

# Attachment I

## 2.4 Definitions - D

**DADRP Component:** The credit requirement for a Demand Reduction Provider to bid into the Day-Ahead Market, and a component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

**Day-Ahead:** Nominally, the twenty-four (24) hour period directly preceding the Dispatch Day, except when this period may be extended by the ISO to accommodate weekends and holidays.

**Day-Ahead LBMP:** The LBMPs calculated based upon the ISO's Day-Ahead Security Constrained Unit Commitment process.

**Day-Ahead Margin:** That portion of Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for an hour that represents the difference between the Supplier's accepted Day-Ahead offer price and the Day-Ahead LBMP, Operating Reserves settlement or Regulation Service settlement for that hour.

**Day-Ahead Margin Assurance Payment:** A supplemental payment made to an eligible Supplier that buys out of a Day-Ahead Energy, Regulation Service, or Operating Reserves schedule such that an hourly balancing payment obligation offsets its Day-Ahead Margin. Rules for calculating these payments, and for determining Suppliers' eligibility to receive them, are **set** forth in Attachment J to this ISO Services Tariff.

**Day-Ahead Market:** The ISO Administered Market in which Capacity, Energy and/or Ancillary Services are scheduled and sold Day-Ahead consisting of the Day-Ahead scheduling process, price calculations and Settlements.

**Day-Ahead Reliability Unit:** A Day-Ahead committed Resource which would not have been committed but for a request by a Transmission Owner that the unit be committed in the Day-Ahead Market in order to meet the reliability needs of the Transmission Owner's local system or as the result of the ISO's analysis indicating the unit was needed in order to meet the reliability requirements of the NYCA.

**Decremental Bid:** A monotonically increasing Bid curve provided by an entity engaged in a Bilateral Import or Internal Transaction to indicate the LBMP below which that entity is willing to reduce its Generator's output, and purchase Energy in the LBMP Markets, or by an entity engaged in a Bilateral Wheel Through Transaction to indicate the Congestion Component cost below which that entity is willing to accept Transmission Service.

**Demand Reduction:** A quantity of reduced electricity demand from a Demand Side Resource that is bid, produced, purchased or sold over a period of time and measured or calculated in Megawatt hours. Demand Reductions offered by a Demand Side Resource as Energy in the LBMP Markets may only be offered in the Day-Ahead Market, and shall be offered only by a Demand Reduction Provider. The same

Demand Reduction may not be offered by a Demand Reduction Provider and by a customer as Operating Reserves or Regulation Service.

**Demand Reduction Aggregator:** A Demand Reduction Provider, qualified pursuant to ISO Procedures, that bids Demand Side Resources of at least 1 MW through contracts with Demand Side Resources and is not a Load Serving Entity.

**Demand Reduction Incentive Payment:** A payment to Demand Reduction Providers that are scheduled to make Day-Ahead Demand Reductions that are not supplied by a Local Generator. The payment shall be equal to the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction bus; and (b) the lesser of the actual hourly Demand Reduction or the Day-Ahead scheduled hourly Demand Reduction in MW.

**Demand Reduction Provider:** A Customer that is eligible, pursuant to the relevant ISO Procedures, to bid Demand Side Resources of at least 1 MW as Energy into the Day-Ahead Market. A Demand Reduction Provider can be (i) a Load Serving Entity or (ii) a Demand Reduction Aggregator.

**Demand Side Ancillary Service Program (DSASP):** An ISO program that allows qualified DSASP Resources to participate in the ISO's Day-Ahead and Real-Time Markets for Operating Reserves and Regulation Service in accordance with the ISO Services Tariff and ISO Procedures.

**Demand Side Ancillary Service Program Resource (DSASP Resource):** A Demand Side Resource or an aggregation of Demand Side Resources located in the NYCA with at least 1 MW of load reduction that is represented by a point identifier (PTID) and is assigned to a Load Zone or Subzone by the ISO and that is:

- i. Capable of controlling demand in a responsive, measurable and verifiable manner within time limits prescribed by the ISO; and
- ii. Qualified to participate in the ISO's Ancillary Services market as a Supplier of Operating Reserves or Regulation Service pursuant to the ISO Services Tariff and ISO Procedures.

**Demand Side Ancillary Service Program Provider (DSASP Provider):** A Customer that is eligible, pursuant to the ISO Tariff and ISO Procedures, to offer DSASP Resource(s) as Operating Reserves or Regulation Service in the Day-Ahead or Real-Time Market. A DSASP Provider is responsible for enrolling its DSASP Resource(s), and, when communicating directly with the ISO via telemetry, is responsible for dispatching its DSASP Resource(s).

