

## Attachment VII

## 2.3 Definitions - C

**Capability Period:** Six-month periods which are established as follows: (i) from May 1 through October 31 of each year (“Summer Capability Period”); and (ii) from November 1 of each year through April 30 of the following year (“Winter Capability Period”).

**Capability Period Auction:** An auction conducted no later than thirty (30) days prior to the start of each Capability Period in which Unforced Capacity may be purchased and sold in a six-month strip.

**Capability Period SCR Load Zone Peak Hours:** The top forty (40) coincident peak hours that, prior to the Summer 2014 Capability Period include hour beginning thirteen through hour beginning eighteen and beginning with the Summer 2014 Capability Period include hour beginning eleven through hour beginning nineteen. The Capability Period SCR Load Zone Peak Hours shall be determined by the NYISO from the Prior Equivalent Capability Period and shall be used by RIPS to report ACL values for the purpose of SCR enrollment. For a SCR enrolled with a Provisional ACL that requires verification data to be reported at the end of the Capability Period in which the SCR was enrolled, the Capability Period SCR Load Zone Peak Hours shall be determined from the Capability Period in which the SCR was enrolled. Such hours shall not include (i) hours in which Special Case Resources located in the specific Load Zone were called by the ISO to respond to a reliability event or test and (ii) hours for which the Emergency Demand Response Program resources were deployed by the ISO in each specific Load Zone. In addition, beginning with the Summer 2014 Capability Period, the NYISO shall not include, in descending rank order of NYCA Load up to a maximum of eight hours per Capability Period, a) the hour before the start time of a reliability event or performance test, in which SCRs located in the specific Load Zone were called by the ISO to respond to a reliability event or performance test, or b) the hour immediately following the end time of such reliability event or performance test.

**Capability Year:** A Summer Capability Period, followed by a Winter Capability Period (*i.e.*, May 1 through April 30).

**Capacity:** The capability to generate or transmit electrical power, or the ability to control demand at the direction of the ISO, measured in megawatts (“MW”).

**Capacity Accreditation Factor:** The factors, set annually by the ISO in accordance with Section 5.12.14.3 and ISO Procedures, that reflect the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year. Capacity Accreditation Factors for each Capacity Accreditation Resource Class will be determined by the ISO for Rest of State, G-J Locality (excluding Load Zone J), NYC Locality, and Long Island Locality, in accordance with Section 5.12.14.3 and ISO Procedures. Capacity Accreditation Factors are applicable to all Resources and/or Aggregations within each Capacity Accreditation Resource Class that has been established in accordance with ISO Procedures.

**Capacity Accreditation Resource Class:** A defined set of Resources and/or Aggregations, as identified in accordance with ISO Procedures, with similar technologies and/or operating

characteristics which are expected to have similar marginal reliability contributions toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year. Each Capacity Accreditation Resource Class will be evaluated through the annual review detailed in Section 5.12.14.3. Each Installed Capacity Supplier will be assigned a Capacity Accreditation Resource Class.

**Capacity Limited Resource:** A Resource that is constrained in its ability to supply Energy above its Normal Upper Operating Limit by operational or plant configuration characteristics. Capacity Limited Resources must register their Capacity limiting characteristics with, and justify them to, the ISO consistent with ISO Procedures. Capacity Limited Resources may submit a schedule indicating that their Normal Upper Operating Limit is a function depending on one or more variables, such as temperature or pondage levels, in which case the Normal Upper Operating Limit applicable at any time shall be determined by reference to that schedule.

**Capacity Reservation Cap:** As defined in the ISO OATT.

**CARL Data:** Control Area Resource and Load (“CARL”) data submitted by Control Area System Resources to the ISO.

**Centralized Transmission Congestion Contracts (“TCC”) Auction (“Auction”):** As defined in the ISO OATT.

**Co-located Storage Resources (“CSR”):** An Energy Storage Resource and one other type of Generator that is not a Withdrawal-Eligible Generator. The second participating Generator can be a wind, solar, or landfill gas fueled Intermittent Power Resource, a Limited Control Run-of-River Hydro Resource, or a Dispatchable Generator which may require commitment and time to start-up. The two Generators must: (a) both be located behind a single Point of Injection (as defined in Section 1.16 of the OATT); (b) participate in the ISO Administered Markets as two distinct Generators; and (c) share a set of CSR Scheduling Limits. Generators that may not participate in the ISO-Administered Markets as components of a CSR include: (a) Limited Energy Storage Resources, (b) a Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, (c) Generators participating via a model that can accommodate several participants, including but not limited to Hybrid Storage Resources and Aggregations, and (d) Generators that serve a Host Load.

**Code of Conduct:** The rules, procedures and restrictions concerning the conduct of the ISO directors and employees, contained in Attachment F to the ISO Open Access Transmission Tariff.

**Commenced Repair:** A determination by the ISO that a Market Participant with a Generator i) has decided to pursue the repair of its Generator, and based on the ISO’s technical/engineering evaluation ii) has a Repair Plan for the Generator that is consistent with a Credible Repair Plan, and iii) has made appropriate progress in pursuing the repair of its Generator when measured against the milestones of a Credible Repair Plan.

**Commission (“FERC”):** The Federal Energy Regulatory Commission, or any successor agency.

**Compensable Overgeneration:** A quantity of Energy provided over a given RTD interval in which a Supplier has offered Energy that exceeds the Real-Time Scheduled Energy established by the ISO for that Supplier and for which the Supplier may be paid pursuant to ISO Procedures.

For (i) Suppliers not covered by other provisions of this Section, (ii) Intermittent Power Resources depending on wind or solar energy as their fuel for which the ISO has imposed a Wind and Solar Output Limit in the given RTD interval, and (iii) Intermittent Power Resources depending on landfill gas as their fuel or Limited Control Run-of-River Hydroelectric Resources that participate as Co-located Storage Resources for which the ISO has imposed a Wind and Solar Output Limit in the given RTD interval, Compensable Overgeneration shall initially equal three percent ( 3%) of the Supplier's Normal Upper Operating Limit which may be modified by the ISO if necessary to maintain good Control Performance.

For a Generator or Aggregation: (i) which is operating in Start-Up or Shutdown Periods, or Testing Periods; or (ii) which is a Limited Control Run of River Hydro Resource that has offered its Energy to the ISO in a given interval not using the ISO-committed Flexible or Self-Committed Flexible bid mode (except as provided above); or (iii) which is an Intermittent Power Resource that depends on landfill gas for its fuel and has offered its Energy to the ISO in a given interval not using the ISO-committed Flexible or Self-Committed Flexible bid mode (except as provided above); or (iv) which is an Intermittent Power Resource that depends on wind or solar energy for its fuel (except as provided above), Compensable Overgeneration shall mean all Energy actually injected by the Generator or Aggregation that exceeds the Real-Time Scheduled Energy established by the ISO for that Generator or Aggregation.

For a Generator or Aggregation operating in intervals when it has been designated as operating Out of Merit at the request of a Transmission Owner or the ISO, Compensable Overgeneration shall mean all Energy actually provided by the Generator or Aggregation that exceeds the Real-Time Scheduled Energy up to the Energy level directed by the Transmission Owner or the ISO.

For a Generator comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, Compensable Overgeneration shall mean that quantity of Energy injected by the Generator, during the period when one of its grouped generating units is operating in a Start-Up or Shutdown Period, that exceeds the Real-Time Scheduled Energy established by the ISO for that period, for that Generator, and for which the Generator may be paid pursuant to ISO Procedures.

**Completed Application:** An Application that satisfies all of the information and other requirements for service under the ISO Services Tariff.

**Confidential Information:** Information and/or data that has been designated by a Customer to be proprietary and confidential, provided that such designation is consistent with the ISO Procedures, the ISO Services Tariff, and the ISO Code of Conduct.

**Congestion:** A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of Energy to

serve the next increment of Load, exclusive of losses, at different locations on the transmission system is unequal.

**Congestion Component:** The component of the LBMP measured at a location or the Transmission Usage Charge between two locations that is attributable to the cost of transmission Congestion as is more completely defined in Attachment B of the Services Tariff.

**Congestion Rent:** As defined in the ISO OATT.

**Congestion Rent Shortfall:** As defined in the ISO OATT.

**Constraint:** An upper or lower limit placed on a variable or set of variables that are used by the ISO in its SCUC, RTC, or RTD programs to control and/or facilitate the operation of the NYS Transmission System.

**Contingency:** An actual or potential unexpected failure or outage of a system component, such as a Generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

**Control Area:** An electric system or combination of electric power systems to which a common Automatic Generation Control scheme is applied in order to: (1) match, at all times, the power output of the Generators and Aggregations within the electric power system(s) and Capacity and Energy purchased from entities outside the electric power system(s), with the Load within the electric power system(s); (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient Capacity to maintain Operating Reserves in accordance with Good Utility Practice.

**Control Area System Resource:** A set of Resources owned or controlled by an entity within a Control Area that also is the operator of such Control Area. Entities supplying Unforced Capacity using Control Area System Resources will not designate particular Resources as the suppliers of Unforced Capacity.

**Control Performance:** A standard for measuring the degree to which a Control Area is providing Regulation Service in conformance with NERC requirements.

**Controllable Transmission:** Any Transmission facility over which power-flow can be directly controlled by power-flow control devices without having to re-dispatch generation.

**Credible Repair Plan:** A Repair Plan that meets the requirements described in Section 5.18.1.4 of this Services Tariff and in ISO Procedures.

**Credit Assessment:** An assessment of a Customer's creditworthiness, conducted by the ISO in accordance with Section 26.5.3 of Attachment K to this Services Tariff.

**Critical Electric System Infrastructure Load:** Load that is critical to maintaining the reliable operation of electric system infrastructure, including, without limitation, Load that is (i)

necessary to maintain the delivery of natural gas, fuel oil, and other fuels used by Generators (including Local Generators) to generate electricity, (ii) likely to impact the supply of natural gas, fuel oil, and other fuel to Generators, or (iii) otherwise likely to impact Generator operation. Critical Electric System Infrastructure Load does not include on-site Load that is consumed for ancillary purposes unless such Load is necessary for compliance with parts (i) – (iii) of this definition.

**Cross-Sound Scheduled Line:** A transmission facility that interconnects the NYCA to the New England Control Area at Shoreham, New York and terminates near New Haven, Connecticut.

**CSR Scheduling Limits:** The CSR injection Scheduling Limit is used to determine the combined Regulation Capacity, Operating Reserve and Energy injection schedules for, and the maximum permitted net injection by a CSR's Generators. The CSR withdrawal Scheduling Limit sets is used to determine the combined Regulation Capacity and Energy withdrawal schedules for, and the maximum permitted net withdrawal by a CSR's Generators.

The Market Participant that is responsible for submitting Bids for a set of CSR Generators shall submit a CSR injection Scheduling Limit and a CSR withdrawal Scheduling Limit with the hourly Day-Ahead and Real-Time Market Bids it submits for each of the CSR Generators. The CSR Scheduling Limit values that the Market Participant submits must reflect the physical capability to inject or withdraw Energy at the Point of Injection/Point of Withdrawal.

To address the real-time variability of Energy deliveries from the Intermittent Power Resource or Limited Control Run-of-River Hydro Resource that participate as Co-located Storage Resources, when the participating Energy Storage Resource has a non-zero Regulation and/or Operating Reserves schedule or is dispatched to inject Energy, and the sum of the participating Energy Storage Resource's and the participating Intermittent Power Resource's or Limited Control Run-of-River Hydro Resource's Energy, Regulation Service and Operating Reserves Schedules is greater than or equal to a specified percentage of the CSR injection Scheduling Limit, then the ISO will issue a Wind and Solar Output Limit to the Intermittent Power Resource or Limited Control Run-of-River Hydro Resource to not exceed its Base Point Signal. The specified percentage that is ordinarily used will be posted on the ISO's website.

**CTS Enabled Interface:** An External Interface at which the ISO has authorized the use of Coordinated Transaction Scheduling ("CTS") market rules and which includes a CTS Enabled Proxy Generator Bus for New York and a CTS Enabled Proxy Generator Bus for the neighboring Control Area.

**CTS Enabled Proxy Generator Bus:** A Proxy Generator Bus at which the ISO either requires or permits the use of CTS Interface Bids for Import and Export Transactions in the Real-Time Market and requires the use of Decremental Bids for Wheels Through in the Real-Time Market. A CTS Enabled Proxy Generator Bus at which the ISO permits CTS Interface Bids will also permit Decremental and Sink Price Cap Bids.

**CTS Interface Bid:** A Real-Time Bid provided by an entity engaged in an External Transaction at a CTS Enabled Interface. CTS Interface Bids shall include a MW amount, a direction

indicating whether the proposed Transaction is to Import Energy to, or Export Energy from, the New York Control Area, and a Bid Price.

**CTS Sink:** Representation of the location(s) within a Control Area where energy associated with a CTS Interface Bid is withdrawn. The NYCA CTS Sinks are Proxy Generator Buses.

**CTS Sink Price:** The price at a CTS Sink.

**CTS Source:** Representation of the location(s) within a Control Area where energy associated with a CTS Interface Bid is injected. The NYCA CTS Sources are Proxy Generator Buses.

**CTS Source Price:** The price at a CTS Source.

**Curtailement or Curtail:** A reduction in Transmission Service in response to a transmission Capacity shortage as a result of system reliability conditions.

**Curtailement Customer Aggregator:** A Curtailement Services Provider that produces real-time verified reductions in NYCA load of at least 100 kW through contracts with retail end-users. The procedure for qualifying as a Curtailement Customer Aggregator is set forth in ISO procedures.

**Curtailement Initiation Cost:** The fixed payment, separate from a variable Demand Reduction Bid, required by a qualified Demand Reduction Provider in order to cover the cost of reducing demand.

**Curtailement Services Provider:** A qualified entity that can produce real-time, verified reductions in NYCA Load of at least 100 kW in a single Load Zone, pursuant to the Emergency Demand Response Program and related ISO procedures. The procedure for qualifying as a Curtailement Services Provider is set forth in Section 3 below and in ISO Procedures.

**Curtailement Services Provider Capacity:** Capacity from a Demand Side Resource nominated by a Curtailement Services Provider for participation in the Emergency Demand Response Program.

**Customer:** An entity which has complied with the requirements contained in the ISO Services Tariff, including having signed a Service Agreement, and is qualified to utilize the Market Services and the Control Area Services provided by the ISO under the ISO Services Tariff; provided, however, that a party taking services under the Tariff pursuant to an unsigned Service Agreement filed with the Commission by the ISO shall be deemed a Customer.

## 2.23 Definitions - W

**West of Central-East (“West” or “Western”):** An electrical area comprised of Load Zones A, B, C, D, and E, as identified in the ISO Procedures.

**Wheels Through:** Transmission Service, originating in another Control Area, that is wheeled through the NYCA to another Control Area.

**Wheels Through Credit Requirement:** A component of the External Transaction Component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

**Wholesale Market:** The sum of purchases and sales of Energy and Capacity for resale along with Ancillary Services needed to maintain reliability and power quality at the transmission level coordinated together through the ISO and Power Exchanges. A party who purchases Energy, Capacity or Ancillary Services in the Wholesale Market to serve its own Load is considered to be a participant in the Wholesale Market.

**Wholesale Transmission Services Charges (“WTSC”):** Those charges calculated pursuant to Attachment H of the OATT, incurred or declared overdue by a Transmission Owner pursuant to Section 26.4.2 of Attachment K, after the effective date of these revisions; provided, however, that these provisions will not apply to pre-petition bankruptcy debts for a company that is currently in bankruptcy.

**Wind and Solar Energy Forecast:** The ISO’s forecast of Energy that is expected to be supplied over a specified interval of time by an Intermittent Power Resource that depends on wind or solar energy as its fuel and which is used in ISO’s Energy market commitment and dispatch. The Wind Energy Forecast does not include a forecast of Energy for Intermittent Power Resources depending on wind as its fuel that participate in a DER Aggregation.

**Wind and Solar Output Limit:** A Base Point Signal calculated for an Intermittent Power Resource depending on wind or solar energy as its fuel and which, when sent to the Intermittent Power Resource, shall include a separate flag directing the Intermittent Power Resource not to exceed its Base Point Signal. Intermittent Power Resources that depend on wind or solar energy as their fuel shall be eligible to receive a Wind and Solar Output Limit, except for those that depend on wind for their fuel and were in commercial operation as of January 1, 2002 with name plate capacity of 12 MWs or fewer, and Resources depending on wind or solar energy as their fuel that participate in a DER Aggregation.

Intermittent Power Resources depending on wind or solar energy or landfill gas as their fuel, or a Limited Control Run of River Hydro Resource, that participate as Co-located Storage Resources shall be eligible to receive a Wind and Solar Output Limit to address the real-time variability of their Energy deliveries consistent with the rules specified for implementing CSR Scheduling Limits.

**Withdrawal-Eligible Generator:** A Generator that is eligible to withdraw energy from the grid at a price for the purposes of recharging or refilling for later injection back into the grid.



**WTSC Component:** A component of the Operating Requirement, calculated in accordance with Section 26.4.2, of Attachment K to this Services Tariff.

## **4.2 Day-Ahead Markets and Schedules**

### **4.2.1 Day-Ahead Load Forecasts, Bids and Bilateral Schedules**

#### **4.2.1.1 General Customer Forecasting and Bidding Requirements**

Subject to the two earlier submission deadlines set forth below, by 5 a.m. on the day prior to the Dispatch Day: (i) All LSEs serving Load in the NYCA shall provide the ISO with Load forecasts for the Dispatch Day and the day after the Dispatch Day; and (ii) Customers and Transmission Customers submitting Bids in the Day-Ahead Market shall provide the ISO, consistent with ISO Procedures:

- a. Bids to supply Energy, including Bids to supply Energy in Virtual Transactions;
- b. Bids to supply Ancillary Services;
- c. Requests for Bilateral Transaction schedules;
- d. Bids to purchase Energy, including Bids to purchase Energy in Virtual Transactions and Bids to withdraw Energy by Withdrawal-Eligible Generators;
- e. Demand Reduction Bids; and
- f. For Behind-the-Meter Net Generation Resources, the forecasted Host Load for each hour of the Dispatch Day.

By 4:50 a.m. on the day prior to the Dispatch Day, all Customers or Transmission Customers shall submit Bids for External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Linden VFT Scheduled Line, or the HTP Scheduled Line.

By 4:45 a.m. on the day prior to the Dispatch Day, all Customers or Transmission Customers shall submit Bids that include revised fuel type or fuel price information to the ISO's Market Information System.

In general, the information provided to the ISO shall include the following:

#### **4.2.1.2 Load Forecasts**

The Load forecast shall indicate the predicted level of Load in MW by Point of Withdrawal for each hour.

#### **4.2.1.3 Bids by Suppliers Using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed Bid Modes to Supply Energy and/or Ancillary Services**

##### **4.2.1.3.1 General Rules**

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes shall identify the Capacity, in MW, available for scheduling in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Supplier will voluntarily enter into dispatch commitments. If the Supplier elects to participate in the Day-Ahead Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not consist solely of Station Power) at a single PTID, it can only participate in the Day-Ahead Market as a Behind-the-Meter Net Generation Resource. If the Supplier is a Behind-the-Meter Net Generation Resource, the ISO shall only consider price-MW pairs in excess of the forecasted Host Load for the Resource.

A Supplier's Day-Ahead Bids for an Energy Storage Resource to withdraw Energy and to inject Energy shall be submitted as a single, continuous, bid curve representing the Capacity, in MW, available for scheduling in the Day-Ahead Market for each hour of the Dispatch Day, and shall indicate whether the Resource's Energy Level will be ISO- or Self-Managed. An Energy Storage Resource may not change its Energy Level Management election within the Day-Ahead Market evaluation period (*i.e.*, within a single day).

A Supplier's Day-Ahead Market Self-Committed Flexible Bid for a DER Aggregation may include Energy withdrawals if the DER Aggregation includes at least one Withdrawal-Eligible Generator. A Supplier's hourly Day-Ahead Bids for a DER Aggregation to withdraw Energy and to supply Energy shall be submitted as a single, continuous bid curve representing the Capacity, in MW, available for each hour of the Dispatch Day. When the Energy Bid for a DER Aggregation includes both Energy supply and Energy withdrawal by a Withdrawal-Eligible Generator that is a component of the Aggregation, each point of the DER Aggregation's Bid curve shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

Co-located Storage Resources can each offer all of their available capability into the Day-Ahead Market. The ISO will account for the CSR Scheduling Limits in the schedules if it issues to CSR Generators.

If the Supplier using the ISO-Committed Flexible or Self-Committed Flexible bid mode is eligible to provide Regulation Service or Operating Reserves under Rate Schedules 3 and 4 respectively of this ISO Services Tariff, the Supplier's Bid may specify the quantity of Regulation Capacity it is making available and shall specify an emergency response rate that determines the quantity of Operating Reserves that it is capable of providing. Offers to provide Regulation Service and Operating Reserves must comply with the rules set forth in Rate Schedules 3 and 4 of this ISO Services Tariff. If a Supplier that is eligible to provide Operating Reserves does not submit a Day-Ahead Availability Bid for Operating Reserves, its Day-Ahead Bid shall be rejected in its entirety. A Behind-the-Meter Net Generation Resource that is comprised of more than one generating unit, or an Aggregation containing at least one generating

unit (unless all of the generating unit(s) use inverter-based energy storage technology) that is dispatched as a single aggregate unit at a single PTID is not qualified to provide Regulation Service or Spinning Reserves. Aggregations may only qualify to offer the Ancillary Services that all individual Resources in the Aggregation are qualified to provide. A Supplier may resubmit a complete Day-Ahead Bid, provided that the new Bid is timely. See Section 4.2.1.9 for bidding requirements for Demand Side Resources offering Energy in the Day-Ahead Market.

Suppliers other than Demand Side Resources entering a Bid into the Day-Ahead Market may also enter Day-Ahead Bids for each of the next nine (9) Dispatch Days. If not subsequently modified or withdrawn, these offers for subsequent Dispatch Days may be used by the ISO as offers from these Suppliers in the Day-Ahead Market for these subsequent Dispatch Days. For Suppliers that are providing Unforced Capacity in the ISO-administered ICAP Market for the month in which the Dispatch Day and the nine-day advance bidding period are encompassed, the ISO may enter the eighth day offer as the Bid for that Supplier's ninth day, if there is, otherwise no ninth-day Bid.

#### **4.2.1.3.2 Bid Parameters**

Day-Ahead Bids by Suppliers using the ISO-Committed Flexible, Self-Committed Flexible or ISO-Committed Fixed bid modes may identify-variable Energy price Bids, consisting of up to eleven monotonically increasing, constant cost incremental Energy steps, and other parameters described in ISO Procedures. Day-Ahead Bids from Demand Side Resources offering Operating Reserves or Regulation Service shall be ISO-Committed Flexible and shall have an Energy Bid price no lower than the Monthly Net Benefit Offer Floor. Day-Ahead Bids by Intermittent Power Resources that depend on wind or solar energy as their fuel shall be ISO-

Committed Flexible and shall include a Minimum Generation Bid of zero megawatts and zero costs and a Start-Up Bid of zero cost.

Day-Ahead Bids by ISO-Committed Fixed and ISO-Committed Flexible Generators, other than Bids from Intermittent Power Resources that depend on wind or solar energy as their fuel, shall also include Minimum Generation Bids and hourly Start-Up Bids. Bids shall specify whether a Supplier is offering to be ISO-Committed Fixed, ISO-Committed Flexible, Self-Committed Fixed, or Self-Committed Flexible.

Co-located Storage Resources must each submit a CSR injection Scheduling Limit and a CSR withdrawal Scheduling Limit for each hour of the Day-Ahead Market to indicate the expected capability of the relevant facilities. Resources that participate as CSR shall not submit Day-Ahead Market Bids that would self-commit either of the Generators, or both of the Generators together, to inject or to withdraw a quantity of Energy that exceeds an applicable CSR Scheduling Limit. An Energy Storage Resource that, together with a Generator that submits a Minimum Generation Bid or is a Fixed Block Unit, participates as Co-located Storage Resources shall not submit Day-Ahead Market Bids that would self-commit the Energy Storage Resource to inject Energy such that the Generator's Minimum Generation (or full output for a Fixed Block Unit), plus the Energy Storage Resource's self schedule, exceeds the CSR injection Scheduling Limit.

When a Generator that submits a Minimum Generation Bid or that is a Fixed Block Unit participates as a Co-located Storage Resource, the ISO will treat the Generator as operating at, at least, its Minimum Generation Level (or full output for a Fixed Block Unit) for the purpose of scheduling the Energy Storage Resource whenever the Generator is scheduled, including during start-up and shut-down periods.

#### **4.2.1.3.3 Upper Operating Limits, Lower Operating Limits, and Response Rates**

All Bids to supply Energy and Ancillary Services must specify a  $UOL_N$  and a  $UOL_E$  for each hour. A Resource's  $UOL_E$  may not be lower than its  $UOL_N$ . Bids from Withdrawal-Eligible Generators, and Aggregations containing at least one Withdrawal-Eligible Generator, shall also specify the Generator's Lower Operating Limit for each hour.

Bids from Suppliers for Generators and Aggregations supplying Energy and Ancillary Services must specify a normal response rate and may provide up to three normal response rates provided the minimum normal response rate may be no less than one percent (1%) of the Generator's or Aggregation's Operating Capacity per minute. All Bids from Suppliers for Generators and Aggregations supplying Energy and Ancillary Services must also specify an emergency response rate which shall be equal to or greater than the maximum normal response rate of the Generator or Aggregation.

