Attachment II

1.2 Definitions - B

Back-Up Operation: The procedures for operating the NYCA in a safe and reliable manner when the ISO's normal communication or computer systems are not fully functional as set forth in Section 2.12 of this ISO OATT and Section 5.3 of the ISO Services Tariff.

Base Point Signals: Electronic signals sent from the ISO and ultimately received by Generators specifying the scheduled MW output for the Generator. Real-Time Dispatch ("RTD") Base Point Signals are typically sent to Generators on a nominal five (5) minute basis. AGC Base Point Signals are typically sent to Generators on a nominal six (6) second basis.

Basis Amount: As defined in the ISO Services Tariff.

Basis Month: As defined in the ISO Services Tariff.

Bid/Post System: An electronic information system used to allow the posting of proposed transmission schedules and Bids for Energy and Ancillary Services by Market Participants for use by the ISO and to allow the ISO to post Locational Based Marginal Prices and schedules.

Bid: Offer to sell or bid to purchase Energy, Demand Reductions or Transmission Congestion Contracts and an offer to sell Ancillary Services at a specified price that is duly submitted to the ISO pursuant to ISO Procedures. Bid shall mean mitigated Bid where appropriate.

Bid Price: The price at which the Customer offering the Bid is willing to provide the product or service, or is willing to pay to receive such product or service, as applicable. In the case of a CTS Interface Bid, the Bid Price is a dollar value that indicates the bidder's willingness to purchase Energy ~~in~~at ~~the~~a CTS Source ~~Control Area~~ and sell it ~~in~~at ~~the~~a CTS Sink ~~Control Area~~ across ~~the~~ a CTS Enabled Interface~~,~~ if, at the time of scheduling, the forecasted ~~difference at scheduling between the~~ CTS Sink ~~Control Area~~ Price minus~~and~~ the forecasted CTS Source ~~Control Area~~ Price is greater than, or equal to, the dollar value specified in the ~~B~~bid.

Bid Production Cost: Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running and Minimum Generation Bid, and Start-Up Bid).

Bidding Requirement: As defined in the ISO Services Tariff.

Bilateral Transaction: A Transaction between two or more parties for the purchase and/or sale of Capacity or Energy other than those in the ISO Administered Markets. A request to schedule a Bilateral Transaction in the Energy Market shall be considered a request to schedule Point-to-Point Transmission Service.

Billing Period: The period of time designated in Sections 2.7.3.2.1, 2.7.3.3.1, or 2.7.3.3.2 of this ISO OATT over which the ISO will aggregate and settle a charge or a payment for services furnished under this ISO OATT or the ISO Services Tariff.

Board of Directors ("Board"): The governing body of the ISO which is comprised of ten (10) persons (Directors) that are unaffiliated with any Market Participants, as described in the ISO Agreement.

Business Issues Committee: A standing committee of the ISO created pursuant to the ISO Agreement to establish rules related to business issues and provide a forum for discussion of those rules and issues.

1.3 Definitions - C

Capability Period: Six-month periods which are established as follows: (1) from May 1 through October 31 of each year ("Summer Capability Period"); and (2) from November 1 of each year through April 30 of the following year ("Winter Capability Period"); or such other periods as may be determined by the Operating Committee of the ISO. A Summer Capability Period followed by a Winter Capability Period shall be referred to as a "Capability Year". Each Capability Period shall consist of On-Peak and Off-Peak periods.

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

Capacity Benefit Margin ("CBM"): That amount of Total Transfer Capability reserved by the ISO on the NYS Transmission System to ensure access to generation from interconnected systems to meet generation reliability requirements.

Capacity Reservation Cap: The maximum percentage of transmission Capacity from a Transmission Owner's sets of ETCNL that may be converted into ETCNL TCCs or the maximum percentage of a Transmission Owner's RCRRs that may be converted into RCRR TCCs, as the case may be, as established by the ISO pursuant to Section 19.4.3 of Attachment M.

Centralized TCC Auction: The auction in which TCCs are released for sale for one or more Capability Periods through a bidding process administered by the ISO.

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

Commission ("FERC"): The Federal Energy Regulatory Commission, or any successor agency.

Completed Application: An Application that satisfies all of the information and other requirements of the Tariff.

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

Congestion: A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of Energy to serve the next increment of Load, exclusive of losses, at different locations on the Transmission System is unequal.

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

Congestion Rent: The opportunity costs of transmission Constraints on the NYS Transmission System. Congestion Rents are collected by the ISO through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions.

Congestion Rent Shortfall: A condition in which the Congestion Rent revenue collected by the ISO in the Day-Ahead Market for Energy is less than the amount of Congestion Rent revenue in the Day-Ahead Market for Energy that the ISO is obligated under the Tariff to pay out to the Primary Holders of TCCs.

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

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

Contract Establishment Date: The date, listed in Attachment L, on which the listed existing agreements which are the source of Grandfathered Rights and Grandfathered TCCs were executed.

Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the Generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the Load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Credit Assessment: As defined in the ISO Services Tariff.

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

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

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

CTS Interface Bid: A Real-Time Bid provided by an entity engaged in an External Transaction at a CTS Enabled Interface~~ other than a Real-Time Bid provided by an entity for a transaction to wheel Energy through New York or through the neighboring Control Area which Bid includes ~~. CTS Interface Bids shall include a MW amount, a direction indicating whether the proposed Transaction is to Import Energy to, or Export Energy from, the New York Control Area, and a Bid Price.

