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 26.3.2 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 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 Dispute Resolution Process established in the ISO Tariffs and ISO Agreement.

Dispute Resolution Process ("DRP"): The procedures: (1) described in the ISO Tariffs and the ISO Agreement that are used to resolve disputes between Market Participants and the ISO involving services provided under the ISO Tariffs (excluding applications for rate changes or other changes to the ISO Tariffs or rules relating to such services); and (2) described in the ISO/NYSRC Agreement that are used to resolve disputes between the ISO and NYSRC involving the implementation and/or application of the Reliability Rules.

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 26.3.2 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.

2.5 Definitions - E

East of Central-East: An electrical area comprised of Load Zones F, G, H, I, J, and K, as identified in the ISO Procedures.

East of Central-East Excluding Long Island: An electrical area comprised of Load Zones F, G, H, I, and J, as identified in the ISO Procedures.

East of Central-East Excluding New York City and Long Island: An electrical area comprised of Load Zones F, G, H, and I, as identified in the ISO Procedures.

Economic Operating Point: The megawatt quantity which is a function of: i) the real-time LBMP at the Resource bus; and ii) the Supplier's real-time eleven constant cost step Energy Bid, for the Resource, such that (a) the offer price associated with Energy offers below that megawatt quantity (if that megawatt quantity is not that Resource's minimum output level) must be less than or equal to the real-time LBMP at the Resource bus, and (b) the offer price associated with Energy offers above that megawatt quantity (if that megawatt quantity is not that Resource's maximum output level) must be greater than or equal to the real-time LBMP at the Resource bus. In cases where multiple megawatt values meet conditions (a) and (b), the Economic Operating Point is the megawatt value meeting these conditions that is closest to the Resource's real-time scheduled Energy injection. In cases where the Economic Operating Point would be less than the minimum output level, the Economic Operating Point will be set equal to the MW value of the first point on the Energy Bid curve and in cases where the Economic Operating Point would be greater than the maximum output level, the Economic Operating Point will be set equal to the MW value of the last point on the Energy Bid curve.

Emergency: Any abnormal system condition that requires immediate automatic or manual action to prevent or limit loss of transmission facilities or Generators that could adversely affect the reliability of an electric system.

Emergency Demand Response Program ("EDRP"): A program pursuant to which the ISO makes payments to Curtailment Service Providers that voluntarily take effective steps in real time, pursuant to ISO procedures, to reduce NYCA demand in Emergency conditions.

Emergency State: The state that the NYS Power System is in when an abnormal condition occurs that requires automatic or immediate, manual action to prevent or limit loss of the NYS Transmission System or Generators that could adversely affect the reliability of the NYS Power System.

Emergency Upper Operating Limit (UOL_E): The upper operating limit that a Generator indicates it expects to be able to reach, or the maximum amount of demand that a Demand Side Resource expects to be able to reduce, at the request of the ISO during extraordinary conditions. Each Generator or Demand Side Resource shall specify a UOL_E in its bids that shall be equal to or greater than its stated Normal Upper Operating Limit.

Energy (“MWh”): A quantity of electricity that is bid, produced, purchased, consumed, sold, or transmitted over a period of time, and measured or calculated in megawatt hours.

Energy and Ancillary Services Component: A component of the Operating Requirement, calculated in accordance with Section 26.3.2 of Attachment K to this Services Tariff.

Energy Limited Resource: Capacity resources that, due to environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis, but are able to operate for at least four consecutive hours each day. Energy Limited Resources must register their Energy limiting characteristics with, and justify them to, the ISO consistent with ISO Procedures.

Energy Profile MW: The maximum schedule desired for an External Transaction. Import, Export and Wheels Through Transactions will specify the Energy Profile MW in their Bid.

Equivalent Demand Forced Outage Rate: The portion of time a unit is in demand, but is unavailable due to forced outages.

Equivalency Rating: A rating determined by the ISO, at a Customer’s request, based on the ISO’s financial evaluation of an Unrated Customer that shall serve as the starting point of the ISO’s determination of an amount of Unsecured Credit to be granted to the Customer, if any, as provided in Table K-1 of Attachment K to this Services Tariff.

ETA Agent: A Customer of the ISO that has been appointed by a Load Serving Entity and approved by the ISO in accordance with ISO Procedures for the purpose of enabling that Customer to hold all of the rights and obligations associated with Fixed Price TCCs, as provided for in this Services Tariff.

ETCNL TCC: A TCC created when a Transmission Owner with ETCNL exercises its right to convert a megawatt of ETCNL into a TCC pursuant to Section 19.4.1 of Attachment M of the OATT.

Excess Amount: The difference, if any, between the dollar amounts charged to purchasers of Unforced Capacity in an ISO–administered Unforced Capacity auction and the dollar amounts paid to sellers of Unforced Capacity in that ISO–administered Installed Capacity auction.

Excess Congestion Rents: Congestion revenues in the Day-Ahead Market for Energy collected by the ISO that are in excess of its Day-Ahead payment obligations. Excess Congestion Rents may arise if Congestion occurs in the Day-Ahead Market for Energy and if the Day-Ahead Transfer Capability of the transmission system is not exhausted by the set of TCCs and Grandfathered Rights that have been allocated at the completion of the last Centralized TCC Auction.

Existing Transmission Capacity for Native Load ("ETCNL"): Transmission Capacity reserved on a Transmission Owner's transmission system to serve the Native Load Customers of the current Transmission Owners (as of the filing date of the original ISO Tariff - January 31, 1997). This includes transmission Capacity required: (1) to deliver the output from operating facilities located out of a Transmission Owner's Transmission District; (2) to deliver power purchased under power supply contracts; and (3) to deliver power purchased under third party agreements (i.e., Non-Utility Generators). Existing Transmission Capacity for Native Load is listed in Attachment L of the ISO OATT.

Existing Transmission Agreement ("ETA"): An agreement between two or more Transmission Owners, or between a Transmission Owner and another entity, as defined in the ISO Agreement and the ISO OATT.

Expected Load Reduction: For purposes of determining the Real-Time Locational Based Marginal Price, the reduction in Load expected to be realized in real-time from activation of the Emergency Demand Response Program and from Load reductions requested from Special Case Resources, as established pursuant to ISO Procedures.

Expedited Dispute Resolution Procedures: The dispute resolution procedures applicable to disputes arising out of the Installed Capacity provisions of this ISO Services Tariff (as set forth in Section 5.16) and the Customer settlements provisions of this ISO Services Tariff (as set forth in Section 7.4.3).

Exports: A Bilateral Transaction or purchases from the LBMP Market where the Energy is delivered to an NYCA Interconnection with another Control Area.

External: An entity (e.g., Supplier, Transmission Customer) or facility (e.g., Generator, Interface) located outside the Control Area being referenced or between two or more Control Areas. Where a specific Control Area is not referenced, the NYCA is the intended reference.

External Transactions: Purchases, sales or exchanges of Energy, Capacity or Ancillary Services for which either the Point of Injection ("POI") or Point of Withdrawal ("POW") or both are located outside the NYCA (i.e., Exports, Imports or Wheels Through).

2.18 Definitions - R

Ramp Capacity: The amount of change in the Desired Net Interchange that generation located in the NYCA can support at any given time. Ramp capacity may be calculated for all Interfaces between the NYCA and neighboring Control Areas as a whole or for any individual Interface between the NYCA and an adjoining Control Area.

RCRR TCC:: A zone-to-zone TCC created when a Transmission Owner with a RCRR exercises its right to convert the RCRR into a TCC pursuant to Section 19.5.4 of Attachment M of the ISO OATT.

Reactive Power (MVAr): The product of voltage and the out-of-phase component of alternating current. Reactive Power, usually measured in MVAr, is produced by capacitors (synchronous condensers), Qualified Non-Generator Voltage Support Resources, and over-excited Generators and absorbed by reactors or under-excited Generators and other inductive devices including the inductive portion of Loads.

Real Power Losses: The loss of Energy, resulting from transporting power over the NYS Transmission System, between the Point of Injection and Point of Withdrawal of that Energy.

Real-Time Bid: A Bid submitted into the Real-Time Commitment before the close of the Real-Time Scheduling Window.

Real-Time Commitment ("RTC"): A multi-period security constrained unit commitment and dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves and Regulation Service on a least as-bid production cost basis over a two hour and fifteen minute optimization period. The optimization evaluates the next ten points in time separated by fifteen minute intervals. Each RTC run within an hour shall have a designation indicating the time at which its results are posted; "$RTC_{00,}$" "$RTC_{15,}$" "$RTC_{30,}$" and "RTC_{45}" post on the hour, and at fifteen, thirty, and forty-five minutes after the hour, respectively. Each RTC run will produce binding commitment instructions for the periods beginning fifteen and thirty minutes after its scheduled posting time and will produce advisory commitment guidance for the remainder of the optimization period. RTC_{15} will also establish hourly External Transaction schedules, while all RTC runs may establish 15 minute External Transaction schedules at Variably Scheduled Proxy Generator Buses. Additional information about RTC's functions is provided in Section 4.4.2 of this ISO Services Tariff.

Real-Time Dispatch ("RTD"): A multi-period security constrained dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least-as-bid production cost basis over a fifty, fifty-five or sixty-minute period (depending on when each RTD run occurs within an hour). The Real-Time Dispatch dispatches, but does not commit, Resources, except that RTD may commit, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting in ten minutes. RTD may also establish 5 minute External Transaction schedules at Dynamically Scheduled Proxy Generator Buses. Real-Time Dispatch runs will normally occur every five minutes. Additional information about RTD's functions is provided in Section 4.4.3 of this ISO Services Tariff. Throughout this ISO Services Tariff the term "RTD" will normally be used to refer to both the Real-Time Dispatch and to the specialized Real-Time Dispatch Corrective Action Mode software.

Real-Time Dispatch–Corrective Action Mode ("RTD-CAM"): A specialized version of the Real-Time Dispatch software that will be activated when it is needed to address unanticipated system conditions. RTD-CAM is described in Section 4.4.4 of this ISO Services Tariff.

Real-Time LBMP: The LBMPs established through the ISO Administered Real-Time Market.

Real-Time Market: The ISO Administered Markets for Energy and Ancillary Services resulting from the operation of the RTC and RTD.

Real-Time Minimum Run Qualified Gas Turbine: One or more gas turbines, offered in the Real-Time Market, which, because of their physical operating characteristics, may qualify for a minimum run time of two hours in the Real-Time Market. Characteristics that qualify gas turbines for this treatment are established by ISO Procedures and include using waste heat from the gas turbine-generated electricity to make steam for the generation of additional electricity via a steam turbine.

Real-Time Scheduled Energy: The quantity of Energy that a Supplier is directed to inject or withdraw in real-time by the ISO. Injections are indicated by positive Base Point Signals and withdrawals are indicated by negative Base Point Signals. Unless otherwise directed by the ISO, Dispatchable Supplier's Real-Time Scheduled Energy is equal to its RTD Base Point Signal, or, if it is providing Regulation Service, to its AGC Base Point Signal, and an ISO Committed Fixed or Self-Committed Fixed Supplier's Real-Time Scheduled Energy is equal to its bid output level in real-time.

Real-Time Scheduling Window: The period of time within which the ISO accepts offers and bids to sell and purchase Energy and Ancillary Services in the Real-Time Market for a given hour which period closes seventy-five (75) minutes before the start of that hour, or eighty-five (85) minutes before the start of that hour for Bids to schedule External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line.

Reconfiguration Auction: The monthly auction administered by the ISO in which Market Participants may purchase and sell one-month TCCs.

Reduction or Reduce: The partial or complete reduction in Non-Firm Transmission Service as a result of transmission Congestion (either anticipated or actual).

Reference Bus: The location on the NYS Transmission System relative to which all mathematical quantities, including Shift Factors and penalty factors relating to physical operation, will be calculated. The NYPA Marcy 345 kV transmission substation is designated as the Reference Bus.

Regulation Service Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Regulation Service corresponding to each possible quantity of Resources that the ISO's software may schedule to satisfy the ISO's Regulation Service constraint. A single Regulation Service Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for Regulation Service. The Shadow Price for Regulation Service shall be used to calculate Regulation Service payments under Rate Schedule 3 of this ISO Services Tariff.

Regulation Revenue Adjustment Charge ("RRAC"): A charge that will be assessed against certain Generators that are providing Regulation Service under Section 15.3.6 of Rate Schedule 3 to this ISO Services Tariff.

Regulation Revenue Adjustment Payment ("RRAP"): A payment that will be made to certain Generators that are providing Regulation Service under Section 15.3.6 of Rate Schedule 3 to this ISO Services Tariff.

Reliability Rules: Those rules, standards, procedures and protocols developed and promulgated by the NYSRC, including Local Reliability Rules, in accordance with NERC, NPCC, FERC, PSC and NRC standards, rules and regulations and other criteria and pursuant to the NYSRC Agreement.

Required System Capability: Generation capability required to meet an LSE's peak Load plus Installed Capacity Reserve obligation as defined in the Reliability Rules.

Reserve Performance Index: An index created by the ISO for the purpose of calculating the Day Ahead Margin Assurance Payment pursuant to Attachment J of this Services Tariff made to Demand Side Resources scheduled to provide Operating Reserves in the Day-Ahead Market.

Residual Adjustment: The adjustment made to ISO costs that are recovered through Schedule 1 of the OATT. The Residual Adjustment is calculated pursuant to Schedule 1 of the OATT.

Residual Capacity Reservation Right ("RCRR"):A megawatt of transmission Capacity from one Load Zone to an electrically contiguous Load Zone, each of which is internal to the NYCA, that may be converted into an RCRR TCC by a Transmission Owner allocated the RCRR pursuant to Section 19.5 of Attachment M of the ISO OATT.

Residual Transmission Capacity: The transmission capacity determined by the ISO before, during and after the Centralized TCC Auction which is conceptually equal to the following:

Residual Transmission Capacity = TTC - TRM - CBM - GTR - GTCC - ETCNL

The TCCs associated with Residual Transmission Capacity cannot be accurately determined until the Centralized TCC Auction is conducted.

TTC is the Total Transfer Capability that can only be determined after the Residual Transmission Capacity is known.

GTR is the transmission capacity associated with Grandfathered Rights.

GTCC is the transmission capacity associated with Grandfathered TCCs.

ETCNL is the transmission capacity associated with Existing Transmission Capacity for Native Load.

TRM is the Transmission Reliability Margin.

CBM is the Capacity Benefit Margin.

Resource: An Energy Limited Resource, Generator, Installed Capacity Marketer, Special Case Resource, Intermittent Power Resource, Limited Control Run of River Hydro Resource, municipally-owned generation, System Resource, Demand Side Resource or Control Area System Resource.

Rest of State: The set of all non-Locality NYCA LBMP Load Zones. As of the 2002-2003 Capability Year, Rest of State includes all NYCA LBMP Load Zones other than LBMP Load Zones J and K.

Rolling RTC: The RTC run that is used to schedule a given 15-minute External Transaction. The Rolling RTC may be an RTC_{00}, RTC_{15}, RTC_{30} or RTC_{45} run.

2.19 Definitions - S

Safe Operations: Actions which avoid placing personnel and equipment in peril with regard to the safety of life and equipment damage.

Scheduled Energy Injections: As defined in the ISO OATT.

Scheduled Energy Withdrawals: As defined in the ISO OATT.

Scheduled Line: A transmission facility or set of transmission facilities: (a) that provide a distinct scheduling path interconnecting the ISO with an adjacent control area, (b) over which Customers are permitted to schedule External Transactions, (c) for which the ISO separately posts TTC and ATC, and (d) for which there is the capability to maintain the Scheduled Line actual interchange at the DNI, or within the tolerances dictated by Good Utility Practice. Each Scheduled Line is associated with a distinct Proxy Generator Bus. Transmission facilities shall only become Scheduled Lines after the Commission accepts for filing revisions to the NYISO's tariffs that identify a specific set or group of transmission facilities as a Scheduled Line. The following transmission facilities are Scheduled Lines: the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Dennison Scheduled Line, the Northport Norwalk Scheduled Line, and the Linden VFT Scheduled Line.

SCUC: Security Constrained Unit Commitment, described in Section 4.2.4 of this ISO Services Tariff.

Secondary Holders: Entities that: (1) purchase TCCs in the Secondary Market; (2) purchase TCCs in a Direct Sale from a Transmission Owner and have not been certified as a Primary Holder by the ISO; or (3) receive an allocation of Native Load TCCs from a Transmission Owner (See Attachment M). A Transmission Customer purchasing TCCs in a Direct Sale may qualify as a Primary Holder with respect to those TCCs purchased in that Direct Sale.

Second Settlement: The process of: (1) identifying differences between Energy production, Energy consumption or NYS Transmission System usage scheduled in a First Settlement and actual production, consumption, or usage during the Dispatch Day; and (2) assigning financial responsibility for those differences to the appropriate Customers and Market Participants. Charges for Energy supplied (to replace generation deficiencies or unscheduled consumption), and payments for Energy consumed (to absorb consumption deficiencies or excess Energy supply) or changes in transmission usage will be based on the Real-Time LBMPs.

Secondary Market: A market in which Primary and Secondary Holders sell TCCs by mechanisms other than through the Centralized TCC Auction or by Direct Sale. Buyers of TCCs in the Secondary Market shall neither pay nor receive Congestion Rents directly to or from the ISO.

Security Coordinator: An entity that provides the security assessment and Emergency operations coordination for a group of Control Areas. A Security Coordinator must not participate in the wholesale or retail merchant functions.

Self-Committed Fixed: A bidding mode in which a Generator is self-committed and opts not to be Dispatchable over any portion of its operating range.

Self-Committed Flexible: A bidding mode in which a Dispatchable Generator follows Base Point Signals within a portion of its operating range, but self-commits.

Self-Supply: The provision of certain Ancillary Services, or the provision of Energy to replace Marginal Losses by a Transmission Customer using either the Transmission Customer's own Generators or generation obtained from an entity other than the ISO.

Service Agreement: The agreement, in the form of Attachment A to the Tariff, and any amendments or supplements thereto entered into by a Customer and the ISO of service under the Tariff, or any unexecuted Service Agreement, amendments or supplements thereto, that the ISO unilaterally files with the Commission.

Service Commencement Date: The date that the ISO begins to provide service pursuant to the terms of a Service Agreement, or in accordance with the Tariff.

Settlement: The process of determining the charges to be paid to, or by, a Customer to satisfy its obligations.

Shadow Price: The marginal value of relieving a particular Constraint which is determined by the reduction in system cost that results from an incremental relaxation of that Constraint.

Shift Factor ("SF"): A ratio, calculated by the ISO, that compares the change in power flow through a transmission facility resulting from the incremental injection and withdrawal of power on the NYS Transmission System.

Shutdown Period: An ISO approved period of time immediately following a shutdown order, such as a zero base point, that has been designated by the Customer, during which unstable operation prevents the unit from accurately following its base points.

Sink Price Cap Bid: A monotonically increasing Bid curve provided by an entity engaged in an Export to indicate the relevant Proxy Generator Bus LBMP below which that entity is willing to either purchase Energy in the LBMP Markets or, in the case of Bilateral Transactions, to accept Transmission Service, where the MW amounts on the Bid curve represent the desired increments of Energy that the entity is willing to purchase at various price points.

Special Case Resource: Demand Side Resources capable of being interrupted upon demand, and Local Generators, rated 100 kW or higher, that are not visible to the ISO's Market Information System and that are subject to special rules, set forth in Section 5.12.11.1 of this ISO Services Tariff and related ISO Procedures, in order to facilitate their participation in the Installed Capacity market as Installed Capacity Suppliers. Special Case Resources that are not Local Generators, may be offered as synchronized Operating Reserves and Regulation Service and Energy in the Day-Ahead Market. Special Case Resources, using Local Generators rated 100 kw or higher, that are not visible to the ISO's Market Information System may also be offered as non-synchronized Operating Reserves.

Special Case Resource Capacity: The Installed Capacity Equivalent of the Unforced Capacity which has been sold by a Special Case Resource in the Installed Capacity market during the current Capability Period.

Start-Up Period: An ISO approved period of time immediately following synchronization to the Bulk power system, which has been designated by a Customer and bid into the Real-Time Market, during which unstable operation prevents the unit from accurately following its base points.

Station Power: Station Power shall mean the Energy used by a Generator:

1. for operating electric equipment located on the Generator site, or portions thereof, owned by the same entity that owns the Generator, which electrical equipment is used by the Generator exclusively for the production of Energy and any useful thermal energy associated with the production of Energy; and

2. for the incidental heating, lighting, air conditioning and office equipment needs of buildings, or portions thereof, that are: owned by the same entity that owns the Generator; located on the Generator site; and

3. used by the Generator exclusively in connection with the production of Energy and any useful thermal energy associated with the production of Energy.

Station Power does not include any Energy: (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility or for charging a Limited Energy Storage Resource; or (iii) provided during a Black Start restoration by Generators that provide Black Start Capability Service.

Start-Up Bid: A Bid parameter that may vary hourly and that identifies the payment a Supplier requires to bring a Generator up to its specified minimum operating level from an offline state or a Demand Side Resource from a level of no Demand Reduction to its specified minimum level of Demand Reduction.