Bids from Suppliers offering Operating Reserves or Regulation Service from Demand Side Resources must specify a normal response rate and an emergency response rate provided that the emergency response rate may not be lower than the normal response rate. For Demand Side Resources the minimum acceptable response rate is one percent (1%) of the quantity of Demand Reduction the Demand Side Resource produces per minute.

#### **4.2.1.3.4 Additional Parameters for Energy Storage Resources and Aggregations Comprised only of Energy Storage Resources**

In addition to the parameters that Suppliers submit for Energy Storage Resources because they are Generators, specific parameters may apply to some Bids for Energy Storage Resources. Consistent with the ISO Procedures, Bids from Suppliers for Energy Storage Resources supplying Energy and Ancillary Services may be required to specify the Beginning Energy Level and the Energy Storage Resource's Roundtrip Efficiency, and must specify its Upper and Lower

Storage Limits. The Energy Level for an Energy Storage Resource shall be managed by the Supplier unless the Supplier elects, in its Bids, to be ISO-Managed.

The Day-Ahead Schedule for Energy Storage Resources with ISO-Managed Energy Levels will reflect the Resource's Energy Level constraints, including the Beginning Energy Level, the Upper and Lower Storage Limits, and the Resource's Roundtrip Efficiency. An Energy Storage Resource that self-manages its Energy Level is obligated to submit Bids that are consistent with its Energy Level constraints, and the Day-Ahead optimization will not honor the above-identified Energy Level constraints.

The rules in this section 4.2.1.3.4 shall also apply to Aggregations comprised entirely of Energy Storage Resources.

#### **4.2.1.4 Offers to Supply Energy from Self-Committed Fixed Generators and Aggregations**

Self-Committed Fixed Generators and Aggregations shall provide the ISO with a schedule of their expected Energy output and withdrawals (when applicable) for each hour. Self-Committed Fixed Generators and Aggregations are responsible for ensuring that any hourly changes in output are consistent with their response rates. Self-Committed Fixed Generators and Aggregations shall also submit UOL<sub>NS</sub>, UOL<sub>ES</sub> and variable Energy Bids for possible use by the ISO in the event that RTD-CAM initiates a maximum generation pickup, as described in Section 4.4.3 of this ISO Services Tariff.

A Supplier may submit a Day-Ahead Market Self-Committed Fixed Bid for a DER Aggregation to withdraw Energy if the DER Aggregation includes at least one Withdrawal-Eligible Generator. When a Self-Committed Fixed Bid for a DER Aggregation reflects both Energy supply and Energy withdrawals by a Withdrawal-Eligible Generator that is a component



of the Aggregation, the DER Aggregation's Bid shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

#### **4.2.1.5 Bids to Supply Energy in Virtual Transactions**

Customers submitting Bids to supply Energy in Virtual Transactions shall identify the Energy, in MW, available in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Customer will voluntarily make it available.

#### **4.2.1.6 Bids to Purchase Energy in Virtual Transactions**

Customers submitting bids to purchase Energy in Virtual Transactions shall identify the Energy, in MW, to be purchased in the Day-Ahead Market (for every hour of the Dispatch Day) and the price(s) at which the Customer will voluntarily purchase it.

#### **4.2.1.7 Bilateral Transactions**

Transmission Customers requesting Bilateral Transaction schedules shall identify hourly Transaction quantities (in MW) by Point of Injection and Point of Withdrawal, minimum run times associated with Firm Point-to-Point Transmission Service, if any, and shall provide other information (as described in ISO Procedures). A Generator can be the Point of Injection for a Bilateral Transaction. A Withdrawal-Eligible Generator can be the Point of Injection or the Point of Withdrawal for a Bilateral Transaction, but it cannot be both the Point of Injection and the Point of Withdrawal for the same Bilateral Transaction. An Aggregation containing one or more Withdrawal-Eligible Generators can be the Point of Injection or the Point of Withdrawal for a Bilateral Transaction, but it cannot be both the Point of Injection and the Point of Withdrawal for the same Bilateral Transaction. An Aggregation containing one or more Demand

Side Resources shall not be the Point of Injection or the Point of Withdrawal for a Bilateral Transaction.

#### **4.2.1.8 Bids to Purchase LBMP Energy in the Day-Ahead Market**

Each purchaser shall submit Bids indicating the hourly quantity of Energy, in MW, that it will purchase from the Day-Ahead Market for each hour of the following Dispatch Day. These Bids shall indicate the quantities to be purchased by Point of Withdrawal. The Bids may identify prices at which the purchaser will voluntarily enter into the Transaction.

#### **4.2.1.9 Day-Ahead Bids from Demand Reduction Providers and DSASP Providers to Supply Energy from Demand Reductions**

Demand Reduction Providers and DSASP Providers offering Energy from Demand Side Resources shall submit Bids: (i) identifying the amount of Demand Reduction, in MWs in accordance with Section 4.1.4, that is available for commitment in the Day-Ahead Market (for every hour of the dispatch day) and (ii) identifying the prices at which the Demand Reduction Provider or DSASP Provider will voluntarily enter into dispatch commitments to reduce demand; provided, however, the price at which the Demand Reduction Provider or DSASP Provider will voluntarily enter into dispatch commitments to reduce demand shall be no lower than the Monthly Net Benefit Offer Floor, as determined in accordance with this section. The Bids will identify the minimum period of time that the Demand Reduction Provider or DSASP Provider is willing to reduce demand, however the minimum period may not be less than one hour. The Bid may separately identify the Demand Reduction Provider's Curtailment Initiation Cost. Demand Reduction Bids from Demand Reduction Providers that are not accepted in the Day-Ahead Market shall expire at the close of the Day-Ahead Market.

The ISO shall perform the Net Benefits Test and post on its web site the Monthly Net Benefit Offer Floor for each month by the 15<sup>th</sup> of the preceding month in accordance with ISO Procedures. The Net Benefits Test shall establish the threshold price below which the dispatch of Energy from Demand Side Resources is not cost-effective. The Net Benefits Test shall consist of the following steps: (1) the ISO shall compile hourly supply curves for the Reference Month; (2) the ISO shall develop the average supply curve for the Study Month by updating the Reference Month supply curves for retirements and new entrants, and adjusting offers for changes in fuel prices; (3) the ISO shall apply an appropriate mathematical formula to smooth the average supply curve; and (4) the ISO shall evaluate the smoothed average supply curve to determine the Monthly Net Benefit Floor for the Study Month. The ISO shall apply the Monthly Net Benefit Offer Floor, as so calculated, to Bids submitted by Demand Response Providers for all hours in the Study Month.

The ISO shall promptly post corrections, where necessary, to the Monthly Net Benefit Offer Floor. Corrections shall only apply to errors in conducting the calculations described above and/or in posting the properly calculated Monthly Net Benefit Offer Floor. Corrections shall not include recalculations based on changes in gas prices as set forth above. The ISO shall not use any correction to the Monthly Net Benefit Offer Floor to determine revised Day-Ahead Market clearing prices for periods prior to the imposition of the correction.

#### **4.2.2 ISO Responsibility to Establish a Statewide Load Forecast**

By 8 a.m., or as soon thereafter as is reasonably possible, the ISO will develop and publish its statewide Load forecast on the OASIS. The ISO will use this forecast to perform the SCUC for the Dispatch Day.

#### **4.2.3 Security Constrained Unit Commitment (“SCUC”)**

Subject to ISO Procedures and Good Utility Practice, the ISO will develop a SCUC schedule over the Dispatch Day using a computer algorithm which simultaneously minimizes the total Bid Production Cost of: (i) supplying Energy or Demand Reductions to satisfy accepted purchasers’ Bids to buy Energy from the Day-Ahead Market; (ii) providing sufficient Ancillary Services to support Energy purchased from the Day-Ahead Market consistent with the Regulation Service Demand curve and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively of this ISO Services Tariff; (iii) committing sufficient Capacity to meet the ISO’s Load forecast and provide associated Ancillary Services; and (iv) meeting Bilateral Transaction schedules submitted Day-Ahead excluding schedules of Bilateral Transactions with Trading Hubs or Withdrawal-Eligible Generators as their POWs. The computer algorithm shall consider whether accepting Demand Reduction Bids will reduce the total Bid Production Cost.

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

The schedule will include commitment of sufficient Generators and/or Demand Side Resources/Aggregations to provide for the safe and reliable operation of the NYS Power System. SCUC will treat Behind-the-Meter Net Generation Resources, Energy Storage Resources, and Aggregations as already being committed and available to be scheduled. Pursuant to ISO Procedures, the ISO may schedule any Resource to run above its  $UOL_N$  up to the level of its  $UOL_E$ . In cases in which the sum of all Bilateral Schedules, excluding Bilateral Schedules for Transactions with Trading Hubs or Withdrawal-Eligible Generators as their POWs, and all Day-

Ahead Market purchases to serve Load within the NYCA in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO will commit Resources in addition to the Operating Reserves it normally maintains to enable it to respond to contingencies. The purpose of these additional resources is to ensure that sufficient Capacity is available to the ISO in real-time to enable it to meet its Load forecast (including associated Ancillary Services). In considering which additional Resources to schedule to meet the ISO's Load forecast, the ISO will evaluate unscheduled Imports, and will not schedule those Transactions if its evaluation determines the cost of those Transactions would effectively exceed a Bid Price cap in the hours in which the Energy provided by those Transactions is required. In addition to all Reliability Rules, the ISO shall consider the following information when developing the SCUC schedule:

- (i) Load forecasts; (ii) Ancillary Service requirements as determined by the ISO given the Regulation Service Demand Curve and Operating Reserve Demand Curves referenced above;
- (iii) Bilateral Transaction schedules excluding Bilateral Schedules for Transactions with Trading Hubs or Withdrawal-Eligible Generators as their POWs; (iv) price Bids and operating Constraints submitted for Generators or for Demand Side Resources/Aggregations; (v) price Bids for Ancillary Services; (vi) Decremental Bids and Sink Price Cap Bids for External Transactions; and (vii) Bids to purchase or sell Energy from or to the Day-Ahead Market.

External Transactions with minimum run times greater than one hour will only be scheduled at the requested Bid for the full minimum run time. External Transactions with identical Bids and minimum run times greater than one hour will not be prorated. The SCUC schedule shall list the hourly injections and withdrawals for: (a) each Customer whose Bid the ISO accepts for the Dispatch Day; and (b) each Bilateral Transaction scheduled Day-Ahead excluding Bilateral Transactions with Trading Hubs or Withdrawal-Eligible Generators as their POWs.

In the development of its SCUC schedule, the ISO may commit and de-commit Generators and Demand Side Resources/Aggregations, based upon any flexible Bids, including Minimum Generation Bids, Start-Up Bids, Curtailment Initiation Cost Bids, Energy, and Incremental Energy Bids and Decremental Bids received by the ISO provided however that: (a) the ISO shall commit zero megawatts of Energy for Demand Side Resources committed to provide Operating Reserves and Regulation Service; and (b) for Behind-the-Meter Net Generation Resources, the ISO will consider for dispatch only those segments of the Resource's Incremental Energy Bids above the forecasted Host Load and subject to the Injection Limit.

The ISO may disable the ISO-Managed Energy Level bid parameter that is ordinarily available to Energy Storage Resources if it determines that there is a significant risk that including the ISO-Managed Energy Level bid parameter in the SCUC evaluation could delay the completion and posting of the Day-Ahead Market beyond the 11:00 a.m. deadline specified in Section 4.2.5 of this Services Tariff. The ISO shall post a notice to its public website by 4:00 p.m. on the day before the Day-Ahead Market closes if it decides to disable the ISO-Managed Energy Level bid parameter. The ISO-Managed Energy Level bid parameter shall remain disabled until the ISO posts a notice that complies with the notice requirement specified above reinstating the bid parameter's availability.

When the ISO-Managed Energy Level bid parameter is disabled, Bids that utilized the ISO-Managed Energy Level functionality that were submitted prior to the issuance of the ISO's notice will be rejected. The ISO will inform affected Suppliers, so that the Suppliers will have the opportunity to resubmit their Day-Ahead Market Bids using Self-Managed Energy Levels prior to the deadlines specified in Section 4.2.1.1 of the Services Tariff. Bids that utilize ISO-

Managed Energy Levels will continue to be rejected until the ISO reinstates the ISO-Managed Energy Level bid parameter, following notice.

The ISO will select the least cost mix of Ancillary Services and Energy from Suppliers, Demand Side Resources, and Customers submitting Virtual Transactions bids. The ISO may substitute higher quality Ancillary Services (*i.e.*, shorter response time) for lower quality Ancillary Services when doing so would result in an overall least bid cost solution. For example, 10-Minute Non-Synchronized Reserve may be substituted for 30-Minute Reserve if doing so would reduce the total bid cost of providing Energy and Ancillary Services.

#### **4.2.3.1 Reliability Forecast for the Dispatch Day**

At the request of a Transmission Owner to meet the reliability of its local system, the ISO may incorporate into the ISO's Security Constrained Unit Commitment constraints specified by the Transmission Owner.

A Transmission Owner may request commitment of certain Generators for a Dispatch Day if it determines that certain Generators are needed to meet the reliability of its local system. Such request shall be made before the Day-Ahead Market for that Dispatch Day has closed if the Transmission Owner knows of the need to commit certain Generators before the Day-Ahead Market close. The ISO may commit one or more Generator(s) in the Day-Ahead Market for a Dispatch Day if it determines that the Generator(s) are needed to meet NYCA reliability requirements.

A Transmission Owner may request commitment of additional Generators and/or Aggregations for a Dispatch Day following the close of the Day-Ahead Market to meet changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the

Dispatch Day to be inadequate to ensure the reliability of its local system. The ISO will use SRE to fulfill a Transmission Owner's request for additional Resources.

All Generator and/or Aggregation commitments made in the Day-Ahead Market pursuant to this Section 4.2.3.1 shall be posted on the ISO website following the close of the Day-Ahead Market, in accordance with ISO procedures. In addition, the ISO shall post on its website a non-binding, advisory notification of a request, or any modifications thereto, made pursuant to this Section 4.2.3.1 in the Day-Ahead Market by a Transmission Owner to commit a Generator and/or Aggregation that is located within a Constrained Area, as defined in Attachment H of this Services Tariff. The advisory notification shall be provided upon receipt of the request and in accordance with ISO procedures. The postings described here may be included with the operator-initiated commitment report that the ISO posts in accordance with Section 4.1.3.4 of this Services Tariff.

After the Day-Ahead schedule is published, the ISO shall evaluate any events, including, but not limited to, the loss of significant Generators, Aggregations, or transmission facilities that may cause the Day-Ahead schedules to be inadequate to meet the Load or reliability requirements for the Dispatch Day.

Prior to the Capability Period beginning May 1, 2025, in order to meet Load or reliability requirements in response to such changed conditions the ISO may: (i) commit additional Resources, beyond those committed Day-Ahead, using a SRE and considering (a) Bids submitted to the ISO that were not previously accepted but were designated by the bidder as continuing to be available; or (b) new Bids from all Suppliers, including neighboring systems; or (ii) take the following actions: (a) after providing notice, require all Resources to run above their UOL<sub>NS</sub>, up to the level of their UOL<sub>ES</sub> (pursuant to ISO Procedures) and/or raise the UOL<sub>NS</sub> of Capacity



Limited Resources and Energy Limited Resources to their UOL<sub>E</sub> levels, or (b) cancel or reschedule transmission facility maintenance outages when possible. Actions taken by the ISO in performing supplemental commitments will not change any financial commitments that resulted from the Day-Ahead Market.

Beginning with the Capability Period beginning May 1, 2025, in order to meet Load or reliability requirements in response to such changed conditions the ISO may: (i) commit additional Resources, beyond those committed Day-Ahead, using a SRE and considering (a) Bids submitted to the ISO that were not previously accepted but were designated by the bidder as continuing to be available; or (b) new Bids from all Suppliers, including neighboring systems; or (ii) take the following actions: (a) after providing notice, require all Resources to run above their UOL<sub>NS</sub>, up to the level of their UOL<sub>ES</sub> (pursuant to ISO Procedures) and/or raise the UOL<sub>NS</sub> of Energy Limited Resources to their UOL<sub>E</sub> levels, or (b) cancel or reschedule transmission facility maintenance outages when possible. Actions taken by the ISO in performing supplemental commitments will not change any financial commitments that resulted from the Day-Ahead Market.

#### **4.2.4 Reliability Forecast for the Six Days Following the Dispatch Day**

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the ISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven (7)-day period that begins with the next Dispatch Day. The ISO will perform a Supplemental Resource Evaluation (“SRE”) for days two (2) through seven (7) of the commitment cycle. If it is determined that a long start-up time Generator (*i.e.*, a Generator that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) is needed for reliability, the ISO shall accept

a Bid from the Generator and the Generator will begin its start-up sequence. During each day of the start-up sequence, the ISO will perform an SRE to determine if long start-up time Generators will still be needed as previously forecasted. If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start-up sequence.

The ISO will commit to long start-up time Generators to preserve reliability. However, the ISO will not commit resources with long start-up times to reduce the cost of meeting Loads that it expects to occur in days following the next Dispatch Day.

A Supplier that bids on behalf of a long start-up time Generator, including one that is committed and whose start is subsequently aborted by the ISO as described in this Section 4.2.4, may be eligible for a Bid Production Cost Guarantee pursuant to the provisions of Section 4.6.6 and Attachment C of this ISO Services Tariff. The costs of such a Bid Production Cost guarantee will be recovered by the ISO under Rate Schedule 1 of the ISO OATT.

The ISO shall perform the SRE as follows: (1) The ISO shall develop a forecast of daily system peak Load for days two (2) through seven (7) in this seven (7)-day period and add the appropriate reserve margin; (2) the ISO shall then forecast its available Generators for the day in question by summing the Operating Capacity for all Generators currently in operation that are available for the commitment cycle, the Operating Capacity of all other Generators capable of starting on subsequent days to be available on the day in question, and an estimate of the net Imports from External Bilateral Transactions; (3) if the forecasted peak Load plus reserves exceeds the ISO's forecast of available Generators for the day in question, then the ISO shall commit additional Generators capable of starting prior to the day in question (*e.g.*, start-up period of two (2) days when looking at day three (3)) to assure system reliability; (4) in choosing

among Generators with comparable start-up periods, the ISO shall schedule Generators to minimize Minimum Generation Bid and Start-Up Bid costs of meeting forecasted peak Load plus Ancillary Services consistent with the Reliability Rules; (5) in determining the appropriate reserve margin for days two (2) through seven (7), the ISO will supplement the normal reserve requirements to allow for forced outages of the short start-up period units (*e.g.*, gas turbines) assumed to be operating at maximum output in the unit commitment analysis for reliability.

Energy Bids are binding for day one (1) only for units in operation or with start-up periods less than one (1) day. Minimum Generation Bids for Generators with start-up periods greater than one (1) day will be binding only for units that are committed by the ISO and only for the first day in which those units could produce Energy given their start-up periods. For example, Minimum Generation Bids for a Generator with a start-up period of two (2) days would be binding only for day three (3) because, if that unit begins to start up at any time during day one (1), it would begin to produce Energy forty-eight (48) hours later on day three (3). Similarly, the Minimum Generation Bids for a Generator with a start-up period of three (3) days would be binding only for day four (4).

#### **4.2.5 Post the Day-Ahead Schedule**

By 11 a.m. on the day prior to the Dispatch Day, the ISO shall close the Day-Ahead scheduling process and post on the Bid/Post System the Day-Ahead 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 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 statewide aggregate resources (Day-Ahead Energy schedules and total operating capability forecast), Day-Ahead scheduled Load, forecast Load for each Load Zone,

and the Day-Ahead LBMP prices (including the Congestion Component and the Marginal Losses Component) for each Load Zone in each hour of the upcoming Dispatch Day. The ISO shall conduct the Day-Ahead Settlement based upon the Day-Ahead schedule determined in accordance with this section and Attachment B to this Services Tariff. The ISO will provide the Transmission Owner with the Load forecast (for seven (7) days) as well as the ISO security evaluation data to enable local area reliability to be assessed.

#### **4.2.6 Day-Ahead LBMP Market Settlements**

The ISO shall calculate the Day-Ahead LBMPs for each Load Zone and at each Generator bus and Demand Reduction Bus/Transmission Node as described in Attachment B. Each Supplier that bids a Generator or Aggregation into the ISO Day-Ahead Market and is scheduled in the SCUC to sell or purchase Energy in the Day-Ahead Market will be settled at the product of: (a) the Day-Ahead hourly LBMP at the applicable Generator bus or Transmission Node; and (b) the hourly Energy schedule. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to sell Energy into the Day-Ahead LBMP Market will be settled at the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. For each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in SCUC to provide Energy from the Demand Reduction, the LSE providing Energy service to the Demand Side Resource that accounts for the Demand Reduction shall be settled at the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction Bus; and (b) the hourly demand reduction scheduled Day-Ahead (in MW). In addition, each Demand Reduction Provider that bids a Demand Reduction into the Day-Ahead Market and is scheduled in the SCUC to provide Energy through Demand Reduction shall receive a Demand Reduction Incentive Payment from

the ISO equal to the product of: (a) the Day-Ahead hourly LBMP at the Demand Reduction bus; and (b) the lesser of the verified actual hourly Demand Reduction or the scheduled hourly Demand Reduction (in MW). Each Customer that bids into the Day-Ahead Market, including each Customer that submits a Bid for a Virtual Transaction, and has a schedule accepted by the ISO to purchase Energy in the Day-Ahead Market will pay the product of: (a) the Day-Ahead hourly Zonal LBMP at each Point of Withdrawal; and (b) the scheduled Energy at each Point of Withdrawal. Each Supplier that bids an External Transaction into the Day-Ahead LBMP Market and is scheduled in the SCUC to buy Energy from the Day-Ahead LBMP Market will pay the product of (a) the Day-Ahead LBMP at the applicable Proxy Generator Bus and (b) the External Transaction schedule. Each Customer that submits a Virtual Transaction bid into the ISO Day-Ahead Market and has a schedule accepted by the ISO to sell Energy in a Load Zone in the Day-Ahead Market will receive a payment equal to the product of (a) the Day-Ahead hourly zonal LBMP for that Load Zone; and (b) the hourly scheduled Energy for the Customer in that Load Zone. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POI and has its schedule accepted by the ISO will pay the product of: (a) the Day-Ahead hourly zonal LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW. Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Day-Ahead Market with a Trading Hub as its POW and has its schedule accepted by the ISO will be paid the product of: (a) the Day-Ahead hourly zonal LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

The ISO shall publish the Day-Ahead Settlement Load Zone LBMPs for each hour in the Dispatch Day.

## **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 Behind-the-Meter Net Generation Resources, Energy Storage Resources, and Aggregations 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.

An Energy Storage Resource shall indicate in its Real-Time Bids whether its Energy Level will be ISO- or Self-Managed. An Energy Storage Resource that elects to Self-Manage its Energy Level shall be responsible for managing its Energy Level through its Bids. An Energy Storage Resource, including an Energy Storage Resource that received a Day-Ahead Schedule, may change its Energy Level Management election for each operating hour in the Real-Time Market day.

A Supplier's Real-Time Market Self-Committed Flexible Bid for a DER Aggregation may include Energy withdrawals if the DER Aggregation includes at least one Withdrawal-Eligible Generator. A Supplier's Real-Time Market Bids for a DER Aggregation to withdraw Energy and to supply Energy shall be submitted in a single, continuous bid curve representing the Capacity, in MW, available. When the Energy Bid for the DER Aggregation includes both Energy supply and Energy withdrawal by a Withdrawal-Eligible Generator that is a component of the Aggregation, each point of the DER Aggregation's Bid curve shall reflect the net offer, such that any Energy withdrawals reduce the Energy the DER Aggregation is capable of supplying.

A Supplier may submit a Real-Time Market Self-Committed Fixed Bid for a DER Aggregation to withdraw Energy if the DER Aggregation includes at least one Withdrawal-Eligible Generator. When a Self-Committed Fixed Bid for a DER Aggregation reflects both Energy supply and Energy withdrawals by a Withdrawal-Eligible Generator that is a component of the Aggregation, the DER Aggregation's Bid shall reflect the net offer, such that any Energy

withdrawals reduce the Energy the DER Aggregation is capable of supplying. However, if the Monthly Net Benefit Threshold price is less than the LBMP, Demand Side Resources shall not be permitted to net Energy withdrawals of Withdrawal-Eligible Generators in the DER Aggregation.

Co-located Storage Resources can each offer all of their available capability into the Real-Time Market. RTC will account for the CSR Scheduling Limits in the schedules it determines for CSR Generators.

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

Intermittent Power Resources and Aggregations that depend solely on wind or solar energy 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 or withdraw Energy, and to supply 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, for portions of the Capacity of Resources that were scheduled in the Day-Ahead Market, and/or Start-Up 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 or Start-Up Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids or Start-Up Bids where appropriate, if not otherwise prohibited pursuant to other provisions of the tariff.



The ISO will use a Fast-Start Resource's single point Start-Up Bid if one is submitted (or the mitigated Bid, where appropriate). If a Fast-Start Resource does not submit a single point Start-Up Bid in real-time, the ISO will use the point on the Fast-Start Resource's multi-point Start-Up Bid curve (or its mitigated multi-point Start-Up Bid curve, where appropriate) that corresponds to the shortest specified down time.