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

CTS Sink ~~Control Area ~~Price: The price at ~~which the~~a CTS Sink~~ Control Area settles CTS Interface Bids~~.

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

CTS Source ~~Control Area ~~Price: The price at ~~which the ~~a CTS Source~~ Control Area settles CTS Interface Bids~~.

Curtailment or Curtail: A reduction in Firm or non-Firm Transmission Service in response to a transmission capacity shortage as a result of system reliability conditions.

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

1.16 Definitions - P

Part 1: Tariff Section 1 pertaining to Definitions.

Part 2: Tariff Section 2 pertaining to Common Service Provisions.

Part 3: Tariff Section 3 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part 2 and appropriate Schedules and Attachments.

Part 4: Tariff Section 4 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part 2 and appropriate Schedules and Attachments.

Part 5: OATT Section 5 – Special Provisions for retail access and the Individual Retail Access Plans

Party or Parties: The ISO and the Transmission Customer receiving service under the Tariff.

Performance Tracking System: A system designed to report metrics for Generators and Loads which include but are not limited to actual output and schedules (See Rate Schedule 3 of the ISO Services Tariff). This system is used by the ISO to measure compliance with criteria associated with the provision of Energy and Ancillary Services.

Point(s) of Delivery: Point(s) on the NYS Transmission System or Proxy Generator Buses where Energy transmitted by the ISO will be made available to the Transmission Customer under the ISO Tariffs. The Point(s) of Delivery shall be specified in the Bid, Bilateral Transaction schedule, or similar entry.

Point(s) of Injection ("POI"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy and Ancillary Services will be made available to the ISO by the Customer or Transmission Customer under the ISO Tariffs. The Point(s) of Injection shall be specified in the Bid, Bilateral Transaction schedule, or similar entry. (May be referred to as "Point of Receipt" or similar in some Existing Transmission Agreements.)

Point(s) of Receipt: Point(s) of interconnection on the NYS Transmission System or Proxy Generator Buses where Energy will be made available to the ISO by the Transmission Customer under the ISO Tariffs. The Point(s) of Receipt shall be specified in the Bid, Bilateral Transaction schedule, or similar entry.

Point(s) of Withdrawal ("POW"): The point(s) on the NYS Transmission System or Proxy Generator Buses where Energy will be made available to the Transmission Customer or Customer under the ISO Tariffs. The Point(s) of Withdrawal shall be specified in the Bid, Bilateral Transaction Schedule, or other similar entry. (May be referred to as "Point of Delivery" or similar in some Existing Transmission Agreements.)

Point-to-Point Transmission Service: The reservation and transmission of Capacity and Energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the ISO Tariffs.

Pool Control Error ("PCE"): The difference between the actual and scheduled interchange with other Control Areas, adjusted for frequency bias.

Post Contingency: Conditions existing on a system immediately following a Contingency.

Power Exchange ("PE"): A commercial entity meeting the requirements for service under the ISO OATT or the ISO Services Tariff that facilitates the purchase and/or sale of Energy, Capacity and/or Ancillary Services in the New York Wholesale Market. A PE may transact with the ISO on its own behalf or as an agent for others.

Power Factor: The ratio of real power to apparent power (the product of volts and amperes, expressed in megavolt-amperes, MVA).

Power Factor Criteria: Criteria to be established by the ISO to monitor a Load's use of Reactive Power.

Power Flow: A simulation which determines the Energy flows on the NYS Transmission System and adjacent transmission systems.

Power Purchaser: The entity that is purchasing the Capacity and Energy to be transmitted under the Tariff.

Primary Holder: The Transmission Customer that is the recognized holder of a TCC, as described in Attachment M of this ISO OATT.

Prior Equivalent Capability Period: The previous same-season Capability Period.

Proxy Generator Bus: A proxy bus located outside the NYCA that is selected by the ISO to represent a typical bus in an adjacent Control Area and at which LBMP prices are calculated. The ISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services available at the Interface.

PSC: The Public Service Commission of the State of New York or any successor agency thereto.

PSL: The New York Public Service Law, N.Y. Pub. Serv. Law § 1 et seq. (McKinney 1989 & Supp. 1997-98).

6.1 Schedule 1 - ISO Annual Budget Charge and Other Non-Budget Charges and Payments

6.1.1 Introduction

The ISO shall bill each Transmission Customer each Billing Period to recover the ISO's annual budgeted costs as set forth in Article 6.1.2 of this Rate Schedule 1.