Start-Up Bids submitted for a Generator that is not able to complete its specified minimum run time (of up to a maximum of 24 hours) within the Dispatch Day are expected to include expected net costs related to the hour(s) that a Generator needs to run on the day following the Dispatch Day in order to complete its minimum run time. The component of the Start-Up Bid that incorporates costs that the Generator expects to incur on the day following the Dispatch Day is expected to reflect the operating costs that the Supplier does not expect to be able to recover through LBMP revenues while operating to meet the Generator's minimum run time, at the minimum operating level Bid for that Generator for the hour of the Dispatch Day in which the Generator is scheduled to start-up. Settlement rules addressing Start-Up Bids that incorporates costs related to the hours that a Generator needs to run on the day following the Dispatch Day on which the Generator is committed are set forth in Attachment C to this ISO Services Tariff.

Storm Watch: Actual or anticipated severe weather conditions under which region-specific portions of the NYS Transmission System are operated in a more conservative manner by reducing transmission transfer limits.

Strandable Costs: Prudent and verifiable expenditures and commitments made pursuant to a Transmission Owner's legal obligations that are currently recovered in the Transmission Owner's retail or wholesale rate that could become unrecoverable as a result of a restructuring of the electric utility industry and/or electricity market, or as a result of retail-turned-wholesale customers, or customers switching generation or Transmission Service suppliers.

Stranded Investment Recovery Charge: A charge established by a Transmission Owner to recover Strandable Costs.

Subzone: That portion of a Load Zone in a Transmission Owner's Transmission District.

Supplemental Event Interval: Any RTD interval in which there is a maximum generation pickup or a large event reserve pickup or which is one of the three RTD intervals following the termination of the maximum generation pickup or the large event reserve pickup.

Supplemental Resource Evaluation ("SRE"): A determination of the least cost selection of additional Generators, which are to be committed, to meet: (i) changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to meet the reliability requirements of the Transmission Owner's local system or to meet Load or reliability requirements of the ISO; or (ii) forecast Load and reserve requirements over the six-day period that follows the Dispatch Day.

Supplier: A Party that is supplying the Capacity, Demand Reduction, Energy and/or associated Ancillary Services to be made available under the ISO OATT or the ISO Services Tariff, including Generators and Demand Side Resources that satisfy all applicable ISO requirements.

System Resource: A portfolio of Unforced Capacity provided by Resources located in a single ISO-defined Locality, the remainder of the NYCA, or any single External Control Area, that is owned by or under the control of a single entity, which is not the operator of the Control Area where such Resources are located, and that is made available, in whole or in part, to the ISO.

2.22 Definitions - V

Variably Scheduled Proxy Generator Bus: A Proxy Generator Bus for which the ISO may schedule Transactions at 15 minute intervals in real time.

Virtual Load: Any Bid to purchase Energy in the Day-Ahead Market submitted at a load bus specified for Virtual Transactions.

Virtual Supply: Any Bid to sell Energy in the Day-Ahead Market submitted at a load bus specified for Virtual Transactions.

Virtual Transaction: Any Bid to purchase or sell Energy in the Day-Ahead Market submitted at a load bus specified for Virtual Transactions.

Virtual Transaction Component: A component of the Operating Requirement, calculated in accordance with Section 26.3.2 of Attachment K to this Services Tariff.

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 co-optimize to solve simultaneously for all Load, Operating Reserves and Regulation Service requirements 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.

4.4.1.2.1 Real-Time Bids to Supply Energy and Ancillary Services

Intermittent Power Resources that depend on wind as their fuel submitting new or revised offers to supply Energy shall bid as ISO-Committed Flexible and shall submit a Minimum

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

Suppliers bidding on behalf of Generators that did not receive a Day-Ahead schedule for a given hour may offer their Generators, for those hours, using the ISO-Committed Flexible, Self-Committed Flexible, Self-Committed Fixed bid mode or, with ISO approval, the ISO-Committed Fixed bid modes in real-time. 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 $75 /MW hour. A Supplier bidding on behalf of a Generator that received a Day-Ahead schedule for a given hour may not change the bidding mode for that Generator for the Real-Time Market for that hour provided, however, that Generators that were scheduled Day-Ahead in Self-Committed Fixed mode may switch, with ISO approval, to ISO-Committed Fixed bidding mode in real-time. Generators that were scheduled Day-Ahead in ISO-Committed Fixed mode will be scheduled as Self-Committed Fixed in the Real-Time Market unless, with ISO approval, they change their bidding mode to ISO-Committed Fixed.

A Generator with a real time physical operating problem that makes it impossible for it to operate in the bidding mode in which it was scheduled Day-Ahead should notify the NYISO.

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

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

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

Except as provided in this section, External Transaction Bids may not vary over the course of an hour. Each such Bid must offer to import, export or wheel the same amount of

Energy at the same price at each point in time within that hour. However, 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. External Transaction Bids submitted to import Energy from, export Energy to, or wheel Energy to or from Proxy Generator Buses that are authorized to schedule transactions on an intra-hour basis shall indicate whether the ISO may vary schedules associated with those Bids within each hour. Transmission Customers scheduling External Bilateral Transactions shall also be subject to the provisions of Section 16, Attachment J of the ISO OATT.

4.4.1.2.3 Self-Commitment Requests

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

4.4.1.2.4 ISO-Committed Fixed

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

RTC shall schedule ISO-Committed Fixed Generators.

4.4.1.3 External Transaction Scheduling

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

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

Except as specifically noted in Section 4.4.2, 4.4.3 and 4.4.4 of this ISO Services Tariff, RTC will make all Resource commitment and de-commitment decisions. RTC will make all economic commitment/de-commitment decisions based upon available offers assuming Suppliers internal to the NYCA have a one-hour minimum run time; provided however, Real-Time Minimum Run Qualified Gas Turbines shall be assumed to have a two-hour minimum run time.

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_{15} 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_{15} run, RTC will:

(i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;

(ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at their scheduled generation levels by that time;

(iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time;

(iv) Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information;

(v) Schedule economic hourly External Transactions for the next hour;

(vi) Schedule economic 15 minute External Transactions for the quarter hour for which the results of the RTC run following the next RTC run are posted at Variably Scheduled Proxy Generator Buses; and

(vii) Schedule ISO-Committed Fixed Resources.

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

(i) Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at that time;

(ii) Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at that time;

(iii) De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected at that time;

(iv) Issue advisory commitment, de-commitment, and dispatching guidance for the period from thirty minutes in the future until the end of the RTC co-optimization period;

(v) Either reaffirm that the External Transactions scheduled by previous RTC runs should continue to flow in the next hour should flow, 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 RTC run following the next RTC run are posted at Variably Scheduled Proxy Generator Buses; and

(vii) 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 is described in Section 17, Attachment B to this ISO Services Tariff.

4.4.2 Real-Time Dispatch

4.4.2.1 Overview

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and Demand Side Resources, produce schedules for intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and 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 4.4.2.3 below. Each Real-Time Dispatch run will co-optimize to solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon (which may be fifty, fifty-five, or sixty minutes long depending on where the run falls in the hour.) In addition to producing a binding schedule for the next five minutes, each Real-Time Dispatch run will produce advisory schedules for the remaining four time steps of its bid-optimization horizon (which may be five, ten, or fifteen minutes long depending on where the run falls in the hour). An advisory schedule may become binding in the absence of a subsequent Real-Time Dispatch run. RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

4.4.2.2 External Transaction Scheduling

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

4.4.2.3 Calculating Real-Time Market LBMPs and Advisory Prices

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

4.4.2.4 Real-Time Pricing Rules for Scheduling Ten Minute Resources

RTD may commit and dispatch, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting within ten minutes (“eligible Resources”) when necessary to meet load. Eligible Resources committed and dispatched by RTD for pricing purposes may be physically started through normal ISO operating processes. In the RTD cycle in which RTD commits and dispatches an eligible Resource, RTD will consider the Resource’s start-up and incremental energy costs and will assume the Resource has a zero downward response rate for purposes of calculating *ex ante* Real-Time LBMPs pursuant to Section 17, Attachment B to this ISO Services Tariff.

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

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

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

Special Case Resource Capacity that has been scheduled in the Day-Ahead Market to provide Operating Reserves, Regulation Service or Energy and that has been instructed as a Special Case Resource to reduce demand shall be considered, for the purpose of applying Real-Time special scarcity pricing rules described in Attachment B of this 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 applying Real-Time special scarcity pricing rules described in Attachment B of this 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 Real-Time Scarcity Pricing Rules Applicable to Regulation Service and Operating Reserves During EDRP and/or SCR Activations

Under Sections 17.1.1.2 and 17.1.1.3 of Attachment B to this ISO Services Tariff, and Sections 16.1.1.2 and 16.1.1.3 of Attachment J to the ISO OATT, the ISO will use special scarcity pricing rules to calculate Real-Time LBMPs during intervals when it has activated the EDRP and/or SCRs in order to avoid reserves shortages. During these intervals, the ISO will also implement special scarcity pricing rules for real-time Regulation Service and Operating Reserves. These rules are set forth in Section 15.3.2.5.2 of Rate Schedule 15.3 and Section 15.4.6.2 of Rate Schedule 15.4 of this ISO Services Tariff.

4.4.2.8 Post the Real-Time Schedule

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

4.4.3 Real-Time Dispatch - Corrective Action Mode

When the ISO needs to respond to system conditions that were not anticipated by RTC or the regular Real-Time Dispatch, *e.g.*, the unexpected loss of a major Generator or Transmission line, it will activate the specialized RTD-CAM program. RTD-CAM runs will be nominally either five or ten minutes long, as is described below. Unlike the Real-Time Dispatch, RTD-CAM will have the ability to commit certain Resources, and schedule intra-hour External Transactions at Dynamically Scheduled Proxy Generator Buses. When RTD-CAM is activated, the ISO will have discretion to implement various measures to restore normal operating conditions. These RTD-CAM measures are described below.

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

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

4.4.3.1 RTD-CAM Modes

4.4.3.1.1 Reserve Pickup

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

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

4.4.3.1.2 Maximum Generation Pickup

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

4.4.3.1.3 Base Points ASAP -- No Commitments

The ISO will enter this RTD-CAM mode when changed circumstances make it necessary to issue an updated set of Base Point Signals. Examples of changed circumstances that could necessitate taking this step include correcting line, contingency, or transfer overloads and/or voltage problems caused by unexpected system events. When operating in this mode, RTD-CAM will produce schedules and Base Point Signals for the next five minutes but will only redispatch Generators that are capable of responding within five minutes. RTD-CAM will not commit or de-commit Resources in this mode.

4.4.3.1.4 Base Points ASAP -- Commit As Needed

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

4.4.3.1.5 Re-Sequencing Mode

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

4.4.3.2 Calculating Real-Time LBMPs

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

4.5 Real-Time Market Settlements

Transmission Customers and Customers taking service under this ISO Services Tariff or the ISO OATT, shall be subject to the Real-Time Market Settlement. All withdrawals and injections not scheduled on a Day-Ahead basis, including Real-Time deviations from any Day-Ahead External Transaction schedules, shall be subject to the Real-Time Market Settlement. Transmission Customers not taking service under this Tariff shall be subject to balancing charges as provided for under the ISO OATT. Settlements with Suppliers scheduling service from External Suppliers to the LBMP Market or to External Loads from the LBMP Market will be based upon scheduled withdrawals or injections. Real-Time Market Settlements for injections by Resources supplying Regulation Service or Operating Reserves shall follow the rules which are described in Rate Schedules 15.3 and 15.4, respectively.

For the purposes of this section, the scheduled output of each of the following Generators in each RTD interval in which it has offered Energy shall retroactively be set equal to its actual output in that RTD interval:

(i) Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does 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;

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric 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 topping or extraction turbine 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 499 MW of such units.

This procedure shall not apply to a Generator for those hours it has used the ISO-Committed Flexible or Self-Committed Flexible bid mode.

In Sections 4.5.1, 4.5.2, 4.5.3, 4.5.4, 4.5.5 and 4.5.6 of this Tariff, references to Scheduled Energy Injections and Scheduled Energy Withdrawals shall encompass injections and withdrawals that are scheduled Day-Ahead, as well as injections and withdrawals that occur in connection with real-time Bilateral Transactions. In Sections 4.5.1, 4.5.3, 4.5.4 and 4.5.6 of this Tariff, references to Energy Withdrawals and Energy Injections shall not include Energy Withdrawals or Energy Injections in Virtual Transactions, or Energy Withdrawals or Energy Injections at Trading Hubs. Generators, including Limited Energy Storage Resources, that are providing Regulation Service shall not be subject to the real-time Energy market settlement provisions set forth in this Section, but shall instead be subject to the Energy settlement rules set forth in Section 15.4.6 of Rate Schedule 15.3 of this ISO Services Tariff.

4.5.1 Settlement When Actual Energy Withdrawals Exceed Scheduled Energy Withdrawals Other Than Scheduled or Actual Withdrawals in Virtual Transactions

When the Actual Energy Withdrawals by a Customer over an RTD interval exceed the Energy withdrawals scheduled over that RTD interval, the ISO shall charge the Real-Time

LBMP for Energy equal to the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the Actual Energy Withdrawals and the Scheduled Energy Withdrawals at that Load Zone.

4.5.2 Settlement for Customers Scheduled To Sell Energy in Virtual Transactions in Load Zones

The Actual Energy Injection in a Load Zone by a Customer scheduled Day-Ahead to sell Energy in a Virtual Transaction is zero and the Customer shall pay a charge for the Energy imbalance equal to the product of: (a) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Injection of the Customer for that Hour in that Load Zone.

4.5.3 Settlement When Actual Energy Injections are Less Than Scheduled Energy Injections or Actual Demand Reductions are Less Than Scheduled Demand Reductions

4.5.3.1 General Rule

When the Actual Energy Injections by a Supplier over an RTD interval are less than the Energy injections scheduled Day-Ahead over that RTD interval, the Supplier shall pay a charge for the Energy imbalance equal to the product of: (a) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus; and (b) the difference between the scheduled Day-Ahead Energy injections and the lesser of: (i) the Actual Energy Injections at that bus; or (ii) the Supplier's Real-Time Scheduled Energy Injection plus any Compensable Overgeneration. If the Energy injections by a Supplier over an RTD interval are less than the Energy injections scheduled for the Supplier Day-Ahead, and if the Supplier reduced its Energy injections in response to instructions by the ISO or a Transmission Owner that were issued in order to maintain a secure and reliable dispatch, the Supplier may be entitled to a Day-Ahead Margin Assurance Payment, pursuant to Attachment J of this ISO Services Tariff.

4.5.3.2 Failed Transactions

If an Energy injection scheduled by RTC at a Proxy Generator Bus fails in the ISO's checkout process , the Supplier or Transmission Customer that was scheduled to make the injection will pay the Energy imbalance charge described above in Section 4.5.3.1. In addition, if the checkout failure occurred for reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Mitigation and Analysis Department will determine whether the Transaction associated with an injection failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy injection at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy injection from the amount of the Import scheduled by RTC; multiplied by (ii) the greater of the difference computed by subtracting the RTC LBMP from the RTD LBMP in the relevant interval, or zero.

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this section and the Financial Impact Charge described below in Section 4.5.4.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 1 of this ISO Services Tariff. In the event that the Energy injections for an Import scheduled by RTC or RTD, at a Proxy Generator Bus is Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible to receive an Import Curtailment Guarantee Payment for its curtailed Import pursuant to Attachment J of this ISO Services Tariff.

4.5.3.3 Capacity Limited Resources and Energy Limited Resources

For any hour in which: (i) a Capacity Limited Resource is scheduled to supply Energy, Operating Reserves, or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in upper operating limit; (iii) the Capacity Limited Resource requests a reduction for Capacity limitation reasons; and (iv) the ISO reduces the Capacity Limited Resource's upper operating limit to a level equal to, or greater than, its bid-in upper operating limit; the imbalance charge for Energy, Operating Reserve Service or Regulation Service imposed on that Capacity Limited Resource for that hour for its Day-Ahead Market obligations above its Capacity limited upper operating limit shall be equal to the product of: (a) the Real-Time price for Energy, Operating Reserve Service and Regulation Service; and (b) the Capacity Limited Resource's Day-Ahead schedule for each of these services minus the amount of these services that it has an obligation to supply pursuant to its ISO-approved schedule. When a Capacity Limited Resource's Day-Ahead obligation above its Capacity limited upper operating limit is balanced as described above, any real-time variation from its obligation pursuant to its Capacity limited schedules shall be settled pursuant to the methodology set forth in Section 4.5.3.1.

For any day in which: (i) an Energy Limited Resource is scheduled to supply Energy, Operating Reserves or Regulation Service in the Day-Ahead Market; (ii) the sum of its schedules to provide these services exceeds its bid-in Normal Upper Operating Limit; (iii) the Energy

Limited Resource requests a reduction for Energy limitation reasons; and (iv) the ISO reduces the Energy Limited Resource's Day-Ahead Emergency Upper Operating Limit to a limit no lower than the Normal Upper Operating Limit; the Resource may be eligible to receive a Day-Ahead Margin Assurance Payment pursuant to Attachment J of this ISO Services Tariff.

4.5.3.4 Demand Reductions

When actual Demand Reduction over an hour from a Demand Reduction Provider that is also the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled for that hour, that-LSE shall pay a Demand Reduction imbalance charge consisting of the product of: (a) the greater of the Day-Ahead LBMP or the Real-Time LBMP for that hour and (b) the difference between the scheduled Demand Reduction and the actual Demand Reduction in that hour.

When actual Demand Reduction over an hour from a Demand Reduction Provider that is not the LSE providing Energy service to the Demand Side Resource(s) that produced the reduction is less than the Demand Reduction scheduled over that hour, then (1) the LSE providing Energy service to the Demand Reduction Provider's Demand Side Resource(s) shall pay a Demand Reduction imbalance charge equal to the product of (a) the Day-Ahead LBMP calculated for that hour for the applicable Load bus and (b) the difference between the scheduled Demand Reduction and the actual Demand Reduction at that bus in that hour, and (2) the Demand Reduction Provider will pay an amount equal to (a) the product of (i) the higher of the Day-Ahead LBMP or the Real-Time LBMP calculated for that hour for the applicable Load bus, and (ii) the difference between the scheduled Demand Reduction and the actual Demand Reduction at that bus in that hour, and (b) minus the amount paid by the LSE providing service to the Demand Reduction Provider's Demand Side Resource(s) under (1), above.

4.5.4 Settlement When Actual Energy Withdrawals are Less Than Scheduled Energy Withdrawals Other Than Actual or Scheduled Withdrawals in Virtual Transactions

4.5.4.1 General Rules

When a Customer's Actual Energy Withdrawals over an SCD interval are less than its Energy withdrawals scheduled Day-Ahead over that SCD interval, the Customer shall be paid the product of: (a) the Real-Time LBMP calculated in that RTD interval for each applicable Load Zone; and (b) the difference between the Scheduled Energy Withdrawals and the Actual Energy Withdrawals in that Load Zone.

4.5.4.2 Failed Transactions

If an Energy withdrawal at a Proxy Generator Bus scheduled by RTC fails in the ISO's checkout process, the Supplier or Transmission Customer that was scheduled to make the withdrawal will pay or be paid the energy imbalance charge described above in Section 4.5.4.1. In addition, if the checkout failure occurred for the reasons within the Supplier's or Transmission Customer's control it will be required to pay the "Financial Impact Charge" described below. The ISO's Market Mitigation and Analysis Department will determine whether the Transaction associated with a withdrawal failed for reasons within a Supplier's or Transmission Customer's control.

If an Energy withdrawal at a Proxy Generator Bus is determined to have failed for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal: (i) the difference computed by subtracting the actual real-time Energy withdrawal from the amount of the Export scheduled by RTC; multiplied by (ii) the greater of the difference computed by subtracting the RTD LBMP in the relevant interval from the RTC LBMP, or zero.

If a Wheel Through fails for reasons within a Supplier's or Transmission Customer's control, the Financial Impact Charge will equal the sum of the Financial Impact Charge described in this subsection and the Financial Impact Charge described above in Section 4.5.3.2.

All Financial Impact Charges collected by the ISO shall be used to reduce the charges assessed under Rate Schedule 15.1 of this ISO Services Tariff.

4.5.5 Settlement for Customers Scheduled To Purchase Energy in Virtual Transactions in Load Zones

The Actual Energy Withdrawal in a Load Zone by a Customer scheduled Day-Ahead to purchase Energy in a Virtual Transaction is zero and the Customer shall be paid the product of: (1) the Real-Time LBMP calculated in that hour for the applicable Load Zone; and (b) the scheduled Day-Ahead Energy Withdrawal of the Customer for that Hour in that Load Zone.