Minimum Generation Bids or Regulation Service Bids for any hour in which Resources received a Day-Ahead Energy schedule or a Regulation Service schedule, as appropriate, may not exceed the Minimum Generation Bids or Regulation Service Bids, as appropriate, submitted for those Resources in the Day-Ahead Market. Provided however, a Fast-Start Resource that receives a Day-Ahead schedule may submit Minimum Generation Bids using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the dollar component of the Bids submitted in the Day-Ahead Market, or the dollar component of the mitigated Day-Ahead Bids where appropriate, if not otherwise prohibited pursuant to other provisions of the tariff.

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 or Aggregations (except Aggregations comprised of only Intermittent Power Resources) that did not receive a Day-Ahead schedule for

a given hour may offer their Generators or Aggregations, 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 or Aggregation that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator or Aggregation for the Real-Time Market for that hour provided, however, that Generators or Aggregations 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 or Aggregations 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.

Co-located Storage Resources must each submit a CSR injection Scheduling Limit and a CSR withdrawal Scheduling Limit for each hour of the Real-Time Market to indicate the expected capability of the relevant facilities. Resources that participate as CSR shall not submit Real-Time Market Bids that would self-commit either of the Generators, or both of the Generators together, to inject or to withdraw a quantity of Energy that exceeds an applicable CSR Scheduling Limit.

An Energy Storage Resource that, together with a Generator that submits a Minimum Generation Bid or is a Fixed Block Unit, participates as Co-located Storage Resources shall not submit Day-Ahead or Real-Time Market Bids that would self-commit the Energy Storage Resource to inject Energy such that the Generator's Minimum Generation (or full output for a Fixed Block Unit), plus the Energy Storage Resource's self schedule, exceeds the CSR injection Scheduling Limit.

When a Generator that submits a Minimum Generation Bid or that is a Fixed Block Unit participates as a Co-located Storage Resource, the ISO will treat the Generator as operating at its Minimum Generation Level (or full output for a Fixed Block Unit) for the purpose of scheduling the Energy Storage Resource whenever the Generator is scheduled, including during start-up and shut-down periods. Generators and Aggregations with a real time physical operating problem that makes it impossible for them: (a) to operate in the bidding mode in which the Generator or Aggregation was scheduled Day-Ahead; or (b) to provide all of the Energy or Ancillary Services offered in their Bids, or (c) to achieve or comply with applicable operating parameters or other requirements, shall notify the ISO. 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 ISO.

Generators and Aggregations 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 minimum run time of at least 15 minutes, but not longer than one hour; 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.

RTC<sub>15</sub> 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 RTC<sub>15</sub> 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 dispatch 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 dispatch 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<sub>30</sub>, RTC<sub>45</sub>, and RTC<sub>00</sub> will begin executing at fifteen minutes before their designated posting times (for example, RTC<sub>30</sub> 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/Aggregations, 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. In each interval, Real-Time Dispatch will review the Beginning Energy Level of each Energy Storage Resource and of each Aggregation comprised only of Energy Storage Resources.

Real-Time Dispatch will attempt to prevent dispatching a Self-Managed Energy Storage Resource or Aggregation composed only of Energy Storage Resources in a manner that would be infeasible based on its Beginning Energy Level. Instead, Real-Time dispatch will consider an Energy Storage Resource's or Aggregation Composed of only Energy Storage Resources' Beginning Energy Level in developing a schedule for the binding interval. An Energy Storage

Resource's Beginning Energy Level will be used to ensure that Operating Reserves scheduled from the Resource can be sustained for one hour if the Operating Reserves are converted to Energy. The Real-Time Dispatch will account for the CSR Scheduling Limits in the schedules and dispatch instructions it issues to CSR Generators.

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, Transmission Node, 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 capable of starting and meeting Minimum Generation Levels 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 4.4.2.5, 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<sub>NS</sub>, up to the level of their UOL<sub>ES</sub> 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.

Resources that are eligible to provide Operating Reserves and that are available to the ISO for dispatch in real-time are required to be able to meet the energy sustainability requirements set forth in applicable NERC, NPCC and/or NYSRC reliability requirements. When the ISO enters a reserve pickup RTD-CAM mode it will determine sustainable Energy schedules for Energy Storage Resources that are eligible to provide Operating Reserves and that are available to the ISO for dispatch based on their telemetered state of charge.

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 ordinarily have this discretion in large events, except that it may determine Energy schedules that satisfy Operating Reserve energy sustainability requirements for Energy Storage Resources. 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 and Aggregations 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 and Aggregations 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, Transmission Node, 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									
OH_GEN_PROXY	24063						✓		
OH_LOAD_PROXY	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.

## **5.12 Requirements Applicable to Installed Capacity Suppliers**

### **5.12.1 Installed Capacity Supplier Qualification Requirements**

In order to qualify as an Installed Capacity Supplier or be part of an Aggregation that is qualified as an Installed Capacity Supplier, Generators, controllable transmission projects electrically located in the NYCA, transmission projects with associated incremental transfer capability, and Distributed Energy Resources that have the ability to inject Energy must have obtained Capacity Resource Interconnection Service (“CRIS”) pursuant to the applicable provisions of Attachments S or HH to the ISO OATT and have entered service; controllable transmission projects must also have obtained Unforced Capacity Deliverability Rights and transmission projects with associated incremental transfer capability must also have obtained External-to-ROS Deliverability Rights. Generators that participate in the market as Co-located Storage Resources must each, independently, obtain CRIS in order to qualify as Installed Capacity Suppliers. Even if a Resource has otherwise satisfied the requirements to participate in the ISO’s Installed Capacity market, a Resource in Inactive Reserves, an ICAP Ineligible Forced Outage, a Mothball Outage, or that is Retired is ineligible to participate in the ISO’s Installed Capacity market. A Resource that elects to participate in the ICAP Market, and is within a defined electrical boundary, electrically interconnected with, and routinely serves a Host Load (which Host Load does not consist solely of Station Power) at a single PTID may only participate in the Installed Capacity market as a Behind-the-Meter Net Generation Resource. In order to participate as part of an Aggregation or as an Energy Storage Resource, such a resource may not participate with the Behind-the-Meter Net Generation configuration. Generators that participate in the market as Co-located Storage Resources must each, independently, comply with all applicable market rules contained in this Services Tariff Section 5.12 as an Energy

Storage Resource, Intermittent Power Resource, Limited Control Run-of-River Hydro Resource, Fast-Start Resource, or other permitted type of Generator, consistent with its resource type.

In addition, to qualify as an Installed Capacity Supplier in the NYCA, Energy Limited Resources, Generators, Installed Capacity Marketers, Intermittent Power Resources, Behind-the-Meter Net Generation Resources, Limited Control Run-of-River Hydro Resources and System Resources rated 1 MW or greater, other than External System Resources and Control Area System Resources which have agreed to certain Curtailment conditions as set forth in the third to last paragraph of Section 5.12.1 below, Responsible Interface Parties, existing municipally-owned generation, Energy Limited Resources, and Intermittent Power Resources, to the extent those entities are subject to the requirements of Section 5.12.11 of this Tariff, Aggregations with a capacity rating of 0.1 MW or greater, and Energy Storage Resources with a nameplate capacity rating that allows a minimum injection to the NYS Transmission System or distribution system of 0.1 MW or greater shall:

- 5.12.1.1        provide information reasonably requested by the ISO including the name and location of Resources, and System Resources;
- 5.12.1.2        in accordance with the ISO Procedures, perform DMNC or DMGC tests and submit the results to the ISO, or provide to the ISO appropriate historical production data;
- 5.12.1.3        abide by the ISO Generator maintenance coordination procedures;
- 5.12.1.4        provide the expected return date from any outages (including partial outages) to the ISO;
- 5.12.1.5        in accordance with the ISO Procedures,

- 5.12.1.5.1 provide documentation demonstrating that it will not use the same Unforced Capacity for more than one (1) buyer at the same time, and
- 5.12.1.5.2 in the event that the Installed Capacity Supplier supplies more Unforced Capacity than it is qualified to supply in any specific month (*i.e.*, is short on Capacity), documentation that it has procured sufficient Unforced Capacity to cover this shortfall.
- 5.12.1.6 except for Installed Capacity Marketers and Intermittent Power Resources that depend upon wind or solar as their fuel or Aggregations that are comprised of Intermittent Power Resources that depend on the same type of fuel, with that fuel being wind or solar, Bid into the Day-Ahead Market, unless the Energy Limited Resource, Generator, Aggregation, Limited Control Run-of-River Hydro Resource or System Resource is unable to do so due to an outage as defined in the ISO Procedures or due to temperature related de-ratings. Resources may also enter into the MIS an upper operating limit that would define the operating limit under normal system conditions. The circumstances under which the ISO will direct a Resource to exceed its upper operating limit are described in the ISO Procedures;
- 5.12.1.6.1 Co-located Storage Resources must each submit a CSR injection Scheduling Limit and a CSR withdrawal Scheduling Limit for each hour of the Day-Ahead Market consistent with Section 5.12.7.1 below;
- 5.12.1.7 provide Operating Data in accordance with Section 5.12.5 of this Tariff;
- 5.12.1.8 provide to the ISO regarding any proposed transfers of deliverability rights to be carried out pursuant to Sections 40.18.3 – 40.18.5 of Attachment HH to the

ISO OATT: (i) if a request to transfer CRIS at a different location, notice of submission of an Interconnection Request or CRIS-Only Request to transfer CRIS, and (ii) if it is a request to transfer CRIS at the same location, notice of submission of the request.

5.12.1.9           comply with the ISO Procedures;

5.12.1.10          when the ISO issues a Supplemental Resource Evaluation request (an SRE), NYCA Resources must Bid into the in-day market unless (and only to the extent) the entity has a bid pending in the Real-Time Market when the SRE request is made or is unable to bid in response to the SRE request due to an outage as defined in the ISO Procedures, or due to other operational issues, or due to temperature related deratings.

If an External Installed Capacity Supplier is a Generator, or if an External Generator is associated with an Unforced Capacity sale using UDRs or EDRs, then except to the extent such a Generator is unable to Bid in response to the SRE request due to an outage as defined in the ISO Procedures, due to physical operating limitations affecting the Generator, or due to other operational issues that are outside the Installed Capacity Supplier's control, as determined by the ISO, it must take all of the following actions for each hour of an SRE request (a) Bid an Import to the NYCA in a MW quantity equal to the lesser of (i) the ICAP equivalent of the UCAP sold, or (ii) the maximum MW the Generator is able to produce, at the approved Proxy Generator Bus, at the applicable minimum Bid Price, and (b) ensure that the External Generator is operating and is available to provide all of the MW that were Bid to be imported into the NYCA, up to the



ICAP equivalent of the UCAP sold, for the entire duration of the SRE request, and (c) obtain all reservations and transmission service necessary to deliver all of the MW that were Bid to be imported into the NYCA or to a Locality from the Generator, up to the ICAP equivalent of the UCAP sold from the External Generator, at the approved Proxy Generator Bus.

If the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, is not able to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Generator or EDR to the NYCA, or if a UDR to the Locality, for every hour of an SRE request then, except to the extent already addressed by a declared outage, the Generator shall provide to the ISO an explanation of the reasons for its failure or inability to perform, including evidence demonstrating any physical operating limitations or other operational issues that prevented the Generator from Importing the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Generator to the NYCA. To the extent the ISO determines that the information and supporting evidence provided demonstrates that the failure or inability to deliver occurred for reasons outside the control of the External Installed Capacity Supplier or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, then the deficiency charge set forth in Section 5.12.12.2 below that applies solely to violations of this Section 5.12.1.10, shall not be assessed.

If an External Installed Capacity Supplier is a Control Area System Resource then, except to the extent it is unable to Bid in response to the SRE

request due to an outage as defined in the ISO Procedures or due to operational issues that are outside the Installed Capacity Supplier's control, it must take all of the following actions for each hour of an SRE request (x) Bid an Import in a MW quantity equal to the ICAP equivalent of the UCAP sold, at the approved Proxy Generator Bus, at the applicable minimum Bid Price, and (y) obtain all reservations and transmission service necessary to deliver the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA at the approved Proxy Generator Bus.

If the External Installed Capacity Supplier that is a Control Area System Resource is not able to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA for every hour of an SRE request then, except to the extent already addressed by a declared outage, the External Installed Capacity Supplier shall provide to the ISO an explanation of the reasons for its failure or inability to perform, including evidence demonstrating any operational issues that prevented the External ICAP Supplier from Importing the quantity of Energy equal to the ICAP equivalent of the UCAP sold from the Control Area System Resource to the NYCA. To the extent the ISO determines that the information and supporting evidence provided demonstrates that the failure or inability to deliver occurred for reasons outside the External Installed Capacity Supplier's control, then the deficiency charge set forth in Section 5.12.12.2 below that applies solely to violations of this Section 5.12.1.10, shall not be assessed. A Control Area System Resource must demonstrate that transmission outage(s) prevented delivery of all

available Resources in order for the ISO to determine that the Control Area System Resource's failure to Import the quantity of Energy equal to the ICAP equivalent of the UCAP sold occurred for a reason that was outside the External Installed Capacity Supplier's control.

When an External Installed Capacity Supplier that is responding to an ISO SRE request Bids its Import at a Non-Competitive Proxy Generator Bus, its obligation to Bid an Import at the applicable minimum Bid Price includes the obligation to ensure that neither the External Installed Capacity Supplier nor any of its Affiliates are offering other Imports at an equivalent or greater economic priority at the Non-Competitive Proxy Generator Bus.

5.12.1.11 Installed Capacity Suppliers located East of Central-East shall Bid in the Day-Ahead and Real-Time Markets all Capacity available for supplying 10-Minute Non-Synchronized Reserve (unless the Generator or Aggregation is unable to meet its commitment because of an outage as defined in the ISO Procedures), except for the Resources described in Subsections 5.12.1.11.1, 5.12.1.11.2 and 5.12.1.11.3 below;

5.12.1.11.1 Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchasers do not control the operation of the supply source but would be responsible for penalties for being off-schedule, with the exception of Generators under must-take PURPA contracts executed and effective on or before November 18, 1999, who have not provided telemetering to their local TO and

historically have not been eligible to participate in the NYPP market, which will continue to be treated as TO Load modifiers under the ISO-administered markets;

5.12.1.11.2 Existing topping turbine Generators and extraction turbine Generators producing Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) in operation on or before November 18, 1999 and/or Generators used in replacing or repowering steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 533 MW of such units; and

5.12.1.11.3 Resources that have demonstrated to the ISO that they are subject to environmental, contractual, ISO Tariff, or other legal or physical requirements that would otherwise preclude them from providing 10-Minute NSR;

5.12.1.12 A Resource that was determined by the ISO to be qualified as a Behind-the-Meter Net Generation Resource and for which Net Unforced Capacity was calculated by the ISO for a Capability Year can annually, by written notice received by the NYISO prior to August 1, elect not to participate in the ISO Administered Markets as a Behind-the-Meter Net Generation Resource. Such notice shall be in accordance with ISO Procedures. A Resource that makes such an election cannot participate as a Behind-the-Meter Net Generation Resource for the entire Capability Year for which it made the election, but can, however, prior to August 1 of any subsequent Capability Year, provide all required information in order to seek to re-qualify as a Behind-the-Meter Net Generation Resource.

5.12.1.13 An Energy Storage Resource, or Aggregations comprised entirely of Energy Storage Resources, may de-rate its maximum capability in order to meet

the applicable Services Tariff Section 5.12.14 run-time requirement. ESRs electing to de-rate their maximum capability shall perform a DMNC test at an output level consistent with its de-rated capability in accordance with Services Tariff Section 5.12.14 and ISO Procedures (*see*, Installed Capacity Manual § 4).

5.12.1.14 Energy Limited Resources, Energy Storage Resources, Aggregations comprised entirely of Energy Storage Resources, DER Aggregations, and Aggregations that are Energy Limited Resources must elect an Energy Duration Limitation that corresponds to a Duration Adjustment Factor, as described in Section 5.12.14 below, and validate the Energy Duration Limitation pursuant to Section 5.12.1.2 above. An Installed Capacity Supplier may elect any Energy Duration Limitation that it can demonstrate pursuant to Section 5.12.1.2.

5.12.1.15 Starting with the Capability Year beginning May 1, 2025, Installed Capacity Suppliers with dual fuel capability that elect to demonstrate firm fuel capability via the use of their alternative fuel will be required to demonstrate operability prior to December 1 of the applicable Capability Period, as that term is defined in, and in accordance with Section 5.12.8 of this Services Tariff and the ISO Procedures.

The ISO shall inform each potential Installed Capacity Supplier that the ISO must receive and approve DMNC or DMGC data, as applicable of its approved DMNC or DMGC ratings for the Summer Capability Period and the Winter Capability Period in accordance with the ISO Procedures.

Requirements to qualify as Installed Capacity Suppliers for External System Resources and Control Area System Resources located in External Control Areas that have agreed not to

Curtail the Energy associated with such Installed Capacity or to afford it the same Curtailment priority that it affords its own Control Area Load shall be established in the ISO Procedures.

External Installed Capacity not associated with UDRs, including capacity associated with External CRIS Rights, EDRs, Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual, the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT, Import Rights, and External System Resources, is only qualified to satisfy a NYCA Minimum Unforced Capacity Requirement and is not eligible to satisfy a Locational Minimum Installed Capacity Requirement.

Not later than 30 days prior to each ICAP Spot Market Auction, each Market Participant that may make offers to sell Unforced Capacity in such auction shall submit information to the ISO, in accordance with ISO Procedures and in the format specified by the ISO that identifies each Affiliated Entity, as that term is defined in Section 23.2.1 of Attachment H of the Services Tariff, of the Market Party or with which the Market Party is an Affiliated Entity. The names of entities that are Affiliated Entities shall not be treated as Confidential Information, but such treatment may be requested for the existence of an Affiliated Entity relationship. The information submitted to the ISO shall identify the nature of the Affiliated Entity relationship by the applicable category specified in the definition of “Affiliated Entity” in Section 23.2.1 of Attachment H of the Services Tariff.

#### **5.12.2 Additional Provisions Applicable to External Installed Capacity Suppliers**

Terms in this Section 5.12.2 not defined in the Services Tariff have the meaning set forth in the OATT.

#### **5.12.2.1 Provisions Addressing the Applicable External Control Area**

External Generators, External System Resources, and Control Area System Resources qualify as Installed Capacity Suppliers if they demonstrate to the satisfaction of the NYISO that the Installed Capacity Equivalent of their Unforced Capacity is deliverable to the NYCA; in the case of an entity using a UDR to meet a Locational Minimum Installed Capacity Requirement, to the NYCA interface associated with that UDR transmission facility and will not be recalled or curtailed by an External Control Area to satisfy its own Control Area Loads; in the case of an EDR, to the NYCA interface over which it creates increased transfer capability; and in the case of Control Area System Resources, if they demonstrate that the External Control Area will afford the NYCA Load the same curtailment priority that they afford their own Control Area Native Load Customers. The amount of Unforced Capacity that may be supplied by such entities qualifying pursuant to the alternative criteria may be reduced by the ISO, pursuant to ISO Procedures, to reflect the possibility of curtailment. External Installed Capacity associated with Import Rights, EDRs or UDRs is subject to the same deliverability requirements applied to Internal Installed Capacity Suppliers associated with UDRs.

#### **5.12.2.2 Additional Provisions Addressing Internal Deliverability and Import Rights**

In addition to the provisions contained in Section 5.12.2.1 above, External Installed Capacity not associated with UDRs, EDRs, or External CRIS Rights will be subject to the deliverability test in Section 40.13.8 and 40.13.9 of Attachment HH to the ISO OATT. The deliverability of External Installed Capacity not associated with UDRs, EDRs, or External CRIS Rights will be evaluated annually as a part of the process that sets import rights for the upcoming Capability Year, to determine the amount of External Installed Capacity that can be imported to the New York Control Area across any individual External Interface and across all of those

External Interfaces, taken together. The External Installed Capacity deliverability test will be performed using the ISO's forecast, for the upcoming Capability Year, of New York Control Area CRIS resources, transmission facilities, and load. Under this process (i) Grandfathered External Installed Capacity Agreements listed in Attachment E of the ISO Installed Capacity Manual, and (ii) the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation in Table 3 of Attachment L to the ISO OATT, will be considered deliverable within the Rest of State. Additionally, 1090 MW of imports made over the Quebec (via Chateauguay) Interface will be considered to be deliverable until the end of the 2010 Summer Capability Period.

The import limit set for External Installed Capacity not associated with UDRs, EDRs or External CRIS Rights will be set no higher than the amount of imports deliverable into Rest of State that (i) would not increase the LOLE as determined in the upcoming Capability Year IRM consistent with Section 2.7 of the NYISO Installed Capacity Manual, "Limitations on Unforced Capacity Flow in External Control Areas," (ii) are deliverable within the Rest of State Capacity Region when evaluated with the New York Control Area CRIS resources (including EDRs and UDRs) and External CRIS Rights forecast for the upcoming Capability Year, and (iii) would not degrade the transfer capability of any Other Interface by more than the threshold identified in Section 40.13.9 of Attachment HH to the ISO OATT. Import limits set for External Installed Capacity will reflect the modeling of awarded External CRIS rights, but the awarded External CRIS rights will not be adjusted as part of import limit-setting process. Procedures for qualifying selling, and delivery of External Installed Capacity are detailed in the Installed Capacity Manual.



Until the grandfathered import rights over the Quebec (via Chateauguay) Interface expire at the end of the 2010 Summer Capability Period, the 1090 MW of grandfathered import rights will be made available on a first-come, first-served basis pursuant to ISO Procedures. Any of the grandfathered import rights over the Quebec (via Chateauguay) Interface not utilized for a Capability Period will be made available to other external resources for that Capability Period, pursuant to ISO Procedures, to the extent the unutilized amount is determined to be deliverable.

Additionally, any of the Existing Transmission Capacity for Native Load listed for New York State Electric & Gas Corporation not utilized by New York State Electric & Gas Corporation for a Capability Period will be made available to other external resources for that Capability Period, pursuant to ISO procedures, to the extent the unutilized amount is determined to be deliverable within the Rest of State Capacity Region.

LSEs with External Installed Capacity as of the effective date of this Tariff will be entitled to designate External Installed Capacity at the same NYCA Interface with another Control Area, in the same amounts in effect on the effective date of this Tariff. To the extent such External Installed Capacity corresponds to Existing Transmission Capacity for Native Load as reflected in Table 3 of Attachment L to the ISO OATT, these External Installed Capacity rights will continue without term and shall be allocated to the LSE's retail access customers in accordance with the LSE's retail access program on file with the PSC and subject to any necessary filings with the Commission. External Installed Capacity rights existing as of September 17, 1999 that do not correspond to Table 3 of Attachment L to the ISO OATT shall survive for the term of the relevant External Installed Capacity contract or until the relevant External Generator is retired.

### **5.12.2.3 One-Time Conversion of Grandfathered Quebec (via Chateauguay) Interface Rights.**

An entity can request to convert a specified number of MW, up to 1090 MW over the Quebec External Interface (via Chateauguay), into External CRIS Rights by making either a Contract Commitment or Non-Contract Commitment that satisfies the requirements of Section 40.13.11.1 of Attachment HH to the ISO OATT. The converted number of MW will not be subject to further evaluation for deliverability within a Cluster Study Deliverability Study under Attachment HH to the ISO OATT, as long as the External CRIS Rights are in effect.

5.12.2.3.1 The External CRIS Rights awarded under this conversion process will first become effective for the 2010-2011 Winter Capability Period.

5.12.2.3.2 Requests to convert these grandfathered rights must be received by the NYISO on or before 5:00 pm Eastern Time on February 1, 2010, with the following information: (a) a statement that the entity is electing to convert by satisfying the requirements of a Contract Commitment or a Non-Contract Commitment in accordance with Section 40.13.11.1 of Attachment HH to the ISO OATT; (b) the length of the commitment in years; (c) for the Summer Capability Period, the requested number of MW; (d) for the Winter Capability Period, the Specified Winter Months, if any, and the requested number of MW; and (e) a minimum number of MW the entity will accept if granted (“Specified Minimum”) for the Summer Capability Period and for all Specified Winter Months, if any.

5.12.2.3.3 An entity cannot submit one or more requests to convert in the aggregate more than 1090 MW in any single month.

5.12.2.3.4 If requests to convert that satisfy all other requirements stated herein are equal to or less than the 1090 MW limit, all requesting entities will be awarded

the requested number of MW of External CRIS Rights. If conversion requests exceed the 1090 MW limit, the NYISO will prorate the allocation based on the weighted average of the requested MW times the length of the contract/commitment (*i.e.*, number of Summer Capability Periods) in accordance with the following formula:

$$\begin{aligned} & \text{Rights allocated to entity } i \\ &= 1090 \\ & \quad * (MW_i * \text{contract/commitment length}_i) \\ & \quad / \sum_j (MW_j * \text{contract/commitment length}_j) \end{aligned}$$

$j = 1, \dots, \#$  entities requesting import rights

In the formula, contract/commitment length means the lesser of the requested contract/commitment length and twenty (20) years. The NYISO will perform separate calculations for the Summer and Winter Capability Periods. The NYISO will determine whether the prorated allocated number of MW for any requesting entity is less than the entity's Specified Minimum. If any allocation is less, the NYISO will remove such request(s) and recalculate the prorated allocations among the remaining requesting entities using the above formula. This process will continue until the prorated allocation meets or exceeds the specified minimum for all remaining requests.

- 5.12.2.3.5 Any portion of the previously grandfathered 1090 MW not converted through this process will no longer be grandfathered from deliverability. Previously grandfathered rights converted to External CRIS Rights but then terminated will no longer be grandfathered from deliverability.