The ISO shall separately bill each Transmission Customer under this Rate Schedule 1 for certain other charges and payments not related to the ISO annual budget charge. Specifically, the ISO shall bill each Transmission Customer on a quarterly basis to recover NERC and NPCC charges as set forth in Article 6.1.3 of this Rate Schedule 1. The ISO shall also bill each Transmission Customer each Billing Period to recover the following costs or allocate the following received payments under this Rate Schedule 1:

(i) bad debt loss charges as set forth in Article 6.1.4;

(ii) Working Capital Fund charges as set forth in Article 6.1.5;

(iii) non-ISO facilities payment charges as set forth in Article 6.1.6;

(iv) charges to recover costs for payments made to Suppliers pursuant to incremental cost recovery for units that responded to Local Reliability Rules I-R3 and I-R5 as set forth in Article 6.1.7;

(v) charges to recover and payments to allocate residual costs as set forth in Article 6.1.8;

(vi) charges for Special Case Resources and Curtailment Service Providers called to meet reliability needs as set forth in Article 6.1.9;

(vii) charges to recover DAMAP costs as set forth in Article 6.1.10;

(viii) charges to recover Import Curtailment Guarantee Payment costs as set forth in Article 6.1.11;

(ix) charges to recover Bid Production Cost guarantee payment costs as set forth in Article 6.1.12;

(x) charges to recover and payments to allocate settlements of disputes as set forth in Article 6.1.13; and

(xi) payments to allocate financial penalties collected by the ISO as set forth in Article 6.1.14.

Transmission Customers who are retail access customers being served by an LSE shall not pay these charges to the ISO; the LSE shall pay these charges.

6.1.2 ISO Annual Budget Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the ISO's recovery of its annual budgeted costs. The ISO annual budgeted costs that are recoverable through this Rate Schedule 1 are set forth in Section 6.1.2.1 of this Rate Schedule 1. The ISO shall calculate the charge for the recovery of these ISO annual budgeted costs from each Transmission Customer on the basis of its participation in physical market activity as indicated in Section 6.1.2.2 of this Rate Schedule 1. The ISO shall calculate this charge for each Transmission Customer on the basis of its participation in non-physical market activity, the Special Case Resource program, and the Emergency Demand Response program as indicated in Section 6.1.2.4 of this Rate Schedule 1. The ISO shall use the revenue collected through Section 6.1.2.4 of this Rate Schedule 1 to recover any of its annual budgeted costs for the immediately preceding calendar year that it has not already recovered under Section 6.1.2.2 of this Rate Schedule for that year. The ISO shall credit any additional revenue collected through Section 6.1.2.4 of this Rate Schedule 1 for the remainder of the calendar year to each Transmission

Customer on the basis of its physical market activity as indicated in Section 6.1.2.5 of this Rate Schedule 1.

6.1.2.1 ISO Annual Budgeted Costs

The ISO annual budgeted costs to be recovered through Article 6.1.2 of this Rate Schedule 1 include, but are not limited to, the following costs associated with the operation of the NYS Transmission System by the ISO and the administration of the ISO Tariffs and ISO Related Agreements by the ISO:

- Processing and implementing requests for Transmission Service including support of the ISO OASIS node;
- Coordination of Transmission System operation and implementation of necessary control actions by the ISO and support for these functions;
- Performing centralized security constrained dispatch to optimally re-dispatch the NYS Power System to mitigate transmission Interface overloads and provide balancing services;
- Costs related to the ISO's administration and operation of the LBMP market and all other markets administered by the ISO;
- Costs related to the ISO's administration of Control Area Services;
- Costs related to the ISO's administration of the ISO's Market Power Mitigation Measures and the ISO's Market Monitoring Plan;
- Costs related to the maintenance of reliability in the NYCA;
- Costs related to the provision of Transmission Service;
- Preparation of settlement statements;
- NYS Transmission System studies, when the costs of the studies are not recoverable from a Transmission Customer;
- Engineering services and operations planning;
- Data and voice communications network service coordination;
- Metering maintenance and calibration scheduling;
- Record keeping and auditing;
- Training of ISO personnel;
- Development and maintenance of information, communication and control systems;

- Professional services;
- Carrying costs on ISO assets, capital requirements and debts;
- Tax expenses, if any;
- Administrative and general expenses;
- Insurance premiums and deductibles related to ISO operations;
- Any indemnification of or by the ISO pursuant to Section 2.11.2 of this ISO OATT or Section 12.4 of the Services Tariff;
- Regulatory fees; and
- The ISO's share of the expenses of Northeast Power Coordinating Council, Inc. or its successor.

6.1.2.2 Calculation of the ISO Annual Budget Charge for Transmission Customers Participating in Physical Market Activity

The ISO shall charge, and each Transmission Customer that participates in physical market activity shall pay, an ISO annual budget charge each Billing Period as calculated according to the following formula.

$$\text{ISO Annual Budget Charge}_{c,P} = \left(\text{InjectionUnits}_{c,P} \times \left(0.28 \times \frac{\text{ISOCosts}_{\text{Annual}}}{\text{TotalEstWithdrawalUnits}_{\text{Annual}}}\right)\right) + \left(\text{WithdrawalUnits}_{c,P} \times \left(0.72 \times \frac{\text{ISOCosts}_{\text{Annual}}}{\text{TotalEstWithdrawalUnits}_{\text{Annual}}}\right)\right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

ISO Annual Budget Charge$_{c,P}$ = The amount, in \$, of the ISO annual budgeted costs for which Transmission Customer c is responsible for Billing Period P.

ISOCosts$_{Annual}$ = The sum, in \$, of the ISO's annual budgeted costs for the current calendar year.