4.5.6 Settlement When Actual Energy Injections Exceed Scheduled Energy Injections

When Actual Energy Injections from a Generator over an RTD interval exceed the Energy injections scheduled Day-Ahead over the RTD interval the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the lesser of (i) the Supplier's Actual Energy Injection or (ii) its Real-Time Scheduled Energy Injection for that RTD interval, plus any Compensable Overgeneration and the Supplier's Day-Ahead Scheduled Energy Injection over the RTD interval, unless the payment that the Supplier would receive for such injections would be negative (i.e., unless the LBMP calculated in that RTD interval at the applicable Generator's bus is negative) in which case the Supplier shall be paid the product of: (1) the Real-Time LBMP calculated in that RTD interval for the applicable Generator bus and (2) the difference between the Supplier's Actual Energy Injection for that RTD interval and the Supplier's Scheduled

Energy Injection over that RTD interval. Suppliers shall not be compensated for Energy in excess of their Real-Time Scheduled Energy Injections, except: (i) for Compensable Overgeneration; (ii) when the ISO initiates a large event reserve pickup or a maximum generation pickup under RTD-CAM; or (iii) when a Transmission Owner initiates a reserve pickup in accordance with a Reliability Rule, including a Local Reliability Rule. When there is no large event reserve pickup or maximum generation pickup, or when there is such an instruction but a Supplier is not located in the area affected by the maximum generation pickup, that Supplier shall not be compensated for Energy in excess of its Real-Time Scheduled Energy Injection plus any Compensable Overgeneration. When there is a reserve pickup, or when there is a maximum generation pickup and a Supplier is located in the area affected by it, and the Supplier was either scheduled to operate in RTD or subsequently was directed to operate by the ISO, that Supplier shall be paid based on the product of: (1) the Real-Time LBMP calculated in that RTD Interval for the applicable Generator bus; and (2) the Actual Energy Injection minus the Energy injection scheduled Day-Ahead.

4.5.7 Settlement for Trading Hub Energy Owner when POI is a Trading Hub

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Real-Time Market with a Trading Hub as its POI and has its schedule accepted by the ISO will pay the product of: (a) the hourly integrated Real-Time LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

4.5.8 Settlement for Trading Hub Energy Owner when POW is a Trading Hub

Each Trading Hub Energy Owner who bids a Bilateral Transaction into the Real-Time Market with a Trading Hub as its POW and has its schedule accepted by the ISO will be paid the product of: (a) the hourly integrated Real-Time LBMP for the Load Zone associated with that Trading Hub; and (b) the Bilateral Transaction scheduled MW.

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 either the Real-Time Dispatch ("RTD") program and during intervals when certain conditions exist at Proxy Generator Buses, the Real-Time Commitment ("RTC") program. LBMPs for Suppliers and Loads in the Day-Ahead Market will be based on the system marginal costs produced by the Security Constrained Unit Commitment ("SCUC"). LBMPs calculated by SCUC and RTD will incorporate the incremental dispatch costs of Resources that would be scheduled to meet an increment of Load and, to the extent that tradeoffs exist between scheduling providers to produce Energy or reduce demand, and scheduling them to provide Regulation Service or Operating Reserves, LBMPs shall reflect the effect of meeting an increment of Load at each location on the Bid Production Cost associated with those services. As such, those LBMPs may incorporate: (i) Availability Bids for Regulation Service or Operating Reserves; or (ii) shortage costs associated with the inability to meet a Regulation Service or Operating Reserves requirement under the Regulation Service Demand Curve and Operating Reserve Demand Curves set forth in Rate Schedules 3 and 4 respectively of this ISO Services Tariff.

Additionally, for the purpose of calculating Real-Time LBMPs when RTD is committing and dispatching Resources meeting Minimum Generation Levels and capable of starting in ten minutes pursuant to Section 4.4.3.3 of this ISO Services Tariff, RTD shall include in the incremental dispatch cost of each such Resource a start-up cost based on the Start-Up Bid of each such Resource and shall assume for each such Resource a zero downward response rate.

17.1.1 LBMP Bus Calculation Method

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

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma^L{}_i + \gamma^C{}_i$$

Where:

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

The Marginal Losses Component of the LBMP at any bus i within the NYCA 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 = system losses; and

P_i = injection at bus i

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

$$\gamma_i^c = -\left(\sum_{k\in K}^{n} GF_{ik}\mu_k\right)$$, except as noted in Sections 17.1.2.2.1 and 17.1.2.3.1 of this Attachment B

Where:

K = the set of Constraints;

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

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

Substituting the equations for γ_i^L and γ_i^C into the first equation yields:

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

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

17.1.2 Real-Time LBMP Calculation Procedures

For each RTD interval, the ISO shall use the procedures described below in Sections 17.1.2.1-17.1.2.1.5 to calculate Real-Time LBMPs at each Load Zone and Generator bus. The LBMP bus and zonal calculation procedures are described in Sections 17.1.1 and 17.1.5 of this Attachment B, respectively. Procedures governing the calculation of LBMPs at Proxy Generator Buses are set forth below in Section 17.1.6 of this Attachment B. In addition, when certain conditions exist, as defined in the table below, the ISO shall employ the special scarcity pricing rules described in Sections 17.1.2.2 and 17.1.2.3.

SCR/EDRP NYCA Called and Needed	SCR/EDRP East Called and Needed	Scarcity Pricing Rule to be Used in the West	Scarcity Pricing Rule to be Used in the East
NO	NO	NONE	NONE
NO	YES	NONE	B
YES	NO	A	A
YES	YES	A	A

Where:

SCR/EDRP NYCA, Called and Needed	Is "YES" if the ISO has called SCR/EDRP resources and determined that, but for the Expected Load Reduction, the Available Reserves would have been less than the NYCA requirement for total 30-Minute Reserves; or is "NO" otherwise.
SCR/EDRP East, Called and Needed	Is "YES" if the ISO has called SCR/EDRP from resources located East of Central-East and determined that, but for the Expected Load Reduction, the Available Reserves located East of Central-East would have been less than the requirement for 10-Minute Reserves located East of Central-East; or is "NO" otherwise.
Pricing Rule West	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Load Zones located West of Central-East, including the Reference Bus.
Pricing Rule East	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Load Zones located East of Central-East.

17.1.2.1 General Procedures

17.1.2.1.1 Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes of each RTD run, except as noted below in Section 17.1.1.1.3. A new RTD run will initialize every five minutes and each run will produce prices and schedules for five points in time (the optimization period). Only the prices and schedules determined for the first time point of the optimization period will be binding. Prices and schedules for the other four time pointsof 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_0") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD_0 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_5") will initialize at the beginning of the hour and produce prices over a fifty minute optimization period. RTD_5 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at five minutes after the hour) and ending at the first time point in its optimization period (i.e., ten minutes after the hour.) It will produce advisory prices and schedules for its second time point (which is five minutes after the first time point), and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at ten minutes after the beginning of the hour (“RTD_{10}”) will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD_{10} will produce binding prices and schedules for the interval beginning when it posts its results (i.e., at ten minutes after the hour) and ending at the first time point in its optimization period (i.e., fifteen minutes after the hour.) It will produce advisory prices and schedules for its second, third, fourth and fifth time points, each of which would be fifteen minutes after the preceding time point.

17.1.2.1.2 Description of the Real-Time Dispatch Process

17.1.2.1.2.1 The First Pass

The first RTD pass consists of a least bid cost, multi-period co-optimized dispatch for Energy, Regulation Service and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO as if they were blocked on at their UOL_N or UOL_E, whichever is applicable. Resources meeting Minimum Generation Levels and capable of being started in ten minutes that have not been committed by RTC are treated as flexible (i.e. able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable). The first pass establishes “physical base points” (i.e., real-time Energy schedules) and real-time schedules for Regulation Service and Operating Reserves for the first time point of the optimization period. Physical base points and schedules established for the first time point shall be binding and shall remain in effect until the results of the next run are posted. Physical base points and schedules established for all subsequent time points shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point Signals that the ISO sends to Suppliers.

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

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

When setting physical base points for a Dispatchable Resource at the first time point, the ISO shall ensure that they do not fall outside of the bounds established by the Dispatchable Resource's lower and upper dispatch limits. A Dispatchable Resource's dispatch limits shall be determined based on whether it was feasible for it to reach the physical base point calculated by the last RTD run given its: (A) metered output level at the time that the RTD run was initialized; (B) response rate; (C) minimum generation level; and (D) UOL_N or UOL_E, whichever is applicable. If it was feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E, as applicable, and starting from its previous base point. If it was not feasible for the Dispatchable Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E, as applicable, but instead starting from the feasible output level closest to its previous base point.

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

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by increasing the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by decreasing the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level or to a Demand Side Resource's Demand Reduction level.

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

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

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

17.1.2.1.2.1.3. Setting Physical Basepoints for Fixed Generators

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

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

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

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

17.1.2.1.2.2 The Second Pass

The second RTD pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats all Fixed Block Units that are committed by RTC, all Resources meeting Minimum Generation Levels and capable of starting in ten minutes that have not been committed by RTC and all units otherwise instructed to be online or remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable), regardless of their minimum run-time status. This pass shall establish "hybrid base points" (i.e., real-time Energy schedules) that are used in the third pass to determine whether minimum run-time constrained Fixed Block Units should be blocked on at their UOL_N or UOL_E, whichever is applicable, or dispatched flexibly. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

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

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

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

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

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

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

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

17.1.2.1.2.3 The Third Pass

The third RTD pass is the same as the second pass with three variations. First, the third pass treats Fixed Block Units that are committed by RTC, or are otherwise instructed to be online or remain online by the ISO that received a non-zero physical base point in the first pass, and that received a hybrid base point of zero in the second pass, as blocked on at their UOL_N or UOL_E, whichever is applicable. Second, the third pass produces "pricing base points" instead of hybrid base points. Third, and finally, the third pass calculates real-time

Energy prices and real-time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Article 4, Rate Schedule 15.3, and Rate Schedule 15.4 of this ISO Services Tariff respectively. The ISO shall not use schedules for Energy, Regulation Service and Operating Reserves that are established in the third pass to dispatch Resources.

17.1.2.1.3 Variations in RTD-CAM

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

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

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the Regulation Service markets will be temporarily suspended as described in Rate Schedule 15.3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments in the affected area before executing the three RTD passes; and (iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator within the affected area towards its UOL_E at its emergency response rate or set it at a level equal to its physical base point.

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

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

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

17.1.2.1.4 The Real-Time Commitment ("RTC") Process and Automated Mitigation

Attachment H of this Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are implemented they shall be incorporated into the RTC software through the establishment of a second, parallel, commitment evaluation that will assess the impact of the mitigation measures. The first evaluation, referred to as the "RTC evaluation," will determine the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the "RT-AMP" evaluation, will determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow the rules governing RTC's operation that are set forth in Article 4 and this Attachment B to this ISO Services Tariff.

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, 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).

17.1.2.2 Scarcity Pricing Rule "A"

The ISO shall implement the following price calculation procedures for intervals when scarcity pricing rule "A" is applicable.

17.1.2.2.1 Except as noted in 17.1.2.2.2 below:

- The system marginal price (λ^R , as defined in Section 17.1.1 of this Attachment B) at the Reference Bus shall be determined by dividing the lowest offer price at which the quantity of Special Case Resources offered is equal to $RREQ_{NYCA} – (RACT_{NYCA} – ELR_{NYCA})$, or \$500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{NYCA} – (RACT_{NYCA} – ELR_{NYCA})$, by the weighted average of the delivery factors produced by RTD that the ISO uses in its calculation of prices for Load Zone J in that RTD interval,

where:

- $RACT_{NYCA}$ equals the quantity of Available Reserves in the RTD interval;
- $RREQ_{NYCA}$ equals the 30-Minute Reserve requirement set by the ISO for the NYCA; and
- ELR_{NYCA} equals the Expected Load Reduction in the NYCA from the Emergency Demand Response Program and Special Case Resources in that RTD interval.

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

- The Congestion Component of the LBMP at each location shall be set to zero.

- The LBMP at each location shall be as defined in Section 17.1.1 of this Attachment: the sum of the Marginal Losses Component of the LBMP at that location, plus the Congestion Component of the LBMP at that location, plus the LBMP at the Reference Bus.

17.1.1.2.2 However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section 17.1.2.1, above. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location pursuant to Section 17.1.2.1 of this Attachment B; or the LBMP calculated for that location using the scarcity pricing rule "A" procedures.

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one.

- The Congestion Component of the LBMP at each location shall be calculated as the LBMP at that location, minus the LBMP at the Reference Bus, minus the Marginal Losses Component of the LBMP at that location.

17.1.2.3 Scarcity Pricing Rule "B"

The ISO shall implement the following procedures in intervals when scarcity pricing rule "B" is applicable:

17.1.2.3.1 Except as noted in Pricing Rule 17.1.2.3.2 below:

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section 17.1.2.1) and a quantity equal to the delivery factor produced by RTD for that location minus one.

- The Congestion Component of the LBMP at each location shall be equal to the lowest offer price at which the quantity of Special Case Resources offered is equal to $RREQ_{East}$ – ($RACT_{East}$ – ELR_{East}), or \$500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{East}$ – ($RACT_{East}$– ELR_{East}), minus the LBMP calculated for the Reference Bus (according to Section 17.1.2.1), minus the Marginal Losses Component of the LBMP for Load Zone J,

  where:

- $RACT_{East}$ equals the quantity of Available Reserves located East of Central-East in that RTD interval;

- $RREQ_{East}$ equals the 10-Minute Reserve requirement set by the ISO for the portion of the NYCA located East of the Central-East interface; and

- ELR_{East} equals the Expected Load Reduction East of Central-East from the Emergency Demand Response Program and Special Case Resources in that RTD interval.The LBMP at each location shall be the sum of the LBMP calculated for the Reference Bus (according to Section 17.1.2.1) and the Marginal Loss Component and the Congestion Component for that location.

17.1.2.3.2 However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section 17.1.2.1, above. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each such location shall be set to the LBMP calculated for that location pursuant to Section 17.1.2.1

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section 17.1.2.1) and a quantity equal to the delivery factor produced by RTD for that location minus one.

- The Congestion Component of the LBMP at each such location shall be calculated as the LBMP at that location, minus the LBMP calculated for the Reference Bus (according to Section 17.1.2.1), minus the Marginal Losses Component of the LBMP at that location.

17.1.3 Day-Ahead LBMP Calculation Procedures

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

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

It consists of several steps. Step 1A is a complete Security Constrained Unit Commitment ("SCUC") to meet Bid Load. At the end of this step, committed Fixed Block Units, Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units are dispatched to meet Bid Load with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure ("AMP") activation.

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

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the SCUC process. At the end of Step 1C, committed Fixed Block Units, Imports, Exports, virtual supply, virtual load, Demand Side Resources, and non-Fixed Block Units are again dispatched to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. For mitigation purposes, LBMPs are again calculated from this dispatch.

All Demand Side Resources and non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of and the AMP) are blocked on at least to minimum load in Passes 4 through 6. The resources required to meet local system reliability are determined in Pass 1.

Pass 2 consists of a least cost commitment and dispatch of Fixed Block Units, Imports, Exports, Demand Side Resources and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load, considering the Wind Energy Forecast, that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fixed Block Units are dispatchable on a flexible basis. Incremental Import Capacity needed to meet forecast Load requirements is determined in Pass 2. Fixed Block Units committed in this pass are not included in the least cost dispatches of Passes 5 or 6. Demand Side Resources and non-Fixed Block Units committed in this step are blocked on at least to minimum Load in Passes 4 through 6. Intermittent Power Resources that depend on wind as their fuel committed in this pass as a result of the consideration of the Wind Energy Forecast are not blocked in Passes 5 or 6.

Pass 3 is reserved for future use.

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

Pass 5 consists of a least cost dispatch of Fixed Block Units, Importss, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units committed to meet

Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fixed Block Units are treated as dispatchable on a flexible basis. LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch. Final schedules for all Imports, Exports, Virtual Supply, Virtual Load, Demand Side Resources and non-Fixed Block Units in the Day-Ahead Market are calculated from this dispatch.

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

17.1.4 Determination of Transmission Shortage Cost

The Transmission Shortage Cost represents the limit on system costs associated with efficient dispatch to meet a particular Constraint. It is the maximum Shadow Price that will be used in calculating LBMPs. The Transmission Shortage Cost is set at $4000 / MWh.

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 NYISO shall file such change with the Commission pursuant to Section 205 of the Federal Power Act within 45 days of such modification. If circumstances reasonably allow, the ISO will consult with its Market Monitoring Unit, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the ISO will consult with those entities as soon as reasonably possible after implementing a temporary modification and shall explain the reasons for the change.

The responsibilities of the ISO and the Market Monitoring Unit in evaluating and modifying the Transmission Shortage 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. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the 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:

γ_j^Z = LBMP for zone j,

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

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

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

W_i = load weighting factor for bus i.

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

17.1.6.1 Definitions

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

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

External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. External Generators may arrange Bilateral Transactions with Internal or External Loads and External Loads may arrange 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 ofProxy 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 three tables below.

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

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location a	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location a)
1	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
2	RTD used to schedule External Transactions in a given 5-minute interval is subject to a Proxy Generator Bus Constraint, and RTC_{15} was not subject to that Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = RTD $LBMP_a$
3	RTD used to schedule External Transactions in a given 5-minute interval is subject to a Proxy Generator Bus Constraint, and RTC_{15} was not subject to that Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = RTD $LBMP_a$
4	RTC_{15} and RTD are subject to the same Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, RTD $LBMP_a$)

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)
5	RTC_{15} and RTD are subject to the same Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, RTD $LBMP_a$)

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

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location a	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location a)
6	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
7	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint, and RTC_{15} was not subject to that Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Rolling RTC $LBMP_a$
8	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Proxy Generator Bus Constraint, and RTC_{15} was not subject to that Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Rolling RTC $LBMP_a$
9	RTC_{15} and the Rolling RTC are subject to the same Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$)
10	RTC_{15} and the Rolling RTC are subject to the same Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$)

The pricing rules for Proxy Generator Buses not designated as 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)

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)
11	Unconstrained in RTC_{15}, Rolling RTC and RTD	N/A	Real-Time $LBMP_a$ = RTD $LBMP_a$
12	RTC_{15} is subject to a Proxy Generator Bus Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = RTC_{15} $LBMP_a$
13	RTC_{15} is subject to a Proxy Generator Bus Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = RTC_{15} $LBMP_a$

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

Real-Time LBMPs for an Interface that is associated with one or more Non-Competitive Proxy Generator Buses or for a Non-Competitive Proxy Generator Bus shall be determined as provided in the three tables below.

The pricing rules for Dynamically 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)
14	RTD used to schedule External Transactions in a given 5-minute interval is subject to a Interface ATC or Interface Ramp Constraint, and RTC_{15} was not subject to that Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTD $LBMP_a$, Min(Unconstrained RTD $LBMP_a$, 0))
15	RTD used to schedule External Transactions in a given 5-minute interval is subject to a Interface ATC or Interface Ramp Constraint, and RTC_{15} was not subject to that Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTD $LBMP_a$, Max(Unconstrained RTD $LBMP_a$, SCUC $LBMP_a$))
16	RTD used to schedule External Transactions in a given 5-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTD $LBMP_a$, Min(Unconstrained RTD $LBMP_a$, 0))

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)
17	RTD used to schedule External Transactions in a given 5-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTD $LBMP_a$, Max(Unconstrained RTD $LBMP_a$, SCUC $LBMP_a$))
18	RTC_{15} and RTD are subject to the same Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, RTD $LBMP_a$, Min(Unconstrained RTD $LBMP_a$, 0))
19	RTC_{15} and RTD are subject to the same Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, RTD $LBMP_a$, Max(Unconstrained RTD $LBMP_a$, SCUC $LBMP_a$))
20	RTC_{15} and RTD are subject to the same NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, RTD $LBMP_a$, Min(Unconstrained RTD $LBMP_a$, 0))
21	RTC_{15} and RTD are subject to the same NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, RTD $LBMP_a$, Max(Unconstrained RTD $LBMP_a$, SCUC $LBMP_a$))

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

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location a	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location a)
22	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Interface ATC or Interface Ramp Constraint, and RTC_{15} was not subject to that Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(Rolling RTC $LBMP_a$, Min(RTD $LBMP_a$, 0))
23	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a Interface ATC or Interface Ramp Constraint, and RTC_{15} was not subject to that Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(Rolling RTC $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))

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)
24	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(Rolling RTC $LBMP_a$, Min(RTD $LBMP_a$, 0))
25	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(Rolling RTC $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))
26	RTC_{15} and the Rolling RTC are subject to the same Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$, Min(RTD $LBMP_a$, 0))
27	RTC_{15} and the Rolling RTC are subject to the same Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))
28	RTC_{15} and the Rolling RTC are subject to the same NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$, Min(RTD $LBMP_a$, 0))
29	RTC_{15} and the Rolling RTC are subject to the same NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))

The pricing rules for Proxy Generator Buses not designated as 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)
30	RTC_{15} is subject to a Interface ATC or Interface Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, Min(RTD $LBMP_a$, 0))
31	RTC_{15} is subject to a Interface ATC or Interface Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))

At all other times, the Real-Time LBMP shall be calculated as specified in Section 17.1.6.2 above.

17.1.6.4 Special Pricing Rules for Scheduled Lines

Real-Time LBMPs for the Proxy Generator Buses associated with designated Scheduled Lines shall be determined as provided in the three tables below.