#### **5.12.2.4 Offer Cap Applicable to Certain External CRIS Rights**

Notwithstanding any other capacity mitigation measures or obligations that may apply, the offers of External Installed Capacity submitted pursuant to a Non-Contract Commitment, as described in Section 40.13.11.1.2 of Attachment HH of the ISO OATT, will be subject to an offer cap in each month of the Summer Capability Period and for all Specified Winter Months. This offer cap will be determined as the higher of:

5.12.2.4.1 1.1 times the price corresponding to all available Unforced Capacity determined from the NYCA ICAP Demand Curve for that Period; and

5.12.2.4.2 The most recent auction clearing price (a) in the External market supplying the External Installed Capacity, if any, and if none, then the most recent auction clearing price in an External market to which the capacity may be wheeled, less (b) any transmission reservation costs in the External market associated with providing the Installed Capacity, in accordance with ISO Procedures.

#### **5.12.3 Installed Capacity Supplier Outage Scheduling Requirements**

All Installed Capacity Suppliers, except for Control Area System Resources and Responsible Interface Parties, that intend to supply Unforced Capacity to the NYCA shall submit a confidential notification to the ISO of their proposed outage schedules in accordance with the ISO Procedures. Transmission Owners will be notified of these and subsequently revised outage schedules. Based upon a reliability assessment, if Operating Reserve deficiencies are projected to occur in certain weeks for the upcoming calendar year, the ISO will request voluntary rescheduling of outages. In the case of Installed Capacity Suppliers actually supplying Unforced Capacity to the NYCA, if voluntary rescheduling is ineffective, the ISO will invoke forced

rescheduling of their outages to ensure that projected Operating Reserves over the upcoming year are adequate.

An Installed Capacity Supplier that refuses a forced rescheduling of its outages for any unit shall be prevented from supplying Unforced Capacity in the NYCA with that unit during any month where it undertakes such outages. The rescheduling process is described in the ISO Procedures.

An Installed Capacity Supplier that intends to supply Unforced Capacity in a given month that did not qualify as an Installed Capacity Supplier prior to the beginning of the Capability Period must notify the ISO in accordance with the ISO Procedures so that it may be subject to forced rescheduling of its proposed outages in order to qualify as an Installed Capacity Supplier. A Resource that refuses the ISO's forced rescheduling of its proposed outages shall not qualify as an Installed Capacity Supplier for that unit for any month during which it schedules or conducts an outage.

Outage schedules for External System Resources and Control Area System Resources shall be coordinated by the External Control Area and the ISO in accordance with the ISO Procedures.

#### **5.12.4 Required Certification for Installed Capacity**

- (a) Each Installed Capacity Supplier must confirm to the ISO, in accordance with ISO Procedures that the Unforced Capacity it has certified has not been sold for use in an External Control Area.
- (b) Each Installed Capacity Supplier holding rights to UDRs or EDRs from an External Control Area must confirm to the ISO, in accordance with ISO Procedures, that it will not use as self-supply or offer, and has not sold, Installed

Capacity associated with the quantity of MW for which it has not made its one time capability adjustment year election pursuant to Section 5.11.4 (if applicable).

- (c) On and after the execution of an RMR Agreement, and for the duration of its term, an RMR Generator shall not enter into any new agreement or extend any other agreement that impairs or otherwise diminishes its ability to comply with its obligation under an RMR Agreement, or that limits its ability to provide Energy, Capacity, or Ancillary Services directly to the ISO Administered Markets. An Interim Service Provider that is required to keep its generating unit(s) in service shall not enter into any new agreement or extend any other agreement that limits its ability to provide Energy, Capacity, or Ancillary Services directly to the ISO Administered Markets or otherwise meet its obligations as an Interim Service Provider.

#### **5.12.5 Operating Data Reporting Requirements**

To qualify as Installed Capacity Suppliers in the NYCA, Resources shall submit to the ISO Operating Data in accordance with this Section 5.12.5 and the ISO Procedures. Resources that do not submit Operating Data in accordance with the following subsections and the ISO Procedures may be subject to the sanctions provided in Section 5.12.12.1 of this Tariff.

Resources that were not in operation on January 1, 2000 shall submit Operating Data to the ISO no later than one month after such Resources commence commercial operation, and in accordance with the ISO Procedures and the following subsections as applicable.

##### **5.12.5.1 Generators, System Resources, Energy Limited Resources, Energy Storage Resources, Responsible Interface Parties, Intermittent Power**

### **Resources, Limited Control Run-of-River Hydro Resources Municipally Owned Generation and Distributed Energy Resources**

To qualify as Installed Capacity Suppliers in the NYCA, Generators, External Generators, System Resources, External System Resources, Energy Limited Resources, Responsible Interface Parties, Intermittent Power Resources, Limited Control Run-of-River Hydro Resources, Energy Storage Resources, and municipally owned generation and Distributed Energy Resources or the purchasers of Unforced Capacity associated with those Resources shall submit GADS Data, data equivalent to GADS Data, and/or other Operating Data to the ISO in accordance with the ISO Procedures. Prior to the successful implementation of a software modification that allows gas turbines to submit multiple bid points, these units shall not be considered to be forced out for any hours that the unit was available at its base load capability in accordance with the ISO Procedures. This section shall also apply to any Installed Capacity Supplier, External or Internal, using UDRs to meet Locational Minimum Installed Capacity Requirements.

#### **5.12.5.2 Control Area System Resources**

To qualify as Installed Capacity Suppliers in the NYCA, Control Area System Resources, or the purchasers of Unforced Capacity associated with those Resources, shall submit CARL Data and actual system failure occurrences data to the ISO each month in accordance with the ISO Procedures.

#### **5.12.5.3 Transmission Projects Granted Unforced Capacity Deliverability Rights**

An owner of a transmission project that receives UDRs must, among other obligations, submit outage data or other operational information in accordance with the ISO procedures to allow the ISO to determine the number of UDRs associated with the transmission facility.

#### **5.12.5.4 Transmission Projects Granted External-to ROS Deliverability Rights**

An owner of a transmission project that receives EDRs must, among other obligations, submit outage data or other operational information when determined applicable by the ISO and in accordance with ISO Procedures.

#### **5.12.5.5 Co-located Storage Resources**

Generators that participate as Co-located Storage Resources must each, individually, comply with the requirements of Section 5.12.5.1 of this Services Tariff. Generators that participate as Co-located Storage Resources must submit outage data or other operational information in accordance with ISO Procedures that will allow the ISO to validate the CSR Scheduling Limits associated with the Co-located Storage Resources. CSR Scheduling Limits will be incorporated into each CSR Generator's UCAP calculation (*see* Services Tariff Section 5.12.6.2).

### **5.12.6 Capacity Calculations, Operating Data Default, Value and Collection**

#### **5.12.6.1 ICAP Calculation for Behind-the-Meter Net Generation Resources**

The ISO shall calculate the amount of Net-ICAP for each Behind-the-Meter Net Generation Resource as the Adjusted DMGC of the Generator of the Behind-the-Meter Net Generation Resource minus the Resource's Adjusted Host Load in accordance with this Tariff and ISO Procedures.

##### **5.12.6.1.1 Adjusted DMGC**

The ISO's calculation of the Adjusted DMGC of a Behind-the-Meter Net Generation Resource shall be the least of: (i) its DMGC for the Capability Period; (ii) its Adjusted Host Load plus its applicable Injection Limit; and (iii) its Adjusted Host Load plus the number of MW



of CRIS it has obtained, as determined in accordance with OATT Section 40 (OATT Attachment HH) and ISO Procedures.

If the Station Power of a Behind-the-Meter Net Generation Resource is separately metered from all other Load of the Resource, such that the Station Power Load can be independently measured and verified, the Generator of a Behind-the-Meter Net Generation Resource may elect to perform a DMNC Test instead of a DMGC Test pursuant to ISO Procedures. Such election must be made in writing to the ISO prior to the start of the DMNC Test Period.

If a Behind-the-Meter Net Generation Resource elects to take a DMNC Test, the Station Power measured during such DMNC Test shall not be included in the Resource's Host Load. A Behind-the-Meter Net Generation Resource's DMNC value for the Capability Period shall be used in lieu of a DMGC value in the calculation of the Resource's Adjusted DMGC for the purposes of Sections 5.12.6.1 and 5.12.6.2 of this Services Tariff.

#### **5.12.6.1.2      Adjusted Host Load**

A Behind-the-Meter Net Generation Resource's Adjusted Host Load shall be equal to the product of the Average Coincident Host Load multiplied by one plus the Installed Reserve Margin.

The Adjusted Host Load shall be calculated by the ISO on an annual basis prior to the start of the Summer Capability Period and in accordance with ISO Procedures, based upon the Behind-the-Meter Net Generation Resource's Average Coincident Host Load for the prior Summer Capability Period and the Winter Capability Period before that.

#### **5.12.6.1.2.1 Average Coincident Host Load**

The ISO must receive the Behind-the-Meter Net Generation Resource's applicable metered Load data required to calculate an Average Coincident Host Load in accordance with ISO Procedures. The ISO shall compute the Average Coincident Host Load for each Capability Year (i) using the metered Host Load data for the applicable NYCA peak Load hours, except as provided below in this Section, and (ii) adjusted for weather normalization and Load growth as determined by the ISO in relation to developing the NYCA Minimum Installed Capacity Requirement in accordance with ISO Procedures.

For each Capability Year, the NYISO shall use the average of the highest twenty (20) one-hour peak Loads of the Host Load of the Behind-the-Meter Net Generation Resource that occur during the top forty (40) NYCA peak Load hours of the prior Summer Capability Period and the Winter Capability Period before that to calculate the Average Coincident Host Load.

If a facility meets the criteria to be, and has not previously been, a Behind-the-Meter Net Generation Resource, but does not have all of the appropriate meter data, its Average Coincident Host Load shall be a value forecasted by the Behind-the-Meter Net Generation Resource. The Behind-the-Meter Net Generation Resource's forecast shall be based on actual meter data, or if not available, billing data or other business data of the Host Load. An estimated Average Coincident Host Load can only be applicable to a Behind-the-Meter Net Generation Resource until actual data becomes available, but in any event no longer than three (3) consecutive Capability Years beginning with the Capability Year it is first an Installed Capacity Supplier.

#### **5.12.6.1.2.2 Determination of Adjusted Host Load**

After the ISO has calculated a Behind-the-Meter Net Generation Resource's Average Coincident Host Load, it shall then apply the NYCA Installed Reserve Margin. The Behind-the-

Meter Net Generation Resource's Adjusted Host Load will be established by multiplying the Resource's Average Coincident Host Load for the Capability Year by the quantity of one plus the NYCA Installed Reserve Margin.

#### **5.12.6.2 UCAP Calculations**

The ISO shall calculate for each Resource the amount of Unforced Capacity that each Installed Capacity Supplier is qualified to supply in the NYCA in accordance with formulae provided in the ISO Procedures. A Resource's Unforced Capacity will be the applicable Adjusted Installed Capacity multiplied by the quantity of 1 minus the Resource's derating factor.

The amount of Unforced Capacity that each Generator, except for the Generator of a Behind-the-Meter Net Generation Resource, System Resource, Energy Limited Resource, Special Case Resource, and municipally-owned generation is authorized to supply in the NYCA shall be based on the ISO's calculations of individual Equivalent Demand Forced Outage Rates. The amount of Unforced Capacity that a Generator that is participating as a part of a Co-located Storage Resource is authorized to supply in the NYCA shall account for reductions to the CSR Scheduling Limits, or the unavailability of the associated facilities, in accordance with ISO Procedures. The amount of Unforced Capacity that each Energy Storage Resource, Aggregation that is comprised entirely of Energy Storage Resources, and DER Aggregation is authorized to supply in the NYCA shall be based on the individual availability of the Energy Storage Resource or the availability of the Aggregation in the Real-Time Market and calculated by the ISO in accordance with ISO Procedures. Except as provided in Section 5.12.6.2.1 of this Services Tariff, this calculation shall not include hours in any month that the Energy Storage Resource or Aggregation was in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market. The amount of Unforced Capacity that

an Energy Storage Resource that is participating as a part of a Co-located Storage Resource is authorized to supply in the NYCA shall account for reductions to the CSR Scheduling Limits, or the unavailability of the associated facilities, in accordance with ISO Procedures.

The amount of Unforced Capacity that each Control Area System Resource is authorized to supply in the NYCA shall be based on the ISO's calculation of each Control Area System Resource's availability. The amount of Unforced Capacity that each Intermittent Power Resource or an Aggregation that is entirely comprised of Intermittent Power Resources that depend on the same type of fuel is authorized to supply in the NYCA shall be based on the ISO's calculation of the amount of capacity that the Intermittent Power Resource or an Aggregation that is entirely comprised of Intermittent Power Resources that depend on the same type of fuel can reliably provide during system peak Load hours in accordance with ISO Procedures.

Starting with the Capability Year beginning May 1, 2021 and continuing until the Capability Year that begins in May 2024, this calculation will be weighted according to the respective Peak Load Window weighting factors provided in the table below. Separate Summer and Winter Peak Load Windows are applicable based on the penetration of duration limited resources in Section 5.12.14.

Hour Beginning	Summer Peak Load Window		Winter Peak Load Window	
	6 Hour	8 Hour	6 Hour	8 Hour
12		5.00%		
13	12.50%	10.00%		
14	18.75%	17.50%		5.00%
15	18.75%	17.50%		5.00%
16	18.75%	17.50%	18.75%	17.50%
17	18.75%	17.50%	18.75%	17.50%
18	12.50%	10.00%	18.75%	17.50%
19		5.00%	18.75%	17.50%
20			12.50%	10.00%

21			12.50%	10.00%
----	--	--	--------	--------

Except as provided in Section 5.12.6.2.1 of this Services Tariff, this calculation shall not include hours in any month that the Intermittent Power Resource or an Aggregation that is entirely comprised of Intermittent Power Resources that depend on the same type of fuel was in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market.

The amount of Unforced Capacity that an Intermittent Power Resource or Limited Control Run-of-River Hydro Resource that is participating as part of a Co-located Storage Resource is authorized to supply in the NYCA shall account for reductions to the CSR Scheduling Limits, or the unavailability of the associated facilities, in accordance with ISO Procedures.

Until the Capability Year that begins in May 2024, the amount of Unforced Capacity that each Limited Control Run-of-River Hydro Resource is authorized to provide in the NYCA shall be determined separately for Summer and Winter Capability Periods as the rolling average of the hourly net Energy provided by each such Resource during the 20 highest NYCA integrated real-time load hours in each of the five previous Summer or Winter Capability Periods, as appropriate, stated in megawatts. Except as provided in Section 5.12.6.2.1 of this Services Tariff, for a Limited Control Run-of-River Hydro Resource in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market during one of the 20 highest NYCA integrated real-time load hours in any one of the five previous Summer or Winter Capability Periods, the ISO shall replace that Winter or Summer Capability Period, as appropriate, with the next most recent Winter or Summer Capability Period such that the rolling average of the hourly net Energy provided by each such Resource shall be

calculated from the 20 highest NYCA integrated real-time load hours in the five most recent prior Summer or Winter Capability Periods in which the Resource was not in an outage state that precluded its eligibility to participate in the Installed Capacity market on one of the 20 highest NYCA integrated real-time load hours in that Capability Period.

Prior to Capability Year beginning May 1, 2021, the ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for each Generator, System Resource, Special Case Resource, Energy Limited Resource, and municipally owned generation and update them periodically using a twelve-month calculation. Starting with the Capability Year beginning May 1, 2021, the ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for each Special Case Resource and update them periodically using a twelve-month calculation in accordance with ISO Procedures. Starting with the Capability Year beginning May 1, 2021, the calculation for each Generator, System Resource, Energy Limited Resource, and municipally owned generation will use the months comprising the two most recent like Capability Periods in accordance with formulae provided in the ISO Procedures; provided, however, except as provided in Section 5.12.6.2.1 of this Services Tariff, for a Generator in an outage state that started on or after May 1, 2015 and that precluded its eligibility to participate in the Installed Capacity market at any time during any month from which GADS or other operating data would otherwise be used to calculate an individual Equivalent Demand Forced Outage Rate, the ISO shall replace such month's GADS or other operating data with GADS or other operating data from the most recent like month in which the Generator was not in an outage state that precluded its eligibility to participate in the Installed Capacity market.

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for Energy Storage Resources and individual Distributed Energy Resources and update them seasonally as described in ISO Procedures.

The ISO shall calculate separate Summer and Winter Capability Period Unforced Capacity values for Intermittent Power Resources and update them seasonally as described in ISO Procedures.

The amount of Unforced Capacity that each Behind-the-Meter Net Generation Resource is authorized to supply in the NYCA shall be its Net-UCAP. Net-UCAP is the lesser of (i) the ISO's calculation of the Generator of the Behind-the-Meter Net Generation Resource Adjusted DMGC multiplied by one minus its Equivalent Demand Forced Outage Rate, and then decreased by its Adjusted Host Load translated into Unforced Capacity terms consistent with Section 5.11.1 of this Tariff, and (ii) the Resource's Net-ICAP.

#### **5.12.6.2.1 Exceptions**

A Resource returning to the Energy market after taking an outage that precluded its participation in the Installed Capacity market and which returns with modifications to its operating characteristics determined by the ISO to be material and which, therefore, requires the submission of a new Interconnection Request will receive, as the initial derating factor for calculation of the Resource's Unforced Capacity upon its return to service, the derating factor it would have received as a newly connecting unit in lieu of a derating factor developed from unit-specific data. A Resource returning to the Energy market after taking an outage that precluded its participation in the Installed Capacity market and which, upon its return, uses as its primary fuel a fuel not previously used at the facility for any purpose other than for ignition purposes will receive, as the initial derating factor for calculation of the Resource's Unforced Capacity upon its

return to service, the default derating factor in lieu of a derating factor developed from unit-specific data even if the modifications to allow use of a new primary fuel are not material and do not require the submission of a new Interconnection Request.

This Section 5.12.6.2.1 shall apply to a Resource returning to the Energy market after taking an outage that started on or after May 1, 2015 and that precluded its participation in the Installed Capacity market.

#### **5.12.6.2.2 UCAP Adjustment for Partial Firm Units**

Starting with the Capability Year beginning May 1, 2025, Installed Capacity Suppliers may receive a Capacity Accreditation Factor comprising multiple Capacity Accreditation Factors derived from multiple corresponding Capacity Accreditation Resource Classes calculated as a MW weighted average of the different levels of firm fuel supply for each portion that satisfies the requirements and characteristics of the respective Capacity Accreditation Resource Class.

#### **5.12.6.3 Default Unforced Capacity**

In its calculation of Unforced Capacity, the ISO shall deem a Resource to be completely forced out for each month for which the Resource has not submitted its Operating Data in accordance with Section 5.12.5 of this Tariff and the ISO Procedures. A Resource that has been deemed completely forced out for a particular month may submit new Operating Data, for that month, to the ISO at any time. The ISO will use such new Operating Data when calculating, in a timely manner in accordance with the ISO Procedures, an Unforced Capacity value for the Resource.

Upon a showing of extraordinary circumstances, the ISO retains the discretion to accept at any time Operating Data which have not been submitted in a timely manner, or which do not fully conform with the ISO Procedures.



#### **5.12.6.4 Exception for Certain Equipment Failures**

When a Generator, Special Case Resource, Energy Limited Resource, or System Resource is forced into an outage by an equipment failure that involves equipment located on the high voltage side of the electric network beyond the step-up transformer, and including such step-up transformer, the outage will not be counted for purposes of calculating that Resource's Equivalent Demand Forced Outage Rate.

#### **5.12.6.5 Unforced Capacity, Outage Data and Operational Information Associated with External-to-ROS Deliverability Rights**

The ISO shall calculate the availability of the External interface associated with each project granted EDRs, in accordance with ISO Procedures. The availability factor (percentage) of the interface will be used to reduce the amount of EDRs for which Unforced Capacity may be offered. This calculation is distinct from and in addition to the calculation the ISO performs for each Installed Capacity Resource qualified for use with EDRs.

#### **5.12.7 Availability Requirements**

Subsequent to qualifying, each Installed Capacity Supplier shall, except as noted in Sections 5.12.1 and 5.12.11 of this Tariff, on a daily basis: (i) schedule a Bilateral Transaction; (ii) Bid Energy in each hour of the Day-Ahead Market in accordance with the requirements set forth in this Section 5.12.7; or (iii) notify the ISO of any outages.

Until the Capability Year that begins in May 2024, Installed Capacity Suppliers with Energy Duration Limitations corresponding to a Duration Adjustment Factor, as described in Section 5.12.14 below, must on a daily basis during the Peak Load Window and for the number of consecutive hours that correspond to its Energy Duration Limitation, or for the entirety of the Peak Load Window for an Energy Storage Resource or an Aggregation comprised entirely of

Energy Storage Resources: (i) schedule a Bilateral Transaction; (ii) Bid Energy in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (iii) notify the ISO of any outages.

Starting with the Capability Year that begins in May 2024, Installed Capacity Suppliers with Energy Duration Limitations less than or equal in length to the number of hours comprising the applicable Peak Load Window, must on a daily basis during the Peak Load Window and for at least the number of consecutive hours that correspond to its Energy Duration Limitation, or for the entirety of the Peak Load Window for an Energy Storage Resource: (i) schedule a Bilateral Transaction; (ii) Bid Energy in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (iii) notify the ISO of any outages. Installed Capacity Suppliers with Energy Duration Limitations greater in length than the number of hours comprising the Peak Load Window, must on a daily basis during the entirety of the applicable Peak Load Window and for additional hours immediately preceding and following the Peak Load Window covering the remaining hours of the Installed Capacity Supplier's Energy Duration Limitation that are not captured in the Peak Load Window, as specified in ISO Procedures: (i) schedule a Bilateral Transaction; (ii) Bid Energy in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (iii) notify the ISO of any outages.

The ISO may adjust the Peak Load Window that Installed Capacity Suppliers with Energy Duration Limitations will be responsible for scheduling, bidding, or notifying for, with scheduling or bidding in hours outside the Peak Load Window in Section 5.12.14. An RMR Generator can only schedule a Bilateral Transaction to the extent expressly authorized in its RMR Agreement.

Prior to the Capability Year beginning May 1, 2025, the total amount of Energy that an Installed Capacity Supplier subject to this Section 5.12.7 schedules, bids, or declares to be unavailable on a given day must equal or exceed the Installed Capacity Equivalent of the Unforced Capacity it supplies. Starting with the Capability Year beginning May 1, 2025, and except as expressly provided under Section 5.12.7.2, the total amount of Energy that an Installed Capacity Supplier schedules, Bids at a Normal Upper Operating Limit, or declares to be unavailable on a given day must equal or exceed the Installed Capacity Equivalent of the Unforced Capacity it supplies.

For Energy Storage Resources without an Energy Duration Limitation, the total amount of Energy that is scheduled, Bid, or declared to be unavailable shall also include the maximum of the Energy Storage Resource's (i) negative Installed Capacity Equivalent, or (ii) Lower Operating Limit, such that amount scheduled, Bid, or declared to be unavailable reflects the entire withdrawal to injection operating range. Until the Capability Year that begins in May 2024, Energy Storage Resources with an Energy Duration Limitation must, on a daily basis, and for each hour outside of the Peak Load Window: (i) Bid in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (ii) notify the ISO of any outages, the maximum of the Energy Storage Resource's (a) negative Installed Capacity Equivalent, or (b) Lower Operating Limit. The amount scheduled, Bid, and/or declared to be unavailable must reflect the Energy Storage Resource's entire withdrawal operating range.

Starting with the Capability Year that begins in May 2024, Energy Storage Resources with an Energy Duration Limitation less than or equal in length to the number of hours comprising the applicable Peak Load Window must, on a daily basis, and for each hour beyond the Peak Load Window: (i) Bid in the Day-Ahead Market in accordance with the applicable

provisions of Section 5.12.1 of this Tariff; or (ii) notify the ISO of any outages, the maximum of the Energy Storage Resource's (a) negative Installed Capacity Equivalent, or (b) Lower Operating Limit. Energy Storage Resources with an Energy Duration Limitation greater in length than the number of hours comprising the applicable Peak Load Window must, on a daily basis, and for each hour beyond the hours that the Energy Storage Resources must schedule, bid, or declare to be unavailable in accordance with paragraph three of Section 5.12.7 of this Tariff: (i) Bid in the Day-Ahead Market in accordance with the applicable provisions of Section 5.12.1 of this Tariff; or (ii) notify the ISO of any outages, the maximum of the Energy Storage Resource's (a) negative Installed Capacity Equivalent, or (b) Lower Operating Limit. The amount scheduled, Bid, and/or declared to be unavailable must reflect the Energy Storage Resource's entire withdrawal operating range.

#### **5.12.7.1 Co-located Storage Resource Availability Requirements**

In addition to independently satisfying the requirements of Section 5.12.7 for each Generator that participates in a Co-located Storage Resource, each Installed Capacity Supplier must, on a daily basis, and for each hour of the Day-Ahead Market Day: (i) provide a CSR injection Scheduling Limit; and (ii) notify the ISO of any derate or outage to the interconnection facilities comprising the point of interconnection. The sum of the CSR injection Scheduling Limit and the derate or outage must equal or exceed the sum of the Installed Capacity Equivalent of the Unforced Capacity supplied by the Intermittent Power Resource, Limited Control Run-of-River Hydro Resource or Generator and the applicable Section 5.12.7 hourly Bid, Schedule, or Notify obligation of the Energy Storage Resource. Each Installed Capacity Supplier must also on a daily basis, and for each hour of the Day-Ahead Market Day: (i) provide a CSR withdrawal Scheduling Limit; and (ii) notify the ISO of any derate or outage to the interconnection facilities

comprising the point of interconnection. The sum of the CSR withdrawal Scheduling Limit and the derate or outage must equal or exceed the Energy Storage Resource's applicable 5.12.7 hourly Bid, Schedule, or Notify obligation.