InjectionUnits$_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Injections resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

$TotalEstWithdrawalUnits_{Annual}$ = The sum, in MWh, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the ISO in the summer prior to the current calendar year, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

6.1.2.3 Review and Modification of the ISO Annual Budget Charge Allocation Methodology

The current 72%/28% cost allocation methodology between Withdrawal Billing Units and Injection Billing Units for the ISO annual budget charge shall remain unchanged through at least December 31, 2016 and shall continue to remain unchanged until such point in time that a study is conducted and the results of the study warrant changing the 72%/28% cost allocation. The following provisions prescribe the process and timeline for the review and, if warranted by the results of a future study, modification of the 72%/28% cost allocation on a going forward basis:

(i) A vote of the Management Committee will be taken in the third calendar quarter of 2015 on whether a new study should be conducted during late-2015 and 2016 to allow modification of the 72%/28% cost allocation, if warranted by the results of the study, to be implemented by January 1, 2017. A positive vote by 58% of the Management Committee will be required to go forward with the study, but there will no longer be a "material change" standard as was historically applied to the determination of whether a study should be conducted.

(ii) If the Management Committee vote discussed in (i) above determines that a study should not be conducted, the 72%/28% cost allocation between Withdrawal

Billing Units and Injection Billing Units shall be extended through at least December 31, 2017. In the third calendar quarter of 2016, a vote will be taken on whether a new study should be conducted during late-2016 and 2017 to allow modification of the percentage allocation, if warranted by the results of the study, to be implemented by January 1, 2018. Unless a 58% vote of the Management Committee is registered in favor of declining to go forward with the study, the study will be conducted.

(iii) If the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above determines that a study should not be conducted, the current 72%/28% cost allocation shall remain unchanged until such point in time as the Management Committee determines that a study shall be conducted and the results of that study warrant changing the percentage allocation between Withdrawal Billing Units and Injection Billing Units. If the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above determines that a study should not be conducted, the Management Committee will revisit the issue of conducting a study annually in the third calendar quarter of each year using the same voting standard (*i.e.* the study shall be performed unless 58% of the Management Committee votes not to commission the study) that was applied to the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above.

(iv) If, and when, the Management Committee determines a study shall be conducted:

(a) Such study shall be completed, and the results thereof shared with Market Participants, before the end of the second calendar quarter of the year prior to the date on which a possible change to the then current allocation may become effective; and

(b) The ISO will present a draft study scope to Market Participants for consideration and comment before the ISO issues the study scope as part of its Request For Proposal process to retain a consultant to perform the study. A meeting shall be held with Market Participants to discuss the components (*e.g.*, categories of costs considered, allocation of benefits, unbundling, etc.) that should be included in the draft study scope before the draft is issued by the ISO.

6.1.2.4 Calculation of the ISO Annual Budget Charge for Transmission Customers Participating in Non-Physical Market Activity, the Special Case Resource Program, or the Emergency Demand Response Program

6.1.2.4.1 Charge for Transmission Customers Engaging in Virtual Transactions

The ISO shall charge, and each Transmission Customer that has its virtual bids accepted and thereby engages in Virtual Transactions shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$VTCharge_{c,P} = VTRate \times VTCleared_{c,P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$VTCharge_{c,P}$ = The amount, in \$, for which Transmission Customer c is responsible for Billing Period P.

VTRate = For calendar year 2012, the applicable rate shall be \$0.0871 per cleared MWh of Virtual Transactions, based on a \$2.6 million projected 2012 annual revenue requirement. For calendar years following 2012, the applicable rate shall be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of this Rate Schedule 1.

$VTCleared_{c,P}$ = The total cleared Virtual Transactions, in MWh, for Transmission Customer c in Billing Period P.

6.1.2.4.2 Charge for Transmission Customers Purchasing Transmission Congestion Contracts

The ISO shall charge, and each Transmission Customer that purchases Transmission Congestion Contracts - excluding Transmission Congestion Contracts that are created prior to January 1, 2010 - shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$TCCCharge_{c,P} = TCCRate \times TCCSettled_{c,P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$TCCCharge_{c,P}$ = The amount, in \$, for which Transmission Customer c is responsible for Billing Period P.

TCCRate = For calendar year 2012, the applicable rate shall be \$0.0372 per settled MWh of Transmission Congestion Contracts, based on a \$4.9 million projected 2012 annual revenue requirement. For calendar years following 2012, the applicable rate shall be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of this Rate Schedule 1.

$TCCSettled_{c,P}$ = The total settled Transmission Congestion Contracts, excluding Transmission Congestion Contracts created prior to January 1, 2010, in MWh, for Transmission Customer c in Billing Period P.

6.1.2.4.3 Charge for Transmission Customers Participating in the Special Case Resource Program or Emergency Demand Response Program

The ISO shall charge, and each Transmission Customer that participates in the ISO's Special Case Resources program or its Emergency Demand Response program shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$\text{SCR and EDR Charge}_{c,P} = DRInjections_{c,P} \times \left(0.28 \times \frac{ISOCosts_{Annual}}{TotalEstWithdrawalUnits_{Annual}} \right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$\text{SCR and EDR Charge}_{c,P}$ = The amount, in $, for which Transmission Customer c is responsible for Billing Period P.

$\text{DRInjections}_{c,P}$ = The total Load reduction, in MWh, measured and compensated during testing or an actual event for Transmission Customer c in Billing Period P.

$\text{ISOCosts}_{\text{Annual}}$ = The sum, in $, of the ISO's annual budgeted costs in the current calendar year.

$\text{TotalEstWithdrawalUnits}_{\text{Annual}}$ = The sum, in MWh, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the ISO in the summer prior to the current calendar year.

