load reduction for a given interval is deemed voluntary or mandatory for purposes of calculating the Scarcity Reserve Requirement, as further described below. If the ISO has satisfied the notification requirements set forth in Section 5.12.11.1 of this ISO Services Tariff for the SCRs within any Load Zone for any hour encompassed by the EDRP/SCR activation(s) for the day at issue, the Load reduction for all intervals encompassed by such activation(s) are deemed to be mandatory for the purposes of calculating any Scarcity Reserve Requirement only and the corresponding value for a mandatory Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. In all other circumstances not encompassed by the preceding sentence, the Load reduction for all intervals encompassed by

such EDRP/SCR activation(s) are deemed to be voluntary for the day at issue and the corresponding value for a voluntary Load reduction is used for SCRs in determining any Scarcity Reserve Requirement. For EDRP, Load reduction is deemed to be voluntary in all intervals and the value for EDRP included in the Expected EDRP/SCR MW value for each Load Zone reflects the voluntary nature of the Load reduction.

15.4.6.3 Operating Reserve Balancing Payments

Any deviation in performance from a Supplier's Day-Ahead schedule to provide Operating Reserves, including deviations that result from schedule modifications made by the ISO, shall be settled pursuant to the following rules.

- (a) When the Supplier's real-time Operating Reserves schedule is less than its Day-Ahead Operating Reserves schedule, the Supplier shall pay a charge for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserves Product in the relevant location or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.
- (b) When the Supplier's real-time Operating Reserves schedule is greater than its Day-Ahead Operating Reserves schedule, the ISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of: (i) the Real-Time Market clearing price for the relevant Operating Reserve product in the relevant location or Scarcity Reserve Region; and (ii) the difference between the Supplier's Day-Ahead and real-time Operating Reserves schedules.

15.4.6.4 Other Real-Time Payments

The ISO shall pay Generators that are selected to provide Operating Reserves Day-Ahead, but are directed to convert to Energy production in real-time, the applicable Real-Time LBMP for all Energy they are directed to produce in excess of their Day-Ahead Energy schedule.

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) a Demand Side Resource that provides Operating Reserves may be eligible for a Bid Production Cost guarantee payment pursuant to Section 4.6.6 and Attachment C of this ISO Services Tariff.

A Supplier that provides Operating Reserves may also be eligible for a Day-Ahead Margin Assurance Payment pursuant to Section 4.6.5 and Attachment J of this ISO Services Tariff.

15.4.7 Operating Reserve Demand Curves and Scarcity Reserve Demand Curve

The ISO shall establish twelve Operating Reserve Demand Curves, one for each locational Operating Reserves requirement. Specifically, there shall be a demand curve for: (i) Total Spinning Reserves; (ii) Eastern, Southeastern or Long Island Spinning Reserves; (iii) Southeastern or Long Island Spinning Reserves (iv) Long Island Spinning Reserves; (v) Total 10-Minute Reserves; (vi) Eastern, Southeastern or Long Island 10-Minute Reserves; (vii) Southeastern or Long Island 10-Minute Reserves; (viii) Long Island 10-Minute Reserves; (ix) Total 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement); (x) Eastern, Southeastern or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); (xi) Southeastern or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); and (xii) Long

Island 30-Minute Reserves (including a separate demand curve applicable for each real-time interval the ISO has established a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply). Each Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location, except for those demand curves that apply to certain Scarcity Reserve Requirements which will be applicable only during the real-time intervals that a Scarcity Reserve Requirement has been established by the ISO. The ISO shall also establish a Scarcity Reserve Demand Curve for each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. A Scarcity Reserve Demand Curve will be applicable only during the real-time intervals that such a Scarcity Reserve Requirement has been established by the ISO.

The market clearing pricing for Operating Reserves shall be calculated pursuant to Sections 15.4.5.1 and 15.4.6.1 of this Rate Schedule and in a manner consistent with the demand curves established in this Section so that Operating Reserves are not purchased by SCUC, RTC or RTD at a cost higher than the relevant demand curve indicates should be paid.