#### **5.12.7.2 Upper Operating Limit Bidding Exemptions**

An Installed Capacity Supplier's Day Ahead Market Bid is not required to include a Normal Upper Operating Limit as set forth in Section 5.12.7 if it meets one of the following two limited circumstances:

5.12.7.2.1 Bids for Combined Cycle Generators qualified to sell Operating Reserves using Duct-Firing technology shall include either an Emergency Upper Operating Limit or a Normal Upper Operating Limit at a level equal to or greater than its Installed Capacity Equivalent of Unforced Capacity supplied. If the Normal Upper Operating Limit is less than the unit's Installed Capacity Equivalent of Unforced Capacity supplied, then the difference between the Emergency Upper Operating Limit and Normal Upper Operating Limit shall not exceed the increase in the unit's maximum output level that results from the operation of duct burners.

5.12.7.2.2 Bids for block-loaded Combustion Turbine Generators with Peak-Firing capability shall include either an Emergency Upper Operating Limit or a Normal Upper Operating Limit at a level equal to or greater than its Installed Capacity Equivalent of Unforced Capacity supplied. If the Normal Upper Operating Limit is less than the unit's Installed Capacity Equivalent of Unforced Capacity supplied, then the difference between the Emergency Upper Operating Limit and Normal Upper Operating Limit shall not exceed the increase in the unit's maximum output level that results from operating the resource in peak-firing mode.

### **5.12.8      Unforced Capacity Sales**

Each Installed Capacity Supplier will, after satisfying the deliverability requirements set forth in the applicable provisions of Attachments S, X, Z, or HH to the ISO OATT, be authorized to supply an amount of Unforced Capacity during each Obligation Procurement Period, based on separate seasonal Unforced Capacity calculations performed by the ISO for the Summer and Winter Capability Periods. Unforced Capacity may be sold in six-month strips, or in monthly, or multi-monthly segments.

External Unforced Capacity (except External Installed Capacity associated with UDRs) may only be offered into Capability Period Auctions or Monthly Auctions for the Rest of State, and ICAP Spot Market Auctions for the NYCA, and may not be offered into a Locality for an ICAP Auction. Bilateral Transactions which certify External Unforced Capacity using Import Rights, EDRs, or External CRIS Rights may not be used to satisfy a Locational Minimum Unforced Capacity Requirement.

UCAP from an RMR Generator may only be offered into the ICAP Spot Market Auction, except and only to the extent that the RMR Agreement expressly permits the RMR Generator's UCAP to be certified in a Bilateral Transaction.

If an Energy Limited Resource's, Generator's, System Resource's, Control Area System Resource's, or Aggregation's DMNC rating, or the DMGC rating of a Generator of a Behind-the-Meter Net Generation Resource, if applicable, is determined to have increased during an Obligation Procurement Period, pursuant to testing procedures described in the ISO Procedures, the amount of Unforced Capacity that it shall be authorized to supply in that or future Obligation Procurement Periods shall also be increased on a prospective basis in accordance with the schedule set forth in the ISO Procedures provided that it first has satisfied the deliverability

requirements set forth in the applicable provisions of Attachments S, X, Z, or HH to the ISO OATT.

New Resources and Resources that have increased their Capacity since the previous Summer Capability Period due to changes in their generating equipment and/or Demand Reduction capabilities may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachments S, X, Z or HH to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Summer Capability Period based upon a DMNC test, or the DMGC test of a Resource of a Behind-the-Meter Net Generation Resource, that is performed and reported to the ISO after March 1 and prior to the beginning of the Summer Capability Period DMNC Test Period. The Resource will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Summer DMNC Test Period. Any shortfall between the amount of Unforced Capacity supplied by the Resource for the Summer Capability Period and the amount verified during the Summer DMNC Test Period will be subject to deficiency charges pursuant to Section 5.14.2 of this Tariff. The deficiency charges will be applied to no more than the difference between the Resource's previous Summer Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Resource supplied for the Summer Capability Period.

New Resources and Resources that have increased their Capacity since the previous Winter Capability Period due to changes in their generating equipment and/or Demand Reduction capabilities may, after satisfying the deliverability requirements set forth in the applicable provisions of Attachments S, X, Z or HH to the ISO OATT, qualify to supply Unforced Capacity on a foregoing basis during the Winter Capability Period based upon a DMNC test, or the DMGC test of a Resource of a Behind-the-Meter Net Generation Resource,

that is performed and reported to the ISO after September 1 and prior to the beginning of the Winter Capability Period DMNC Test Period. The Resource will be required to verify the claimed DMNC or DMGC rating by performing an additional test during the Winter Capability Period DMNC Test Period. Any shortfall between the amount of Unforced Capacity certified by the Resource for the Winter Capability Period and the amount verified during the Winter Capability Period DMNC Test Period will be subject to deficiency charges pursuant to Section 5.14.2 of this Tariff. The deficiency charges will be applied to no more than the difference between the Resource's previous Winter Capability Period Unforced Capacity and the amount of Unforced Capacity equivalent the Resource supplied for the Winter Capability Period.

Starting with the Capability Period beginning May 1, 2025, Installed Capacity Suppliers that are dual fuel units electing to demonstrate firm fuel capability via the use of their alternate fuel will be required to demonstrate operability prior to December 1 of the Winter Capability Period in the subject Capability Year. Pursuant to ISO Procedures, Installed Capacity Suppliers will be required to demonstrate operability by submitting to the ISO two separate tests. The first test shall be a DMNC test on their primary fuel. The second test shall be performed using the unit's alternate fuel. The alternate fuel test must demonstrate the unit's maximum output using the alternative fuel for at least one (1) hour.

Installed Capacity Suppliers electing to demonstrate firm fuel capability based on partial satisfaction of alternate fuel requirements will be subject to the testing requirements described in this Section 5.12.8 and will have their Installed Capacity value set by the maximum of the two test values. Any MW difference between the two test values will be treated as non-firm if a Capacity Accreditation Factor is calculated as a MW-weighted average of two Capacity Accreditation Factors.



Any Installed Capacity Supplier, except as noted in Section 5.12.11 of this ISO Services Tariff, which fails on a daily basis to schedule, Bid, or declare to be unavailable in the Day-Ahead Market an amount of Unforced Capacity, expressed in terms of Installed Capacity Equivalent, that it certified for that day, rounded down to the nearest 0.1 MW, or rounded down to the nearest whole MW for an External Installed Capacity Supplier, is subject to sanctions pursuant to Section 5.12.12.2 of this Tariff. If an entity other than the owner of an Energy Limited Resource, Generator, System Resource, Behind-the-Meter Net Generation Resource, Control Area System Resource, or Aggregation that is providing Unforced Capacity is responsible for fulfilling bidding, scheduling, and notification requirements, the owner and that entity must designate to the ISO which of them will be responsible for complying with the scheduling, bidding, and notification requirements. The designated bidding and scheduling entity shall be subject to sanctions pursuant to Section 5.12.12.2 of this ISO Services Tariff.

#### **5.12.9 Sales of Unforced Capacity by System Resources**

Installed Capacity Suppliers offering to supply Unforced Capacity associated with Internal System Resources shall submit for each of their Resources the Operating Data and DMNC testing data or historical data described in Sections 5.12.1 and 5.12.5 of this ISO Services Tariff in accordance with the ISO Procedures. Such Installed Capacity Suppliers will be allowed to supply the amount of Unforced Capacity that the ISO determines pursuant to the ISO Procedures to reflect the appropriate Equivalent Demand Forced Outage Rate. Installed Capacity Suppliers offering to sell the Unforced Capacity associated with System Resources may only aggregate Resources in accordance with the ISO Procedures.

#### **5.12.10 Curtailment of External Transactions In-Hour**

All Unforced Capacity that is not out of service, or scheduled to serve the Internal NYCA Load in the Day-Ahead Market may be scheduled to supply Energy for use in External Transactions provided, however, that such External Transactions shall be subject to Curtailment within the hour, consistent with ISO Procedures. Such Curtailment shall not exceed the Installed Capacity Equivalent committed to the NYCA.

#### **5.12.11 Responsible Interface Parties, Municipally-Owned Generation, Energy Limited Resources, Intermittent Power Resources, and Installed Capacity Suppliers with Energy Duration Limitations**

##### **5.12.11.1 Responsible Interface Parties**

Responsible Interface Parties may qualify as Installed Capacity Suppliers, without having to comply with the daily bidding, scheduling, and notification requirements set forth in Section 5.12.7 of this Tariff, if their Special Case Resources are available to operate at the direction of the ISO in order to reduce Load from the NYS Transmission System and/or the distribution system for a minimum of four (4) consecutive hours each day, following notice of the potential need to operate twenty-one (21) hours in advance if notification is provided by 3:00 P.M. ET, or twenty-four (24) hours in advance otherwise, and a notification to operate two (2) hours ahead. Special Case Resources will be considered to have a four (4) hour Energy Duration Limitation to align with their obligation. In order for a Responsible Interface Party to enroll an SCR that uses an eligible Local Generator, any amount of generation that can reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO that was produced by the Local Generator during the hour coincident with the NYCA or Locality peaks, upon which the LSE Unforced Capacity Obligation of the LSE that serves that SCR is based, must be accounted for when the LSE's Unforced Capacity Obligation for the upcoming

Capability Year is established. Responsible Interface Parties must provide this generator data in accordance with ISO Procedures so that the ISO can adjust upwards the LSE Unforced Capacity Obligation to prevent double-counting.

Responsible Interface Parties supplying Unforced Capacity cannot offer the Demand Reduction associated with such Unforced Capacity in the Emergency Demand Response Program. A Resource with sufficient metering to distinguish MWs of Demand Reduction may participate as a Special Case Resource and in the Emergency Demand Response Program provided that the same MWs are not committed both as Unforced Capacity and to the Emergency Demand Response Program.

The ISO will have discretion, pursuant to ISO Procedures, to exempt Local Generators that are incapable of starting in two (2) hours from the requirement to operate on two (2) hours notification. Local Generators that can be operated to reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO and Loads capable of being interrupted upon demand, that are not available on certain hours or days will be derated by the ISO, pursuant to ISO Procedures, to reflect the Load serving equivalence of the hours they are actually available.

Responsible Interface Parties must submit a Minimum Payment Nomination, in accordance with ISO Procedures. The ISO may request Special Case Resource performance from less than the total number of Special Case Resources within the NYCA or a Load Zone in accordance with ISO Procedures.

Special Case Resources with Local Generators that can be operated to reduce Load from the NYS Transmission System and/or distribution system at the direction of the ISO and Special Case Resources with Loads capable of being interrupted upon demand will be required to

comply with verification and validation procedures set forth in the ISO Procedures. Such procedures will not require metering other than interval billing meters on customer Load or testing other than DMNC or sustained disconnect, as appropriate, unless agreed to by the customer.

Each Special Case Resource enrolled in a Capability Period shall demonstrate its maximum enrolled megawatt value at least once in the Capability Period via performance in a mandatory event or performance test in accordance with Installed Capacity Manual Section 4.12. When a Special Case Resource is enrolled in a Capability Period and transitions to become a Distributed Energy Resource within that same Capability Period, it shall demonstrate its maximum enrolled megawatt value via performance in a mandatory event or in a performance test, provided, however, that if no such mandatory event occurs prior to the Special Case Resource becoming a Distributed Energy Resource, the Distributed Energy Resource shall participate in a performance test in accordance with the ISO's Aggregation Manual. Responsible Interface Parties are not eligible to receive Energy payments, as described in this Services Tariff Section 5.12.11.1, for Demand Reductions caused by Distributed Energy Resources performing in a performance test. When a Demand Side Resource that is participating, or has participated, in a DER Aggregation and seeks to become a Special Case Resource, the Resource's Average Coincident Load shall be calculated in accordance with the provisions of Services Tariff Section 5.12.11.1 and its subparts.

Unforced Capacity supplied in a Bilateral Transaction by a Special Case Resource pursuant to this subsection may only be resold if the purchasing entity or the Installed Capacity Marketer has agreed to become a Responsible Interface Party and comply with the ISO notification requirements for Special Case Resources. LSEs and Installed Capacity Marketers

may become Responsible Interface Parties and aggregate Special Case Resources and sell the Unforced Capacity associated with them in an ISO-administered auction if they comply with ISO notification requirements for Special Case Resources.

Responsible Interface Parties that were requested to reduce Load in any month shall submit performance data to the NYISO, within 75 days of each called event or test, in accordance with ISO Procedures. Failure by a Responsible Interface Party to submit performance data for any Special Case Resources required to respond to the event or test within the 75-day limit will result in zero performance attributed to those Special Case Resources for purposes of satisfying the Special Case Resource's capacity obligation as well as for determining energy payments. All performance data are subject to audit by the NYISO and its market monitoring unit. If the ISO determines that it has made an erroneous payment to a Responsible Interface Party, the ISO shall have the right to recover it either by reducing other payments to that Responsible Interface Parties or by resolving the issue pursuant to other provisions of this Services Tariff or other lawful means.

Provided the Responsible Interface Party supplies evidence of such reductions in 75 days, the ISO shall pay the Responsible Interface Party that, through their Special Case Resources, caused a verified Load reduction in response to (i) an ISO request to perform due to a forecast reserve shortage (ii) an ISO declared Major Emergency State, (iii) an ISO request to perform made in response to a request for assistance for Load relief purposes or as a result of a Local Reliability Rule, or (iv) a test called by the ISO, for such Load reduction, in accordance with ISO Procedures. Subject to performance evidence and verification, in the case of a response pursuant to clauses (i), (ii), of (iii) of this subsection, Suppliers that schedule Responsible Interface Parties shall be paid the zonal Real-Time LBMP for the period of requested performance or four (4)

hours, whichever is greater, in accordance with ISO Procedures; provided, however, Special Case Resource Capacity shall settle Demand Reductions, in the interval and for the capacity for which Special Case Resource Capacity has been scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy, as being provided by a Supplier of Operating Reserves, Regulation Service or Energy.

In the event that a Responsible Interface Party's Minimum Payment Nomination for a Special Case Resource, for the number of hours of requested performance or the minimum four (4) hour period, whichever is greater, exceeds the LBMP revenue received, the Special Case Resource will be eligible for a Bid Production Cost Guarantee to make up the difference, in accordance with Section 4.23 of this Services Tariff and ISO Procedures; provided, however, the ISO shall set to zero the Minimum Payment Nomination for Special Case Resource Capacity in each interval in which such Capacity was scheduled Day-Ahead to provide Operating Reserves, Regulation Service or Energy. Subject to performance evidence and verification, in the case of a response pursuant to clause (iv) of this subsection, payment for participation in tests called by the ISO shall be equal to the zonal Real Time LBMP for the MWh of Energy reduced within the test period.

Transmission Owners that require assistance from enrolled Special Case Resources with Local Generators larger than 100 kW and Special Case Resources with Loads capable of being interrupted upon demand for Load relief purposes or as a result of a Local Reliability Rule, shall direct their requests for assistance to the ISO for implementation consistent with the terms of this section. Within Load Zone J, participation in response to an ISO request to perform made as a result of a request for assistance from a Transmission Owner for less than the total number of Special Case Resources, for Load relief purposes or as a result of a Local Reliability Rule, in

accordance with ISO Procedures, shall be voluntary and the responsiveness of the Special Case Resource shall not be taken into account for performance measurement.

#### **5.12.11.1.1 Special Case Resource Average Coincident Load**

The ISO must receive from the Responsible Interface Party that enrolls a Special Case Resource, the applicable metered Load data required to calculate an ACL for that SCR as provided below and in accordance with ISO Procedures. The ACL shall be computed using the metered Load for the applicable Capability Period SCR Load Zone Peak Hours that indicates the Load consumed by each SCR that is supplied by the NYS Transmission System and/or distribution system and is exclusive of any generation produced by a Local Generator, other behind-the-meter generator, or other supply source located behind the SCR's meter, that served some of the SCR's Load.

Beginning with the Winter 2011-2012 Capability Period and thereafter, the ISO shall use the average of the highest twenty (20) one-hour peak Loads of the SCR taken from the Load data reported for the Capability Period SCR Load Zone Peak Hours during the Prior Equivalent Capability Period, and taking into account the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours, to create a SCR ACL baseline. In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours will be taken into account when creating the SCR ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to

a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence. The ISO will post to its website the Capability Period SCR Load Zone Peak Hours for each zone ninety (90) days prior to the beginning of the Capability Period for which the ACL will be in effect.

In the SCR enrollment file uploaded by the RIP each month within the Capability Period, among other required information, the RIP shall provide the SCR's metered Load values for the applicable Capability Period SCR Load Zone Peak Hours necessary to compute the ACL for each SCR.

The exception to this requirement to report the required metered Load data for the ACL, when enrolling a SCR prior to the Summer 2014 Capability Period, is if (i) the SCR has not previously been enrolled with the ISO and (ii) never had interval metering Load data for each month in the Prior Equivalent Capability Period needed to compute the SCR's ACL. Beginning with the Summer 2014 Capability Period, the exception to this requirement to report the required



metered Load data for the ACL, is dependent upon one or more of the eligibility conditions for SCR enrollment with a Provisional ACL provided in Section 5.12.11.1.2 of this Services Tariff and ISO Procedures. For SCRs that meet the criteria to enroll with a Provisional ACL, the ISO must receive from the RIP a Provisional ACL as provided in Section 5.12.11.1.2 of this Services Tariff and in accordance with ISO Procedures.

Beginning with the Summer 2014 Capability Period, in addition to the requirement for RIPs to report each SCR's metered Load values that occurred during the Capability Period SCR Load Zone Peak Hours, in accordance with this Services Tariff and ISO Procedures during the enrollment process, any qualifying increase in a SCR's Load that will be supplied by the NYS Transmission System and/or distribution system may be reported as an Incremental ACL, subject to the limitations and verification reporting requirements provided in Section 5.12.11.1.5 of this Services Tariff and in accordance with ISO Procedures. Incremental ACL values must be reported using the required enrollment file that may be uploaded by the RIP during each month's enrollment period. RIPs may not report Incremental ACL values for any SCRs that are enrolled in the Capability Period with a Provisional ACL.

A reduction in a SCR's Load that is supplied by the NYS Transmission System and/or distribution system and meets the criteria for a SCR Change of Status must be reported as a SCR Change of Status as provided by Section 5.12.11.1.3 of this Services Tariff and in accordance with ISO Procedures.

The ACL is the basis for the upper limit of ICAP, except in circumstances when the SCR has reported a SCR Change of Status or reported an Incremental ACL pursuant to Sections 5.12.11.1.3 and 5.12.11.1.5 of this Services Tariff. The basis for the upper limit of ICAP for a

SCR that has experienced a SCR Change of Status or reported an Incremental ACL shall be the Net ACL.

#### **5.12.11.1.2 Use of a Provisional Average Coincident Load**

Prior to the Summer 2014 Capability Period, as provided in Section 5.12.11.1.1 of this Services Tariff, if a new Special Case Resource has not previously been enrolled with the ISO and never had interval billing meter data from the Prior Equivalent Capability Period, its Installed Capacity value shall be its Provisional Average Coincident Load for the Capability Period for which the new SCR is enrolled. The Provisional ACL may be applicable to a new SCR for a maximum of three (3) consecutive Capability Periods, beginning with the Capability Period in which the SCR is first enrolled.

Beginning with the Summer 2014 Capability Period, a SCR may be enrolled using a Provisional ACL in lieu of an ACL when one of the following conditions has been determined by the ISO to apply: (i) the SCR has not previously been enrolled with the ISO for the seasonal Capability Period for which the SCR enrollment with a Provisional ACL is intended, (ii) the SCR was enrolled with a Provisional ACL in the Prior Equivalent Capability Period and was required to report fewer than twenty (20) hours of metered Load verification data that correspond with the Capability Period SCR Load Zone Peak Hours based on the meter installation date of the SCR, (iii) the RIP attempting to enroll the SCR with a Provisional ACL is not the same RIP that enrolled the SCR in the Prior Equivalent Capability Period and interval billing meter data for the SCR from the Prior Equivalent Capability Period is not obtainable by the enrolling RIP and not available to be provided to the enrolling RIP by the ISO. The Provisional ACL may be applicable to a SCR for a maximum of three (3) consecutive Capability Periods when enrolled

with the same RIP, beginning with the Capability Period in which the SCR is first enrolled by the RIP.

A SCR enrolled in the Capability Period with a Provisional ACL may not be enrolled by another RIP for the remainder of the Capability Period and the Provisional ACL value shall apply to the resource for the entire Capability Period for which the value is established.

The Provisional ACL is the RIP's forecast of the SCR's ACL and shall be the basis for the upper limit of ICAP for which the RIP may enroll the SCR during the Capability Period.

Any SCR enrolled with a Provisional ACL shall be subject to actual in-period verification. A Verified ACL shall be calculated by the ISO using the top twenty (20) one-hour peak Loads reported for the SCR from the Capability Period SCR Load Zone Peak Hours that are applicable to verify the Provisional ACL in accordance with ISO Procedures and taking into account the resource's reported verified Load reductions in a Transmission Owner's demand response program that are coincident with any of the applicable Capability Period SCR Load Zone Peak Hours. In addition, beginning with the Summer 2014 Capability Period, the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of the applicable Capability Period SCR Load Zone Peak Hours will be taken into account when creating the SCR Verified ACL. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Capability Period SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the Verified ACL for each hour during the Capability Period SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the

resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Capability Period SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Capability Period SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Capability Period SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Capability Period SCR Load Zone Peak Hour, in accordance with the preceding sentence.

Following the Capability Period for which a resource with a Provisional ACL was enrolled, the RIP shall provide to the ISO the metered Load data required to compute the Verified ACL of the resource. The ISO shall compare the Provisional ACL to the Verified ACL to determine, after applying the applicable performance factor, whether the UCAP of the SCR had been oversold and whether a shortfall has occurred as provided under Section 5.14.2 of this Services Tariff. If the RIP fails to provide verification data required to compute the Verified ACL of the resource enrolled with a Provisional ACL by the deadline: (a) the Verified ACL of the resource shall be set to zero for each Capability Period in which the resource with a Provisional ACL was enrolled and verification data was not reported, and (b) the RIP may be subject to penalties in accordance with this Services Tariff.

#### **5.12.11.1.3 Reporting a SCR Change of Load or SCR Change of Status**

##### **5.12.11.1.3.1 SCR Change of Load**

The Responsible Interface Party shall report any SCR Change of Load in accordance with ISO Procedures. The RIP is required to document the SCR Change of Load and when the total

Load reduction for SCRs that have a SCR Change of Load within the same Load Zone is greater than or equal to 5 MWs, the RIP shall report the SCR Change of Load for each SCR in accordance with ISO Procedures.

#### **5.12.11.1.3.2 SCR Change of Status**

The Responsible Interface Party shall report any SCR Change of Status in accordance with ISO Procedures. The ISO shall adjust the reported ACL of the SCR for a reported SCR Change of Status to the Net ACL, for all prospective months to which the SCR Change of Status is applicable. When a SCR Change of Status is reported under clause (i), (ii) or (iii) within the definition of a Qualified Change of Status Condition and the SCR has sold capacity, the SCR shall be evaluated for a potential shortfall under Section 5.14.2 of this Services Tariff. Failure by the RIP to report a SCR Change of Status shall be evaluated as a potential shortfall under Section 5.14.2 of this Service Tariff and evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

Beginning with the Summer 2014 Capability Period, SCRs that were required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and that subsequently report or change a reported SCR Change of Status value after the first performance test in the Capability Period shall be required to demonstrate the performance of the resource against the Net ACL value in the second performance test in the Capability Period. The exceptions to this provision occur when a SCR's eligible Installed Capacity is set to zero throughout the period of the SCR Change of Status, when a SCR's eligible Installed Capacity is decreased by at least the same kW value as the reported SCR Change of Status, or if a SCR Change of Status is reported, and prior to the second performance test, the SCR returns to the full applicable ACL enrolled prior to the SCR Change of Status. Performance in both performance

tests shall be used in calculation of the resource's performance factors and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a resource that was required to perform in the second performance test in the Capability Period: (a) the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

#### **5.12.11.1.4 Average Coincident Load of an SCR Aggregation**

The ISO shall compute the Average Coincident Load of an SCR Aggregation each month in accordance with ISO Procedures.

#### **5.12.11.1.5 Use of an Incremental Average Coincident Load**

Beginning with the Summer 2014 Capability Period, a Responsible Interface Party may report any qualifying increase to a Special Case Resource's Average Coincident Load as Incremental Average Coincident Load in the RIP enrollment file upload and in accordance with this Services Tariff and ISO Procedures.