6.1.2.4.4 Re-setting of Rate for Virtual Transaction and Transmission Congestion Contracts Related Charges

For each calendar year after calendar year 2012, the ISO shall use the following formula to calculate (i) the rate for the charge to Transmission Customers engaging in Virtual Transactions as determined in Section 6.1.2.4.1 of this Rate Schedule 1, and (ii) the rate for the charge to Transmission Customers purchasing Transmission Congestion Contracts as determined in Section 6.1.2.4.2 of this Rate Schedule 1.

$$\text{ResetRate} = \frac{\text{AnnRevRequirement - Over/UnderCollection}}{\text{3YearRollingAvgBillUnits}}$$

Where:

ResetRate = For each calendar year after calendar year 2012, this rate will be used for either (i) the VTRate in the formula in Section 6.1.2.4.1 of this Rate Schedule 1, or (ii) the TCCRate in the formula in Section 6.1.2.4.2 of this Rate Schedule 1.

AnnRevRequirement = The product, in $, of (i) the prior year's annual revenue requirement for either (A) Virtual Transaction market activity or (B) Transmission Congestion Contract market activity, and (ii) an escalation factor. The ISO shall calculate the escalation factor as the percentage change in the ISO budget between (i) the ISO budget for the calendar year two years prior to the current calendar year ("Calendar

Year Minus 2") and (ii) the ISO budget for the calendar year one year prior to the current calendar year ("Calendar Year Minus 1").

Over/Under Collection = The ISO shall calculate the amount, in $, that it has over or under collected for the prior year's annual revenue requirement for either (A) Virtual Transaction market activity or (B) Transmission Congestion Contract market activity, as the case may be, as follows: (i) The ISO shall divide the annual revenue requirements for the applicable market activity for Calendar Year Minus 2 and for Calendar Year Minus 1 into twelve equal monthly revenue requirements for each of these calendar years. (ii) The ISO shall then calculate the amount of revenue, in $, that it over or under collected for each of the months from July of Calendar Year Minus 2 through June of Calendar Year Minus 1, which shall be calculated as (a) the revenue amount, in $, that the ISO collected for each month for the applicable market activity, minus (b) the monthly revenue requirement, in $, for that month as determined above. If the result of this calculation is positive, then the ISO overcollected for that month. If the result of this calculation is negative, then the ISO undercollected for that month. (iii) The ISO shall then calculate the total over or under collection amount, in $, for the period of July of Calendar Year Minus 2 through June of Calendar Year Minus 1, which shall be equal to (a) the sum, in $, of the revenue that the ISO overcollected for each month during this period (i.e., the sum of the positive monthly results determined above), minus (b) the sum, in $, of the absolute value of the revenue that the ISO undercollected for each month during this period (i.e., the sum of the absolute value of the negative monthly results determined above).

3YearRollingAvgBillUnits = The ISO shall calculate the three year rolling average of billing units, in MWh, using twelve-month averages of the appropriate billing units for the period between July of the calendar year four years prior to the current calendar year ("Calendar Year Minus 4") and June of Calendar Year Minus 1.

The annual rate computed through the formula in this Section 6.1.2.4.4 shall be subject to a 25% maximum increase or decrease for each year.

6.1.2.5 Credit for Transmission Customers Participating in Physical Market Activity After Recovery of ISO Annual Budgeted Costs for the Preceding Year

The ISO shall use the revenue collected each Billing Period pursuant to Section 6.1.2.4 of this Rate Schedule 1 to recover any of its annual budgeted costs for the immediately preceding calendar year that it has not already recovered under Section 6.1.2 of this Rate Schedule for that year. Once it has recovered its annual budgeted costs for the immediately preceding calendar year, the ISO shall distribute each Billing Period for the remainder of the calendar year any additional revenue collected pursuant to Section 6.1.2.4 of this Rate Schedule to each Transmission Customer that participates in physical market activity as calculated according to the following formula.

ISO Annual Budget Credit$_{c,P}$ =

$$\left(\text{NonPhysicalActivityRevenue}_P \times \left(0.28 \times \frac{\text{InjectionUnits}_{c,P}}{\text{TotalInjectionUnits}_P}\right)\right) +$$
$$\left(\text{NonPhysicalActivityRevenue}_P \times \left(0.72 \times \frac{\text{WithdrawalUnits}_{c,P}}{\text{TotalWithdrawalUnits}_P}\right)\right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

ISO Annual Budget Credit$_{c,P}$ = The amount, in \$, that Transmission Customer c will receive for Billing Period P.

.

NonPhysicalActivityRevenue$_P$= The sum, in \$, of the revenue collected by the ISO for Billing Period P through the charges to Transmission Customers for non-physical market activity, the Special Cases Resource program, and the Emergency Demand Response program as calculated in Section 6.1.2.4 of this Rate Schedule 1, less the amount the ISO is using to recover the annual budgeted costs for the immediately preceding calendar year that it did not recover 1) under Section 6.1.2.2 of this Rate Schedule for that year or 2) through NonPhysicalActivityRevenue previously used for this purpose in the current calendar year provided, however, NonPhysicalActivityRevenue$_P$ shall not be less than zero

InjectionUnits$_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Injections resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

WithdrawalUnits$_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

TotalInjectionUnits$_P$ = The sum, in MWh, of Injection Billing Units for all Transmission Customers in Billing Period P, except for Scheduled Energy Injections resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

TotalWithdrawalUnits$_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in Billing Period P, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

Following the end of calendar year 2017, the ISO shall review the credits that have been made to Transmission Customers participating in physical market activity pursuant to this Section 6.1.2.5 and shall present the results of its review to Market Participants for comment.