The ISO Procedures shall establish and post a target level for each locational Operating Reserves requirement for each hour, which will be the number of MW of Operating Reserves meeting that requirement that the ISO would seek to maintain in that hour. To the extent not otherwise already adjusted pursuant to Section 15.4.6.1.1(a) of this Rate Schedule, during each real-time interval in which the ISO has established a Scarcity Reserve Requirement, the ISO will adjust the target level for the locational 30-Minute Reserves requirement to account for the Scarcity Reserve Requirement within the existing locational reserve region(s) to which all the Load Zones included in the Scarcity Reserve Region belong. The ISO will then define an

Operating Reserves demand curve for that hour corresponding to each Operating Reserves requirement as follows:

- (a) Total Spinning Reserves: For quantities of Operating Reserves meeting the total Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total Spinning Reserves demand curve shall be \$775/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be \$0/MW.
- (b) Eastern, Southeastern or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island Spinning Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island Spinning Reserves demand curve shall be \$0/MW.
- (c) Southeastern or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern or Long Island Spinning Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Southeastern or Long Island Spinning Reserves demand curve shall be \$0/MW.
- (d) Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Long Island Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island Spinning

Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Long Island Spinning Reserves demand curve shall be \$0/MW.

- (e) Total 10-Minute Reserves: For quantities of Operating Reserves meeting the total 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the total 10-minute reserves demand curve shall be \$750/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be \$0/MW.
- (f) Eastern, Southeastern or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island 10-minute reserves demand curve shall be \$775/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 10-minute reserves demand curve shall be \$0/MW.
- (g) Southeastern or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island 10-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern or Long Island 10-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Southeastern or Long Island 10-Minute Reserves demand curve shall be \$0/MW.
- (h) Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 10-

minute reserves demand curve shall be \$25/MW. For all other quantities, the price on the Long Island 10-minute reserves demand curve shall be \$0/MW.

- (i) Total 30-Minute Reserves: For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be \$750/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 655 MW but that exceed the target level for that locational requirement minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be \$200/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus 300 MW but that exceed the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be \$100/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement but that exceed the target level for that locational requirement minus 300 MW, the price on the total 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be \$0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the requirement for that hour. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in

Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement (“NYCA scarcity target level”) that are less than or equal to the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be \$750/MW. For quantities of Operating Reserves meeting the NYCA scarcity target level that are less than or equal to the NYCA scarcity target level but that exceed the NYCA scarcity target level minus an amount equal to the sum of 955 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be \$500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be \$0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the Scarcity Reserve Requirement for that interval.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(i) of this Rate Schedule apply, the applicable Operating Reserves demand curve for total 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the total 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) (“adjusted NYCA target

level”) that are less than or equal to the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be \$750/MW. For quantities of Operating Reserves meeting the adjusted NYCA target level that are less than or equal to the adjusted NYCA target level but that exceed the adjusted NYCA target level minus 955 MW, the price on the total 30-Minute Reserves demand curve shall be \$500/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be \$0/MW. However, the ISO will not schedule more total 30-Minute Reserves than the level defined by the total 30-Minute Reserves locational requirement plus the applicable Scarcity Reserve Requirement(s) for that interval.

- (j) Eastern, Southeastern or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement

target level plus the Scarcity Reserve Requirement (“Eastern scarcity target level”) that are less than or equal to the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For the quantities of Operating Reserves meeting the Eastern scarcity target level that are less than or equal to the Eastern scarcity target level but exceed the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target level, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the East of Central-East reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(ii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Eastern, Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) (“adjusted Eastern target level”) that are less than or equal to the adjusted Eastern target level, the price on the Eastern, Southeastern or Long

Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Eastern, Southeastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

- (k) Southeastern or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.
- During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement (“Southeastern scarcity target level”) that are less than or equal to the Southeastern scarcity target level, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