**Demand Side Resources:** A Resource located in the NYCA that is capable of controlling demand in a responsive, measurable and verifiable manner within time limits, and that is qualified to participate in competitive Energy, Capacity, Operating Reserves or Regulation Service markets, or in the Emergency Demand Response Program pursuant to this ISO Services Tariff and the ISO Procedures.

**Dennison Scheduled Line:** A transmission facility that interconnects the NYCA to the Hydro Quebec Control Area at the Dennison substation, located near Massena, New York and extends through the province of Ontario, Canada (near the City of Cornwall) to the Cedars substation in Quebec, Canada.

**Dependable Maximum Net Capability (“DMNC”):** The sustained maximum net output of a Generator, as demonstrated by the performance of a test or through actual operation, averaged over a continuous time period as defined in the ISO Procedures.

**Desired Net Interchange (“DNI”):** A mechanism used to set and maintain the desired Energy interchange (or transfer) between two Control Areas; it is scheduled ahead of time and can be changed manually in real-time.

**Direct Sale:** The sale of TCCs directly to a buyer by the Primary Owner through a non-discriminatory auditable sale conducted on the ISO’s OASIS, in compliance with the requirements and restrictions set forth in Commission Order Nos. 888 et seq. and 889 et seq.

**Dispatchable:** A bidding mode in which Generators or Demand Side Resources indicate that they are willing to respond to real-time control from the ISO. Dispatchable Generators may be either ISO-Committed Flexible or Self-Committed Flexible. Dispatchable Demand Side Resources must be ISO-Committed Flexible. Dispatchable Resources that are not providing Regulation Service will follow five-minute RTD Base Point Signals. Dispatchable Resources that are providing Regulation Service will follow six-second AGC Base Point Signals.

**Dispatch Day:** The twenty-four (24) hour (or, if appropriate, the twenty-three (23) or twenty-five (25) hour) period commencing at the beginning of each day (0000 hour).

**Dispute Resolution Administrator (“DRA”):** An individual hired by the ISO to administer the Expedited Dispute Resolution Procedures in Section 5.16 of the ISO Services Tariff.

**DMNC Test Period:** The period within a Capability Period during which a Resource required to do so pursuant to ISO procedures shall conduct a DMNC test if that DMNC test is to be valid for purposes of determining the amount of Installed Capacity used to calculate the Unforced Capacity that this Resource is permitted to supply to the NYCA. Such periods will be established pursuant to the ISO Procedures.

**DSASP Component:** The credit requirement for a Demand Side Resource to offer Ancillary Services, and a component of the Operating Requirement, calculated in accordance with Section 26.4.2 of Attachment K to this Services Tariff.

**Dynamically Scheduled Proxy Generator Bus:** A Proxy Generator Bus for which the ISO may schedule Transactions at 5 minute intervals in real time. Dynamically Scheduled Proxy Generator Buses are identified in Section 4.4.4 of the Services Tariff.

## **4.1 Market Services - General Rules**

### **4.1.1 Overview**

Market Services include all services and functions performed by the ISO under this Tariff related to the sale and purchase of Energy, Capacity or Demand Reductions, and the payment to Suppliers who provide Ancillary Services in the ISO Administered Markets.

### **4.1.2 Independent System Operator Authority**

The ISO shall provide all Market Services in accordance with the terms of the ISO Services Tariff and the ISO Related Agreements. The ISO shall be the sole point of Application for all Market Services provided in the NYCA. Each Market Participant that sells or purchases Energy, including Demand Side Resources, Special Case Resources and Emergency Demand Response Program participants, sells or purchases Capacity, or provides Ancillary Services in the ISO Administered Markets utilizes Market Services and must take service as a Customer under this Tariff and enter into a Service Agreement under the Tariff, as set forth in Attachment A; each entity that withdraws Energy to supply Load within the NYCA or provides Installed Capacity to an LSE serving Load within the NYCA utilizes the Control Area Services provided by the ISO and benefits from the reliability achieved as a result of ISO Control Area Services, must take service as a Customer under this Tariff and enter into a Service Agreement under this Tariff, as set forth in Attachment A; and each entity that has its virtual bids accepted and thereby engages in Virtual Transactions and each entity that purchases Transmission Congestion Contracts, excluding Transmission Congestion Contracts that are created prior to January 1, 2010, utilizes Market Services and must take service as a Customer under this Tariff and enter into a Services Agreement under this Tariff, as set forth in Attachment A. Each Customer that

utilizes Market Services also utilizes Transmission Service and shall obtain Transmission Service under the ISO OATT.