The pricing rules for Dynamically 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)
32	RTD used to schedule External Transactions in a given 5-minute interval is subject to an Interface ATC Constraint, and RTC_{15} was not subject to that Interface ATC Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTD $LBMP_a$, Min(Unconstrained RTD $LBMP_a$, 0))
33	RTD used to schedule External Transactions in a given 5-minute interval is subject to an Interface ATC Constraint, and RTC_{15} was not subject to that Interface ATC Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTD $LBMP_a$, Max(Unconstrained RTD $LBMP_a$, SCUC $LBMP_a$))
34	RTD used to schedule External Transactions in a given 5-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTD $LBMP_a$, Min(Unconstrained RTD $LBMP_a$, 0))
35	RTD used to schedule External Transactions in a given 5-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTD $LBMP_a$, Max(Unconstrained RTD $LBMP_a$, SCUC $LBMP_a$))
36	RTC_{15} and RTD are subject to the same Interface ATC Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, RTD $LBMP_a$, Min(Unconstrained RTD $LBMP_a$, 0))
37	RTC_{15} and RTD are subject to the same Interface ATC Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, RTD $LBMP_a$, Max(Unconstrained RTD $LBMP_a$, SCUC $LBMP_a$))

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)
38	RTC_{15} and RTD are subject to the same NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, RTD $LBMP_a$, Min(Unconstrained RTD $LBMP_a$, 0))
39	RTC_{15} and RTD are subject to the same NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, RTD $LBMP_a$, Max(Unconstrained RTD $LBMP_a$, SCUC $LBMP_a$))

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

Rule No.	Proxy Generator Bus Constraint affecting External Schedules at location a	Direction of Proxy Generator Bus Constraint	Real-Time Pricing Rule (for location a)
40	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint, and RTC_{15} was not subject to that Interface ATC Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(Rolling RTC $LBMP_a$, Min(RTD $LBMP_a$, 0))
41	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to an Interface ATC Constraint, and RTC_{15} was not subject to that Interface ATC Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(Rolling RTC $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))
42	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(Rolling RTC $LBMP_a$, Min(RTD $LBMP_a$, 0))
43	The Rolling RTC used to schedule External Transactions in a given 15-minute interval is subject to a NYCA Ramp Constraint, and RTC_{15} was not subject to that NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(Rolling RTC $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))
44	RTC_{15} and the Rolling RTC are subject to the same Interface ATC Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$, Min(RTD $LBMP_a$, 0))

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)
45	RTC_{15} and the Rolling RTC are subject to the same Interface ATC Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))
46	RTC_{15} and the Rolling RTC are subject to the same NYCA Ramp Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$, Min(RTD $LBMP_a$, 0))
47	RTC_{15} and the Rolling RTC are subject to the same NYCA Ramp Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, Rolling RTC $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))

The pricing rules for Proxy Generator Buses not designated asDynamically 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)
48	RTC_{15} is subject to a Interface ATC Constraint	Into NYCA (Import)	Real-Time $LBMP_a$ = Max(RTC_{15} $LBMP_a$, Min(RTD $LBMP_a$, 0))
49	RTC_{15} is subject to a Interface ATC Constraint	Out of NYCA (Export)	Real-Time $LBMP_a$ = Min(RTC_{15} $LBMP_a$, Max(RTD $LBMP_a$, SCUC $LBMP_a$))

At all other times, the Real-Time LBMP shall be calculated as specified in Section 17.1.6.2 above.

The Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line are designated Scheduled Lines.

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 Scheduled Lines

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

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

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

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

When the Real-Time LBMP is set to the Day-Ahead LBMP:

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

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

where:

$\text{Energy}_{\text{RTC REF BUS}}$	=	(1) At Proxy Generator Buses that are authorized to schedule transactions hourly only, the marginal Bid cost of providing Energy at the reference Bus, as calculated by RTC_{15} for the hour; (2) At Variably Scheduled Proxy Generator Buses, the marginal Bid cost of providing Energy at the reference Bus, as calculated by the Rolling RTC used to schedule External Transactions for that 15-minute interval; (3) At Dynamically Scheduled Proxy Generator Buses, the marginal Bid cost of providing Energy at the reference Bus, as calculated by RTD used to schedule External Transactions for that 5-minute interval;

$\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$ = (1) At Proxy Generator Buses that are authorized to schedule transactions hourly only, the Marginal Losses Component of the LBMP as calculated by RTC_{15} at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line for the hour: (2) At Variably Scheduled Proxy Generator Buses, the Marginal Losses Component of the LBMP as calculated by the Rolling RTC used to schedule External Transactions for that 15-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line; (3) At Dynamically Scheduled Proxy Generator Buses, the Marginal Losses Component of the LBMP as calculated by RTD used to schedule External Transactions for that 5-minute interval at the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line; and

$\text{Day-Ahead LBMP}_{\text{PROXY GENERATOR BUS}}$ = Day-Ahead LBMP as calculated by SCUC for the Non-Competitive Proxy Generator Bus or Proxy Generator Bus associated with a designated Scheduled Line for the hour.

17.1.6.6 The Marginal Losses Component of LBMP at Proxy Generator Buses

The components of LBMP will be posted in the Day-Ahead and Real-Time Markets as described in this Section 17.1.6, except that the Marginal Losses Component of LBMP will be calculated differently for Internal locations. The Marginal Losses Component of the LBMP at each bus, as described above, includes the difference between the marginal cost of losses at that bus and the Reference Bus. If this formulation were employed for an External bus, then the Marginal Losses Component would include the difference in the cost of Marginal Losses for a section of the transmission system External to the NYCA. Since the ISO will not charge for losses incurred Externally, the formulation will exclude these loss effects. To exclude these External loss effects, the Marginal Losses Component will be calculated from points on the boundary of the NYCA to the Reference Bus.

The Marginal Losses Component of the LBMP at the External bus will be a weighted average of the Marginal Losses Components of the LBMPs at the Interconnection Points. To derive the Marginal Losses Component of the LBMP at an External location, a Transaction will be assumed to be scheduled from the External bus to the Reference Bus. The Shift Factors for this Transaction on the tie lines into these Interconnection buses, which measure the per-unit effect of flows over each of those tie lines that results from the hypothetical transaction, will provide the weights for this calculation. Since all the power from this assumed Transaction crosses the NYCA boundary, the sum of these weights is unity.

The sum of the products of these Shift Factors and the Marginal Losses Component of the LBMP at each of these Interconnection buses yields the Marginal Losses Component of the LBMP that will be used for the External bus. Therefore, the Marginal Losses Component of the LBMP at an External bus E is calculated using the equation:

$$\gamma_E^L = \sum_{b \in I} F_{Eb} (DF_b - 1)\lambda^R$$

where:

γ_E^L	=	Marginal Losses Component of the LBMP at an External bus E;
F_{Eb}	=	Shift Factor for the tie line going through bus b, computed for a hypothetical Bilateral Transaction from bus E to the Reference Bus;
$(DF_b - 1)\lambda^R$	=	Marginal Losses Component of the LBMP at bus b; and
I	=	The set of Interconnection buses between the NYCA and adjacent Control Areas.

18 Attachment C -Formulas For Determining Bid Production Cost Guarantee Payments

18.1 Introduction

Ten Bid Production Cost Guarantee (BPCG) payments for eligible Suppliers are described in this attachment: (i) a Day-Ahead BPCG for Generators; (ii) a Day-Ahead BPCG for Imports; (iii) a real-time BPCG for Generators in RTD intervals other than Supplemental Event Intervals ; (iv) a BPCG for Generators for Supplemental Event Intervals; (v) a real-time BPCG for Imports; (vi) a BPCG for long start-up time Generators (i.e., Generators that cannot be scheduled by SCUC to start up in time for the next Dispatch Day) whose start is aborted by the ISO prior to their dispatch; (vii) a BPCG for Demand Reduction in the Day-Ahead Market; (viii) a Special Case Resources BPCG; (ix) a BPCG for Demand Side Resources providing synchronized Operating Reserves in the Day-Ahead Market; and (x) a BPCG for Demand Side Resources providing synchronized Operating Reserves in the Real-Time Market. Suppliers shall be eligible for these payments in accordance with the eligibility requirements and formulas established in this Attachment C.

The Bid Production Cost guarantee payments described in this Attachment C are each calculated and paid independently from each other. A Customer’s eligibility to receive one type of Bid Production Cost guarantee payment shall have no impact on the Customer’s eligibility to be considered to receive another type of Bid Production Cost guarantee payment, in accordance with the rule set forth in this Attachment C.

18.2 Day-Ahead BPCG For Generators

18.2.1 Eligibility to Receive a Day-Ahead BPCG for Generators

18.2.1.1 Eligibility.

A Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO Committed Flexible Generator that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment.

18.2.1.2 Non-Eligibility (includes both partial and complete exclusions).

Notwithstanding Section 18.2.1.1:

18.2.1.2.1 a Supplier that bids on behalf of a Limited Energy Storage Resource shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment; and

18.2.1.2.2 A Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator that is committed by the ISO in the Day-Ahead Market shall not be eligible to receive a Day-Ahead Bid Production Cost guarantee payment if that Generator has been committed in the Day-Ahead Market for any other hour of the day as a result of a Self-Committed Fixed or Self-Committed Flexible bid.

18.2.2 Formulas for Determining Day-Ahead BPCG for Generators

18.2.2.1 Applicable Formula. A Supplier's BPCG for a Generator "g" shall be as follows:

Day-Ahead Bid Production Cost Guarantee for Generator g =

$$\max\left[\sum_{h=1}^{N}\left(\begin{array}{l}\displaystyle\int_{MGH_{gh}^{DA}}^{EH_{gh}^{DA}} C_{gh}^{DA} + MGC_{gh}^{DA}\, MGH_{gh}^{DA} + SUC_{gh}^{DA}\, NSUH_{gh}^{DA} \\ - LBMP_{gh}^{DA}\, EH_{gh}^{DA} - NASR_{gh}^{DA}\end{array}\right), 0\right]$$

18.2.2.2 Variable Definitions. The terms used in this Section 18.2.2 shall be defined as follows:

N = number of hours in the Day-Ahead Market day;

EH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by Generator g in hour h expressed in terms of MWh;

MGH_{gh}^{DA} = Energy scheduled Day-Ahead to be produced by the minimum generation segment of Generator g in hour h expressed in terms of MWh;

C_{gh}^{DA} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost curve for Generator g, in the Day-Ahead Market for hour h expressed in terms of $/MWh;

MGC_{gh}^{DA} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, for hour h in the Day-Ahead Market, expressed in terms of $/MWh.

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day and Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), then Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Day-Ahead Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gh}^{DA} = Start-Up Bid by Generator g in hour h, or when applicable the mitigated Start-Up Bid for Generator g, in hour h in the Day-Ahead Market expressed in terms of $/start; *provided, however*, that the Start-Up Bid for Generator g in hour h or, when applicable, the mitigated Start-Up Bid, for Generator g in hour h, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled, and to operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator g's Day-Ahead or SRE schedule.

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* Generator g shall have its Start-Up Bid set to zero for purposes of calculating a Day-Ahead Bid Production Cost guarantee.

For 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) that is committed by the ISO and runs in real-time, the Start-Up Bid for Generator g in hour h shall be the Generator's Start-Up Bid, or when applicable the mitigated Start-Up Bid for Generator g, for the hour (as determined at the point in time in which the ISO provided notice of the request for start-up):

$NSUH_{gh}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in hour h;

$LBMP_{gh}^{DA}$ = Day-Ahead LBMP at Generator g's bus in hour h expressed in $/MWh;

$NASR_{gh}^{DA}$ = Net Ancillary Services revenue, expressed in terms of $, paid to Generator g as a result of having been committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that hour, if it is not a Supplier of Installed Capacity and has been scheduled to operate in that hour; (2) Regulation Service payments made to that Generator for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less that Generator's Day-Ahead Bid to provide that amount of Regulation Service in that hour (unless the Bid exceeds the payments that Generator receives for providing Regulation Service that was committed to produce Energy for the LBMP Market and/or Ancillary Services Day-Ahead, in which case this component shall be zero); and (3) payments made to that Generator for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves in that hour, less that Generator's Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.3 Day-Ahead BPCG For Imports

18.3.1 Eligibility to Receive a Day-Ahead BPCG for Imports

A Supplier that bids an Import sale to the LBMP Market that is committed by the ISO in the Day-Ahead Market shall be eligible to receive a Day-Ahead Bid Production Cost guarantee payment.

18.3.2 BPCG Calculated by Transaction ID

For purposes of calculating a Day-Ahead Bid Production Cost guarantee payment for an Import under this Section 18.3, the ISO shall treat the Import as being from a single Resource for all hours of the Day-Ahead Market day in which the same Transaction ID is used, and the ISO shall treat the Import as being from a different Resource for all hours of the Day-Ahead Market day in which a different Transaction ID is used.

18.3.3 Formula for Determining Day-Ahead BPCG for Imports

Day-Ahead Bid Production Cost guarantee for Import t by Supplier =

$$\max\left[\sum_{h=1}^{N}\left(\mathrm{DecBid}_{th}^{DA}-\mathrm{LBMP}_{th}^{DA}\right)\bullet \mathrm{SchImport}_{th}^{DA},0\right]$$

Where;

N = number of hours in the Day-Ahead Market day;

$DecBid_{th}^{DA}$ = Decremental Bid, in \$/MWh, supplied for Import t for hour h;

$LBMP_{th}^{DA}$ = Day-Ahead LBMP, in \$/MWh, for hour h at the Proxy Generator Bus that is the source of the Import t and

$SchImport_{th}^{DA}$ = total Day-Ahead schedule, in MWh, for Import t in hour h.

18.4 Real-Time BPCG For Generators In RTD Intervals Other Than Supplemental Event Intervals

18.4.1 Eligibility for Receiving Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event Intervals

18.4.1.1 Eligibility.

A Supplier shall be eligible to receive a real-time Bid Production Cost guarantee payment for intervals (excluding Supplemental Event Intervals) if it bids on behalf of:

18.4.1.1.1 an ISO-Committed Flexible Generator or an ISO-Committed Fixed Generator that is committed by the ISO in the Real-Time Market; or

18.4.1.1.2 a Self-Committed Flexible Generator if the Generator's minimum generation MW level does not exceed its Day-Ahead schedule at any point during the Dispatch Day; or

18.4.1.1.3 a Generator committed via SRE, or committed or dispatched by the ISO as Out-of-Merit generation to ensure NYCA or local system reliability for the hours of the day that it is committed via SRE or is committed or dispatched by the ISO as Out-of-Merit generation to meet NYCA or local system reliability without regard to the Bid mode(s) employed during the Dispatch Day, except as provided in Sections 18.4.2 and 18.12, below.

18.4.1.2 Non-Eligibility (includes both partial and complete exclusions).

Notwithstanding Section 18.4.1.1:

18.4.1.2.1 a Supplier that bids on behalf of a Limited Energy Storage Resource shall not be eligible to receive a real-time Bid Production Cost guarantee payment;

18.4.1.2.2 a Supplier that bids on behalf of an ISO-Committed Fixed Generator or an ISO-Committed Flexible Generator that is committed by the ISO in the real-time market shall not be eligible to receive a real-time Bid Production Cost guarantee payment if that Generator has been committed in real-time, in any other hour of the day, as the result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule, *provided however*, a Generator that has been committed in real time as a result of a Self-Committed Fixed bid, or a Self-Committed Flexible bid with a minimum operating level that exceeds its Day-Ahead schedule will not be precluded from receiving a real-time Bid Production Cost guarantee payment for other hours of the Dispatch Day, in which it is otherwise eligible, due to these Self-Committed mode Bids if such bid mode was used for: (i) an ISO authorized Start-Up, Shutdown or Testing Period, or (ii) for hours in which such Generator was committed via SRE or committed or dispatched by the ISO as Out-of-Merit to meet NYCA or local system reliability.

18.4.2 Formula for Determining Real-Time BPCG for Generators in RTD Intervals Other Than Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee for Generator g =

$$\max\left[\left(\begin{array}{l}\displaystyle\sum_{i\in M}\left(\left(\begin{array}{l}\displaystyle\int_{\max\left(EI_{gi}^{DA},MGI_{gi}^{RT}\right)}^{\max\left(EI_{gi}^{RT},MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT}\cdot\left(MGI_{gi}^{RT}-MGI_{gi}^{DA}\right)\\ \quad - LBMP_{gi}^{RT}\cdot\left(EI_{gi}^{RT}-EI_{gi}^{DA}\right)\end{array}\right)\cdot\frac{s_i}{3600}\\ - \left(NASR_{gi}^{TOT}-NASR_{gi}^{DA}\right) - RRAP_{gi} + RRAC_{gi}\end{array}\right)\\ \quad + \displaystyle\sum_{j\in L} SUC_{gj}^{RT}\cdot\left(NSUI_{gj}^{RT}-NSUI_{gj}^{DA}\right)\end{array}\right),0\right].$$

where:

s_i = number of seconds in RTD interval i;

C_{gi}^{RT} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost for Generator g, in the RTD for the hour that includes RTD interval i expressed in terms of \$/MWh, except in intervals in which the dispatch of the Generator is constrained by its downward ramp rate for that interval, unless that Generator was scheduled to provide Regulation Service in that interval and its RTD basepoint was less than its AGC basepoint, and except in hours in which the NYISO has increased Generator g's minimum operating level, either (i) at the Generator's request, or (ii) in order to reconcile the ISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

MGI_{gi}^{RT} = metered Energy produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;

MGI_{gi}^{DA} = Energy scheduled Day-Ahead to be produced by minimum generation segment of Generator g in RTD interval i expressed in terms of MW;

MGC_{gi}^{RT} = Minimum Generation Bid by Generator g, or when applicable the mitigated Minimum Generation Bid for Generator g, in the Real-Time Market for the hour that includes RTD interval i, expressed in terms of \$/MWh, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

If Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via Supplemental Resource Evaluation ("SRE"), on the day prior to the Dispatch Day *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate), *then* Generator g shall have its minimum generation cost set equal to the revenues received for energy produced at its minimum operating level for purposes of calculating a Real-Time Bid Production Cost guarantee until Generator g completes the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day;

SUC_{gj}^{RT} = Start-Up Bid by Generator g, or when applicable the mitigated Start-Up Bid for Generator g, for hour j into RTD expressed in terms of \$/start, which Bid or mitigated Bid may include costs pursuant to Section 4.1.8;

provided, however,

(i) the Start-Up Bid shall be deemed to be zero for (1) Self-Committed Fixed and Self-Committed Flexible Generators, (2) Generators that are economically committed by RTC or RTD that have 10-minute start-up times that are not synchronized and producing Energy within 20 minutes after their scheduled start time, and (3) Generators that are economically committed by RTC that have greater than 10-minute start-up times that are not synchronized and producing Energy within 45 minutes after their scheduled start time;

(ii) if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time commitment that did not result from a Day-Ahead commitment, the Generator's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be the Start-Up Bid submitted in response to the SRE request (subject to mitigation, where appropriate);

(iii) if a Generator has been committed via SRE and its SRE schedule immediately precedes or follows a real-time schedule that resulted from a Day-Ahead commitment, then the Generator's Start-Up Bid included in its daily real-time Bid Production Cost guarantee calculation for this contiguous real-time commitment period shall be set to zero;

(iv) the real-time Start-Up Bid for Generator g for hour j or, when applicable, the mitigated real-time Start-Up Bid, for Generator g for hour j, may be subject to *pro rata* reduction in accordance with the rules set forth in Section 18.12 of this Attachment C. Bases for *pro rata* reduction include, but are not limited to, failure to be scheduled and operate in real-time to produce, in each hour, the MWh specified in the accepted Minimum Generation Bid that was submitted for the first hour of Generator g's Day-Ahead or SRE schedule, and failure to operate for the minimum run time specified in the Bid submitted for the first hour of Generator g's Day-Ahead or SRE schedule; and

(v) if Generator g was committed in the Day-Ahead Market, or in the Real-Time Market via SRE, on the day prior to the Dispatch Day, *and* Generator g has not yet completed the minimum run time reflected in the accepted Bid for the hour in which it was scheduled to start on the day before the Dispatch Day (as mitigated, where appropriate) plus the contiguous hour that follows the conclusion of such minimum run time, *then* Generator g shall have its Start-Up Bid set to zero for purposes of calculating a Real-Time Bid Production Cost guarantee.

$NSUI_{gj}^{RT}$ = number of times Generator g started up in hour j;

$NSUI_{gj}^{DA}$ = number of times Generator g is scheduled Day-Ahead to start up in hour j;

$LBMP_{gi}^{RT}$ = Real-Time LBMP at Generator g's bus in RTD interval i expressed in terms of $/MWh;

M = the set of eligible RTD intervals in the Dispatch Day consisting of all of the RTD intervals in the Dispatch Day except:

(i) Supplemental Event Intervals (which are addressed separately in Section 18.5 below);

(ii) intervals during authorized Start-Up Periods, Shutdown Periods, or Testing Periods for Generator g;

L = the set of all hours in the Dispatch Day

EI_{gi}^{RT} = either, as the case may be:

(i) if $EOP_{ig} > AEI_{ig}$ then $\min(\max(AEI_{ig},RTSen_{ig}),EOP_{ig})$; or

(ii) if otherwise, then $\max(\min(AEI_{ig},RTSen_{ig}),EOP_{ig})$.