During each real-time interval that the ISO has established a Scarcity Reserve Requirement(s) in the Real-Time Market for which all the Load Zones encompassed by such Scarcity Reserve Requirement belong to the Southeastern

New York reserve region, other than a Scarcity Reserve Requirement for which the pricing rules established in Section 15.4.6.1.1(a)(iii) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Southeastern or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern or Long Island 30-Minute Reserves locational requirement target level plus the applicable Scarcity Reserve Requirement(s) (“adjusted Southeastern target level”) that are less than or equal to the adjusted Southeastern target level, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For all other quantities, the price on the Southeastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

- (l) Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the Long Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be \$0/MW. During each real-time interval that the ISO has established a Scarcity Reserve Requirement in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(a)(iv) of this Rate Schedule apply, the applicable Operating Reserves demand curve for Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement (“Long Island scarcity target level”) that are less than or equal to the

Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target, the price on the Long Island 30-Minute Reserves demand curve shall be \$500/MW. For the quantities of Operating Reserves meeting the Long Island scarcity target level that are less than or equal to the Long Island scarcity target level but exceed the Long Island scarcity target level minus an amount equal to the Long Island 30-Minute Reserves locational requirement target level, the price on the Long Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be \$0/MW.

The ISO will procure additional Operating Reserves to meet each Scarcity Reserve Requirement established by the ISO in the Real-Time Market for which the pricing rules established in Section 15.4.6.1.1(b) of this Rate Schedule apply. The Scarcity Reserve Demand Curve for each real-time interval in which the ISO has established such a Scarcity Reserve Requirement shall be defined as follows: For quantities of Operating Reserves meeting the Scarcity Reserve Requirement that are less than or equal to the Scarcity Reserve Requirement, the price on the Scarcity Reserve Demand Curve shall be \$500/MW. For all other quantities, the price on the Scarcity Reserve Demand Curve shall be \$0/MW.

In order to respond to operational or reliability problems that arise in real-time, the ISO may procure any Operating Reserve product at a quantity and/or price point different than those specified above. The ISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The ISO shall also immediately initiate an investigation to determine whether it is necessary to modify the quantity and price points specified above to avoid future operational or

reliability problems. The ISO will consult with its Market Monitoring Unit when it conducts this investigation.

If the ISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. 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.

Not later than 90 days after the implementation of the Operating Reserves Demand Curves the ISO, in consultation with its Market Advisor, shall conduct an initial review of them in accordance with the ISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether any Operating Reserve Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the ISO Administered Markets. The ISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 15.4.7 is in effect. After the first year, the ISO shall perform periodic reviews, subject to the same scope requirement, and the Market Monitoring Unit shall be given the opportunity to review and comment on the ISO's periodic reviews of the Operating Reserve Demand Curves and Scarcity Reserve Demand Curve.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Rate Schedule 4 to the Services Tariff are also addressed in Section 30.4.6.4.2 of Attachment O.

15.4.8 Self-Supply

Transactions may be entered into to provide for Self-Supply of Operating Reserves. Except as noted in the next paragraph, Customers seeking to Self-Supply Operating Reserves must place the Generator(s) supplying any one of the Operating Reserves under ISO control. The Generator(s) must meet ISO rules for acceptability. The amount that any such Customer will be charged for Operating Reserves will be reduced by the market value of the services provided by the specified Generator(s) as determined in the ISO Services Tariff.

Alternatively, Customers, including LSEs, may enter into Day-Ahead Bilateral financial Transactions, *e.g.*, contracts-for-differences, in order to hedge against price volatility in the Operating Reserves markets.

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 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.

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:

γ_i	=	LBMP at bus i in \$/MWh
λ^R	=	the system marginal price at the Reference Bus
γ_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
γ_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:

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

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

μ_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 γ_i^L and γ_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 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.

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 ("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. 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. 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 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.

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) 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, given its UOL_N or UOL_E , 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 UOL_N or UOL_E , as applicable, but instead starting from the feasible output level closest to its previous base point.