6.1.3 NERC and NPCC Charges

The ISO receives an invoice from NERC and NPCC (as defined below) on a quarterly basis for the recovery of the upcoming calendar quarter's costs related to the dues, fees, and related charges of:

(i) the NERC for its service as the Electric Reliability Organization for the United States ("ERO"), recovered pursuant to FERC Docket Nos. RM05-30-000, RR06-1-000 and RR06-3-000 and related dockets, and

(ii) the Northeast Power Coordinating Council: Cross-Border Regional Entity, Inc. ("NPCC"), or its successors, incurred to carry out functions that are delegated by the NERC and that are related to ERO matters pursuant to Section 215 of the FPA.

The ISO shall charge on a quarterly basis, and each Transmission Customer taking service under the ISO Tariffs shall pay, a charge for the recovery of the NERC and NPCC costs in accordance with Section 6.1.3.1 of this Rate Schedule 1.

Notwithstanding any applicable provisions of this ISO OATT or of the ISO Services Tariff, the ISO may supply to NERC the name of any LSE failing to pay any amounts due to NERC and the amounts not paid.

6.1.3.1 Calculation of NERC and NPCC Charges

The ISO shall charge, and each Transmission Customer shall pay, a charge on a quarterly basis to recover the NERC and NPCC costs invoiced to the NYISO by NERC and NPCC for the upcoming calendar quarter. This charge shall be calculated according to the following formula.

$$\text{NERC\&NPCC Charge}_{c,Q} = \text{NERC\&NPCCCosts}_{Q} \times \frac{\text{TUWithdrawalUnits}_{c,M}}{\text{TUTotalWithdrawalUnits}_{M}}$$

Where:

c = Transmission Customer.

Q = The relevant calendar quarter, for which the NERC and NPCC costs apply.

$\text{NERC\&NPCC Charge}_{c,Q}$ = The amount of the NERC and NPCC costs invoiced to the ISO, in $, for which Transmission Customer c is responsible for calendar quarter Q.

$\text{NERC\&NPCCCosts}_{Q}$ = The NERC and NPCC costs, in $, invoiced to the ISO for calendar quarter Q.

M = The month in which the ISO charges Transmission Customers to recover NERC and NPCC costs for calendar quarter Q.

$\text{TUWithdrawalUnits}_{c,M}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in its four-month true-up invoice that is issued with its regular monthly invoice in month M, except for Withdrawal Billing Units for Wheels Through and Exports.

$\text{TUTotalWithdrawalUnits}_{M}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in their four-month true-up invoices that are issued with their regular monthly invoices in month M, except for Withdrawal Billing Units for Wheels Through and Exports.

In calculating the Withdrawal Billing Units for this NERC and NPCC charge, the ISO shall use the LSE bus meter data that have been submitted by the meter authorities for use in the calculation of the four-month true-up of the Transmission Customer’s monthly invoice pursuant to Sections 7.4.1.1.2 and 7.4.1.1.3 of the ISO Services Tariff and Sections 2.7.4.2.1(ii) and 2.7.4.2.1(iii) of this ISO OATT. This calculation of the NERC and NPCC charge shall not be subject to correction or adjustment.

6.1.4 Bad Debt Loss Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of bad debt losses in accordance with the methodology established in Attachment U of this ISO OATT.

6.1.5 Working Capital Fund Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the collection and maintenance of the Working Capital Fund in accordance with the methodology established in Attachment V of this ISO OATT.

6.1.6 Non-ISO Facilities Payment Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge in accordance with Section 6.1.6.1 of this Rate Schedule 1 for the recovery of the costs of the ISO's monthly payments to the owners of facilities that are needed for the economic and reliable operation of the NYS Transmission System. At present, the ISO makes such payments to:

(i) Consolidated Edison Co. of New York, Inc. for the purchase, installation, operation, and maintenance of phase angle regulators at the Branchburg-Ramapo Interconnection between the ISO and PJM Interconnection, LLC, and

(ii) Rochester Gas & Electric Corporation for the installation of a 135 MVAR Capacitor Bank at Rochester Station 80 on the cross-state 345 kV system.

6.1.6.1 Calculation of Non-ISO Facilities Payment Charge

6.1.6.1.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a non-ISO facilities payment charge for each Billing Period. This charge shall be equal to the sum of the hourly non-ISO facilities payment charges for the Transmission Customer, as calculated according to the following formula, for each hour in the relevant Billing Period.

Non-ISO Facilities Payment $\text{Charge}_{c,h}$ =

$$\frac{\text{NonISOFacilitiesCosts}_M}{N} \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

M = The relevant month.

h = A given hour in the relevant Billing Period in month M.

N = Total number of hours h in month M.

Non-ISO Facilities Payment $\text{Charge}_{c,h}$ = The amount, in $, for which Transmission Customer c is responsible for hour h.