EI_{gi}^{DA} = Energy scheduled in the Day-Ahead Market to be produced by Generator g in the hour that includes RTD interval i expressed in terms of MW;

$RTSen_{ig}$ = Real-time Energy scheduled for Generator g in interval i, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Generator g during the course of interval i expressed in terms of MW;

AEI_{ig} = average Actual Energy Injection by Generator g in interval i but not more than $RTSen_{ig}$ plus any Compensable Overgeneration expressed in terms of MW;

EOP_{ig} = the Economic Operating Point of Generator g in interval i expressed in terms of MW;

$NASR_{gi}^{TOT}$ = Net Ancillary Services revenue, expressed in terms of $, paid to Generator g as a result of either having been committed Day-Ahead to operate in the hour that includes RTD interval i or having operated in interval i which is computed by summing the following: (1) Voltage Support Service payments received by that Generator for that RTD interval, if it is not a Supplier of Installed Capacity; (2) Regulation Service payments that would be made to that Generator for that hour based on a Performance Index of 1, less the Bid(s) placed by that Generator to provide Regulation Service in that hour at the time it was committed to produce Energy for the LBMP Market and/or Ancillary Services to do so (unless the Bid(s) exceeds the payments that Generator receives for providing Regulation

Service, in which case this component shall be zero); (3) payments made to that Generator for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by that Generator to provide such reserves in that hour at the time it was scheduled to do so; and (4) Lost Opportunity Cost payments made to that Generator in that hour as a result of reducing that Generator's output in order for it to provide Voltage Support Service.

$NASR_{gi}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, expressed in terms of $, that is applicable to interval i calculated by multiplying the $NASR_{gh}^{DA}$ for the hour that includes interval i by $_{Si}$/3600.

$RRAP_{gi}$ = Regulation Revenue Adjustment Payment for Generator g in RTD interval i expressed in terms of $.

$RRAC_{gi}$ = Regulation Revenue Adjustment Charge for Generator g in RTD interval i expressed in terms of $.

18.4.3 Bids Used For Intervals at the End of the Hour

For RTD intervals in an hour that start 55 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour in accordance with ISO Procedures. For RTD-CAM intervals in an hour that start 50 minutes or later after the start of that hour, a Bid used to determine real-time BPCG in Section 18.4.2 will be the Bid for the next hour, in accordance with ISO Procedures.

18.5 BPCG For Generators In Supplemental Event Intervals

18.5.1 Eligibility for BPCG for Generators in Supplemental Event Intervals

18.5.1.1 Eligibility

For intervals in which the ISO has called a large event reserve pick-up, as described in Section 4.4.4.1.1 of this ISO Services Tariff, or an emergency under Section 4.4.4.1.2 of this ISO Services Tariff, any Supplier who meets the eligibility requirements for a real-time Bid Production Cost guarantee payment described in subsection 18.4.1.1 of this Attachment C, shall be eligible to receive a BPCG under this Section 18.5.

18.5.1.2 Non-Eligibility

Notwithstanding subsection 18.5.1.1, a Supplier shall not be eligible to receive a Bid Production Cost guarantee payment for Supplemental Event Intervals if the Supplier is not eligible for a real-time Bid Production Cost guarantee payment for the reasons described in Section 18.4.1.2 of this Attachment C.

18.5.1.3 Additional Eligibility

Notwithstanding Section 18.5.1.2, a Supplier shall be eligible to receive a Bid Production Cost guarantee payment for a Generator, not a Limited Energy Storage Resource, producing energy during Supplemental Event Intervals occurring as a result of an ISO emergency under Section 4.4.4.1.2 of this ISO Services Tariff regardless of bid mode used for the day.

18.5.2 Formula for Determining BPCG for Generators in Supplemental Event Intervals

Real-Time Bid Production Cost Guarantee Payment for Generator g =

$$\sum_{i\in P}\left(\max\left(\left(\begin{array}{l}\left(\begin{array}{l}\int_{\max\left(EI_{gi}^{DA},MGI_{gi}^{RT}\right)}^{\max\left(EI_{gi}^{RT},MGI_{gi}^{RT}\right)} C_{gi}^{RT} + MGC_{gi}^{RT}\cdot\left(MGI_{gi}^{RT}-MGI_{gi}^{DA}\right)\\ -LBMP_{gi}^{RT}\cdot\left(EI_{gi}^{RT}-EI_{gi}^{DA}\right)\end{array}\right)\cdot\frac{s_i}{3600}\\ -\left(NASR_{gi}^{TOT}-NASR_{gi}^{DA}\right)-RRAP_{gi}+RRAC_{gi}\end{array}\right),0\right)\right)$$

where:

P = the set of Supplemental Event Intervals in the Dispatch Day but excluding any intervals in which there are maximum generation pickups or large event reserve pickups where EI_{gi}^{RT} is less than or equal to EI_{gi}^{DA}; and

EI_{gi}^{RT} = (i) for any intervals in which there are maximum generation pickups, and the three intervals following, for Generators in the location for which the maximum generation pickup has been called -- the average Actual Energy Injections, expressed in MWh, for Generator g in interval i, and for all other Generators EI_{gi}^{RT} is as defined in Section 18.4.2 above.

(ii) for any intervals in which there are large event reserve pickups and the three intervals following, EI_{gi}^{RT} is as defined in Section 18.4.2 above.

C_{gi}^{RT} = Bid cost submitted by Generator g, or when applicable the mitigated Bid cost for Generator g, in the RTD for the hour that includes RTD interval i expressed in terms of \$/MWh, except in hours in which the NYISO has increased Generator g's minimum operating level, either (i) at the Generator's request, or (ii) in order to reconcile the ISO's dispatch with the Generator's actual output or to address reliability concerns that arise because the Generator is not following Base Point Signals, in which case C_{gi}^{RT} shall be deemed to be zero;

The definition of all other variables is identical to those defined in Section 18.4 above.

In the event that the ISO re-institutes penalties for poor Regulation Service performance under Section 15.3.8 of Rate Schedule 3 such penalties will not be taken into account when calculating supplemental payments under this Attachment C.

18.6 Real-Time BPCG For Imports

18.6.1 Eligibility for Receiving Real-Time BPCG for Imports

18.6.1.1 Eligibility.

A Supplier that bids an Import to sell Energy to the LBMP Market that is committed by the ISO in the Real-Time Market shall be eligible to receive a real-time Bid Production Cost guarantee payment for all intervals.

18.6.1.2 Non-Eligibility.

Notwithstanding Section 18.6.1.1:

18.6.1.2.1 Customers that schedule hourly Import Transactions at either Variably Scheduled Proxy Generator Buses or Dynamically Scheduled Proxy Generator Buses will not be eligible for Real-Time shortfall payments for those Transactions for the day;

18.6.1.2.2 when a Non-Competitive Proxy Generator Bus or the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located is export constrained due to limits on available Interface Capacity or Ramp Capacity limits for that Interface in an hour, Customers scheduling an Import at such Non-Competitive Proxy Generator Bus in that hour shall not be eligible for a real-time Bid Production Cost guarantee payment for this Transaction;

18.6.1.2.3 when a Proxy Generator Bus that is associated with a designated Scheduled Line is export constrained due to limits on available Interface Capacity in an hour, Customers scheduling an Import at such Proxy Generator Bus in that hour will not be eligible for a real-time Bid Production Cost guarantee payment for this Transaction;

18.6.1.2.4 when the Rolling RTC is export constrained due to limits on NYCA Ramp Capacity in an hour, Customers scheduling Imports at Proxy Generator Buses associated with designated Scheduled Lines and Non-Competitive Proxy Generator Buses in that hour will not be eligible for real-time shortfall payments for those Transactions.

18.6.2 BPCG Calculated by Transaction ID

For purposes of calculating a real-time Bid Production Cost guarantee payment for an Import under this Section 18.6, the ISO shall treat the Import as being from a single Resource for all hours of the Dispatch Day in which the same Transaction ID is used, and the ISO shall treat the Import as being from a different Resource for all hours of the Dispatch Day in which a different Transaction ID is used.

18.6.3 Formula for Determining Real-Time BPCG for Imports

Real-Time Bid Production Cost Guarantee for Import t by a Supplier =

$$Max\left(\sum_{i=1}^{Q}\left[\left(\mathrm{DecBid}_{ti}^{RT}-\mathrm{LBMP}_{ti}^{RT}\right)\bullet \max\left(\mathrm{SchImport}_{ti}^{RT}-\mathrm{SchImport}_{ti}^{DA},0\right)\bullet \mathrm{S_i}/3600\right],0\right)$$

Where:

Q = number of intervals in the Dispatch Day;

$\mathrm{DecBid}_{ti}^{RT}$ = Decremental Bid, in \$/MWh, supplied for Import t for interval i;

LBMP_{ti}^{RT} = real-time LBMP, in \$/MWh, for interval i at Proxy Generator Bus ~~p~~ which is the source of the Import t;

$\mathrm{SchImport}_{ti}^{RT}$ = total real-time schedule, in MW, for Import t in interval i; and

$SchImport_{ti}^{DA}$ = total Day-Ahead schedule, in MW, for Import t in hour that contains interval i.

$S_{i,}$ = number of seconds in RTD interval i.

18.7. BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their dispatch

18.7.1 Eligibility for BPCG for Long Start-Up Time Generators Whose Starts Are Aborted by the ISO Prior to their Dispatch

A Supplier that bids on behalf of 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) that is committed by the ISO for reliability purposes as a result of a Supplemental Resource Evaluation and whose start is aborted by the ISO prior to its dispatch, as described in Section 4.2.5 of the ISO Services Tariff, shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.7.

18.7.2 Methodology for Determining BPCG for Long Start-Up Time Generators Whose Starts are Aborted by the ISO Prior to their Dispatch

A Supplier whose long start-up time Generator's start-up is aborted shall receive a prorated portion of its Start-Up Bid submitted for the hour in which the ISO requested that the Generator begin its start-up sequence, based on the portion of the start-up sequence that it has completed prior to the signal to abort the start-up (*e.g.*, if a long start-up time Generator with a seventy-two (72) hour start-up time has its start-up sequence aborted after forty-eight (48) hours, it would receive two-thirds (2/3) of its Start-Up Bid).

18.8 BPCG For Demand Reduction In The Day-Ahead Market

18.8.1 Eligibility for BPCG for Demand Reduction in the Day-Ahead Market

A Demand Reduction Provider that bids a Demand Side Resource that is committed by the ISO in the Day-Ahead Market to provide Demand Reduction shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.8.

18.8.2 Formula for Determining BPCG for Demand Reduction in the Day-Ahead Market

Day-Ahead BPCG for Demand Reduction Provider d =

$$\text{Max}\left[\sum_{h=1}^{N}\left(\text{MinCurCost}_d^h + \text{IncrCurCost}_d^h - \text{CurRev}_d^h\right) + \text{CurInitCost}_d, 0\right]$$

where:

$$\text{CurInitCost}_d = \left(\sum_{h=1}^{N} \left(Min\left(\text{ActCur}_d^h, \text{SchdCur}_d^h\right)\right) / \left(\sum_{h=1}^{N} \text{SchdCur}_d^h\right) \right) * \text{CurCost}_d$$

$$\text{MinCurCost}_d^h = \text{Min}\left[\left(\max\left(\text{ActCur}_d^h, 0\right), \text{MinCur}_d^h\right)\right] * \text{MinCurBid}_d^h$$

$$\text{IncrCurCost}_d^h = \int_{\text{MinCur}_d^h}^{\max\left(\text{MinCur}_d^h, \min\left(SchdCur_d^h, ActCur_d^h\right)\right)} \text{IncrCurBid}_d^h]$$

$$\text{CurRev}_d^h = \text{LBMP}_{dh}^{DA} * \min\left(\max\left(\text{ActCur}_d^h, 0\right), \text{SchdCur}_d^h\right)$$

N	=	number of hours in the Day-Ahead Market day.
CurInitCost_d	=	daily Curtailment Initiation Cost credit for Day-Ahead Demand Reduction Provider d;

$MinCurCost_d^h$ = minimum Curtailment cost credit for Day-Ahead Demand Reduction Provider d in hour h;

$IncrCurCost_d^h$ = incremental Curtailment cost credit for Day-Ahead Demand Reduction Provider d for hour h;

$CurCost_d$ = total bid Curtailment Initiation Costs for Day-Ahead Demand Reduction Provider d for the day;

$CurRev_d^h$ = actual revenue for Day-Ahead Demand Reduction Provider d in hour h;

$ActCur_d^h$ = actual Energy curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$SchdCur_d^h$ = Energy scheduled Day-Ahead to be curtailed by Day-Ahead Demand Reduction Provider d in hour h expressed in terms of MWh;

$MinCurBid_d^h$ = minimum Curtailment initiation Bid submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of \$/MWh;

$IncrCurBid_d^h$ = Bid cost submitted by Day-Ahead Demand Reduction Provider d for hour h expressed in terms of \$/MWh;

$MinCur_d^h$ = Energy scheduled Day-Ahead to be produced by the minimum Curtailment segment of Day-Ahead Demand Reduction Provider d for hour h expressed in terms of MWh; and

$LBMP_{dh}^{DA}$ = Day-Ahead LBMP for Day-Ahead Demand Reduction Provider d for hour h expressed in \$/MWh.

18.9 BPCG For Special Case Resources

18.9.1 Eligibility for Special Case Resources BPCG

Any Supplier that bids a Special Case Resource that is committed by the ISO for an event in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.9. Suppliers shall not be eligible for a Special Case Resource Bid Production Cost guarantee payment for the period over which a Special Case Resource is performing a test.

18.9.2 Methodology for Determining Special Case Resources BPCG

A Special Case Resource Bid Production Cost guarantee payment shall be made when the Minimum Payment Nomination for any Special Case Resource committed by the ISO over the period of requested performance or four (4) hours, whichever is greater, exceeds the LBMP revenue received for performance by that Special Case Resource; provided, however, that 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.

18.10 BPCG For Demand Side Resources Providing Synchronized Operating Reserves In The Day-Ahead Market

18.10.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Day-Ahead Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves in the Day-Ahead Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.10.

18.10.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Day-Ahead Market

A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves schedule in the Day-Ahead Market shall be calculated as follows:

BPCG for Demand Side Resource d Providing synchronized Operating Reserves Day-Ahead =

$$\max\left[\left(-\sum_{h=1}^{N} NASR_{dh}^{DA}\right),0\right]$$

where:

N	=	number of hours in the Day-Ahead Market day.
$NASR_{dh}^{DA}$	=	Net Ancillary Services revenue, in $, paid to Demand Side Resource d as a result of having been committed to provide Ancillary Services Day-Ahead in hour h which is computed by summing the following: (1) Regulation Service payments made to that Demand Side Resource for all Regulation Service it is scheduled Day-Ahead to provide in that hour, less Demand Side Resource d’s Day-Ahead Bid to provide that amount of Regulation Service in that hour (unless the Bid exceeds the payments that the Demand Side Resource receives for providing Regulation Service that was committed to provide Ancillary Services Day-Ahead, in which case this component shall be zero); and (2) payments made to Demand Side Resource d for providing Spinning Reserve and synchronized 30-Minute Reserve in that hour if it is committed Day-Ahead to provide such reserves

in that hour, less Demand Side Resource d’s Day-Ahead Bid to provide Spinning Reserve and synchronized 30-Minute Reserve in that hour.

18.11 BPCG For Demand Side Resources Providing Synchronized Operating Reserves In The Real-Time Market

18.11.1 Eligibility for BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Real-Time Market

Any Supplier that bids a Demand Side Resource that is committed by the ISO to provide synchronized Operating Reserves in the Real-Time Market shall be eligible to receive a Bid Production Cost guarantee payment under this Section 18.11.

18.11.2 Formula for Determining BPCG for Demand Side Resources Providing Synchronized Operating Reserves in the Real-Time Market

A Bid Production Cost guarantee payment to a Demand Side Resource with a synchronized Operating Reserves schedule in the real-time Market shall be calculated as follows:

BPCG for Demand Side Resource d Providing synchronized Operating Reserves in Real-Time =

$$\max\left[-\sum_{i \in L}\left\langle NASR_{di}^{TOT} - NASR_{di}^{DA}\right\rangle, 0\right]$$

where:

L	=	set of RTD intervals in the Dispatch Day;
$NASR_{di}^{TOT}$	=	Net Ancillary Services revenue, in $, paid to Demand Side Resource d as a result of either having been scheduled Day-Ahead in the hour that includes RTD interval i or having been scheduled in real-time interval i which is computed by summing the following: (1) Regulation Service payments that would be made to Demand Side Resource d for that hour based on a Performance Index of 1, less the Bid(s) placed by Demand Side Resource d to provide Regulation Service in that hour at the time it was committed to provide Ancillary Services (unless the Bid(s) exceeds the payments that Demand Side Resource d receives for providing Regulation Service, in which case this component shall be zero); and (2) payments made to Demand Side Resource d for providing Spinning Reserve or synchronized 30-Minute Reserve in that hour, less the Bid placed by Demand Side Resource d to provide such reserves in that hour at the time it was scheduled to do so; and

$NASR_{di}^{DA}$ = The proportion of the Day-Ahead net Ancillary Services revenue, in $, that is applicable to interval i calculated by multiplying the $NASR_{dh}^{DA}$ for the hour that includes interval i by the quotient of the number of seconds in RTD interval i divided by 3600.

18.12 Proration Of Start-Up Bid For Generators That Are Committed In The Day-Ahead Market, Or Via Supplemental Resource Evaluation

18.12.1 Eligibility to Recover Operating Costs and Resulting Obligations

Generators committed in the Day-Ahead Market or via SRE that are not able to complete their minimum run time within the Dispatch Day in which they are committed are eligible to include in their Start-Up Bid expected net costs of operating on the day following the dispatch day at the minimum operating level specified for the hour in which the Generator is committed, for the hours necessary to complete the Generator's minimum run time.

Generators that receive Day-Ahead or SRE schedules that are not scheduled to operate in real-time, or that do not operate in real-time, at the MW level included in the Minimum Generation Bid for the first hour of the Generator's Day-Ahead or SRE schedule, for the longer of (a) the duration of the Generator's Day-Ahead or SRE schedule, or (b) the minimum run time specified in the Bid that was accepted for the first hour of the Generator's Day-Ahead or SRE schedule, will have the start-up cost component of the Bid Production Cost guarantee calculation prorated in accordance with the formula specified in Section 18.12.2, below. The rules for prorating the start-up cost component of the Bid Production Cost guarantee calculation apply both to operation within the Dispatch Day and to operation on the day following the Dispatch Day to satisfy the minimum run time specified for the hour in which the Generator was scheduled to start-up on the Dispatch Day.

Rules for calculating the reference level that the NYISO uses to test Start-Up Bids for possible mitigation are included in the Market Power Mitigation Measures that are set forth in Attachment H to the ISO Services Tariff. Proration of the start-up cost component of a

Generator's Bid Production Cost guarantee based on the Generator's operation in real-time is different/distinct from the mitigation of a Start-Up Bid.

18.12.2 Proration of Eligible Start-Up Cost when a Generator Is Not Scheduled, or Does Not Operate to Meet the Schedule Specified in the Accepted Day-Ahead or SRE Start-Up Bid.

The start-up costs included in the Bid Production Cost guarantee calculation may be reduced *pro rata* based on a comparison of the actual MWs delivered in real-time to an hourly minimum MW requirement. The hourly MWh requirement is determined based on the MW component of the Minimum Generation Bid submitted for the Generator's accepted start hour (as mitigated, where appropriate).

18.12.2.1 Total Energy Required to be Provided in Order to Avoid Proration of a Generator's Start-Up Costs

$TotMWReq_{g,s} = MinOpMW_{g,s} * n_{g,s}$,

Where:

$TotMWReq_{g,s}$ = Total amount of Energy that Generator g, when started in hour s, must provide for its start-up costs not to be prorated
$MinOpMW_{g,s}$ = Minimum operating level (in MW) specified by Generator g in its hour s Bid
$n_{g,s}$ = The last hour that Generator g must operate when started in hour s to complete both its minimum run time and its Day-Ahead schedule. The variable $n_{g,s}$ is calculated as follows:

$$n_{g,s} = \max\left(LastHrDASched_{g,s}, LastMinRunHr_{g,s}\right),$$

Where:

$LastHrDASched_{g,s}$ = The last date/hour in a contiguous set of hours in the Dispatch Day, beginning with hour s, in which Generator g is scheduled to operate in the Day-Ahead Market
$LastMinRunHr_{g,s}$ = The last date/hour in a contiguous set of hours in which Generator g would need to operate to complete its minimum run time if it starts in hour s

18.12.2.2 Calculation of Prorated Start-Up Cost

$$ProratedSUC_{g,s} = SubmittedSUC_{g,s} \cdot \frac{\sum_{h=s}^{n_{g,s}} MinOpEnergy_{g,h,s}}{TotalMWReq_{g,s}},$$

Where:

ProratedSUC$_{g,s}$ = the prorated start-up cost used to calculate the Bid Production Cost guarantee for Generator g that is scheduled to start in hour s

SubmittedSUC$_{g,s}$ = the Start-Up Bid submitted (as mitigated, where appropriate) for Generator g that is scheduled to start in hour s

MinOpEnergy$_{g,h,s}$ = the amount of Energy produced during hour h by Generator g during the time required to complete both its minimum run time and its Day-Ahead schedule, if that generator is started in hour s. MinOpEnergy$_{g,h,s}$ is calculated as follows:

$$MinOpEnergy_{g,h,s} = \min\left(MetActEnergy_{g,h}, MinOpMW_{g,s}\right),$$

Where:

MetActEnergy$_{g,h}$ = the metered amount of Energy produced by Generator g during hour h

18.12.2.3 Additional Rules/Clarifications that Apply to the Calculation of Prorated Start-Up Cost

a. For any hour that a Generator is derated below the minimum operating level specified in its accepted Start-Up Bid for reliability, either by the ISO or at the request of a Transmission Owner, the Generator will receive credit for that hour as if the Generator had produced metered actual MWh equal to its MinOpMW$_{g,s}$.

b. A Generator must be scheduled and operate in real-time to produce Energy consistent with the MinOpMW$_{g,s}$ specified in the accepted Start-Up Bid for each hour that it is expected to run. *See* Section 18.12.2.1, above. These rules do not specify or require any particular bidding construct that must be used to achieve the desired commitment.