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

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by increasing the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E , whichever is applicable. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by decreasing the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level or to 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 UOL_N or UOL_E , whichever is applicable), regardless of their minimum run-time status. 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 Article 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.

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 UOL_N or UOL_E , whichever is applicable. The lower dispatch limit for the later time points of the second pass for such a Resource shall be determined

by decreasing its lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level.

17.1.2.1.2.2 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 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 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 UOL_E at its emergency response rate or set it at a level equal to its physical base point.

Third, if the ISO enters basepoints ASAP – no commitments mode it will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period).

Fourth, if the ISO enters basepoints ASAP – commit as needed mode: (i) the ISO will produce price and schedules for a single five minute interval (not for a multi-point co-optimization period); and (ii) the ISO may make additional commitments of Generators that are capable of starting within ten minutes before executing the three 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).

17.1.3 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 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 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:

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

where:

$$\gamma_j^Z = \text{LBMP for zone } j,$$

$\gamma_j^{L,Z} = \sum_{i=1}^n W_i \gamma_i^L$ 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_BRUCE	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 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 $LBMP_a = RTD\ LBMP_a$
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 $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a$

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 $LBMP_a = RTD\ LBMP_a$

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>)
3	RTC ₁₅ is subject to a Proxy Generator Bus Constraint	Into NYCA or out of NYCA (Import or Export)	Real-Time LBMP _{<i>a</i>} = RTD LBMP _{<i>a</i>} + RTC ₁₅ External Interface Congestion _{<i>a</i>}

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 <i>a</i>	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location <i>a</i>)
1	Unconstrained in RTC ₁₅ , Rolling RTC and RTD	N/A	Real-Time LBMP _{<i>a</i>} = RTD LBMP _{<i>a</i>}
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 LBMP_{<i>a</i>} > 0, then Real-Time LBMP_{<i>a</i>} = RTD LBMP_{<i>a</i>} + Rolling RTC External Interface Congestion_{<i>a</i>}</p> <p>Otherwise, Real-Time LBMP_{<i>a</i>} = Minimum of (i) RTD LBMP_{<i>a</i>} and (ii) zero</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 $LBMP_a < 0$, then Real-Time $LBMP_a = RTD LBMP_a + \text{Rolling RTC External Interface Congestion}_a$</p> <p>Otherwise, Real-Time $LBMP_a = RTD LBMP_a$</p>
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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 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 or Interface Ramp Constraint	Into NYCA (Import)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + RTC_{15}$ External Interface Congestion $_a$ Otherwise, Real-Time $LBMP_a =$ Minimum of (i) $RTD\ LBMP_a$ and (ii) zero
7	RTC_{15} is subject to an Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	If RTC_{15} Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + RTC_{15}$ External Interface Congestion $_a$ Otherwise, Real-Time $LBMP_a = RTD\ LBMP_a$

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)	If Rolling RTC Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a$ Otherwise, Real-Time $LBMP_a = \text{Minimum of (i) } RTD\ LBMP_a \text{ and (ii) zero}$
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)	If Rolling RTC Proxy Generator Bus $LBMP_a < 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + \text{Rolling RTC External Interface Congestion}_a$ Otherwise, Real-Time $LBMP_a = RTD\ LBMP_a$

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)	If RTC_{15} Proxy Generator Bus $LBMP_a > 0$, then Real-Time $LBMP_a = RTD\ LBMP_a + RTC_{15} \text{ External Interface Congestion}_a$ Otherwise, Real-Time $LBMP_a = \text{Minimum of (i) } RTD\ LBMP_a \text{ and (ii) zero}$

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 ₁₅ is subject to an Interface ATC Constraint	Out of NYCA (Export)	<p>If RTC₁₅ Proxy Generator Bus LBMP_a < 0, then Real-Time LBMP_a = RTD LBMP_a + RTC₁₅ External Interface Congestion_a</p> <p>Otherwise, Real-Time LBMP_a = RTD LBMP_a</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.