#### **4.1.3 Informational and Reporting Requirements**

The ISO shall operate and maintain an OASIS, including a Bid/Post System that will facilitate the posting of Bids to supply Energy, Ancillary Services and Demand Reductions by Suppliers for use by the ISO and the posting of Locational Based Marginal Prices (“LBMP”) and schedules for accepted Bids for Energy, Ancillary Services and Demand Reductions. The Bid/Post System will be used to post schedules for Bilateral Transactions. The Bid Post System also will provide historical data regarding Energy and Capacity market clearing prices in addition to Congestion Costs.

#### **4.1.4 Scheduling Prerequisites**

Pursuant to ISO Procedures, each Transaction offered in the Energy, Installed Capacity, Ancillary Services or Transmission Congestion Contract market shall be subject to a minimum size of one (1) megawatt (“MW”), provided however, Regulation Service may be offered in tenths of a MW and provided further, pursuant to ISO Procedures, Special Case Resources may offer a minimum of 100 kW of Unforced Capacity in the Installed Capacity Market. Each Transaction above one (1) megawatt may be scheduled in tenths of a megawatt provided, however, Bilateral Transactions and External Transactions in the LBMP Market must be bid and scheduled in increments of one (1) megawatt.

#### **4.1.5 Communication Requirements for Market Services**

Customers and Transmission Customers shall utilize Internet service providers to access the ISO’s OASIS and bid/post system. Customers shall arrange for and maintain all

communications facilities for the purpose of communication of commercial data to the ISO.

Each Customer shall be the customer of record for the telecommunications facilities and services its uses and shall assume all duties and responsibilities associated with the procurement, installation and maintenance of the subject equipment and software.

#### **4.1.6 Customer Responsibilities**

All purchasers in the Day-Ahead or Real-Time Markets who withdraw Energy within the NYCA or at an NYCA Interconnection with another Control Area must obtain Transmission Service under the ISO OATT. All Customers requesting service under the ISO Services Tariff to engage in Virtual Transactions must obtain Transmission Service under the ISO OATT.

All LSEs serving Load in the NYCA must comply with the Installed Capacity requirements set forth in Article 5 of this ISO Services Tariff.

All Customers taking service under the ISO Services Tariff must pay the Market Administration and Control Area Services Charge, as specified in Rate Schedule 1 of this ISO Services Tariff.

A Supplier with a Generator or Demand Side Resource with a real time physical operating problem that makes it impossible for it to operate in the bidding mode in which it was scheduled shall notify the NYISO.

#### **4.1.7 Customer Compliance with Laws, Regulations and Orders**

All Customers shall comply with all applicable federal, state and local laws, regulations and orders, including orders from the ISO.

4.1.7.1 Violations of FERC's orders, rules and regulations also violate this

Section 4.1.7 of the ISO Services Tariff. In particular, if FERC or a court of competent jurisdiction determines there has been a violation of FERC's

regulations related to electric energy market manipulation (see 18 C.F.R. Section 1c.2, or any successor provision thereto), such violation is also a violation of this ISO Services Tariff if such violation affects or is related to the ISO Administered Markets.

4.1.7.2 If the ISO becomes aware that a Customer may be engaging in, or might have engaged in, electric energy market manipulation, it shall promptly inform its Market Monitoring Unit.

4.1.7.3 This Section 4.1.7 of the ISO Services Tariff does not independently empower the ISO or its Market Monitoring Unit to impose penalties for, or to provide a remedy for, violations of FERC's prohibition against electric energy market manipulation, or for other violations of the ISO's Tariffs.

#### **4.1.8 Commitment for Reliability**

Suppliers with generating units committed by the ISO for service to ensure NYCA reliability or local system reliability will recover startup and minimum generation costs that were not bid, that were not known before the close of the Real-Time Scheduling Window, and that were not recovered in the Dispatch Day, provided however, eligibility to recover such additional costs shall not be available for megawatts scheduled Day-Ahead. Payment for such costs shall be determined, as if bid, pursuant to the provisions of Attachment C of this Tariff. Payments for securing NYCA reliability and local system reliability shall be recovered by the ISO in accordance with Rate Schedule 1 of the ISO OATT.