For SCRs with a total Load increase equal to or greater than twenty (20) percent and less than thirty (30) percent of the applicable ACL, the RIP may enroll the SCR with an Incremental ACL provided that the eligible Installed Capacity does not increase from the prior enrollment months within the same Capability Period and prior to enrollment with an Incremental ACL. If the SCR is enrolled with an Incremental ACL and it is the first month of the SCR's enrollment in the applicable Capability Period, the enrolled eligible Installed Capacity value shall not exceed the maximum eligible Installed Capacity of the SCR from the Prior Equivalent Capability Period. When no enrollment exists for the SCR in the Prior Equivalent Capability Period and it is the first month of the SCR's enrollment in the applicable Capability Period, the enrolled eligible Installed Capacity of the SCR shall not exceed the ACL calculated from the Capability Period

SCR Load Zone Peak Hours. For SCRs with a total Load increase equal to or greater than thirty (30) percent of the applicable ACL, the RIP may enroll the SCR with an Incremental ACL and an increase to the SCR's eligible Installed Capacity and is required to test as described in this section of the Service Tariff.

The ISO shall adjust the ACL of the SCR for an Incremental ACL for all months for which the Incremental ACL is reported by the RIP. For resources reporting an Incremental ACL, the Net ACL shall equal the enrolled ACL plus the reported Incremental ACL less any applicable SCR Change of Status and shall be the basis for the upper limit of ICAP for which the RIP may enroll the SCR during the Capability Period.

An Incremental ACL is a discrete change to the SCR operations that is expected to result in an increase to the Load that the SCR will consume from the NYS Transmission System and/or distribution system. It is not available to account for random fluctuations in Load, such as those caused by weather or other seasonal Load variations. Therefore, the ACL of a SCR may only be increased once per Capability Period and the amount of the increase enrolled must remain the same for all months for which the Incremental ACL is reported. A SCR enrolled in the Capability Period with an Incremental ACL may not be enrolled by another RIP for the remainder of the Capability Period. A SCR enrolled in the Capability Period with a Provisional ACL is not eligible to enroll with an Incremental ACL.

Following the Capability Period for which a SCR has been enrolled with an Incremental ACL, the RIP shall provide the hourly metered Load verification data that corresponds to the Monthly SCR Load Zone Peak Hours identified by the ISO for all months in which an Incremental ACL value was reported for the SCR. For each month for which verification data was required to be reported, the ISO shall calculate a Monthly ACL that will be used in the

calculation of a Verified ACL. The Monthly ACL shall equal the average of the SCR's top twenty (20) one-hour metered Load values that correspond with the applicable Monthly SCR Load Zone Peak Hours, and taking into account (i) the resource's reported verified Load reduction in a Transmission Owner's demand response program in hours coincident with any of these hours. and (ii) the resource's verified Load reduction in either of the ISO's economic demand response programs (the Day Ahead Demand Response Program and the Demand Side Ancillary Services Program) in hours coincident with any of these hours. For the Day Ahead Demand Response Program, the verified Load reduction that occurred in response to a DADRP schedule shall be added to the Monthly SCR Load Zone Peak Hour for which the reduction in response to a DADRP schedule occurred. For the Demand Side Ancillary Services Program, the Load value to be used in calculating the Monthly ACL for each hour during the Monthly SCR Load Zone Peak Hours in which a non-zero Base Point Signal the ISO provides to the resource, shall be the greater of (a) the DSASP Baseline MW value in the interval immediately preceding the first non-zero Base Point Signal in the Monthly SCR Load Zone Peak Hour and (b) the metered Load of the resource as reported by the RIP for the Monthly SCR Load Zone Peak Hour. When the non-zero Base Point Signal dispatch of a DSASP resource begins in one hour and continues into consecutive hours, and the consecutive hour is identified as being a Monthly SCR Load Zone Peak Hour, the DSASP Baseline MW value in effect at the beginning of the dispatch of the non-zero Base Point Signal shall be the MW value used for purposes of determining the applicable Load value for that Monthly SCR Load Zone Peak Hour, in accordance with the preceding sentence. The Verified ACL shall be the average of the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period.



For any month in which verification data for the Incremental ACL is required but not timely submitted to the ISO in accordance with ISO procedures, the ISO shall set the metered Load values to zero. When a Monthly ACL is set to zero, the Verified ACL will be calculated as the average of: a) the two (2) highest Monthly ACLs during the Capability Period in which the SCR was enrolled with an Incremental ACL within the same Capability Period; plus b) the Monthly ACLs for all months in which the SCR was enrolled within the same Capability Period with an Incremental ACL in the Capability Period in which the RIP failed to provide the minimum verification data required. In addition, a RIP may be subject to a penalty for each month for which verification data was required and not reported in accordance with this Services Tariff.

For each SCR that is enrolled with an Incremental ACL, the ISO shall compare the Net ACL calculated from the resource enrollment (ACL plus Incremental ACL less any applicable SCR Change of Status) to the Verified ACL calculated for the SCR to determine if the RIP's use of an Incremental ACL may have resulted in a shortfall pursuant to Section 5.14.2.

A Special Case Resource that was required to perform in the first performance test in the Capability Period in accordance with ISO Procedures and was subsequently enrolled using an Incremental ACL and an increase in the amount of Installed Capacity that the SCR is eligible to sell, shall be required to demonstrate performance against the maximum amount of eligible Installed Capacity reported for the SCR in the second performance test in the Capability Period. Performance in this test shall be measured from the Net ACL. Performance in both performance tests shall be used in calculation of the resource's performance factor and all associated performance factors, deficiencies and penalties. If the RIP fails to report the performance for a resource that was required to perform in the second performance test in the Capability Period: (a)

the resource will be assigned a performance of zero (0) for the test hour, and (b) the RIP shall be evaluated for failure to report under Section 5.12.12.2 of this Services Tariff.

#### **5.12.11.2 Existing Municipally-Owned Generation**

A municipal utility that owns existing generation in excess of its Unforced Capacity requirement, net of NYPA-provided Capacity may, consistent with the deliverability requirements set forth in Attachment HH to the ISO OATT, offer the excess Capacity for sale as Installed Capacity provided that it is willing to operate the generation at the ISO's request, and provided that the Energy produced is deliverable to the New York State Power System. Such a municipal utility shall not be required to comply with the requirement of Section 5.12.7 of this Tariff that an Installed Capacity Supplier bid into the Energy market or enter into Bilateral Transactions. Municipal utilities shall, however, be required to submit their typical physical operating parameters, such as their start-up times, to the ISO. This subsection is only applicable to municipally-owned generation in service or under construction as of December 31, 1999.

#### **5.12.11.3 Energy Limited Resources**

An Energy Limited Resource or an Aggregation that is comprised entirely of a single Resource-type Energy Limited Resource may, consistent with the deliverability requirements set forth in Attachment HH to the ISO OATT, qualify as an Installed Capacity Supplier if it Bids its Installed Capacity Equivalent into the Day-Ahead Market each day and if it is able to provide the Energy equivalent of the Unforced Capacity for the number of consecutive hours that correspond to its Energy Duration Limitation each day. Energy Limited Resources or Aggregations that are Energy Limited Resources shall also Bid a Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, designating their desired operating limits. Energy Limited Resources or Aggregations that are Energy Limited Resources that are not scheduled in the Day-

Ahead Market to operate at a level above their bid-in upper operating limit, may be scheduled in the RTC, or may be called in real-time pursuant to a manual intervention by ISO dispatchers, who will account for the fact that Energy Limited Resource or an Aggregation that is an Energy Limited Resource may not be capable of responding.

#### **5.12.11.4 Intermittent Power Resources**

Intermittent Power Resources that depend upon wind or solar as their fuel or Aggregations that are entirely comprised of Intermittent Power Resources that depend on the same type of fuel, with that fuel being wind or solar, may qualify as Installed Capacity Suppliers, without having to comply with the daily bidding and scheduling requirements set forth in Section 5.12.7 of this Tariff, and may, consistent with the deliverability requirements set forth in Attachment HH to the ISO OATT, claim up to their nameplate Capacity as Installed Capacity. To qualify as Installed Capacity Suppliers, such Intermittent Power Resources shall comply with the requirements of Section 5.12.1 and the outage notification requirements of 5.12.7 of this Tariff.

#### **5.12.11.5 Installed Capacity Suppliers with an Energy Duration Limitation**

A Resource with an Energy Duration Limitation may, consistent with the deliverability requirements set forth in Attachment HH to the ISO OATT, qualify as an Installed Capacity Supplier with an Energy Duration Limitation if it Bids its Installed Capacity Equivalent into the Day-Ahead Market each day and if it is able to provide the Energy equivalent of the Unforced Capacity for the number of consecutive hours that correspond to its Energy Duration Limitation each day. Installed Capacity Suppliers with an Energy Duration Limitation shall also Bid a Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, designating their desired operating limits. Installed Capacity Suppliers with an Energy Duration Limitation

that are not scheduled in the Day-Ahead Market to operate at a level above their bid-in upper operating limit, may be scheduled in the RTC, or may be called in real-time pursuant to a manual intervention by ISO dispatchers, who will account for the fact that Installed Capacity Suppliers with an Energy Duration Limitation may not be capable of responding.

#### **5.12.12 Sanctions Applicable to Installed Capacity Suppliers and Transmission Owners**

Pursuant to this section, the ISO may impose financial sanctions on Installed Capacity Suppliers and Transmission Owners that fail to comply with certain provisions of this Tariff. The ISO shall notify Installed Capacity Suppliers and Transmission Owners prior to imposing any sanction and shall afford them a reasonable opportunity to demonstrate that they should not be sanctioned and/or to offer mitigating reasons why they should be subject to a lesser sanction. The ISO may impose a sanction lower than the maximum amounts allowed by this section at its sole discretion. Installed Capacity Suppliers and Transmission Owners may challenge any sanction imposed by the ISO pursuant to the ISO Dispute Resolution Procedures.

Any sanctions collected by the ISO pursuant to this section will be applied to reduce the Rate Schedule 1 charge under this Tariff.

##### **5.12.12.1 Sanctions for Failing to Provide Required Information**

If (i) an Installed Capacity Supplier fails to provide the information required by Sections 5.12.1.1, 5.12.1.2, 5.12.1.3, 5.12.1.4, 5.12.1.7 or 5.12.1.8 of this Tariff in a timely fashion, or (ii) a Supplier of Unforced Capacity from External System Resources located in an External Control Area or from a Control Area System Resource that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to provide the information required for certification as

an Installed Capacity Supplier established in the ISO Procedures, the ISO may take the following actions: On the first day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of \$500 or \$5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing. Starting on the tenth day that the required information is late, the ISO may impose a daily financial sanction of up to the higher of \$1000 or \$10 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

If an Installed Capacity Supplier fails to provide the information required by Subsection 5.12.1.5 of this Tariff in a timely fashion, the ISO may take the following actions: On the first calendar day that required information is late, the ISO shall notify the Installed Capacity Supplier that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of that first calendar day. Starting on the second calendar day that the required information is late, the ISO may impose a daily financial sanction up to the higher of \$500 or \$5 per MW of Installed Capacity that the Generator, System Resource, or Control Area System Resource in question is capable of providing.

If a TO fails to provide the information required by Subsection 5.11.3 of this Tariff in a timely fashion, the ISO may take the following actions: On the first day that required information is late, the ISO shall notify the TO that required information is past due and that it reserves the right to impose financial sanctions if the information is not provided by the end of the following day. Starting on the third day that the required information is late, the ISO may

impose a daily financial sanction up to \$5,000 a day. Starting on the tenth day that required information is late, the ISO may impose a daily financial sanction up to \$10,000.

#### **5.12.12.2 Sanctions for Failing to Comply with Scheduling, Bidding, and Notification Requirements**

On any day in which an Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or in which a Supplier of Installed Capacity from External System Resources or Control Area System Resources located in an External Control Area that has agreed not to Curtail the Energy associated with such Installed Capacity, or to afford it the same Curtailment priority that it affords its own Control Area Load, fails to comply with scheduling, bidding, or notification requirements for certification as an Installed Capacity Supplier established in the ISO Procedures, the ISO may impose a financial sanction up to the product of a deficiency charge (pro-rated on a daily basis for Installed Capacity Suppliers) and the maximum number of MWs that the Installed Capacity Supplier failed to schedule or Bid in any hour in that day provided, however, that no financial sanction shall apply to any Installed Capacity Supplier who demonstrates that the Energy it schedules, bids, or declares to be unavailable on any day is not less than the Installed Capacity that it supplies for that day rounded down to the nearest 0.1 MW, or rounded down to the nearest whole MW for an External Installed Capacity Supplier. For Installed Capacity Suppliers that have an Energy Duration Limitation, the deficiency charge will be pro-rated on a daily basis only taking into account hours during the Peak Load Window corresponding with the Resource's Energy Duration Limitation obligation, excluding Energy Storage Resources which will be evaluated over all hours during the Peak Load Window, and the maximum number of MWs that the Installed Capacity Supplier with an Energy Duration Limitation failed to schedule or Bid in any hour in the Peak Load Window of that day provided,

however, that no financial sanction shall apply to any Installed Capacity Supplier that demonstrates that the Energy it schedules, bids, or declares to be unavailable on any day is not less than the Installed Capacity that it supplies for that day rounded down to the nearest 0.1 MW. The deficiency charge may be up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction corresponding to where the Installed Capacity Supplier's capacity cleared, and for each month in which the Installed Capacity Supplier is determined not to have complied with the foregoing requirements.

In addition to the financial sanctions described above, the Installed Capacity Supplier offering a Generator that participates as a Co-located Storage Resource may also be subject to a financial sanction for failing to comply with the requirements of Services Tariff Section 5.12.7.1. When such Installed Capacity Supplier fails to comply with Services Tariff Section 5.12.7.1, the ISO may impose a financial sanction up to the product of a deficiency charge and the difference between Installed Capacity Equivalent of the Unforced Capacity of the Generator and the CSR Scheduling Limit. If an Installed Capacity Supplier is subject to financial sanctions for its failure to comply with Services Tariff Section 5.12.7.1 is also subject to a penalty under this Section for failing to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff for the same Day-Ahead Market hour, the NYISO shall assess only the greater of the two sanctions for that hour.

In addition, if any Installed Capacity Supplier fails to comply with the scheduling, bidding, or notification requirements of Sections 5.12.1.6 or 5.12.1.10, or with Section 5.12.7 of this Tariff, or if an Installed Capacity Supplier of Unforced Capacity from an External Control Area fails to comply with the scheduling, bidding, or notification requirements for certification as an Installed Capacity Supplier established in the ISO Procedures, during an hour in which the

ISO curtails Exports associated with NYCA Installed Capacity Suppliers consistent with Section 5.12.10 of this Tariff and with ISO Procedures, then the ISO may impose an additional financial sanction equal to the product of the number of MWs the Installed Capacity Supplier failed to schedule during that hour and the corresponding Real-Time LBMP at the applicable Proxy Generator Bus.

To the extent an Installed Capacity Supplier of Unforced Capacity from an External Control Area or an External Generator associated with an Unforced Capacity sale using UDRs or EDRs fails to comply with Section 5.12.1.10 of this Tariff, the Installed Capacity Supplier or External Generator associated with an Unforced Capacity sale using UDRs or EDRs shall be subject to a deficiency charge calculated in accordance with the formula set forth below for each Obligation Procurement Period:

$$Deficiency\ charge = 1.5 * PRICE * \left( \frac{1000kW}{1MW} \right) * \left( \frac{\sum_{n=1}^N (\max (ICAP_n^{MWh} - SRE_n^{MWh}, 0))}{N} \right)$$

Where:

N = total number of hours of SRE calls during the relevant Obligation Procurement Period

PRICE = ICAP Spot Market Auction clearing price for the relevant Obligation Procurement Period

$ICAP_n^{MWh}$  = for each hour  $n$  of SRE calls during the relevant Obligation Procurement Period, the ICAP equivalent of the UCAP sold from the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, or the Control Area System Resource in MWh, minus (x) any MWh that are unavailable due to an outage as defined in the ISO Procedures, or due to physical operating



limitations affecting the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, or due to other operational issues that the ISO determines to be outside the Installed Capacity Supplier's control, and (y) any MWh that were Bid as Imports to the NYCA at the appropriate Proxy Generator Bus at a price that was designed to ensure the Import was scheduled to the greatest extent possible, but that were not scheduled by the ISO

$SRE_n^{MWh}$  = MWh provided to the NYCA at the appropriate Proxy Generator Bus from the External Installed Capacity Supplier that is a Generator, or the External Generator associated with an Unforced Capacity sale using UDRs or EDRs, or the Control Area System Resource, during each hour  $n$  of SRE calls during the relevant Obligation Procurement Period.

If an Installed Capacity Supplier's failure to fully comply with this Tariff would, in addition to being assessed a deficiency charge calculated in accordance with the formula set forth above, also permit the ISO to impose a different deficiency charge or a financial sanction under this Section 5.12.12.2, or to impose a deficiency charge for a shortfall under Section 5.14.2.2 of this Tariff, then the ISO shall only impose the penalty for failure to comply with Section 5.12.1.10 of this Tariff on the Installed Capacity Supplier for the hour(s) in which the Installed Capacity Supplier failed to meet its obligations under Section 5.12.1.10 of this Tariff.

If the Installed Capacity Supplier is a Responsible Interface Party that enrolled a SCR with an Incremental ACL in accordance with this Services Tariff, and also reported an increase to the Installed Capacity the SCR has eligible to sell after the first performance test in the Capability Period, the ISO may impose an additional financial sanction due to the failure of the

RIP to report the required performance of the SCR against the Net ACL value in the second performance test in the Capability Period. This sanction shall be the value of the reported increase in the eligible Installed Capacity associated with the SCR that was sold by the RIP in each month of the Capability Period, during which the reported increase was in effect, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

If the Installed Capacity Supplier is a Responsible Interface Party, and the Average Coincident Load of the Special Case Resource has been decreased after the first performance test in the Capability Period, due to a SCR Change of Status in accordance with this Services Tariff and ISO Procedures, the ISO may impose an additional financial sanction resulting from the failure of the RIP to report the required performance of the SCR against the Net ACL value of the SCR when the SCR was required to perform in the second performance test in the Capability Period in accordance with Section 5.12.11.1.3.2 of this Services Tariff. This sanction shall be the value of the Unforced Capacity equivalent of the SCR Change of Status MW reported for the SCR during the months for which the SCR was enrolled with a SCR Change of Status and was required to demonstrate in the second performance test as specified in Section 5.12.11.1.3.2 of this Services Tariff, multiplied by up to one and one-half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each such month.

If a RIP fails to provide the information required by Section 5.12.11.1.3 of this Services Tariff in accordance with the ISO Procedures for reporting a Qualified Change of Status Condition, and the ISO determines that a SCR Change of Status occurred within a Capability Period, the ISO may impose a financial sanction equal to the difference, if positive, between the enrolled ACL and the maximum one hour metered Load for the month multiplied by up to one-

half times the applicable Market-Clearing Price of Unforced Capacity determined in the ICAP Spot Market Auction for each month the Installed Capacity Supplier is deemed to have a shortfall in addition to the corresponding shortfall penalty as provided in Section 5.14.2.

For each month in which a RIP fails to report required verification data and the applicable ACL value is set to zero in accordance with Section 5.12.11 of this Services Tariff, the ISO shall have the right to recover any energy payments made to the RIP for performance of the SCR by reducing other payments or other lawful means.

### **5.12.13 Aggregations**

#### **5.12.13.1 Resources Entering and Changing Aggregations**

A qualified Installed Capacity Supplier, which meets the requirements to participate in an Aggregation, may enter an Aggregation pursuant to the rules set forth in Services Tariff Section 4.1.10.3.

When an Installed Capacity Supplier that is a Special Case Resource enters an Aggregation to become a Distributed Energy Resource within the same Capability Period, the maximum Installed Capacity that an Aggregator can declare for the Distributed Energy Resource shall be the upper limit of Installed Capacity calculated for the Special Case Resource in accordance with Services Tariff Section 5.12.11.1.1. When an existing Special Case Resource enters an Aggregation and becomes a Distributed Energy Resource at the beginning of a Capability Period (*i.e.*, begins participating as a Distributed Energy Resource on May 1 or November 1), the maximum Installed Capacity that an Aggregator can declare for that Distributed Energy Resource shall be the upper limit of Installed Capacity calculated for the Special Case Resource for the immediately prior like Capability Period, calculated in accordance with Services Tariff Section 5.12.11.1.1, if such value was calculated.

When a Generator with an approved in-period DMNC rating enters an Aggregation to become a Distributed Energy Resource, the maximum Installed Capacity that an Aggregator can declare for the Distributed Energy Resource shall be the minimum of the Generator's approved in-period DMNC rating and the Generator's CRIS.

Individual Distributed Energy Resources may elect to leave their current Aggregation and join a new Aggregation pursuant to the Resources Changing Aggregation rules set forth in this Services Tariff section below and in Services Tariff section 4.1.10.3. The Installed Capacity of a Distributed Energy Resource that enters a new Aggregation will be assigned to the new Aggregation on a monthly basis beginning on the first day of the month in which the Distributed Energy Resource enters the new Aggregation. The Installed Capacity of a Distributed Energy Resource that exits an Aggregation will be removed from the Aggregation on the last day in which the Distributed Energy Resource is registered in the Aggregation. The specific processes for transferring a Distributed Energy Resource and its Installed Capacity to another Aggregation are located in the ISO Procedures.

An individual resource within an Aggregation may only change from participating in a homogenous Aggregation that is not a DER Aggregation to participating in a DER Aggregation at the beginning of a Capability Year, provided that the Aggregation notifies the ISO by August 1 of the year prior to the beginning of the Capability Year. An individual resource within an Aggregation may only change from participating in a DER Aggregation to participating in a homogeneous Aggregation that is not a DER Aggregation at the beginning of a Capability Year, provided that the Aggregation notifies the ISO by August 1 of the year prior to the beginning of the Capability Year. If the composition of a homogeneous Aggregation that is not a DER Aggregation changes during a Capability Year such that the homogeneous Aggregation that is

not a DER Aggregation would no longer qualify as a homogeneous Aggregation that is not a DER Aggregation, the homogeneous Aggregation that is not a DER Aggregation will maintain the qualifications as a homogeneous Aggregation that is not a DER Aggregation for the remainder of the Capability Year, and, it will have to elect (i) a different Aggregation by August 1, (ii) to participate in the ISO Administered Markets as a Generator, if qualified, or (iii) to leave the ISO Administered Markets for the following Capability Year. If the composition of a DER Aggregation changes during a Capability Year such that the DER Aggregation would no longer qualify as a DER Aggregation, the DER Aggregation will maintain the qualifications as a DER Aggregation for the remainder of the Capability Year, and, it will have to elect (i) a different Aggregation by August 1, (ii) to participate in the ISO Administered Markets as a Generator, if qualified, or (iii) to leave the ISO Administered Markets for the following Capability Year. An individual Distributed Energy Resource seeking to participate in the ISO-administered Installed Capacity auctions that has previously acted as a retail load modifier may only register as an Installed Capacity Supplier for the upcoming Capability Year, provided that Resource notified the ISO of its intention to become an Installed Capacity Supplier by August 1 of the year prior to the start of the Capability Year and provided the output data in accordance with ISO Procedures.

#### **5.12.13.2 Time-stacking Resources in an Aggregation**

An Aggregator may sequentially stack individual Distributed Energy Resources within an Aggregation in order to meet the Energy Duration Limitations specified in Section 5.12.14. In addition to the requirements and obligations described in this section 5.12.13, the following rules apply to an Aggregation that seeks to sequentially stack individual Distributed Energy Resources:

5.12.13.2.1 each individual Distributed Energy Resource must be able to provide  
Energy for a minimum of one 1-hour block each day;

5.12.13.2.2 individual Distributed Energy Resources duration will be rounded-down to  
the nearest hour and stacked in whole-hour increments;

5.12.13.2.3 Time-stacked Aggregations will be qualified for the amount of Capacity it  
can sustain over the run-time requirement; and

The specific processes related to time-stacking Distributed Energy Resources in an  
Aggregation are located in the ISO Procedures.

#### **5.12.14 Energy Duration Limitations, Duration Adjustment Factors, and Capacity Accreditation Factors for Installed Capacity Suppliers**

Starting with the Capability Year that begins on May 1, 2021, Resources with a limited  
run-time that meet the Energy Duration Limitations identified in the tables below may qualify to  
participate as Installed Capacity Suppliers. Resources with a limited run-time must elect an  
Energy Duration Limitation that is less than or equal to the Resource's ability to demonstrate  
sustained output at its qualified MW amount. Resources that do not have an Energy Duration  
Limitation will have a Duration Adjustment Factor of 100%. The Adjusted Installed Capacity  
for an Installed Capacity Supplier shall be calculated using the applicable Energy Duration  
Limitations and Duration Adjustment Factors, and in accordance with ISO Procedures, starting  
with the 2021/2022 Capability Year, as determined by the MW count of incremental penetration  
of Resources with Energy Duration Limitations as listed below:

Table 1:

Incremental Penetration of Resources with Energy Duration Limitations is less than 1000 MW	
Energy Duration Limitations (hours)	Duration Adjustment Factor (%)

8	100
6	100
4	90
2	45

Table 2:

Incremental Penetration of Resources with Energy Duration Limitations 1000 MW and above	
Energy Duration Limitations (hours)	Duration Adjustment Factor (%)
8	100
6	90
4	75
2	37.5

While Table 1 is in effect, Resources with an Energy Duration Limitation of 6 hours or less must fulfill the availability requirements given in Section 5.12.7 for a 6-hour Peak Load Window. While Table 2 is in effect, Resources with an Energy Duration Limitation of 6 hours or less must fulfill the availability requirements given in Section 5.12.7 for an 8-hour Peak Load Window. Resources with an Energy Duration Limitation of 8 hours must always fulfill the availability requirements given in Section 5.12.7 for an 8-hour Peak Load Window. The 6 hour Peak Load Window for the Summer Capability Period is HB 13 through HB 18, and the 6 hour Peak Load Window for the Winter Capability Period is HB 16 through HB 21. The 8 hour Peak Load Window for the Summer Capability Period is HB 12 through HB 19, and the 8 hour Peak Load Window for the Winter Capability Period is HB 14 through HB 21.