However, submitting a self-committed Bid may preclude a Generator from receiving a BPCG. *See, e.g.*, Sections 18.2.1.2.2 and 18.4.1.2.3 of this Attachment C.

25 Attachment J – Determination of Day-Ahead Margin Assurance Payments and Import Curtailment Guarantee Payments

25.1 Introduction

If a Supplier that is eligible pursuant to Section 25.2 of this Attachment J buys out of a Day-Ahead Energy, Regulation Service or Operating Reserve schedule in a manner that reduces its Day-Ahead Margin it shall receive a Day-Ahead Margin Assurance Payment, except as noted in Sections 25.4, and 25.5 of this Attachment J. The purpose of such payments is to protect Suppliers' Day-Ahead Margins associated with real-time reductions after accounting for: (I) any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve schedules; and (ii) any Supplier-requested real-time de-rate granted by the ISO.

In addition, a Supplier may be eligible to receive an Import Curtailment Guarantee Payment if its Import is curtailed at the request of the ISO as determined pursuant to Section 25.6 of this Attachment J.

25.2 Eligibility for Receiving Day-Ahead Margin Assurance Payments

25.2.1 General Eligibility Requirements for Suppliers to Receive Day-Ahead Margin Assurance Payments

Subject to Section 25.2.2 of this Attachment J, the following categories of Resources bid by Suppliers shall be eligible to receive Day-Ahead Margin Assurance Payments: (I) all Self-Committed Flexible and ISO-Committed Flexible Generators that are online and dispatched by RTD; (ii) Demand Side Resources committed to provide Operating Reserves or Regulation Service; (iii) any Resource that is scheduled out of economic merit order by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; (iv) any Resource internal to the NYCA that is derated or decommitted by the ISO in response to an ISO or Transmission Owner system security need or to permit the ISO to procure additional Operating Reserves; and (v) Energy Limited Resources with an ISO-approved real-time reduction in scheduled output from its Day-Ahead schedule.

25.2.2 Exceptions

Notwithstanding Section 25.2.1 of this Attachment J, no Day-Ahead Margin Assurance Payment shall be paid to:

25.2.2.1 a Resource otherwise eligible for a Day-Ahead Margin Assurance Payment in hours in which the NYISO has increased the Resource's minimum operating level either: (i) at the Resource's request; or (ii) in order to reconcile the ISO's dispatch with the Resource's actual output or to address reliability concerns that arise because the Resource is not following Base Point Signals; or (iii) an Intermittent Power Resource that depends on wind as its fuel.

25.2.2.2 a Generator, otherwise eligible for Day-Ahead Margin Assurance Payments, for (i) any hour in which the Incremental Energy Bids submitted in the real-time market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market; and (ii) the two hours immediately preceding and the two hours immediately following the hour(s) in which the Incremental Energy Bids submitted in the real-time market for that Generator exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for the portion of that Generator's Capacity that was scheduled in the Day-Ahead Market.

25.3 Calculation of Day-Ahead Margin Assurance Payments

25.3.1 Formula for Day-Ahead Margin Assurance Payments for Generators, Except for Limited Energy Storage Resources

Subject to Sections 25.4 and 25.5 of this Attachment J, Day-Ahead Margin Assurance Payments for Generators, except for Limited Energy Storage Resources, shall be determined by applying the following equations to each individual Generator using the terms as defined in Section 25.3.4:

$$DMAP_{hu} = \max\left(0, \sum_{i \in h} CDMAP_{iu}\right) \quad \text{where:}$$

$$CDMAP_{iu} = CDMAPen_{iu} + \sum_{P} CDMA\Pr es_{iup} + CDMA\Pr eg_{iu}$$

If the Generator's real-time Energy schedule is lower than its Day-Ahead Energy schedule then:

$$\mathrm{CDMAPen}_{iu} = \left\{ \begin{matrix} [\mathrm{DASen}_{hu} - \mathrm{LL}_{iu}] \times \mathrm{RTPen}_{iu} \\ - \int_{\mathrm{LL}_{iu}}^{\mathrm{DASen}_{hu}} \mathrm{DABen}_{hu} \end{matrix} \right\} * \frac{\mathrm{Seconds}_i}{3600},$$

If the Generator's real-time Energy schedule is greater than or equal to its Day-Ahead Energy schedule then:

$$\mathrm{CDMAPen}_{iu} = \mathrm{MIN}\left(\left\{ \begin{matrix} [\mathrm{DASen}_{hu} - \mathrm{UL}_{iu})] \times \mathrm{RTPen}_{iu} \\ + \int_{\mathrm{DASen}_{hu}}^{\mathrm{UL}_{iu}} \mathrm{RTBen}_{iu} \end{matrix} \right\} * \frac{\mathrm{Seconds}_i}{3600}, 0 \right)$$

If the Generator's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$\mathrm{CDMAPres}_{iup} = \left[\left(\mathrm{DASres}_{hup} - \mathrm{RTSres}_{iup}\right) \times \left(\mathrm{RTPres}_{iup} - \mathrm{DABres}_{hup}\right) \right] * \frac{\mathrm{Seconds}_i}{3600}$$

If the Generator's real-time schedule for a given Operating Reserve product, p, is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) \times \left(RTPres_{iup}\right)\right] * \frac{Seconds_i}{3600}$$

If the Generator's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu}\right) \times \left(RTPreg_{iu} - DABreg_{hu}\right)\right] * \frac{Seconds_i}{3600}$$

If the Generator's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu}\right) \times MAX\left(\left(RTPreg_{iu} - RTBreg_{iu}\right), 0\right)\right] * \frac{Seconds_i}{3600}.$$

25.3.2 Formula for Day-Ahead Margin Assurance Payments for Demand Side Resources

25.3.2.1 Formula for Day-Ahead Margin Assurance Payment for Demand Side Resources

Subject to Section 25.5 of this Attachment J, Day-Ahead Margin Assurance Payments for Demand Side resources scheduled to provide Operating Reserves or Regulation Service shall be determined by applying the following equations to each individual Demand Side Resource using the terms as defined in Section 25.3.4, except for RPIiu, which is defined in Section 25.3.2.2:

$$DMAP_{hu} = \max\left(0, \sum_{i \in h} CDMAP_{iu}\right) \text{where:}$$

$$CDMAP_{iu} = \sum_{p} CDMAPres_{iup} + CDMAPreg_{iu},$$

If the Demand Side Resource's real-time schedule for a given Operating Reserve product, p, is lower than its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) \times \left(RTPres_{iup} - DABres_{hup}\right)\right] * RPIiu * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time schedule for a given Operating Reserve product, p, is greater than or equal to its Day-Ahead Operating Reserve schedule for that product then:

$$CDMAPres_{iup} = \left[\left(DASres_{hup} - RTSres_{iup}\right) \times \left(RTPres_{iup}\right)\right] * RPI\,iu * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu}\right) \times \left(RTPreg_{iu} - DABreg_{hu}\right)\right] * \frac{Seconds_i}{3600}$$

If the Demand Side Resource's real-time Regulation Schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu}\right) \times MAX\left(\left(RTPreg_{iu} - RTBreg_{iu}\right), 0\right)\right] * \frac{Seconds_i}{3600}.$$

25.3.2.2 Reserve Performance Index for Demand Side Resource Suppliers of Operating Reserves

The ISO shall produce a Reserve Performance Index for purposes of calculating a Day Ahead Margin Assurance Payment for a Demand Side Resource providing Operating Reserves. The Reserve Performance Index shall take account of the actual Demand Reduction achieved by the Supplier of Operating Reserves following the ISO's instruction to convert Operating Reserves to Demand Reduction.

The Reserve Performance Index shall be a factor with a value between 0.0 and 1.0 inclusive. For each interval in which the ISO has not instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction, the Reserve Performance Index shall have a value of one. For each interval in which the ISO has instructed the Demand Side Resource to convert its Operating Reserves to Demand Reduction the Reserve Performance Index shall be calculated pursuant to the following formula, provided however when UAGi is zero or less, the Reserve Performance Index shall be set to zero:

$$RPI_{iu} = \text{Min}\left[(UAGi / ADGi + .1), 1\right]$$

Where:

RPI_{iu}	=	Reserve Performance Index in interval i for Demand Side Resource u;
UAGi	=	average actual Demand Reduction for interval i, represented as a positive generation value; and
ADGi	=	average scheduled Demand Reduction for interval i, represented as a positive generation base point.

25.3.3 Formula for Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources

Day-Ahead Margin Assurance Payments for Limited Energy Storage Resources scheduled to provide Regulation Service shall be determined by applying the following equations to each Resource using the terms as defined in Section 25.3.4; *provided, however*, that a Day-Ahead Margin Assurance Payment is payable only for intervals in which the NYISO has reduced the real-time Regulation Service offer (in MWs) of a Limited Energy Storage Resource and the NYISO is not pursuing LESR Energy Management for such Resource for such interval, pursuant to ISO Procedures:

If the LESR's real-time Regulation Service schedule is less than its Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu} \right) * \left(RTPreg_{iu} - DABreg_{hu} \right) \right] * K_{PI} * \frac{Seconds_i}{3600}$$

If the LESR's real-time Regulation Service schedule is greater than or equal to the Day-Ahead Regulation Service schedule then:

$$CDMAPreg_{iu} = \left[\left(DASreg_{hu} - RTSreg_{iu}\right) \times MAX\left(\left(RTPreg_{iu} - RTBreg_{iu}\right), 0\right)\right] * \frac{Seconds_i}{3600}$$

25.3. 4 Terms Used in this Attachment J

The terms used in the formulas in this Attachment J shall be defined as follows:

h is the hour that includes interval *i*;

DMAPhu	=	the Day-Ahead Margin Assurance Payment attributable in any hour h to any Supplier u;
$CDMAP_{iu}$	=	the contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;
$CDMAPen_{iu}$	=	the Energy contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;
$CDMAPreg_{iu}$	=	the Regulation Service contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u*;
$CDMAPres_{iup}$	=	the Operating Reserve contribution of RTD interval *i* to the Day-Ahead Margin Assurance Payment for Supplier *u* determined separately for each Operating Reserve product p;
$DASen_{hu}$	=	Day-Ahead Energy schedule for Supplier *u* in hour *h*;
$DASreg_{hu}$	=	Day-Ahead schedule for Regulation Service for Supplier *u* in hour *h*;
$DASres_{hup}$	=	Day-Ahead schedule for Operating Reserve product p, for Supplier *u* in hour *h*;
$DABen_{hu}$	=	Day-Ahead Energy bid curve for Supplier *u* in hour *h*;
$DABreg_{hu}$	=	Day-Ahead Availability Bid for Regulation Service for Supplier *u* in hour *h*;
$DABres_{hup}$	=	Day-Ahead Availability Bid for Operating Reserve product p for Supplier *u* in hour *h*;

$RTSen_{iu}$ = real-time Energy scheduled for Supplier *u* in interval *i*, and calculated as the arithmetic average of the 6-second AGC Base Point Signals sent to Supplier *u* during the course of interval *i*;

$RTSreg_{iu}$ = real-time schedule for Regulation Service for Supplier *u* in interval *i*.

$RTSres_{iup}$ = real-time schedule for Operating Reserve product p for Supplier *u* in interval *i*.

$RTBreg_{iu}$ = real-time Availability Bid for Regulation Service for Supplier *u* in interval *i*.

$RTBen_{iu}$ = real-time Energy bid curve for Supplier *u* in interval *i*.

AEI_{iu} = average Actual Energy Injection by Supplier u in interval *i* but not more than $RTSen_{iu}$ plus Compensable Overgeneration;

$RTPen_{iu}$ = real-time price of Energy at the location of Supplier *u* in interval *i*;

$RTPreg_{iu}$ = real-time price of Regulation Service at the location of Supplier *u* in interval *i*;

$RTPres_{iup}$ = real-time price of Operating Reserve product p at the location of Supplier *u* in interval *i*;

LL_{iu} = either, as the case may be:

(a) if $RTSen_{iu} < EOP_{iu}$, then $LL_{iu} = \min(\max(RTSen_{iu}, \min(AEI_{iu},EOP_{iu})), DASen_{hu})$; or

(b) if $RTSen_{iu} \geq EOP_{iu}$, then $LL_{iu} = \min(RTSen_{iu}, \max(AEI_{iu},EOP_{iu}), DASen_{hu})$,

UL_{iu} = either, as the case may be:

(a) if $RTSen_{iu} \geq EOP_{iu} \geq DASen_{hu}$, then $UL_{iu} = \max(\min(RTSen_{iu}, \max(AEI_{iu},EOP_{iu})), DASen_{hu})$; or

(b) otherwise, then $UL_{iu} = \max(RTSen_{iu}, \min(AEI_{iu},EOP_{iu}), DASen_{hu})$;

EOP_{iu} = the Economic Operating Point of Supplier *u* in interval *i* calculated without regard to ramp rates;

$Seconds_i$ = number of seconds in interval *i*

K_{PI} = the factor derived from the Regulation Service Performance index for Resource u for interval i as defined in Rate Schedule 3 of this Services Tariff which shall initially be set at 1.0 for LESRs.

25.4 Exception for Generators Lagging Behind RTD Base Point Signals

If an otherwise eligible Generator's average Actual Energy Injection in an RTD interval (*i.e.*, its Actual Energy Injections averaged over the RTD interval) is less than or equal to its penalty limit for under-generation value for that interval, as computed below, it shall not be eligible for Day-Ahead Margin Assurance Payments for that interval.

The penalty limit for under-generation value is the tolerance described in Section 15.3A.1 of Rate Schedule 3-A of this ISO Services Tariff, which is used in the calculation of the persistent under-generation charge applicable to Generators that are not providing Regulation Service.

25.5 Rules Applicable to Supplier Derates

Suppliers that request and are granted a derate of their real-time Operating Capacity, but that are otherwise eligible to receive Day-Ahead Margin Assurance Payments may receive a payment up to a Capacity level consistent with their revised Emergency Upper Operating Limit or Normal Upper Operating Limit, whichever is applicable. The foregoing rule shall also apply to a Generator otherwise eligible for a Day-Ahead Margin Assurance Payment in hours in which the ISO has derated the Generator's Operating Capacity in order to reconcile the ISO's dispatch with the Generator's actual output, or to address reliability concerns that arise because the Generator is not following Base Point Signals. If a Supplier's derated real-time Operating Capacity is lower than the sum of its Day-Ahead Energy Regulation Services and Operating Reserve schedules then when the ISO conducts the calculations described in Section 25.3 above, the DASen, DASeg and $DASres_p$ variables will be reduced by REDen, REDreg and $REDres_p$ respectively. REDen, REDreg and $REDres_p$ shall be calculated using the formulas below:

$$REDtot_{iu} = \max(DASen_{hu} + DASreg_{hu} + \Sigma_p DASres_{hup} - RTUOL_{iu}, 0)$$

$$POTREDen_{iu} = \max(DASen_{hu} - RTSen_{iu}, 0)$$

$$POTREDreg_{iu} = \max(DASreg_{hu} - RTSreg_{iu}, 0)$$

$$POTREDres_{iup} = \max(DASres_{hup} - RTSres_{iup}, 0)$$

$$REDen_{iu} = ((POTREDen_{iu}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$$

$$REDreg_{iu} = ((POTREDreg_{iu}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$$

$$REDres_{iup} = ((POTREDres_{iup}/(POTREDen_{iu}+ POTREDreg_{iu}+ \Sigma_p POTREDres_{iup}))*REDtot_{iu}$$

where:

$RTUOL_{iu}$ = The real-time Emergency Upper Operating Limit or Normal Upper Operating Limit whichever is applicable of Supplier u in interval i

$REDtot_{iu}$ = The total amount in MW that Day-Ahead schedules need to be reduced to account for the derate of Supplier u in interval i;

$REDen_{iu}$ = The amount in MW that the Day-Ahead Energy schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier u in interval i;

$REDreg_{iu}$ = The amount in MW that Supplier u's Day-Ahead Regulation Service schedule is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval i;

$REDres_{iup}$ = The amount in MW that Supplier u's Day-Ahead Operating Reserve schedule for Operating Reserves product p is reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment in interval i;

$POTREDen_{iu}$ = The potential amount in MW that Supplier u's Day-Ahead Energy schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier u in interval i;

$POTREDreg_{iu}$ = The potential amount in MW that Supplier u's Day-Ahead Regulation Service schedule could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier u in interval i;

$POTREDres_{iup}$ = The potential amount in MW that Supplier u's Day-Ahead Operating Reserve Schedule for Operating Reserve product p could be reduced for the purposes of calculating the Day-Ahead Margin Assurance Payment for Supplier in interval;

All other variables are as defined above.

25.6 Import Curtailment Guarantee Payments

25.6.1 Eligibility for an Import Curtailment Guarantee Payment for an Import Curtailed by the ISO

In the event that the Energy injections for an Import scheduled by RTC or RTD at a Proxy Generator Bus are Curtailed at the request of the ISO, and (i) the real-time Energy Profile MW is equal to or greater than the Day-Ahead Energy Schedule for that interval, and (ii) the real-time Decremental Bid is less than or equal to the default real-time Decremental Bid amount as established by ISO procedures, then the Supplier or Transmission Customer that is subjected to the Curtailment, in addition to the charge for Energy Imbalance, shall be eligible for an Import Curtailment Guarantee Payment as determined in Section 25.6.2 of this Attachment J.

25.6.2 Formula for an Import Curtailment Guarantee Payment for a Supplier Whose Import Was Curtailed by the ISO

A Supplier eligible under Section 25.6.1 of this Attachment J shall receive an Import Curtailment Guarantee Payment for its curtailed Energy injections that is equal to the sum for each hour of the interval payments determined in the formula below.

Import Curtailment Guarantee Payment to Supplier u in association with Import t=

$$\max\left[\left(RTLBMP_{ti} - \max\left(DADecBid_{ti}, 0\right)\right) \cdot \left(DAen_{ti} - RTDen_{ti}\right) \cdot \frac{S_i}{3600}, 0\right].$$

Where

i = the relevant interval;

S_i = number of seconds in interval i;

$RTLBMP_{t,i}$ = the real-time LBMP, in $/MWh, for interval i at the Proxy Generator Bus which is the source of the Import t.

$DADecBid_{t\,i}$ = the Day Ahead Decremental Bid price associated with the Day-Ahead energy schedule, in \$/MWh, for Import t in hour h containing interval i;

$DAen_{t,i}$ = the Day Ahead scheduled Energy injections, in MWh, for Import t in hour h containing interval i as determined by Security Constrained Unit Commitment (SCUC); and

$RTDen_{t,i}$ = the scheduled Energy injections, in MWh, for Import t in interval i as determined by Real-Time Dispatch (RTD).

1.4 Definitions - D

DADRP Component: As defined in the ISO 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 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 the commitment request by a Transmission Owner in order to meet the reliability needs of the Transmission Owner's local system which request was made known to the ISO prior to the close of the Day-Ahead Market.

Decremental Bid: A monotonically increasing Bid Price 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 Side Resources: A Resource that results in the control of a Load in a responsive, measurable, and verifiable manner and within time limits established in 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.

Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

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.

Developer: An Eligible Customer developing a generation project larger than 20 megawatts, or a merchant transmission project, proposing to interconnect to the New York State Transmission System, in compliance with the NYISO Minimum Interconnection Standard and, depending on the Developer's interconnection service election, also in compliance with the NYISO Deliverability Interconnection Standard.

Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Owner(s) for the sole use/benefit of a particular Transmission Customer requesting service under the ISO OATT. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Sale: The sale of ETCNL, and Grandfathered TCCs directly to a buyer by the Transmission Owner that is the Primary Holder through a non-discriminatory auditable sale conducted on the ISO's OASIS, in compliance with the requirements and restrictions set forth in Commission Orders 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 Resources may either be 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 Dispute Resolution Process established in the ISO Tariffs and ISO Agreement.

Dispute Resolution Process ("DRP"): The procedures: (1) described in the ISO Tariffs and the ISO Agreement that are used to resolve disputes between Market Participants and the ISO involving services provided under the ISO Tariffs (excluding applications for rate changes or other changes to the ISO Tariffs or rules relating to such services); and (2) described in the

ISO/NYSRC Agreement that are used to resolve disputes between the ISO and NYSRC involving the implementation and/or application of the Reliability Rules.

DSASP Component: As defined in the ISO 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.

1.5 Definitions - E

East of Central-East: An electrical area comprised of Lead Zones F, G, H, I, J, and K, as identifies in the ISO Procedures.

East of Central-East Excluding Long Island: An electrical area comprised of Lead Zones F, G, H, I, and J, as identified in the ISO Procedures.