Re-dispatching costs incurred as a result of reductions in Transfer Capability caused by Storm Watch ("Storm Watch Costs") shall be aggregated and recovered on a monthly basis by the ISO exclusively from Transmission Customers in Load Zone J. The ISO shall calculate



Storm Watch Costs by multiplying the real-time Shadow Price of any binding constraint associated with a Storm Watch, by the higher of (a) zero; or (b) the scheduled Day-Ahead flow across the constraint minus the actual real-time flow across the constraint.

#### **4.1.9 Cost Recovery for Units Responding to Local Reliability Rule I-R3 or I-R5**

##### **4.1.9.1 Eligibility for Cost Recovery**

Generating units designated pursuant to the New York State Reliability Council's Local Reliability Rule I-R3 -- Loss of Generator Gas Supply (New York City) or I-R5 -- Loss of Generator Gas Supply (Long Island), as being required to burn an alternate fuel at designated minimum levels based on forecast Load levels in Load Zones J and K (for purposes of this Section 4.1.9, "Eligible Units"), shall be eligible to recover costs associated with burning the required alternate fuel pursuant to the provisions of this Section 4.1.9. For purposes of this Section 4.1.9, the periods of time for which Local Reliability Rule I-R3 or I-R5 is invoked and in which the Eligible Unit burns its required alternate fuel, including that period of time required to move into and out of Rule I-R3 or I-R5 compliance, shall be referred to as the "Eligibility Period."

##### **4.1.9.2 Variable Operating Cost Recovery**

For Eligibility Periods, the Eligible Unit shall recover costs that vary with the amount of alternate fuel burned because Local Reliability Rule I-R3 or I-R5 was invoked ("variable operating costs") if: (i) such costs are not reflected in the reference level for that Eligible Unit for the hours included in the Eligibility Period, pursuant to ISO Procedures, and (ii) the hour is one for which the commodity cost of the alternate fuel including taxes and emission allowance costs is greater than the commodity cost for natural gas, including taxes and emission allowance costs, as determined by the ISO. These relative commodity cost determinations shall use the same

indices used by the ISO to establish daily Reference Levels. Variable operating costs shall include the commodity cost, associated taxes and emission allowance costs, of the required alternate fuel burned during an Eligibility Period pursuant to Rule I-R3 or I-R5.

#### **4.1.9.3 Additional Cost Recovery**

An eligible unit that seeks to recover costs incurred in connection with its compliance with Rule I-R3 or I-R5, in addition to the commodity cost, associated taxes and emission allowance cost recovery specified in Section 4.1.9.2, shall negotiate an Implementation Agreement with the ISO. The eligible unit and the ISO shall consult with and consider the input of the New York State Public Service Commission, and the Transmission Owner designated by Rule I-R3 or I-R5. Such Implementation Agreements shall specify, among other terms and conditions, the facilities (or portions of facilities) used to meet obligations under Rule I-R3 or I-R5. The Implementation Agreement shall indicate the rate to be charged during the period of the Implementation Agreement to recover such additional costs.

The Implementation Agreement may also include costs in addition to commodity cost, associated taxes and emission allowance costs of the alternate fuel incurred in connection with compliance with Rule I-R3 or I-R5 that vary with the amount of alternate fuel burned because I-R3 or I-R5 was invoked. These variable costs shall be paid pursuant to Section 4.1.9.2 as variable operating costs so as to not duplicate payments.

Each such Implementation Agreement shall have a duration of one or more Capability Periods and shall commence at the beginning of a Capability Period unless another date is approved by the Commission. If the Eligible Unit and the ISO reach agreement on the terms and conditions of the Implementation Agreement, the ISO shall file it with the Commission for its review and acceptance.

In the event that the Eligible Unit and the ISO have not come to an agreement six months prior to the beginning of the Capability Period that the Implementation Agreement is intended to govern, then either one of them may request the assistance of the Commission's Dispute Resolution Service. If the Dispute Resolution Service agrees to provide its assistance the Eligible Unit and the ISO shall participate in whatever dispute resolution process the Dispute Resolution Service may recommend. The Commission's Dispute Resolution Service may include other stakeholders to the extent confidentiality protections are in place. If, however, there is no agreement four months prior to the beginning of the relevant Capability Period then the Eligible Unit and the ISO may each file an unexecuted Implementation Agreement for the Commission's review and acceptance.