Starting with the Capability Year that begins in May 2024, ICAP Suppliers will have their Adjusted ICAP calculated pursuant to Section 5.12.14.2 using the applicable Capacity Accreditation Factor. Resources with a limited run-time must elect an Energy Duration Limitation that is less than or equal to the Resource's ability to demonstrate sustained output at its qualified MW amount and will use the corresponding Capacity Accreditation Factor.

Resources with an Energy Duration Limitation must fulfill the availability requirements given in Section 5.12.7 for the duration of the Peak Load Window.

#### **5.12.14.1 Counting Incremental Penetration of Resources with Energy Duration Limitations**

The penetration levels of CRIS MW will be the sum of CRIS for Resources with Energy Duration Limitations that have elected to participate in ISO Administered Markets with less than 8 hour duration and that have entered into service after January 1, 2019 and incremental CRIS awarded after January 1, 2019 to Resources with Energy Duration Limitations that have elected to participate in ISO Administered Markets with less than 8 hour duration as specified below.

Penetration levels of CRIS MW for Resources with Energy Duration Limitations will be calculated in accordance with ISO Procedures as the sum of CRIS for Resources with Energy Duration Limitations of 2 hours, CRIS for Resources with Energy Duration Limitations of 4 hours and CRIS for Resources with Energy Duration Limitations of 6 hours that have entered into service and have participated in the ISO Markets after January 1, 2019. Penetration levels of Demand Side Resources will be calculated as the sum of the Demand Side Resource MW that have elected to participate in the ISO Capacity markets with less than 8 hour duration as of July 1, as pursuant to ISO Procedures. The MW count of Resources with Energy Duration Limitations that were in service prior to January 1, 2019 and have Retired will include CRIS for Resources with Energy Duration Limitations of 2 hours, CRIS for Resources with Energy



Duration Limitations of 4 hours and CRIS for Resources with Energy Duration Limitations of 6 hours that have Retired as of July 1 each year, pursuant to ISO Procedures. Resources that obtained CRIS and were in service prior to January 1, 2019 that qualify as Resources with Energy Duration Limitations at a later date will not be included in the penetration levels of Resources with Energy Duration Limitations.

The MW count of incremental penetration of Resources with Energy Duration Limitations used to determine the applicable Duration Adjustment Factors provided in Section 5.12.14 for the upcoming Capability Year will be calculated in accordance with ISO Procedures as the sum of the penetration levels of CRIS MW, as described above, and penetration levels of Demand Side Resources, as described above, less the sum of CRIS MW for Resources with Energy Duration Limitations that have Retired, as described above, and less 1309.1 MW of SCR MW. The MW count of incremental penetration of Resources with Energy Duration Limitations with their Energy Duration Limitation election will be counted as of July 1 and posted by July 15. Once there are 1000 MW or more incremental penetration of Resources with Energy Duration Limitations, the Duration Adjustment Factors listed in Table 2 provided above in Section 5.12.14 will be effective May 1 of the following Capability Year and Table 2 will be effective notwithstanding future MW count of incremental penetration of Resources with Energy Duration Limitations.

#### **5.12.14.2 Adjusted Installed Capacity**

Starting with the Capability Year beginning May 1, 2021 and continuing until the Capability Year that begins in May 2024, a Resource's Unforced Capacity shall reflect the applicable Duration Adjustment Factor for the Resource's elected Energy Duration Limitation. The Adjusted Installed Capacity is equal to a Resource's Installed Capacity multiplied by the

Duration Adjustment Factor. If a Resource or Aggregation wants to change its duration election it must inform the ISO by August 1 preceding the upcoming Capability Year.

Starting with the Capability Year that begins in May 2024, an ICAP Supplier's Unforced Capacity shall reflect the applicable Capacity Accreditation Factor of its Capacity Accreditation Resource Class. The ICAP Supplier's Adjusted Installed Capacity is equal to its Installed Capacity multiplied by its applicable Capacity Accreditation Factor. If an existing Resource wishes to join an Aggregation, or, if a Resource or Aggregation wishes to elect a different Energy Duration Limitation than its current duration, it must inform the ISO by August 1 preceding the upcoming Capability Year.

#### **5.12.14.3 Periodic Review of Capacity Values Accreditation Factors**

Starting with the Capability Year that begins in May 2024 and occurring every year, the ISO shall review the existing Capacity Accreditation Factors established for each Capacity Accreditation Resource Class and assess for the upcoming Capability Year the marginal reliability contributions of each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements. The annual review shall: (i) use the Installed Reserve Margin/Locational Minimum Installed Capacity Requirement study model that is approved by the NYSRC for the upcoming Capability Year as a starting database, (ii) be performed at the conditions that reflect the expected NYCA system that meets the resource adequacy criterion, (iii) develop Capacity Accreditation Factors for all Capacity Accreditation Resource Classes that reflect the marginal reliability contributions toward meeting NYSRC resource adequacy requirements, and (iv) be performed for Rest of State, G-J Locality (excluding Load Zone J), NYC Locality, and Long Island Locality to the extent there exists an ICAP Supplier or projected

ICAP Supplier in the given Capacity Accreditation Resource Classes in the applicable location, as specified in ISO Procedures.

In conjunction with this review, the ISO shall review the Peak Load Window associated with the bidding requirements for Resources with Energy Duration Limitations and modify the Peak Load Window accordingly, pursuant to ISO Procedures.

#### **5.12.15 Capacity Accreditation Resource Class Characteristic Elections**

Starting with the Capability Year beginning May 1, 2025, an Installed Capacity Supplier that elects to demonstrate any amount of firm fuel capability based on its expected ability to meet specified fuel requirements must notify the ISO of its election by August 1 of the calendar year preceding the subject Capability Year and provide supporting documentation composed of firm fuel contracts or liquid fuel inventory documentation and a description of how its fuel procurement and operational characteristics allow the unit to meet the applicable requirements at the relevant MW level in accordance with ISO Procedures. An ICAP Supplier must submit such data and description, in accordance with the above requirements, after August 1 and by December 1 in the subject Capability Year in accordance with ISO Procedures.

Installed Capacity Suppliers may submit the relevant data for a subject Capability Year (either prior to or after making an election pursuant to this Section) starting January 1 of the calendar year preceding the subject Capability Year (*e.g.*, January 1, 2025, for the 2026-2027 Capability Year). If the required information is submitted to the NYISO between January 1 of the calendar year preceding the subject Capability Year and August 1 of the subject Capability Year, the NYISO will undertake reasonable efforts to review the submitted data and notify the Installed Capacity Supplier in a timely manner if the documentation provided is not sufficient to support the elected level of firm capability, in accordance with ISO Procedures. Only

information submitted after August 1 of the subject Capability Year will meet the December 1 data submission requirement (*i.e.*, data submitted prior to August 1 of the subject Capability Year and previously validated by the NYISO must be confirmed after August 1 of the subject Capability Year in accordance with ISO Procedures). The NYISO will notify an ICAP Supplier in a timely manner in accordance with the ISO Procedures if the data submitted to meet the December 1 data submission requirement does not support its firm fuel election. An Installed Capacity Supplier that has not elected to demonstrate any amount of firm fuel is not subject to the requirements of this paragraph.

An Installed Capacity Supplier that elects to demonstrate any firm fuel capability that is unable to substantiate fulfillment of the requirements in accordance with ISO Procedures by the December 1 deadline, or is unable to maintain the required level of firm fuel supply, may be subject to an Installed Capacity shortfall penalty pursuant to Section 5.14.2 of the Services Tariff, and will only be permitted to sell Unforced Capacity at a MW value that is achievable consistent with the unit's new firm fuel level for any remaining months in the subject Capability Year in which it is unable to reestablish its firm fuel supply in accordance with ISO Procedures.

## **7.2 Billing and Payment Procedures**

For purposes of this Section 7.2:

- (i) the term “Complete Week Settlement Period” shall mean the seven day period between Saturday and Friday for which all of the days are in the same month; and
- (ii) the term “Stub Week Settlement Period” shall mean the six or fewer day period between Saturday and Friday for which all of the days are in the same month.

### **7.2.1 Billing and Settlement Information**

The ISO shall provide settlement and billing information to Customers. The ISO shall inform each Customer that provides or is provided services furnished under this ISO Services Tariff or the ISO OATT of the payments due for such service. Such information shall be made electronically available to the Customer.

### **7.2.2 Invoicing and Payment**

#### **7.2.2.1 Weekly Invoice**

On or about each Wednesday, as set forth in ISO Procedures, the ISO shall submit an invoice to a Customer that indicates the net amount owed by or owed to the Customer for those services furnished under this ISO Services Tariff or the ISO OATT for the previous Complete Week Settlement Period or Stub Week Settlement Period that are designated as Weekly Invoice Components in ISO Procedures; *provided, however*, that the net amount owed by or owed to the Customer for those services furnished for a Stub Week Settlement Period that concludes a month shall be included in the next monthly invoice issued in accordance with Section 7.2.2.2 of this ISO Services Tariff.

#### **7.2.2.2 Monthly Invoice**

Within five (5) business days after the first day of each month, the ISO shall submit an invoice to a Customer that indicates the net amount owed by or owed to the Customer:

- (i) for those services furnished under this ISO Services Tariff or the ISO OATT for a Stub Week Settlement Period that concludes the previous month that are designated as Weekly Invoice Components in ISO Procedures;
- (ii) for any adjustments to amounts contained in the weekly invoices issued in the previous month pursuant to Section 7.2.2.1 of this ISO Services Tariff;
- (iii) for those services furnished under this ISO Services Tariff or the ISO OATT in the previous month that are designated as Monthly Invoice Components in ISO Procedures;
- (iv) for any adjustments to amounts contained in a previously issued monthly invoice that was issued on or about one hundred twenty (120) days prior to the issuance of this invoice;  
and
- (v) for any adjustments to amounts contained in a previously issued monthly invoice as part of the Close-Out Settlement of that monthly invoice pursuant to Section 7.4.1.2 of this ISO Services Tariff.

#### **7.2.2.3 Payment by the Customer**

A Customer owing payments on net in its weekly invoice or its monthly invoice shall make those payments to the ISO through the ISO Clearing Account by the second business day after the date on which the weekly invoice or monthly invoice is rendered by the ISO unless otherwise specified in ISO Procedures. In accordance with Section 7.1.2 of this ISO Services

Tariff, the ISO may net any overpayment by the Customer for past estimated charges against current amounts due from the Customer or, if the Customer has no outstanding amounts due, the ISO may pay to the Customer an amount equal to the overpayment.

#### **7.2.2.4 Payment by the ISO**

Except as provided in Section 7.1.4 of this ISO Services Tariff, the ISO shall pay all net monies owed to a Customer in its weekly invoice or its monthly invoice from the ISO Clearing Account by the second business day after the due date for Customer payments set forth in Section 7.2.2.3 of this ISO Services Tariff unless otherwise specified in ISO Procedures.

#### **7.2.3 Use of Estimated Data and Meter Data**

The ISO may use estimates, including estimated meter data, in whole or in part to settle a weekly or monthly invoice in accordance with ISO Procedures. The ISO shall use meter data submitted to the ISO in accordance with Article 13 of this ISO Services Tariff. Any charges based on estimates shall be subject to true-up in invoices subsequently issued by the ISO after the ISO has obtained the requisite actual information, provided that the ISO shall only true-up charges based on meter data prior to the deadline for finalizing meter data established in Section 7.4 of this ISO Services Tariff. A trued-up charge shall include interest amounts calculated at the rate set forth in Section 7.3 of this ISO Services Tariff from the weekly or monthly due date for the charge until the date of payment of the trued-up amount for that charge.

#### **7.2.4 Method of Payment**

All payments by the Customer shall be made by either (i) wire transfer in immediately available funds payable to the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures. All payments by the ISO shall be made either (i) by wire transfer in

immediately available funds payable to the Customer by the ISO through the ISO Clearing Account or (ii) any other method set forth in ISO Procedures.

#### **7.2.5 TCC Auction Settlements**

Notwithstanding Sections 7.2.2.1 and 7.2.2.2 of this ISO Services Tariff, the ISO shall make settlements related to the Centralized TCC Auction and the Reconfiguration Auction as set forth in this Section 7.2.5.

7.2.5.1 The ISO shall submit invoices to, and make settlements with, Transmission Owners in connection with the allocation of Net Auction Revenues in accordance with the timeline set forth in ISO Procedures.

7.2.5.2 Customers owing payments to the ISO as a result of their activity in or related to a Centralized TCC Auction or Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, shall make those payments to the ISO through the ISO Clearing Account in accordance with the timeline set forth in ISO Procedures.

7.2.5.3 Except as provided in Section 7.1.4 of this ISO Service Tariff, the ISO shall pay all net monies owed to Customers as a result of their activity in or related to a Centralized TCC Auction or a Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, from the ISO Clearing Account in accordance with ISO Procedures.

7.2.5.4 Sections 7.2.1, 7.2.3, 7.2.4, and 7.2.6 of this ISO Services Tariff and Section 19.9.6 of Attachment M of the ISO OATT shall apply to settlements calculated in accordance with this Section 7.2.5.



## **7.2.6 Verification of Payments**

The ISO shall verify that all payments owed by Customers in accordance with this ISO Services Tariff and the ISO OATT have been paid to the ISO in a timely manner. If a Customer fails to make a payment within the time period established in Sections 7.2.2.1, 7.2.2.2, and 7.2.5 of this ISO Services Tariff or pays less than the amount due, the ISO shall take measures pursuant to Section 7.5 of this ISO Services Tariff. Except as provided in Section 7.1.4 of this ISO Services Tariff, the ISO shall also ensure that monies owed to Customers in accordance with this ISO Services Tariff and the ISO OATT are paid through the ISO Clearing Account in a timely manner.

## **7.2.7 Payments for TSCs**

Bills and payments for TSCs shall be issued in accordance with the ISO OATT. Accordingly, this Section 7 shall not apply to TSCs.

## **7.2.8 Payment for Actual Energy Withdrawals by Energy Storage Resources**

A Customer that is participating in the ISO-administered Energy and Ancillary Services markets with an Energy Storage Resource, or an Aggregation containing one or more Energy Storage Resources, will be subject to Day Ahead Market settlements pursuant to Section 4.2.6 and Real Time Market settlements pursuant to 4.5.2, or in the case of a Supplier of Regulation Service pursuant to Rate Schedule 15.3.6.1 of this ISO Services Tariff.

If a Load Serving Entity requires the Energy Storage Resource, including an Energy Storage Resource participating in an Aggregation, to also pay a retail rate for its charging withdrawals, then the ISO shall issue a credit to the affected Customer for the associated Actual

Energy Withdrawals and assess a charge to this Load Serving Entity for the same Actual Energy Withdrawals.

An Energy Storage Resource must identify whether its Energy withdrawals for charging will be invoiced at wholesale or at retail rates as part of the ISO's Customer registration process. After an Energy Storage Resource's initial registration, a Load Serving Entity that possesses the necessary authority must notify the ISO and all affected Energy Storage Resources, including Energy Storage Resources participating in an Aggregation, at least 30 days prior to the start of a month in which it will change how one or more Energy Storage Resources are charged for their Actual Energy Withdrawals (at wholesale or at retail). Advance notice is required to switch from charging at wholesale to charging at retail or *vice-versa*. The ISO shall effectuate the change at the start of a month, after it has been provided the required advance notice.

When an Energy Storage Resource participates as a Co-located Storage Resource, the credit issued to an affected Customer and the corresponding charge assessed to the Load Serving Entity will not include the Energy Storage Resource's charging Energy received from the co-located Generator behind the Co-located Storage Resource's shared Point of Injection/Point of Withdrawal. The credit and offsetting charge shall be calculated as the product of the Actual Energy Withdrawals of the Energy Storage Resource and the time weighted average Real-Time Market LBMP for the hour at the Energy Storage Resource's location.

## **15.3A Rate Schedule “3-A” -Charges Applicable to Suppliers That Are Not Providing Regulation Service**

### **15.3A.1 Persistent Undergeneration Charges**

A Supplier, other than a Supplier exempted in Section 15.3A.2 of this Rate Schedule, that is not providing Regulation Service, and persistently operates at a level below its schedule to provide Energy shall pay a persistent undergeneration charge to the ISO, unless its operation is within a tolerance described below, provided, however, no persistent undergeneration charges shall apply to a Fixed Block Unit that has reached a percentage of its Normal Upper Operating Limit, which percentage shall be set pursuant to ISO Procedures and shall be initially set at seventy percent (70%). Persistent undergeneration charges per interval shall be calculated as follows:

$$\text{Persistent undergeneration charge} = \text{Energy Difference} \times \text{Max (MPRC}_{\text{DAM}}, \text{MPRC}_{\text{RT}}) \times \text{Length of Interval in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the actual Energy provided by the Supplier from its RTD Base Point Signal for the dispatch interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall initially be 3% of the Supplier’s Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes;

MPRC<sub>DAM</sub> is the Regulation Capacity Market Price in the Day-Ahead Market; and

MPRC<sub>RT</sub> is the Regulation Capacity Market Price in the Real-Time Market.

### **15.3A.1.1 Overgeneration Charges**

An Intermittent Power Resource that depends on wind or solar energy as its fuel, for which the ISO has imposed a Wind and Solar Output Limit, that operates at a level above its schedule shall pay an overgeneration charge to the ISO, unless its operation is within a tolerance described below. An Intermittent Power Resource that depends on landfill gas as its fuel, or a Limited Control Run-of-River Hydro Resource that participates in the ISO-Administered Markets as part of a Co-located Storage Resource, for which the ISO has imposed a Wind and Solar Output Limit, that operates at a level above its schedule shall pay an overgeneration charge to the ISO, unless the Resource's operation is within a tolerance described below.

Overgeneration charges per interval shall be calculated as follows:

$$\text{Overgeneration charge} = \text{Energy Difference} \times \text{Max} (\text{MPRC}_{\text{DAM}}, \text{MPRC}_{\text{RT}}) \times \text{Length of Interval} \\ \text{in seconds}/3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the RTD Base Point Signal for the dispatch interval from the actual Energy provided by the Resource for the same interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, which shall initially be set at 3% of the Resources' Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable;

$\text{MPRC}_{\text{DAM}}$  is the Regulation Capacity Market Price in the Day-Ahead Market; and

$\text{MPRC}_{\text{RT}}$  is the Regulation Capacity Market Price in the Real-Time Market

### **15.3A.1.2 Persistent Over-Withdrawal Charges**

An Energy Storage Resource, an Aggregation of Energy Storage Resources, or DER Aggregation that includes at least one Withdrawal-Eligible Generator that is (a) scheduled to

withdraw Energy, (b) not providing Regulation Services, and (c) persistently withdrawing Energy at a level exceeding its withdrawal schedule, shall pay a persistent over-withdrawal charge to the ISO unless its operation is within the applicable tolerance described below.

Persistent over-withdrawal charges per interval shall be calculated as follows:

$$\text{Persistent Over-Withdrawal Charge} = \text{Energy Difference} \times \text{Max} (\text{MPRC}_{\text{DAM}}, \text{MPRC}_{\text{RT}}) \times \\ \text{Length of Interval in seconds} / 3600 \text{ seconds}$$

Where:

Energy Difference in (MW) is determined by subtracting the Resource's actual energy operating level from its RTD Base Point Signal. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to ISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall initially be an absolute value of 3% of the Resource's Maximum Withdrawal Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes;

$\text{MPRC}_{\text{DAM}}$  is the Regulation Capacity Market Price in the Day-Ahead Market; and

$\text{MPRC}_{\text{RT}}$  is the Regulation Capacity Market Price in the Real-Time Market.

### **15.3A.2 Exemptions**

The following types of Generator shall not be subject to persistent undergeneration charges:

#### **15.3A.2.1 Generators, except for the Generator of a Behind-the-Meter Net**

Generation Resource and a Generator in an Aggregation, providing Energy under contracts (including PURPA contracts), executed and effective on or before November 18, 1999, in which the power purchaser does not control the operation

of the supply source but would be responsible for payment of the persistent undergeneration or performance charge;

15.3A.2.2 Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system in operation on or before November 18, 1999 and/or Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 533 MW of such units;

15.3A.2.3 Limited Control Run of River Hydro Resources;

15.3A.2.4 Intermittent Power Resources and Aggregations of Intermittent Power Resources that depend on landfill gas as their fuel;

15.3A.2.5 Intermittent Power Resources and Aggregations of Intermittent Power Resources that depend on wind or solar energy as their fuel;

15.3A.2.6 Prior to the Capability Period beginning May 1, 2025, Capacity Limited Resources, Aggregations of Capacity Limited Resources, Energy Limited Resources and Aggregations of Capacity Limited Resources, to the extent that their real-time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their Real-Time Scheduled Energy Injections. Beginning with the Capability Period beginning May 1, 2025, Energy Limited Resources to the extent that their real-time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their Real-Time Scheduled Energy Injections;

15.3A.2.7 Generators operating in their Start-Up Period or their Shutdown Period and, for Generators comprised of a group of generating units at a single location, which grouped generating units are separately committed and dispatched by the ISO, and for which Energy injections are measured at a single location, each of the grouped generating units when one of the grouped generating units is operating in its Start-Up or Shutdown Period; and

15.3A.2.8 Generators operating during a Testing Period.

15.3A.2.9 Energy Storage Resources with schedules to withdraw Energy are instead subject to persistent over-withdrawal charges.

For Generators and Resources described in Sections 15.3A.2.1, 15.3A.2.2, 15.3A.2.3, and 15.3A.2.4 above, this exemption shall not apply in an hour if the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible.

## **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, in New York City, 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, requirements for Operating Reserve located in New York City may only be met by eligible Suppliers that are located in New York City, 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 not utilizing inverter-based energy storage technology). The following types of resources are only eligible to provide Spinning Reserve if all of the generating units use inverter-based energy storage technology and meet the criteria set forth in the ISO Procedures: (a) Aggregations comprised of one or more generating units, (b) Aggregations that include Demand Side Resource(s) where at least one Demand Side Resource facilitates its Demand Reduction by utilizing a Local Generator, and (c) Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit. Suppliers utilizing inverter-based energy storage technology, and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply Spinning Reserve when withdrawing or injecting Energy, and when idle.

#### **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/Aggregations comprised solely of generating units that are capable of increasing their supply level 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:**

(i) Generators, except Behind-the-Meter Net Generation Resources and Aggregations that are comprised of more than one generating unit, that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range shall be eligible to supply synchronized 30-Minute Reserves. Aggregations that include/Demand Side Resource(s) that do not facilitate demand reduction using Local Generators, or that facilitate demand reduction using a Local Generator utilizing inverter-based energy storage technology, that are capable of reducing their Energy usage within thirty (30) minutes shall be eligible to supply synchronized 30-Minute Reserves. Suppliers utilizing inverter-based energy storage technology, including Aggregations with a combination of Resources utilizing inverter-based energy storage technology and Demand Side Resources, and that meet the criteria set forth in the ISO Procedures, shall be eligible to supply synchronized 30-Minute Reserves when withdrawing or when injecting Energy, and when idle; (ii) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty (30) minutes; (iii) 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 (iv) Demand Side Resources that are capable of reducing their Energy usage/Aggregations comprised of one or more generating units that are capable of increasing their output level 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 and Aggregations:**

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.

Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market may increase their Incremental Energy Bids or Demand Reduction Bids, respectively, for portions of their Resources that have been scheduled; provided however, that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Withdrawal-Eligible Generators or Aggregations comprised of one or more Withdrawal-Eligible Generators that are

scheduled to withdraw Energy, and that are selected to provide Operating Reserve in the Day-Ahead Market, may decrease their Bids to withdraw Energy for portions of their resources that have been scheduled through those processes; provided that they are not otherwise prohibited from doing so pursuant to other provisions of the ISO's Tariffs. Suppliers that are selected to provide Operating Reserve in the Day-Ahead Market may not reduce the  $UOL_N$  in their Real-Time Market Bids below the sum of their Day-Ahead Market schedules for Energy, Operating Reserve, and Regulation Service, except to the extent that they are directed to do so by the ISO. The ISO may reduce the real-time Operating Reserve schedule (in MW) from an Energy Storage Resource to account for the Energy Level of such Resource, as discussed in Section 4.4.2.1 of this ISO Services Tariff. Suppliers 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 least of the Resource's emergency response rate multiplied by ten, or the Resource's applicable Upper Operating Limit (*i.e.*,  $UOL_N$ ,  $UOL_E$ ); (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 least of the Resource's emergency response rate multiplied by twenty and its applicable Upper Operating Limit.

However, the sum of the amount of Energy or Demand Reduction a 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. For an Energy Storage Resource or an Aggregation of Energy Storage Resources, the Resource's Energy schedule minus its Regulation Service schedule shall not be less than the Resource's Lower Operating Limit.

For an Energy Storage Resource or Aggregation of Energy Storage Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy Schedule, the amount of Regulation Capacity it is scheduled to provide, and the amount of Operating Reserves product it is scheduled to provide shall not exceed its Upper Operating Limit.