$\text{NonISOFacilitiesCosts}_M$ = The sum, in $, of the ISO's bills for month M for the non-ISO facilities from (i) Consolidated Edison Co. of New York (less the one-half of such bill paid by PJM Interconnection, LLC) and (ii) Rochester Gas and Electric Corporation.

$\text{WithdrawalUnits}_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

$\text{TotalWithdrawalUnits}_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

6.1.6.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT.

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a non-ISO facilities payment charge for each Billing Period. This charge shall be equal to the sum of the daily non-ISO facilities payment charges for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

Non-ISO Facilities Payment $\text{Charge}_{c,d}$ =

$$\frac{\text{NonISOFacilitiesCosts}_M}{N} \times \frac{\text{StationPower}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period in month M.

N = Number of days d in month M.

$\text{StationPower}_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.6.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.1.2 shall be determined for day d.

6.1.6.1.3 Non-ISO Facilities Payment Credit

The ISO shall credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the non-ISO facilities payment charge under Section 6.1.6.1.2 of this Rate Schedule 1 for each Billing Period. This credit shall be equal to the sum of daily payments for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

Non-ISO Facilities Payment $\text{Credit}_{c,d}$ =

$$\text{NonISOFacPayCharge}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period.

Non-ISO Facilities Payment $\text{Credit}_{c,d}$ = The amount, in \$, that Transmission Customer c will receive for day d.

$\text{NonISOFacPayCharge}_d$ = The sum of non-ISO facilities payment charges, in \$, for all Transmission Customers as calculated in Section 6.1.6.1.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.6.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.1.3 shall be determined for day d.

6.1.7 Charge to Recover Payments Made to Suppliers Pursuant to Incremental Cost Recovery for Units Responding to Local Reliability Rules I-R3 and I-R5

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge for the recovery of the costs of payments to Suppliers pursuant to the incremental cost recovery for units that responded to either (i) Local Reliability Rule I-R3 or (ii) Local Reliability Rule I-R5, as applicable, for each Billing Period. This charge shall be equal to the sum of the daily charges for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period. The ISO shall perform this calculation separately to recover as applicable either (i) the payment costs related to Local Reliability I-R3, or (ii) the payment costs related to Local Reliability Rule I-R5.

Local Reliability Rules Payment Recovery $\text{Charge}_{c,d}$ =

$$\text{LRRPayment}_d \times \frac{\text{TDWithdrawalUnits}_{c,d}}{\text{TDTotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

Local Reliability Rules Payment Recovery $\text{Charge}_{c,d}$ = The amount, in $, for which Transmission Customer c is responsible for day d.

LRRPayment_{d} - The amount, in $, paid in day d to Suppliers pursuant to the incremental cost recovery for units that responded, as applicable, to either (i) Local Reliability Rule I-R3 in the Consolidated Edison Transmission District or (ii) Local Reliability Rule I-R5 in the LIPA Transmission District.

$\text{TDWithdrawalUnits}_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

$\text{TDTotalWithdrawalUnits}_{d}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as third-party providers.

6.1.8 Residual Costs Payment/Charge

The ISO's payments for market transactions by Transmission Customers will not equal the ISO's payments to Suppliers for market transactions. Part of the difference consists of Day-Ahead Congestion Rent. The remainder comprises a residual adjustment, which the ISO shall calculate and each Transmission Customer shall receive or pay on the basis of its Withdrawal Billing Units. The most significant component of the residual adjustment is the residual costs payment or charge calculated in accordance with Section 6.1.8.1 of this Rate Schedule 1.

6.1.8.1 Calculation of Residual Costs Payment/Charge

6.1.8.1.1 Transmission Customers Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each Billing Period. The payment or charge for the relevant Billing Period shall be equal to (i) the sum of the hourly residual costs payments for the Transmission Customer as calculated according to the following formula for each hour in the relevant Billing Period, minus (ii) the sum of the hourly residual costs charges for the Transmission Customer as calculated in the following formula for each hour in the relevant Billing Period. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant Billing Period. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant Billing Period.

Residual Costs Payment/Charge$_{c,h}$ =

$$\left(\text{CustomerPayments}_h - \text{ISOPayments}_h\right) \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

Residual Costs Payment/Charge $_{c,h}$ = The amount, in \$, for hour h that Transmission Customer c will receive (if positive) or for which Transmission Customer c is responsible (if negative).

WithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

TotalWithdrawalUnits$_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

CustomerPayments$_h$ = The ISO's receipts, in \$, for each hour h from Transmission Customers that equal the sum of the following components, which could be either positive or negative amounts:

(i) payments of the Energy component and Marginal Losses Component of LBMP for Energy scheduled in the LBMP Market in hour h in the Day-Ahead Market;

(ii) payments of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy purchased in the Real-Time LBMP Market for hour h that was not scheduled Day-Ahead;

(iii) payments of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy by Suppliers that provided less Energy in the real-time dispatch for hour h than they were scheduled Day-Ahead to provide in hour h for the LBMP Market;

(iv) the Marginal Losses Component of the TUC payments made in accordance with this ISO OATT for Bilateral Transactions that were scheduled in hour h in the Day-Ahead Market; and

(v) the Marginal Losses Component and Congestion Component of the real-time TUC payments made in accordance with this ISO OATT for Bilateral Transactions that were not scheduled in hour h in the Day-Ahead Market.