In the event that any provisions of this Section 4.1.9 are modified prior to the termination date of any Commission-accepted Implementation Agreement, such Implementation Agreement will remain in full force and effect until it expires in accordance with its contractual terms and conditions.

Rules for establishing Eligibility Periods shall be specified in ISO Procedures.

#### **4.1.9.4 Billing**

Payments made by the ISO to the Eligible Unit to pay variable operating costs and to pay the rate established by the Implementation Agreement pursuant to this Section 4.1.9 shall be in addition to any LBMP, Ancillary Service or other revenues received as a result of the Eligible Unit's Day-Ahead or Real-Time dispatch for that day. Payment by the ISO of variable operating costs pursuant to Section 4.1.9.2 shall be based on the Eligibility Period, quantity of alternate fuel burned, and relative costs of alternate fuel compared to natural gas. Payment by the ISO of the rate established in the Implementation Agreement for costs incurred other than

variable operating costs shall be made as part of the ISO billing cycle regardless of whether an alternate fuel is burned pursuant to I-R3 or I-R5 and regardless of the relative cost of the alternate fuel compared to natural gas reflected in reference levels.

#### **4.1.9.5 Other Provisions**

The ISO shall make available for the Transmission Owner in whose subzone the Generator is located: (i) the identity of Generators determined by the ISO to be eligible to recover the costs associated with burning the required alternate fuel pursuant to the provisions of this Section 4.1.9; (ii) the start and stop hours for each claimed Eligibility Period and (iii) the amount of alternate fuel for which the Generator has sought to recover variable operating costs.

## **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**

By 5 a.m., on the day prior to the Dispatch Day (or by 4:50 a.m. for Customers or Transmission Customers seeking to schedule External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line): (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:

4.2.1.1.1 Bids to supply Energy, including Bids to supply Energy in Virtual Transactions;

4.2.1.1.2 Bids to supply Ancillary Services;

4.2.1.1.3 Requests for Bilateral Transaction schedules;

4.2.1.1.4 Bids to purchase Energy, including Bids to purchase Energy in Virtual Transactions; and

4.2.1.1.5 Demand Reduction Bids.

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 commitment 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 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 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 offers by Intermittent Power Resources that depend on wind 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 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.

#### **4.2.1.3.3 Upper 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 Suppliers for Generators 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

Operating Capacity per minute. All Bids from Suppliers for Generators 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.

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.

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

Self-Committed Fixed Generators shall provide the ISO with a schedule of their expected Energy output for each hour. Self-Committed Fixed Generators are responsible for ensuring that any hourly changes in output are consistent with their response rates. Self-Committed Fixed Generators shall also submit  $UOL_{NS}$ ,  $UOL_{ES}$  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.

#### **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).

#### **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: (i) bid in whole megawatts and (ii) identify the amount of demand in megawatts, that is available for commitment in the Day-Ahead Market (for every hour of the dispatch day) and (iii) identify 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. Following the posting of the Monthly Net Benefit Offer Floor, the ISO shall monitor the gas prices utilized in the Net Benefits Test and recalculate the Monthly Net Benefit Offer Floor in the event that such prices vary by more than \$0.75/mmBTU, as measured on the last gas trading day that is no less than 4 business days prior to the first day of the Study Month. The ISO shall post any recalculated Monthly Net Benefit Offer Floor to its website in accordance with ISO Procedures.

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 power 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 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 to provide for the safe and reliable operation of the NYS Power System. 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 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 as their POWs; (iv) price Bids and operating Constraints submitted for Generators or for Demand Side Resources; (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 as their POWs.

In the development of its SCUC schedule, the ISO may commit and de-commit Generators and Demand Side Resources, 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 the ISO shall commit zero megawatts of Energy for Demand Side Resources committed to provide Operating Reserves and Regulation Service.

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 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 units.

All Generator 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 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.

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

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  $UOL_{NS}$ , up to the level of their  $UOL_{ES}$  (pursuant to ISO Procedures) and/or raise the  $UOL_{NS}$  of Capacity Limited Resources and Energy Limited Resources to their  $UOL_E$  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 as described in Attachment B. Each Supplier that bids a Generator into the ISO Day-Ahead Market and is scheduled in the SCUC to sell Energy in the Day-Ahead Market will be paid the product of: (a) the Day-Ahead hourly LBMP at the applicable Generator bus; 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 paid 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 paid 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.