For Co-located Storage Resources the sum of the amount of Energy each Generator is scheduled to provide, the amount of Regulation Service the Energy Storage Resource and any other participating Generator that is eligible to provide Regulation Service are scheduled to provide, and the amount of each Operating Reserves product the Energy Storage Resource and any other participating Generator that is eligible to provide Operating Reserves are scheduled to provide, shall account for the CSR injection Scheduling Limit consistent with ISO Procedures. The net amount of Energy that the CSR Generators are scheduled to withdraw, plus the amount

of Regulation Service the Energy Storage Resource is scheduled to provide, shall account for the CSR withdrawal Scheduling Limit consistent with ISO Procedures.

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 Section 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 least of the Resource's emergency response rate multiplied by ten and the Resource's applicable Upper Operating Limit ( $UOL_N$  or  $UOL_E$ ); (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 least of the Resource's emergency response rate multiplied by twenty and the Resource's applicable Upper Operating Limit ( $UOL_N$  or  $UOL_E$ ). 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.



For an Energy Storage Resource or an Aggregation of Energy Storage Resources that is withdrawing Energy, the sum of the Resource's or Aggregation's Energy Schedule, the amount of Regulation Capacity it is scheduled to provide and the amount of Operating Reserves product it is scheduled to provide shall not exceed its UOL. The ISO may limit the availability of a Withdrawal-Eligible Generator to provide Operating Reserves based on its Energy Level constraints.

For Co-located Storage Resources the sum of the amount of Energy each Generator is scheduled to provide, the amount of Regulation Service the Energy Storage Resource and any other participating Generator that is eligible to provide Regulation Service are scheduled to provide, and the amount of each Operating Reserves product the Energy Storage Resource and any other participating Generator that is eligible to provide Operating Reserves are scheduled to provide, shall account for the CSR injection Scheduling Limit consistent with ISO Procedures. The net amount of Energy that the CSR Generators are scheduled to withdraw, plus the amount of Regulation Service the Energy Storage Resource and any other participating Generator that is eligible to provide Regulation Service are scheduled to provide, shall account for the CSR withdrawal Scheduling Limit consistent with ISO Procedures.

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 injections, withdrawals, and Demand Reductions against its expected performance in real-time. The ISO may disqualify Suppliers that consistently fail to provide Energy, Demand Reduction, or to reduce Energy withdrawals, 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 five locations: (i) West of Central-East ("West"

or “Western”); (ii) East of Central-East excluding Southeastern New York (“Eastern”); (iii) Southeastern New York excluding New York City and Long Island (“Southeastern”); (iv) New York City (“N.Y.C.”); and (v) Long Island (“L.I.”). The ISO will thus calculate fifteen 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:

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

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

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

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

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

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

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

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

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

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

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

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

$$\text{Market clearing price for L.I. 30-Minute Reserves} = SP1 + SP4 + SP7 + SP13$$

$$\begin{aligned} \text{Market clearing price for L.I. 10-Minute Non-Synchronized Reserves} = & SP1 + SP2 + \\ & SP4 + SP5 + \\ & SP7 + SP8 + \\ & SP13 + SP14 \end{aligned}$$

$$\begin{aligned} \text{Market clearing price for L.I. Spinning Reserves} = & SP1 + SP2 + SP3 + SP4 + SP5 + SP6 \\ & + SP7 + SP8 + SP9 + SP13 + SP14 + \\ & SP15 \end{aligned}$$

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, N.Y.C., or L.I. 30-Minute Reserve requirement constraint for the hour
- SP5 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the hour
- SP6 = Shadow Price for Eastern, Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the hour
- SP7 = Shadow Price for Southeastern, N.Y.C., or L.I. 30-Minute Reserve requirement constraint for the hour
- SP8 = Shadow Price for Southeastern, N.Y.C., or L.I. 10-Minute Reserve requirement constraint for the hour
- SP9 = Shadow Price for Southeastern, N.Y.C., or L.I. Spinning Reserve requirement constraint for the hour
- SP10 = Shadow Price for New York City 30-Minute Reserve requirement constraint for the hour
- SP11 = Shadow Price for New York City 10-Minute Reserve requirement constraint for the hour
- SP12 = Shadow Price for New York City Spinning Reserve requirement constraint for the hour
- SP13 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour
- SP14 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour
- SP15 = 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/Aggregation 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 N.Y.C. 30-Minute Reserves =  $SP1 + SP4 + SP7 + SP10$

Market clearing price for N.Y.C. 10-Minute Non-Synchronized Reserves =  $SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP10 + SP11$

Market clearing price for N.Y.C. Spinning Reserves =  $SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP10 + SP11 + SP12$

Market clearing price for L.I. 30-Minute Reserves =  $SP1 + SP4 + SP7 + SP13$

Market clearing price for L.I. 10-Minute Non-Synchronized Reserves =  $SP1 + SP2 + SP4 + SP5 + SP7 + SP8 + SP13 + SP14$

Market clearing price for L.I. Spinning Reserves =  $SP1 + SP2 + SP3 + SP4 + SP5 + SP6 + SP7 + SP8 + SP9 + SP13 + SP14 + SP15$

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, N.Y.C., or L.I. 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

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

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

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

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

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

SP10 = Shadow Price for New York City 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP11 = Shadow Price for New York City 10-Minute Reserve requirement constraint for the interval

SP12 = Shadow Price for New York City Spinning Reserve requirement constraint for the interval

SP13 = Shadow Price for Long Island 30-Minute Reserve requirement constraint and, if applicable, Scarcity Reserve Requirement constraint for the interval

SP14 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP15 = 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;

- iv. If the Scarcity Reserve Requirement is for a Scarcity Reserve Region that includes Load Zone J (*i.e.*, New York City only), but does not include Load Zones A, B, C, D, E, F, G, H, I, or K, 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;  
or
  - v. 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 SP13. SP13 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, J, or K but does not include Load Zones A, B, C, D, E, or F and Sections 15.4.6.1.1(a)(iii), 15.4.6.1.1(a)(iv), or 15.4.6.1.1(a)(v) of this Rate Schedule are 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 and Aggregations that are selected to provide Operating Reserves Day-Ahead, but are directed to convert to Energy production or, for Withdrawal-Eligible Generators and Aggregations that include Withdrawal-Eligible Generator(s), to reduce Energy withdrawals in real-time, the applicable Real-Time LBMP for all Energy they are directed to provide in excess of their Day-Ahead Energy schedule.

A Supplier that bids on behalf of (i) a Generator that provides Operating Reserves or (ii) an Demand Side Resource/Aggregation 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 Operating Reserve Demand Curves for each locational Operating Reserves requirement. Specifically, there shall be a demand curve for: (i) Total Spinning Reserves; (ii) Eastern, Southeastern, New York City, or Long Island Spinning Reserves; (iii) Southeastern, New York City, or Long Island Spinning Reserves; (iv) New York City Spinning Reserves; (v) Long Island Spinning Reserves; (vi) Total 10-Minute Reserves; (vii) Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves; (viii) Southeastern, New York City, or Long Island 10-Minute Reserves; (ix) New York City 10-Minute Reserves; (x) Long Island 10-Minute Reserves; (xi) Total 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established a Scarcity Reserve

Requirement); (xii) Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); (xiii) Southeastern, New York City, or Long Island 30-Minute Reserves (including separate demand curves applicable for each real-time interval the ISO has established certain Scarcity Reserve Requirements); (xiv) New York City 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); and (xv) 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)(v) 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 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, New York City, or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, 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, New York City, or Long Island Spinning Reserves demand curve shall be \$40/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be \$0/MW.

- (c) Southeastern, New York City, or Long Island Spinning Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, 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, New York City, or Long Island Spinning Reserves demand curve shall be \$40/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island Spinning Reserves demand curve shall be \$0/MW.
- (d) New York City Spinning Reserves: For quantities of Operating Reserves meeting the New York City Spinning Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York City Spinning Reserves demand curve shall be \$25/MW. For all other quantities, the price on the New York City Spinning Reserves demand curve shall be \$0/MW.
- (e) 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.
- (f) 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.

- (g) Eastern, Southeastern, New York City, or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, 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, New York City, or Long Island 10-minute reserves demand curve shall be \$775/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 10-minute reserves demand curve shall be \$0/MW.
- (h) Southeastern, New York City, or Long Island 10-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, 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, New York City, or Long Island 10-minute reserves demand curve shall be \$40/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 10-Minute Reserves demand curve shall be \$0/MW.
- (i) New York City 10-Minute Reserves: For quantities of Operating Reserves meeting the New York City 10-minute reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York City 10-minute reserves demand curve shall be \$25/MW. For all other quantities, the price on the New York City 10-minute reserves demand curve shall be \$0/MW.
- (j) 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.

- (k) 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 655 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 (i) are less than or equal to the target level for that locational requirement minus 600 MW, but (ii) exceed the target level for that locational requirement minus 655 MW, the price on the total 30-Minute Reserves demand curve shall be \$625/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 545 MW, but (ii) exceed the target level for that locational requirement minus 600 MW, the price on the total 30-Minute Reserves demand curve shall be \$500/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 490 MW, but (ii) exceed the target level for that locational requirement minus 545 MW, the price on the total 30-Minute Reserves demand curve shall be \$375/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 435 MW, but (ii) exceed the target level for that locational requirement minus 490 MW, the price on the total 30-Minute

Reserves demand curve shall be \$300/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 380 MW, but (ii) exceed the target level for that locational requirement minus 435 MW, the price on the total 30-Minute Reserves demand curve shall be \$225/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 325 MW, but (ii) exceed the target level for that locational requirement minus 380 MW, the price on the total 30-Minute Reserves demand curve shall be \$175/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement minus 200 MW, but (ii) exceed the target level for that locational requirement minus 325 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 (i) are less than or equal to the target level for that locational requirement, but (ii) exceed the target level for that locational requirement minus 200 MW, the price on the total 30-Minute Reserves demand curve shall be \$40/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 target level established for 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 655 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 (i) are less than or equal to the NYCA scarcity target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement, but (ii) exceed the NYCA scarcity target level minus an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement, the price on the total 30-Minute Reserves demand curve shall be \$625/MW. For quantities of Operating Reserves meeting the NYCA scarcity target level that (i) are less than or equal to the NYCA scarcity target, but (ii) exceed the NYCA scarcity target level minus an amount equal to the sum of 600 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 NYCA scarcity target level 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 an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement(s), 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 (i) are less than or equal to the adjusted NYCA target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement(s), but (ii) exceed the adjusted NYCA target level minus an amount equal to the sum of 655 MW and the Scarcity Reserve Requirement(s), the price on the total 30-Minute Reserves demand curve shall be \$625/MW. For quantities of Operating Reserves meeting the adjusted NYCA target level that (i) are less than or equal to the adjusted NYCA target level, but (ii) exceed the adjusted NYCA target level minus an amount equal to the sum of 600 MW and the Scarcity Reserve Requirement(s), 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 adjusted NYCA target level for that interval.

- (1) Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, 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, New York City, or Long Island 30-Minute Reserves demand curve shall be \$40/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, 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, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, 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, New York City, or Long Island 30-Minute Reserves locational requirement target level, the price on the Eastern, Southeastern, New York City, 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 (i) are less than or equal to the Eastern scarcity target level, but (ii) exceed the Eastern scarcity target level minus an amount equal to the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves locational requirement target level, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be \$40/MW. For all other quantities, the price on the Eastern,

Southeastern, New York City, 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, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Eastern, Southeastern, New York City, 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, New York City, or Long Island 30-Minute Reserves demand curve shall be \$40/MW. For all other quantities, the price on the Eastern, Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

- (m) Southeastern, New York City, or Long Island 30-Minute Reserves: For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement minus any incremental 30-Minute Reserve target level established by the ISO for an amount not to exceed 500 MW (“SENY incremental reserve target level”), the price on the Southeastern, New York City, or Long

Island 30-Minute Reserves demand curve shall be \$500/MW. For quantities of Operating Reserves meeting the Southeastern, New York City, or Long Island 30-Minute Reserves requirement that (i) are less than or equal to the target level for that locational requirement, but (ii) exceed the target level for that locational requirement minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be \$40/MW. For all other quantities, the price on the Southeastern, New York City, 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, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern, New York City, 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 minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For quantities of Operating Reserves meeting the Southeastern scarcity target level that (i) are less than or equal to the Southeastern scarcity target level, but (ii) exceed the Southeastern scarcity target level minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve

shall be \$40/MW. For all other quantities, the price on the Southeastern, New York City, 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, New York City, or Long Island 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the Southeastern, New York City, 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 minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be \$500/MW. For quantities of Operating Reserves meeting the adjusted Southeastern target level that (i) are less than or equal to the adjusted Southeastern target level, but (ii) exceed the adjusted Southeastern target level minus the SENY incremental reserve target level, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be \$40/MW. For all other quantities, the price on the Southeastern, New York City, or Long Island 30-Minute Reserves demand curve shall be \$0/MW.

- (n) New York City 30-Minute Reserves: For quantities of Operating Reserves meeting the New York City 30-Minute Reserves requirement that are less than or equal to the target level for that locational requirement, the price on the New York City 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the New York City 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 New York City 30-Minute Reserves shall be as follows: For quantities of Operating Reserves meeting the New York City 30-Minute Reserves locational requirement target level plus the Scarcity Reserve Requirement (“N.Y.C. scarcity target level”) that are less than or equal to the N.Y.C. scarcity target level minus an amount equal to the New York City 30-Minute Reserves locational requirement target level, the price on the New York City 30-Minute Reserves demand curve shall be \$500/MW. For the quantities of Operating Reserves meeting the N.Y.C. scarcity target level that (i) are less than or equal to the N.Y.C. scarcity target level, but (ii) exceed the N.Y.C. scarcity target level minus an amount equal to the New York City 30-Minute Reserves locational requirement target level, the price on the New York City 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the New York City 30-Minute Reserves demand curve shall be \$0/MW.

- (o) 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)(v) 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 level, 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 (i) are less than or equal to the Long Island scarcity target level, but (ii) 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) or Aggregation(s) supplying any one of the Operating Reserves under ISO control. The Generator(s) or Aggregation(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) or Aggregation(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 Dispatchable Resources that would be scheduled to meet an increment of Load. For pricing purposes, the incremental dispatch costs of Fast-Start Resources that Bid ISO-Committed Flexible shall be adjusted to include start-up costs and minimum generation costs based on the Start-Up Bids and Minimum Generation Bids or mitigated Start-Up Bids and Minimum Generation Bids of each such Resource, as described in Section 17.1.1.2 below.

To the extent that tradeoffs exist between scheduling providers to produce Energy or reduce demand, and scheduling them to provide Regulation Service or Operating Reserves, LBMPs shall reflect the effect of meeting an increment of Load, given those tradeoffs, at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Bids for Regulation Service or Operating Reserves; or (ii) shortage costs associated with the inability to meet a Regulation Service or Operating Reserves requirement under the Regulation Service Demand Curve set forth in Rate Schedule 3 of this ISO Services Tariff and Operating Reserve Demand Curves and Scarcity Reserve Demand Curve set forth in Rate Schedule 4 of this ISO Services Tariff. For the purposes of calculating LBMPs under this

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

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

#### **17.1.1 LBMP Bus Calculation Method**

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

The LBMP at bus  $i$  can be written as:

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

Where:

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

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

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

Where:

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

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

Where:

$L$  = NYCA losses; and

$P_i$  = injection at bus  $i$

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

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

Where:

$K$  = the set of Constraints;

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

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

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

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

LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the Day-Ahead Market, the three components of the LBMP at each location will be calculated from the SCUC results and posted for each of the twenty four (24) hours of the next day. The Real-Time LBMPs will be calculated and posted for each execution of RTD.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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



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

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

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

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

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

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

### **17.1.2.1 General Procedures**

#### **17.1.2.1.1 Overview**

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

Each RTD run shall, depending on when it occurs during the hour, have a bid optimization horizon of fifty, fifty-five, or sixty minutes beyond the first, or binding, point in time that it addresses. The posting time and the first time point in each RTD run, which establishes binding prices and schedules, will be five minutes apart. The remaining points in time in each optimization period can be either five, ten, or fifteen minutes apart depending on when the run begins within the hour. The points in time in each RTD optimization period are arranged so that they parallel as closely as possible RTC's fifteen minute evaluations.

For example, the RTD run that posts its results at the beginning of an hour ("RTD<sub>0</sub>") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD<sub>0</sub> will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at the beginning of the hour) and ending at the first time point in its optimization period (i.e., five minutes after the hour). It will produce advisory prices and schedules for its second time point, which is ten minutes after the first time point in its optimization period, and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at five minutes after the beginning of the hour ("RTD<sub>5</sub>") will initialize at the beginning of the hour

and produce prices over a fifty minute optimization period. RTD<sub>5</sub> will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at five minutes after the hour) and ending at the first time point in its optimization period (i.e., ten minutes after the hour.) It will produce advisory prices and schedules for its second time point (which is five minutes after the first time point), and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at ten minutes after the beginning of the hour (“RTD<sub>10</sub>”) will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD<sub>10</sub> 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<sub>N</sub> or UOL<sub>E</sub>, whichever is applicable. Fixed Block Units that do not participate in a Co-located Storage Resource, are capable of being started and meeting Minimum Generation Levels in ten minutes or less, and that have not been committed by RTC, are treated as flexible (i.e. able to be dispatched anywhere between zero (0) MW and their UOL<sub>N</sub> or UOL<sub>E</sub>, whichever is applicable). The first pass establishes “physical base points” (i.e., real-

time Energy schedules) and real-time schedules for Regulation Service and Operating Reserves for the first time point of the optimization period. Physical base points and schedules established for the first time point shall be binding and shall remain in effect until the results of the next run are posted. Physical base points and schedules established for all subsequent time points shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point Signals that the ISO sends to Suppliers.

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

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

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

When setting physical base points for a Dispatchable Resource at the first time point, the ISO shall ensure that they do not fall outside of the bounds established by the Dispatchable Resource's lower and upper dispatch limits. A Dispatchable Resource's dispatch limits shall be determined based on whether it was feasible for it to reach the physical base point calculated by the last RTD run given its: (A) metered output level and metered Energy Level (if applicable) at the time that the RTD run was initialized; (B) response rate; (C) minimum generation level/LOL; (D) USL and LSL (if applicable); and (E) UOL<sub>N</sub> or UOL<sub>E</sub>, whichever is applicable. If it was feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval starting from its previous base point, subject to factors (A) through (E) specified above.

If it was not feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, subject to factors (A) through (E) specified above, but instead starting from the feasible output level closest to its previous base point.

When setting physical base points for a Dispatchable Resource at later time points, the ISO shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper dispatch limits for that time point. A Resource's dispatch limits at later time points shall be based on its: (A) dispatch limits from the first time point; (B) response rate; (C) minimum generation level/LOL; (D) Energy Level, USL and LSL (if applicable); and (E) UOL<sub>N</sub> or UOL<sub>E</sub>, whichever is applicable.

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL<sub>N</sub> or UOL<sub>E</sub>, whichever is applicable, considering Energy Level limitations for ISO-Managed ESRs. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by adjusting the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level/LOL considering applicable Energy Level limitations for ISO-Managed ESRs, or to a Demand Side Resource's Demand Reduction level.

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

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

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

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

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

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

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

The RTD Base Point Signals sent to Self-Committed Fixed Generators and Aggregations shall follow the quarter hour operating schedules that those Generators and Aggregations submitted in their real-time self-commitment requests.

The RTD Base Point Signals sent to ISO-Committed Fixed Generators shall follow the quarter hour operating schedules established for those Generators by RTC, regardless of their actual performance. To the extent possible, the ISO shall honor the response rates specified by such Generators when establishing RTD Base Point Signals. If a Self-Committed Fixed Generator's or Aggregation's operating schedule is not feasible based on its real-time self-

commitment requests then its RTD Base Point Signals shall be determined using a response rate consistent with the operating schedule changes.

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

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats: (i) all Fast-Start Resources that are committed by RTC; (ii) Fixed Block Units that do not participate in a Co-located Storage Resource, are capable of starting and meeting Minimum Generation Levels in ten minutes, and have not been committed by RTC; and (iii) all Fixed Block Units otherwise instructed to be online or remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero (0) MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable), regardless of their minimum run-time status. The dispatch of Generators, including Fast-Start Resources and Fixed Block Units, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. The second pass calculates real-time Energy prices and real-time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Section 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this ISO Services Tariff respectively. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

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

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

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource shall be the higher of: (A) its upper dispatch limit from the first pass; or (B) its “pricing

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

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

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



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

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

#### **17.1.2.1.2.3 The Third Pass**

The third RTD pass is reserved for future use.

#### **17.1.2.1.3 Variations in RTD-CAM**

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections 17.1.2.1.1 and 17.1.2.1.2 shall apply.

First, if the ISO enters reserve pickup mode: (i) the ISO will produce prices and schedules for a single ten minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator and Aggregations commitments before executing the three RTD passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator or Aggregation to be set to the higher of the Generator's or Aggregation's physical base point or its actual supply level.

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the ISO shall set Regulation Service schedules to zero as described in Rate Schedule

15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator and Aggregation commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator and Aggregation within the affected area towards its  $UOL_E$  at its emergency response rate or set it at a level equal to its physical base point.

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

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

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization period consisting of two five-minute time points.

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

Attachment H of this Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are implemented they shall be incorporated into the RTC software through the establishment of a second, parallel, commitment evaluation that will assess the impact of the mitigation measures. The first evaluation, referred to as the “RTC evaluation,” will determine the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the “RT-AMP” evaluation, will

determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow the rules governing RTC's operation that are set forth in Section 4 of and this Attachment B to this ISO Services Tariff.

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example,  $RTC_{15}$  and  $RT-AMP_{15}$  will perform Resource commitment evaluations simultaneously.  $RT-AMP_{15}$  will then apply the mitigation "impact" test, account for reference bid levels as appropriate and determine which Resources are actually to be mitigated. This information will then be conveyed to  $RTC_{30}$  which will make Resource commitments consistent with the application of the mitigation measures (and will thus indirectly be incorporated into future RTD runs).

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

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

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

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

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

If AMP is activated, Step 1B tests to determine if the AMP will be triggered by mitigating offer prices subject to mitigation that exceed the conduct threshold to their respective reference prices. These mitigated offer prices together with all originally submitted offer prices not subject to automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This step is another iteration of the SCUC process. At the end of Step 1B, committed Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources, and non-Fast-Start Resources are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable. For mitigation purposes, LBMPs are again calculated from this dispatch. The LBMPs determined at the end of Step 1B are compared to the LBMPs determined at the end of Step 1A to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the SCUC process. At the end of Step 1C, committed Fast-Start Resources, Imports, Exports, virtual supply, virtual load, Demand Side Resources, and non- Fast-Start Resources are again dispatched to meet Bid Load. Fast-Start Resources are treated as dispatchable between zero MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable. The dispatch for Generators,

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

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

Pass 2 consists of a least cost commitment and dispatch of Fast-Start Resources, Imports, Exports, Demand Side Resources and non- Fast-Start Resources to meet forecast Load requirements in excess of Bid Load, considering the Wind and Solar Energy Forecast, that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fast-Start Resources are dispatchable between zero MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable. The dispatch for Generators, including Fast-Start Resources, that participate as Co-located Storage Resources will consider CSR Scheduling Limits. Incremental Import Capacity needed to meet forecast Load requirements is determined in Pass 2. Fixed Block Units committed in this pass are not included in the least cost dispatches of Passes 5 or 6. Demand Side Resources and non-Fast-Start Resources committed in this step are blocked on at least to minimum generation level in Passes 4 through 6. Intermittent Power Resources that depend on

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

Pass 3 is reserved for future use.

Pass 4 consists of a least cost dispatch to forecast Load. It is not used to set schedules or prices. It is used for operational purposes and provides a dispatch of Fast-Start Resources, Imports, Exports, Demand Side Resources and non- Fast-Start Resources committed in Passes 1 or 2. Incremental Import Capacity committed in Pass 2 is re-evaluated and may be reduced if no longer required.

Pass 5 consists of a least cost dispatch of Fast-Start Resources, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non- Fast-Start Resources committed to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fast-Start Resources are treated as dispatchable between zero MW and their  $UOL_N$  or  $UOL_E$ , whichever is applicable. LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fast-Start Resources in the Day-Ahead Market are calculated from this dispatch.

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

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

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

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

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

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

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



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

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

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

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

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

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

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

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

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

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

where:

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

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

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

$$n = \text{number of Load buses in zone j for which LBMPs are calculated; and}$$

$$W_i = \text{Load weighting factor for bus i.}$$

The NYISO also calculates and posts zonal LBMP for four (4) external zones for informational purposes only. Settlements for External Transactions are determined using the Proxy Generator Bus LBMP. Each external zonal LBMP is equal to the LBMP of the Proxy Generator Bus associated with that external zone. The table below identifies which Proxy Generator Bus LBMP is used to determine each of the posted external zonal LBMPs.

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

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

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

### **17.1.6.1 Definitions**

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

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

**NYCA Ramp Constraint:** A NYCA Ramp Constraint exists when proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole.

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

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

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

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

### **17.1.6.2 General Rules**

Transmission Customers and Customers with External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. Those with External Generators may arrange LBMP Market sales and/or Bilateral Transactions with Internal or External Loads and External Loads may arrange LBMP Market purchases and/or Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of Proxy Generator Buses. LBMPs will be calculated for each Proxy

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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



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

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

Under the conditions specified below, the Marginal Losses Component and the Congestion Component of the Real-Time LBMP, calculated pursuant to the preceding paragraphs in Sections 17.1.6.3 and 17.1.6.4, shall be constructed as follows:

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

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

and

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

where:

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

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