East of Central-East Excluding New York City and Long Island: An electrical area comprised of Land Zones F, G, H, I, as identifies in the ISO Procedures.

Economic Operating Point: The megawatt quantity which is a function of: i) the real-time LBMP at the Resource bus; and ii) the Supplier's real-time eleven constant cost step Energy Bid, for the Resource, such that (a) the offer price associated with Energy offers below that megawatt quantity (if that megawatt quantity is not that Resource's minimum output level) must be less than or equal to the real-time LBMP at the Resource bus, and (b) the offer price associated with Energy offers above that megawatt quantity (if that megawatt quantity is not that Resource's maximum output level) must be greater than or equal to the real-time LBMP at the Resource bus. In cases where multiple megawatt values meet conditions (a) and (b), the Economic Operating Point is the megawatt value meeting these conditions that is closest to the Resource's real-time scheduled Energy injection. In cases where the Economic Operating Point would be less than the minimum output level, the Economic Operating Point will be set equal to the MW value of the first point on the Energy Bid curve and in cases where the Economic Operating Point would be greater than the maximum output level, the Economic Operating Point will be set equal to the MW value of the last point on the Energy Bid curve.

Eligible Customer: (i) An entity that is engaged, or proposes to engage, in the wholesale or retail electric power business including any electric utility, power marketer, Federal power marketing agency, or any person generating Energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner offer the unbundled Transmission Service, or pursuant to a voluntary offer of such service by the Transmission Owner. (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Owner, is an Eligible Customer under the Tariff.

Emergency: Any abnormal system condition that requires immediate automatic or manual action to prevent or limit loss of transmission facilities or Generators that could adversely affect the reliability of an electric system.

Emergency State: The state that the NYS Power System is in when an abnormal condition occurs that requires automatic or immediate, manual action to prevent or limit loss of the NYS Transmission System or Generators that could adversely affect the reliability of the NYS Power System.

End-State Centralized TCC Auction: A Centralized TCC Auction that the ISO will conduct after the ISO develops the necessary software.

Energy ("MWh"): A quantity of electricity that is Bid, produced, purchased, consumed, sold, or transmitted over a period of time, and measured or calculated in megawatt hours.

Energy and Ancillary Services Component: As defined in the ISO Services Tariff.

Energy Profile MW: The maximum schedule desired for an External Transaction. Import, Export and Wheels Through Transactions will specify the Energy Profile MW in their Bids.

Equivalency Rating: As defined in the ISO Services Tariff.

ETA Agent: A Transmission Customer of the ISO that has been appointed by a Load Serving Entity and approved by the ISO in accordance with ISO Procedures for the purpose of enabling that Transmission Customer to hold all of the rights and obligations associated with Fixed Price TCCs, as provided for in Attachment M of this OATT.

ETCNL TCC: A TCC created when a Transmission Owner with ETCNL exercises its right to convert a megawatt of ETCNL into a TCC pursuant to Section 19.4.1 of Attachment M of this ISO OATT.

Excess Congestion Rents: Congestion revenues in the Day-Ahead Market for Energy collected by the ISO that are in excess of its Day-Ahead payment obligations. Excess Congestion Rents may arise if Congestion occurs in the Day- Ahead Market for Energy and if the Day-Ahead Transfer Capability of the Transmission System is not exhausted by the set of TCCs and Grandfathered Rights that have been allocated at the completion of the last Centralized TCC Auction.

Existing Transmission Agreement ("ETA"): An agreement between two or more Transmission Owners, or between a Transmission Owner and another entity, as defined in this Tariff.

Existing Transmission Capacity for Native Load: Transmission capacity identified on a Transmission Owner's transmission system to serve the Native Load Customers of the current Transmission Owners (as of the filing date of the original ISO Tariff-January 31, 1997) for the purposes of allocating revenues from the sale of TCCs related to that capacity. This includes transmission capacity required: (1) to deliver the output from generating facilities located out of a Transmission Owner's Transmission District; (2) to deliver power purchased under power supply contracts; and (3) to deliver power purchased under third party agreements (i.e., Non-Utility Generators). Existing Transmission Capacity for Native Load is listed in Attachment L, Table 3, "Existing Transmission Capacity Reservations for Native Load Table."

Expected Load Reduction: For purposes of determining the Real-Time Locational Based Marginal Price, the reduction in Load expected to be realized in real-time from activation of the Emergency Demand Response Program and from Load reductions requested from Special Case Resources, as established pursuant to ISO Procedures.

Exports: A Bilateral Transaction or purchases from the LBMP Market where the Energy is delivered to an NYCA interconnection with another Control Area.

External: An entity (e.g., Supplier, Transmission Customer) or facility (e.g., Generator, Interface) located outside the Control Area being referenced or between two or more Control Areas. Where a specific Control Area is not referenced, the NYCA is the intended reference.

External Transactions: Purchases, sales or exchanges of Energy, Capacity or Ancillary Services for which either the Point of Injection ("POI") or Point of Withdrawal ("POW") or both are located outside the NYCA (i.e., Exports, Imports or Wheels Through).

1.18 Definitions - R

RCRR TCC: A Load Zone-to-Load Zone TCC created when a Transmission Owner with a RCRR exercises its right to convert the RCRR into a TCC pursuant to Section 19.5.4 of Attachment M of this ISO OATT.

Reactive Power (MVAr): The product of voltage and the out-of-phase component of alternating current. Reactive Power, usually measured in MVAr, is produced by capacitors (synchronous condensers), over-excited Generators, and Qualified Non-Generator Voltage Support Resources, and absorbed by reactors or under-excited Generators and other inductive devices including the inductive portion of Loads.

Ramp Capacity: The amount of change in the Desired Net Interchange that generation located in the NYCA can support at any given time. Ramp Capacity may be calculated for all Interfaces between the NYCA and neighboring Control Areas as a whole or for any individual Interface between the NYCA and an adjoining Control Area.

Real Power Losses: The loss of Energy, resulting from transporting power over the NYS Transmission System, between the Point of Injection and Point of Withdrawal of that Energy.

Real-Time Bid: A Bid submitted into the Real-Time Commitment at least seventy-five minutes before the start of a dispatch hour, or at least eighty-five minutes before the start of a dispatch hour if the Bid seeks to schedule an External Transaction at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line.

Real-Time Commitment ("RTC"): A multi-period security constrained unit commitment and dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves and Regulation Service on a least as-bid production cost basis over a two hour and fifteen minute optimization period. The optimization evaluates the next ten points in time separated by fifteen minute intervals. Each RTC run within an hour shall have a designation indicating the time at which its results are posted: "RTC_{00}," RTC_{30}, and "RTC_{45}: post on the hour, and at fifteen, thirty, and forty-five minutes after the hour, respectively. Each RTC run will produce binding commitment instructions for the periods beginning fifteen and thirty minutes after its scheduled posting time and will produce advisory commitment guidance for the remainder of the optimization period, RTC_{15} will also establish hourly External Transaction schedules, while all RTC runs may establish 15 minute External Transaction schedules at Variably Scheduled Proxy Generator Buses. Additional information about RTC's functions is provided in Section 4.4.2 of the ISO Services Tariff.

Real-Time Dispatch ("RTD"): A multi-period security constrained dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least-as-bid production cost basis over a fifty, fifty-five or sixty-minute period (depending on when each RTD run covers within an hour). The Real-Time Dispatch dispatches, but does not commit, Resources, except that RTD may commit, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting in ten minutes. RTD may also establish 5-minute External Transaction schedules at Dynamically Scheduled Proxy Generator Buses. Real-Time Dispatch runs will normally occur every five minutes. Additional information about RTD's functions is provided in Section 4.4.3 of the ISO Services Tariff. Throughout the ISO Services Tariff the term "RTD" will normally be used to refer to both the Real-Time Dispatch and to the specialized Real-Time Dispatch Corrective Action Mode software.

Real-Time Dispatch-Corrective Action Mode ("RTD-CAM"): A specialized version of the Real-Time Dispatch software that will be activated when it is needed to address unanticipated system conditions. RTD-CAM is described in Section 4.4.4 of the ISO Services Tariff.

Real-Time LBMP: The LBMPs established through the ISO Administered Real- Time Market.

Real-Time Market: The ISO Administered Markets for Energy and Ancillary Services resulting from the operation of the RTC and the RTD.

Real-Time Scheduling Window: The period of time within which the ISO accepts offers and Bids to sell and purchase Energy and Ancillary Services in the real-time market which period closes seventy-five (75) minutes before each hour, or eighty-five (85) minutes before each hour for Bids to schedule External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line.

Reconfiguration Auction: The monthly auction administered by the ISO in which Transmission Customers may purchase and sell one-month TCCs.

Reduction or Reduce: The partial or complete reduction in non-Firm Transmission Service as a result of transmission Congestion (either anticipated or actual).

Reference Bus: The location on the NYS Transmission System relative to which all mathematical quantities, including Shift Factors and penalty factors relating to physical operation, will be calculated. The NYPA Marcy 345 kV transmission substation is designated as the Reference Bus.

Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation Service Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Regulation Service corresponding to each possible quantity of Resources that the ISO's software may schedule to satisfy the ISO's Regulation Service constraint. A single Regulation Service Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for Regulation Service. The Shadow Price for Regulation Service shall be used to calculate Regulation Service payments under Rate Schedule 3 of the Service Tariff.

Reliability Rules: Those rules, standards, procedures and protocols developed and promulgated by the NYSRC, including Local Reliability Rules, in accordance with NERC, NPCC, FERC, PSC and NRC standards, rules and regulations, and other criteria and pursuant to the NYSRC Agreement.

Required System Capability: Generation capability required to meet an LSE's peak Load plus Installed Capacity reserve obligation as defined in the Reliability Rules.

Reserved Capacity: The maximum amount of Capacity and Energy that the ISO agrees to transmit for the Transmission Customer over the NYS Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part 3 of this Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Residual Adjustment: The adjustment made to ISO costs that are recovered through Schedule 1. The Residual Adjustment is calculated pursuant to Schedule 1.

Residual Capacity Reservation Right ("RCRR"): A megawatt of transmission capacity from one Load Zone to an electrically contiguous Load Zone, each of which is internal to the NYCA, that may be converted into an RCRR TCC by a Transmission Owner allocated the RCRR pursuant to Section 19.5 of Attachment M.

Residual Transmission Capacity: The transmission capacity determined by the ISO before, during and after the Centralized TCC Auction which is conceptually equal to the following:

Residual Transmission Capacity = TTC - TRM - CBM - GTR - GTCC - ETCNL

The TCCs associated with Residual Transmission Capacity cannot be accurately determined until the Centralized TCC Auction is conducted.

TTC is the Total Transfer Capability that can only be determined after the Residual Transmission Capacity is known.

GTR is the transmission capacity associated with Grandfathered Rights.

GTCC is the transmission capacity associated with Grandfathered TCCs.

ETCNL is the transmission capacity associated with Existing Transmission Capacity for Native Load.

TRM is the Transmission Reliability Margin.

CBM is the Capacity Benefit Margin.

Rolling RTC: The RTC run that is used to schedule a given 15-minute External Transaction. The Rolling RTC may be an RTC_{00}, RTC_{15}, RTC_{30} or RTC_{45} run.

1.19 Definitions - S

Safe Operations: Actions which avoid placing personnel and equipment in peril with regard to the safety of life and equipment damage.

Scheduled Energy Injection: Energy injections which are scheduled on a real-time basis by RTC.

Scheduled Line: A transmission facility or set of transmission facilities: (a) that provide a distinct scheduling path interconnecting the ISO with an adjacent control area, (b) over which Customers are permitted to schedule External Transactions, (c) for which the NYISO separately posts TTC and ATC, and (d) for which there is the capability to maintain the Scheduled Line actual interchange at the DNI, or within the tolerances dictated by Good Utility Practice. Each Scheduled Line is associated with a distinct Proxy Generator Bus. Transmission facilities shall only become Scheduled Lines after the Commission accepts for filing revisions to the NYISO's tariffs that identify a specific set or group of transmission facilities as a Scheduled Line. The following transmission facilities are Scheduled Lines: the Cross-Sound Scheduled Line, the Neptune Scheduled Line, the Dennison Scheduled Line, the Northport-Norwalk Scheduled Line, and the Linden VFT Scheduled Line.

SCUC: Security Constrained Unit Commitment, described in Attachment C of the Tariff.

Second Contingency Design and Operation: The planning, design and operation of a power system such that the loss of any two (2) facilities will not result in a service interruption to either native load customers or contracted firm Transmission Customers. Second Contingency Design and Operation criteria do not include the simultaneous loss of two (2) facilities, but rather consider the loss of one (1) facility and the restoration of the system to within acceptable operating parameters, prior to the loss of a second facility. These criteria apply to thermal, voltage and stability limits and are generally equal to or more stringent than NYPP, NPCC and NERC criteria.

Second Settlement: The process of: (1) identifying differences between Energy production, Energy consumption or NYS Transmission System usage scheduled in a First Settlement, and the actual production, consumption, or NYS Transmission System usage during the Dispatch Day; and (2) assigning financial responsibility for those differences to the appropriate Customers and Market Participants. Charges for Energy supplied (to replace Generation deficiencies or unscheduled consumption), and payments for Energy consumed (to absorb consumption deficiencies or excess Energy supply) or changes in transmission usage will be based on the Real-Time LBMPs.

Secondary Holder: Entities that purchase TCCs and have not been certified as a Primary Holder by the ISO.

Secondary Market: A market in which Primary and Secondary Holders sell TCCs by mechanisms other than through the Centralized TCC Auction, Reconfiguration Auction, or by Direct Sale.

Security Coordinator: An entity that provides the security assessment and Emergency operations coordination for a group of Control Areas. A Security Coordinator must not participate in the wholesale or retail merchant functions.

Self-Committed Fixed: A bidding mode in which a Generator is self-committed and opts not to be Dispatchable over any portion of its operating range.

Self-Committed Flexible: A bidding mode in which a dispatchable Generator follows Base Point Signals within a portion of its operating range, but self-commits.

Self-Supply: The provision of certain Ancillary Services, or the provision of Energy to replace Marginal Losses by a Transmission Customer using either the Transmission Customer's own Generators or generation obtained from an entity other than the ISO.

Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the ISO for service under the Tariff or any unexecuted Service Agreement, amendments on supplements thereto, that the ISO unilaterally files with the Commission.

Service Commencement Date: The date the ISO begins to provide service pursuant to the terms of an executed Service Agreement, or the date the ISO begins to provide service in accordance with Section 3.3.3 or Section 4.2.1 under the Tariff.

Settlement: The process of determining the charges to be paid to, or by a Transmission Customer to satisfy its obligations

Shadow Price: The marginal value of relieving a particular Constraint which is determined by the reduction in system cost that results from an incremental relaxation of that Constraint.

Shift Factor ("SF"): A ratio, calculated by the ISO, that compares the change in power flow through a transmission facility resulting from the incremental injection and withdrawal of power on the NYS Transmission System.

Short-Term Firm Point-To-Point Transmission Service: Firm Point-to-Point Service, the price of which is fixed for a short term by a Transmission Customer acquiring sufficient TCCs with the same Points of Receipt and Delivery as its Transmission Service.

Sink Price Cap Bid: A monotonically increasing Bid curve provided by an entity engaged in an Export to indicate the relevant Proxy Generator Bus LBMP below which that entity is willing to either purchase Energy in the LBMP Markets or, in the case of Bilateral Transactions, to accept Transmission Service, where the MW amounts on the Bid curve represent the desired increments of Energy that the entity is willing to purchase at various price points.

Special Test Transactions: The revenues or costs from purchases and/or sales of Energy that may occur pursuant to virtual regional dispatch/intra-hour transaction pilot tests conducted by the ISO to analyze potential solutions for, or approaches to resolving inter-market "seams" issues with neighboring control area operators.

Start-Up Bid: A Bid parameter that may vary hourly and that identifies the payment a Supplier requires to bring a Generator up to its specified minimum operating level from an offline state or a Demand Side Resource from a level of no Demand Reduction to its specified minimum level of Demand Reduction.

Start-Up Bids submitted for a Generator that is not able to complete its specified minimum run time (of up to a maximum of 24 hours) within the Dispatch Day are expected to include expected net costs related to the hour(s) that a Generator needs to run on the day following the Dispatch Day in order to complete its minimum run time. The component of the Start-Up Bid that incorporates costs that the Generator expects to incur on the day following the Dispatch Day is expected to reflect the operating costs that the Supplier does not expect to be able to recover through LBMP revenues while operating to meet the Generator's minimum run time, at the minimum operating level Bid for that Generator for the hour of the Dispatch Day in which the Generator is scheduled to start-up. Settlement rules addressing Start-Up Bids that incorporates costs related to the hours that a Generator needs to run on the day following the Dispatch Day on which the Generator is committed are set forth in Attachment C to the ISO Services Tariff.

Storm Watch: Actual or anticipated severe weather conditions under which region-specific portions of the NYS Transmission System are operated in a more conservative manner by reducing transmission transfer limits.

Strandable Costs: Prudent and verifiable expenditures and commitments made pursuant to a Transmission Owner's legal obligations that are currently recovered in the Transmission Owner's retail or wholesale rate that could become unrecoverable as a result of a restructuring of the electric utility industry and/or electricity market, or as a result of retail-turned-wholesale customers, or customers switching generation or transmission service suppliers.

Stranded Investment Recovery Charge ("SIRC"): A charge established by a Transmission Owner to recover Strandable Costs.

Sub-Auctions: The set of rounds in a given Capability Period Auction in which TCCs of a given duration may be purchased.

Subzone: That portion of a Load Zone in a Transmission Owner's Transmission District.

Supplier: A Party that is supplying the Capacity, Energy and/or associated Ancillary Services to be made available under the ISO OATT or the ISO Services Tariff, including Generators and Demand Side Resources that satisfy all applicable ISO requirements.

Supplemental Event Interval: Any RTD interval in which there is a maximum generation pickup or a large event reserve pickup or which is one of the three RTD intervals following the termination of the maximum generation pickup or the large event reserve pickup.

Supplemental Resource Evaluation ("SRE"): A determination of the least cost selection of additional Generators, which are to be committed, to meet: (i) changed or local system conditions for the Dispatch Day that may cause the Day-Ahead schedules for the Dispatch Day to be inadequate to meet the reliability requirements of the Transmission Owner's local system or to meet Load or reliability requirements of the ISO; or (ii) forecast Load and reserve requirements over the six-day period that follows the Dispatch Day.

System Impact Study: An assessment by the ISO of (i) the adequacy of the NYS Transmission System to accommodate a request to build facilities in order to create incremental transfer capability, resulting in incremental TCCs, in connection with a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service; and (ii) the additional costs to be incurred in order to provide the incremental transfer capability.

1.22 Definitions - V

Variably Scheduled Proxy Generator Bus: A Proxy Generator Bus for which the ISO may schedule Transactions at 15 minute intervals in real time.

Virtual Load: As defined in the ISO Services Tariff.

Virtual Supply: As defined in the ISO Services Tariff.

Virtual Transaction: As defined in the ISO Services Tariff.

Virtual Transaction Component: As defined in the ISO Services Tariff.

Voting Share: The method used in the ISO Agreement to allocate voting rights among the members of the Management Committee. The formula for calculating a Party's Voting Share is provided in the ISO Agreement.

3.1 Nature of Firm Point-To-Point Transmission Service

3.1.1 Term:

The minimum term of Firm Point-To-Point Transmission Service shall be provided in nominal one hour increments and the maximum term shall not exceed the maximum permissible term as specified in ISO Procedures.

3.1.2. Reservation Priority:

All requests for Firm Point-to-Point Transmission Service will be deemed to have the same reservation priority. Firm Point-to-Point Transmission Service will have the same priority as Network Service subject to Section 3.1.6. All Firm Point-to-Point Transmission Service will have priority over Non-Firm Point-to-Point Transmission Service under the Tariff.

3.1.3 Use of Firm Transmission Service by the Transmission Owner(s):

The Transmission Owner will be subject to the rates, terms and conditions of Part 3 of the Tariff when making Third-Party Sales under (i) agreements executed on or after the effective date of ISO, or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Owners will maintain separate accounting, pursuant to Section 2.8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

3.1.4 Service Agreements:

The ISO shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Firm Point-To-Point Transmission Service. Executed Service Agreements that contain the information required under this Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

3.1.5 Transmission Customer Obligation for Facility Additions or Redispatch Cost:

The ISO continuously redispatches all resources subject to its control in order to meet Load and to accommodate requests for a Firm Transmission Service through the use of SCUC, RTC, and RTD. Firm Point-To-Point Transmission Customers are charged for these redispatch costs in accordance with Attachment J. Transmission Owner(s) will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 3.7. The Transmission Customer or Eligible Customer must agree to compensate the Transmission Owner(s) for any necessary transmission facility additions pursuant to Section 3.7.

3.1.6 Curtailment of Firm Transmission Service:

In the event that a Curtailment on the NYS Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the Transaction(s) that effectively relieve the Constraint. When applicable, the ISO will follow the Lake Erie Emergency Redispatch ("LEER") Procedure filed on February 26, 1999, in Docket No. EL99-52-000 which is incorporated by reference herein. The LEER Procedure is intended to prevent the necessity of implementing the Curtailment procedures contained in the Commission and NERC tariffs and policies. To the extent possible, Curtailments of External Transactions at the Proxy Generator Buses associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line shall be based on the transmission priority of the associated Advance Reservation for use of the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line (as appropriate). The ISO reserves the right to Curtail Firm Transmission Service provided under this Tariff for reliability reasons, in whole or in part, when, in the ISO's sole discretion, an Emergency or other unforeseen condition threatens to or does impair or degrade the reliability of the NYS Power System. The ISO will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. If the ISO declares a Major Emergency State, Transmission Customers shall comply with all directions issued by the ISO concerning the avoidance, management, and alleviation of the Major Emergency and shall comply with all procedures concerning a Major Emergency set forth in the ISO Procedures and the Reliability Rules. If the ISO is required to Curtail Transmission Service as a result of a Transmission Loading Relief ("TLR") event, the ISO will perform such Curtailment in accordance with the NERC TLR Procedure.

3.1.7 Classification of Firm Transmission Service:

3.1.7.1 The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 3.15.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 3.15.2.

3.1.7.2 The ISO shall provide firm Transmission Service for the delivery of Energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt shall be set forth in the Firm Point-To-Point Service schedule submitted by the Transmission Customer.

3.1.8 Scheduling of Firm Point-To-Point Transmission Service:

3.1.8.1 In the Day-Ahead Market: Schedules for the Transmission Customer's Firm Point-to-Point Transmission Service Day-Ahead must be submitted to the

ISO no later than 5:00 a.m. of the day prior to commencement of the Dispatch Day or 4:50 a.m. for Transmission Service over the Cross-Sound Scheduled Line, the Neptune Scheduled Line, or the Linden VFT Scheduled Line. Schedules involving the use of LIPA's facilities shall be treated in accordance with Section 2.5.7. Schedules submitted after 5:00 a.m., or 4:50 a.m. as appropriate, will not be accepted in the Day-Ahead schedule. Schedules of Energy to be delivered must be stated in increments of 1,000 kWh per hour between each Point of Receipt and corresponding Point of Delivery. For Firm Transmission Service requests between a Point of Receipt and Point of Delivery that are internal to the NYCA, and between a Point of Receipt at the Proxy Generator Bus designated for Imports and a Point of Delivery that is a Load Bus internal to the NYCA, the ISO will furnish to the Transmission Customer hour-to-hour schedules equal to those requested and shall deliver the Energy provided by such schedules. Energy shall be provided from the Point of Receipt if economic, and from the LBMP Market otherwise. For Firm Transmission Service requests between a Point of Delivery at the Proxy Generator Bus designated for Exports and a Point of Receipt that is a Generator Bus internal to the NYCA the ISO will furnish to the Transmission Customer, hour-to-hour schedules equal to the Export Transaction schedule and shall deliver the Energy provided by such schedules. For Firm Transmission Service requests between a Point of Receipt at the Proxy Generator Bus designated for Imports and a Point of Delivery at the Proxy Generator Bus designated for Exports, the ISO will furnish to the Transmission Customer hour-to-hour schedules equal to the Wheel-Through Transaction schedule and shall deliver the Energy provided by such schedules. Should the Transmission Customer revise or terminate any schedule, such party shall notify the ISO prior to the close of the Real-Time Scheduling Window, and the ISO shall have the right to adjust accordingly the schedule for Energy to be received and to be delivered.

3.1.8.2 **In the Real-Time Market:** Schedules for the Transmission Customer's Firm Point-to-Point Transmission Service in Real-Time must be submitted to the ISO no later than the close of the Real-Time Scheduling Window.

Schedules involving the use of LIPA's facilities shall be treated in accordance with Section 2.5.7. Schedules submitted after the close of the Real-Time Scheduling Window shall not be accepted in the Real-Time schedule. Schedules of any Energy that is to be delivered must be stated in increments of 1,000 kWh per hour between each Point of Receipt and corresponding Point of Delivery. For Firm Transmission Service requests between a Point of Receipt and Point of Delivery that are internal to the NYCA, or between a Point of Receipt at the Proxy Generator Bus designated for Imports and a Point of Delivery that is a Load Bus internal to the NYCA, the ISO will furnish to the Transmission Customer schedules equal to those requested and shall deliver the Energy provided by such schedules. Energy shall be provided from the Point of Receipt if economic, and from the LBMP Market otherwise. For Firm Transmission Service requests between a Point of Delivery at the Proxy Generator Bus designated for Exports and a Point of Receipt that is a Generator Bus internal to the NYCA, the ISO will furnish to the Transmission Customer hour-to-hour schedules equal to the Export Transaction schedule and shall deliver the Energy provided by such schedules. For Firm Transmission Service requests between a Point of Receipt at the Proxy Generator Bus designated for Imports and a Point of Delivery at the Proxy Generator Bus designated for Exports, the ISO will furnish to the Transmission Customer hour-to-hour schedules equal to the Wheel-Through Transaction schedule and shall deliver the Energy provided by such schedules. Should the Transmission Customer revise or terminate any schedule, such party shall notify the ISO prior to the close of the Real-Time Scheduling Window and the ISO shall have the right to adjust accordingly the schedule for Energy to be received and to be delivered.

16.3 Transmission Service, Schedules and Curtailment

16.3.1 Requests for Bilateral Transaction Schedules

Firm Point-to-Point Transmission Service only shall be available for internal Bilateral Transactions. Firm and Non-Firm Point-to-Point Transmission Service shall be available for Import and Export Bilateral Transactions and Wheel-Through Transactions.

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. However, 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 External Transaction Bids submitted to import Energy from, export Energy to, or wheel Energy to or from Proxy Generator Buses that are authorized to schedule transactions on an intra-hour basis shall indicate whether the ISO may vary schedules associated with those Bids within each hour.

Transmission Customers may modify Bilateral Transactions that were scheduled Day-Ahead or propose new Bilateral Transactions, including External Bilateral Transactions, for economic evaluation within the Real-Time Market, provided however, that Bilateral Transactions with Trading Hubs as their POWs that were previously scheduled Day-Ahead may not be modified.

Transmission Customers scheduling Transmission Service to support a Bilateral Transaction with Energy supplied by an External Generator or Internal Generator shall submit the following information to the ISO:

(1) Point of Injection location. For Transactions with Internal sources, the Point of Injection is the Generator's bus; for Transactions with Trading Hubs as their

sources, the Point of Injection is the Trading Hub Generator bus; for Transactions with External sources, the Point of Injection is the Proxy Generator Bus designated for Imports.

(2) Point of Withdrawal location. For Transactions to serve Internal Load, the Point of Withdrawal is the Load bus; for Transactions to serve External load, the Point of Withdrawal is the Proxy Generator Bus designated for Exports; for Transactions with Trading Hubs as their sinks, the Point of Withdrawal is the Trading Hub Load bus;

(3) Desired hourly MW schedules;

(4) Whether Firm or Non-Firm Transmission Service is requested,

(5) NERC Tag data;

(6) A Sink Price Cap Bid for Export Transactions up to the MW level of the desired schedule, a Decremental Bid for Import and Wheel Through Transactions up to the MW level of the desired schedule; and

(7) Other data required by the ISO.

16.3.2 ISO's General Responsibilities

The ISO shall evaluate requests for Bilateral Transactions, and associated Transmission Service, submitted in the Day-Ahead scheduling process using Security Constrained Unit Commitment ("SCUC"), and will subsequently establish a Day-Ahead schedule. During the Dispatch Day, the ISO shall use the Real-Time Market to establish schedules for each hour of dispatch in that day.

The ISO shall use the information provided by Real-Time Market when making Curtailment decisions pursuant to the Curtailment rules described in Section 16.3.4 of this Attachment J.

16.3.3 Scheduling of Bilateral Transactions in the Day-Ahead Market and Real-Time Market

16.3.3.1 ISO Responsibilities

The ISO shall model Bids for Import Bilateral Transactions and Bids for Export Bilateral Transactions as Bids to buy or sell a block of MW at a single price at their respective buses.

The ISO shall compute all NYCA Interface Transfer Capabilities and interface Ramp and NYCA Ramp capabilities prior to scheduling Transmission Service Day-Ahead and in real-time. The ISO shall evaluate (i) Decremental Bids from entities engaged in Bilateral Import Transactions, Imports to the LBMP Market, and Wheels Through; (ii) Energy Bids from internal Generators; and (iii) Sink Price Cap Bids from entities engaged in Bilateral Export Transactions and Exports from the LBMP Market simultaneously when committing internal Generators and scheduling Import, Export and Wheel Through Transactions and Imports and Exports to and from the LBMP Market in the Day Ahead and Real-Time Markets, provided however, the ISO shall also evaluate Price Capped Load Bids simultaneously with (i) through (iii) in the Day Ahead Market.

The ISO shall not use Decremental Bids submitted by Transmission Customers for Generators associated with Non-Firm Point-to-Point Transmission Service in the determination of the Day-Ahead schedule.

16.3.3.2 Scheduling Internal Bilateral Transactions

The ISO shall schedule Firm Transmission Service between the Point of Injection at the Generator bus to the Point of Withdrawal at the Load bus equal to the request for Transmission Service in both the Day-Ahead and Real-Time Markets. The ISO shall use Energy Bids to determine commitment and dispatch schedules for internal Generators including those providing Energy for an Internal Bilateral Transaction.

16.3.3.3 Scheduling Export Bilateral Transactions and Firm Point-to-Point Transmission Service to Support Them

The ISO shall use Sink Price Cap Bids supplied by Transmission Customers proposing Export Bilateral Transactions in the Day Ahead and Real-Time Markets to determine the amount of Energy scheduled to be exported under those Transactions in the Day-Ahead and Real-Time Markets respectively. The ISO shall not schedule Energy to be exported under an Export Bilateral Transaction in amounts that exceed the Transfer Capability of the Interface.

The ISO shall schedule in the Day-Ahead and Real-Time Markets Firm Transmission Service for Export Bilateral Transactions between the Point of Receipt at the internal Generator bus and the Point of Delivery at the Proxy Generator Bus designated for Exports in an amount equal to the amount of Energy scheduled to be exported under those Transactions Day-Ahead and in real-time respectively.

The ISO shall use Energy Bids supplied by internal Generators designated as supporting Export Bilateral Transactions scheduled with Firm Transmission Service in the Day Ahead and Real-Time Markets to determine the Generator's commitment and dispatch schedule.

16.3.3.4 Scheduling Import Bilateral Transactions and Firm Point-to-Point Transmission Service to Support Them

The ISO shall use Decremental Bids from Transmission Customers proposing Import Bilateral Transactions in the Day Ahead and Real-Time Markets to determine the amount of Energy scheduled to be imported under those Transactions in the Day-Ahead and Real-Time Markets respectively. The ISO shall not schedule Energy to be imported in amounts that exceed the Transfer Capability of the Interface. The ISO shall schedule Firm Transmission Service in the Day-Ahead and Real-Time Markets for Import Bilateral Transactions between the Point of Receipt at the Proxy Generator Bus and the Point of Delivery at the Load bus equal to the amount of Transmission Service requested to support those Transactions Day-Ahead and in real-time respectively.

16.3.3.5 Scheduling Wheel Through Bilateral Transactions and Firm Point-to-Point Transmission Service to Support Them

The ISO shall use Decremental Bids supplied by Transmission Customers proposing Wheel-Through Transactions in the Day Ahead and Real-Time Markets to determine the amount of Energy scheduled to be wheeled under those Transactions Day-Ahead and in real-time respectively. The ISO shall schedule Firm Transmission Service in the Day-Ahead and Real-Time Markets between the Point of Receipt at the Proxy Generator Bus and the Point of Delivery at the Proxy Generator bus designated for Exports equal to the amount of Energy scheduled to be imported and Wheeled Through under those Transactions Day-Ahead and in real-time respectively.

16.3.3.6 Scheduling Non Firm Transmission Service

The ISO shall not use Decremental Bids submitted by Transmission Customers associated with Non-Firm Point-to-Point Transmission Service in the determination of the Day-

Ahead or real-time schedules. The ISO shall not schedule Non-Firm Transmission Service Day-Ahead for a Transaction if Congestion Rents associated with that Transaction are positive, nor will the ISO schedule Non-Firm Transmission Service in the RTC if Congestion Rents associated with that Transaction are expected to be positive. All schedules for Non-Firm Point-to-Point Transmission Service are advisory only and are subject to Reduction if real-time Congestion Rents associated with those Transactions become positive.

Transmission Customers receiving Non-Firm Transmission Service will be required to pay Real-Time Congestion Rents during any delay in the implementation of Reduction (*e.g.*, during the nominal five-minute RTD intervals that elapse before the implementation of Reduction) calculated pursuant to Section 17, Attachment B of the Services Tariff.

16.3.3.7. Scheduling External Transactions at the Proxy Generator Buses Associated with Scheduled Lines

Scheduling External Transactions at the Proxy Generator Buses that are associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line shall also be governed by Section 29, Attachment N to the ISO Services Tariff.

16.3.3.8 Prohibited Transmission Paths

The ISO shall not permit Market Participants to schedule External Transactions over the following eight scheduling paths:

1. External Transactions that are scheduled to exit the NYCA at the Proxy Generator Bus that represents its Interface with the Control Area operated by the Independent Electricity System Operator of Ontario (“IESO”), and to sink in the Control Area operated by PJM Interconnection, LLC (“PJM”);

2. External Transactions that are scheduled to exit the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to sink in the Control Area operated by IESO;
3. External Transactions that are scheduled to enter the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to source from the Control Area operated by IESO;
4. External Transactions that are scheduled to enter the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by IESO, and to source from the Control Area operated by PJM;
5. Wheels Through the NYCA that are scheduled to enter the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to sink in the Control Area operated by the Midwest Independent Transmission System Operator, Inc. ("MISO");
6. Wheels Through the NYCA that are scheduled to exit the NYCA at the Proxy Generator Buses that represent the NYCA's common border with the Control Area operated by PJM, and to source from the Control Area operated by the MISO;
7. Wheels Through the NYCA that are scheduled to enter the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by IESO, and to sink in the Control Area operated by the MISO; and
8. Wheels Through the NYCA that are scheduled to exit the NYCA at the Proxy Generator Bus that represents the NYCA's Interface with the Control Area operated by IESO, and to source from the Control Area operated by the MISO.

16.3.4 Bilateral Transaction Adjustments, Curtailments and Settlements

The DNI between the NYCA and adjoining Control Areas will be adjusted as necessary to reflect the effects of any Curtailments of Import or Export Transactions.

To the extent possible, Curtailments of External Transactions at the Proxy Generator Bus associated with the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line shall be based on the transmission priority of the associated Advance Reservation for use of the Cross-Sound Scheduled Line, the Neptune Scheduled Line, and the Linden VFT Scheduled Line (as appropriate).

If a Transmission Customer's Firm Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Internal Bilateral Transaction, or an Import, the ISO shall not reduce the Transmission Service. If a Transmission Customer's Firm Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Export Bilateral Transaction or a Wheel Through, the ISO shall reduce Transmission Service to the extent the amount of Energy scheduled to be exported or wheeled is reduced.

16.3.4.1 Import Bilateral Transactions

If the amount of Energy scheduled to be imported in an Import Bilateral Transaction in the Day-Ahead Market is less than the amount of Transmission Service requested and scheduled Day-Ahead in association with that Import Bilateral Transaction, the Transmission Customer shall pay the Energy Imbalance Service Charge pursuant to Rate Schedule 4 of this OATT. The Transmission Customer shall continue to pay the Day-Ahead TUC for the amount of Transmission Service scheduled.

If the Import Bilateral Transaction was scheduled following the Day-Ahead Market, or the schedule for the Import Bilateral Transaction was revised following the Day-Ahead Market, and the amount of Energy scheduled to be imported in real-time (modified for within-hour changes in DNI, if any) is less than the amount of Transmission Service requested in real-time in association with that Transaction, then the Transmission Customer shall pay an Energy Imbalance Service Charge pursuant to Rate Schedule 4 of this OATT. If the Import Bilateral Transaction was scheduled following the Day-Ahead Market, or the schedule for the Import Bilateral Transaction was revised following the Day-Ahead Market, the Transmission Customer shall pay or be paid the Real-Time TUC for the amount of Transmission Service requested in real-time in association with that Transaction minus the amount of Transmission Service requested Day-Ahead in association with that Transaction.

16.3.4.2 Export Bilateral Transactions, Internal Bilateral Transactions and Wheel Through Transactions

If the internal Generator designated to supply the Export Bilateral Transaction or internal Bilateral Transaction has been scheduled Day-Ahead to produce Energy in an amount that is less than the amount of Transmission Service scheduled Day-Ahead in association with that internal or Export Bilateral Transaction, the internal Generator shall pay an Energy Imbalance Service Charge pursuant to Rate Schedule 4 of this OATT.

If the internal Generator designated to supply the Export Bilateral Transaction or internal Bilateral Transaction has been dispatched in real-time to produce Energy in an amount that is less than the amount of Transmission Service scheduled in real-time in association with that internal or Export Bilateral Transaction, the internal Generator shall pay an Energy Imbalance Service Charge pursuant to Rate Schedule 4 of this OATT.

If the Export Bilateral Transaction or internal Bilateral Transaction was scheduled following the Day-Ahead Market, or the schedule for the Export Bilateral Transaction or internal Transaction was revised following the Day-Ahead Market, the Transmission Customer shall pay or be paid the Real-Time TUC for the amount of Transmission Service scheduled in real time in association with that Transaction minus the amount of Transmission Service scheduled Day-Ahead in association with that Transaction.

If a Wheel-Through Transaction was scheduled following the Day-Ahead Market, or the schedule for the Wheel-Through transaction was revised following the Day-Ahead Market, the Transmission Customer shall pay or be paid the Real-Time TUC for the amount of Transmission Service scheduled in real time in association with that Transaction minus the amount of Transmission Service scheduled Day-Ahead in association with that Transaction.

Notwithstanding the foregoing, the amount of Transmission Service scheduled in real-time for internal Bilateral Transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each RTD interval:

16.3.4.2.1 Generators

16.3.4.2.1.1 Generators providing Energy under contracts executed and effective on or before November 18, 1999 (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule;

16.3.4.2.1.2 Existing topping turbine Generators and extraction turbine Generators producing electric 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 topping or extraction turbine 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 499 MW of such units; and

16.3.4.2.3 Intermittent Power Resources that depend on landfill gas or solar for their fuel, existing Intermittent Power Resources that depend on wind as their fuel, other than those for which the NYISO has imposed a Wind Output Limit, and Limited Control Run of River Hydro Resources in operation on or before November 18, 1999 within the NYCA, plus up to an additional 3300 MW of such Generators.

This procedure shall not apply for those hours the Generator supplying that Transaction has bid in a manner that indicates it is available to provide Regulation Service or Operating Reserves.

16.3.4.3 Non-Firm Transmission

If the Transmission Customer was receiving Non-Firm Point-to-Point Transmission Service for an Import, and its Transmission Service was Reduced or Curtailed, the Load will purchase Energy in the Real-Time LBMP Market, at the Real-Time LBMP, for the amount of Energy Reduced or Curtailed. An Internal Generator supplying Energy for non-Firm Point-to-Point Transmission Service for an Export that is Reduced or Curtailed may sell the Energy no longer serving the Export in the Real-Time LBMP Market.

The ISO shall not automatically reinstate Non-Firm Point-to-Point Transmission Service that was Reduced or Curtailed. Transmission Customers may submit new schedules to restore the Non-Firm Point-to-Point Transmission Service in the next hour of the Real-Time Market.

16.3.4.4 Procedure for Relieving Security Violations

If a security violation occurs or is anticipated to occur, the ISO shall attempt to relieve the violation using the following procedures:

16.3.4.4.1 Reduce Non-Firm Point-to-Point Transmission Service: Partially or fully physically Curtail External Non-Firm Transmission Service (Imports, Exports and Wheels Through) by changing DNI schedules to (1) Curtail those in the lowest NERC priority categories first; (2) Curtail within each NERC priority category, based on Decremental Bids; and Incremental Energy Bids for Imports and Wheel Throughs; and based on Sink Price Cap Bids for Exports and (3) prorate Curtailment of equal cost transactions within a priority category ;

16.3.4.4.2 Curtail non-Firm Point-to-Point Transmission Service: Curtail (through changing DNI) unscheduled non-Firm Transactions which contribute to the violation, starting with the lowest NERC priority category;

16.3.4.4.3 Dispatch Internal Generators, based on Incremental Energy Bids and Decremental Bids, including committing additional resources, if necessary;

16.3.4.4.4 Adjust the DNI associated with Transactions supplied by External Resources: Curtail External Firm Transactions until the Constraint is relieved by (1) Curtailing based on Incremental Energy Bids, Decremental Bids and Sink Price Cap Bids; and (2) except for External Transactions with minimum run times, prorating Curtailment of equal cost transactions;

16.3.4.4.5 Request Internal Generators to voluntarily operate in manual mode below minimum or above maximum dispatchable levels. When operating in manual mode, Generators will not be required to adhere to minimum ramp rates, nor will they be required to be respond to RTD Base Point Signals;

16.3.4.4.6 In over generation conditions, decommit Internal Generators based on Minimum Generation Bid rate in descending order; and

16.3.4.4.7 Invoke other emergency procedures including involuntary load Curtailment, if necessary.