(vi) the M2M settlement between the ISO and PJM Interconnection, L.L.C. for hour h, determined in accordance with Section 8 of Schedule D to Attachment CC to this ISO OATT.

$ISOPayments_h$ = The ISO's payments, in \$, in each hour h to Suppliers that equal the sum of the following components, which could be either positive or negative amounts:

(i) payments of the Energy component and Marginal Losses Components of LBMP for Energy to Suppliers that were scheduled to provide in the LBMP Market in hour h in the Day-Ahead Market;

(ii) payments to Suppliers of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy provided to the ISO in the Real-Time Dispatch for hour h that those Suppliers were not scheduled to provide Energy in hour h in the Day-Ahead Market;

(iii) payments of the Energy component and Marginal Losses Component of LBMP for Energy to LSEs that consumed less Energy in the real-time dispatch than those LSEs were scheduled Day-Ahead to consume in hour h; and

(iv) payments of the Marginal Losses Component and Congestion Component of the real-time TUC to Transmission Customers that reduced their Bilateral Transaction schedules for hour h after the Day-Ahead Market.

6.1.8.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT.

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each Billing Period. The payment or charge for the relevant Billing Period shall be equal to (i) the sum of the daily residual costs payments for the Transmission Customer as calculated according to the following formula for each day in the relevant Billing Period, minus (ii) the sum of the daily residual costs charges for the Transmission Customer as calculated in the following formula for each day in the relevant Billing Period. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant Billing Period. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant Billing Period.

Residual Costs Payment/$\text{Charge}_{c,d}$ =

$$\frac{\left(\text{CustomerPayments}_d\text{-ISOPayments}_d\right)}{\text{TotalWithdrawalUnits}_d}\times\text{StationPower}_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$\text{StationPower}_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c that it used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.8.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.8.1.2 shall be determined for day d.

6.1.8.1.3 Residual Costs Adjustment

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs adjustment for each Billing Period. This adjustment shall be equal to the sum of the daily adjustments (positive and negative) for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period. If the summed amount is positive for the Billing Period, the ISO shall pay the Transmission Customer the adjustment amount. If the summed amount is negative for the Billing Period, the ISO shall charge the Transmission Customer the adjustment amount.

Residual Costs $\text{Adjustment}_{c,d}$ =

$$\text{ResidCharge/PaymentCosts}_d\times\frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period.

Residual Costs $\text{Adjustment}_{c,d}$ = The amount, in $, for day d that Transmission Customer c will receive (if positive) or for which Transmission Customer c is responsible (if negative).

$\text{ResidCharge/PaymentCosts}_d$ = (i) If Transmission Customers were responsible for a residual costs charge for day d pursuant to Section 6.1.8.1.2 of this Rate Schedule 1, the (positive) amount, in $, of the costs that the ISO has collected through the residual costs charges for all Transmission Customers for day d. (ii) If Transmission Customers received a residual costs payment for day d pursuant to Section 6.1.8.1.2 of this Rate Schedule 1, the (negative) amount, in $, of the revenue that the ISO has paid through the residual costs payments to all Transmission Customers for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.8.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.8.1.3 shall be determined for day d.

6.1.9 Recovery of Special Case Resources and Curtailment Services Providers Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of Special Case Resources and Curtailment Service Providers costs for each Billing Period. This charge shall be equal to the sum of the hourly charges for the Transmission Customer, as calculated in Sections 6.1.9.1 and 6.1.9.2 of this Rate Schedule 1, for each hour in the relevant Billing Period and, where applicable, for each Subzone.

6.1.9.1 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.9.1, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers that were called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone for which the reliability services of the Special Case Resources and Curtailment Service Providers were called shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

Local Reliability SCR and CSP $\text{Charge}_{c,h}$ =

$$\text{LocalReliabilityCosts}_h \times \frac{\text{SZWithdrawalUnits}_{c,h}}{\text{SZTotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

Local Reliability SCR and CSP $\text{Charge}_{c,h}$ = The amount, in $, for which Transmission Customer c is responsible for hour h for the relevant Subzone.

$\text{LocalReliabilityCosts}_h$ = The payments, in $, for hour h in the relevant Subzone made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of that Subzone.

$\text{SZWithdrawalUnits}_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

$\text{SZTotalWithdrawalUnits}_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.9.2 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.9.2, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units except for Withdrawal Billing Units for Wheels ~~t~~Through, Exports or to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

NYCA Reliability SCR and CSP $\text{Charge}_{c,h}$ =

$$NYCAReliabilityCosts_h \times \frac{WithdrawalUnits_{c,h}}{TotalWithdrawalUnits_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

NYCA Reliability SCR and CSP Charge$_{c,h}$ = The amount, in \$, for which Transmission Customer c is responsible for hour h.

NYCAReliabilityCosts$_h$ = The payments, in \$, for hour h made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA.

WithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units for Wheels ~~t~~Through, Exports or to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units for Wheels ~~t~~Through, Exports or to supply Station Power as third-party providers.

6.1.10. Recovery of Day-Ahead Margin Assurance Payment Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of DAMAP costs for each Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.10.1 and 6.1.10.2 of this Rate Schedule 1, for each hour or each day, as applicable, in the relevant Billing Period and for each Subzone, where applicable.

6.1.10.1 Recovery of Costs of DAMAPs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.10.1, the ISO shall recover the costs for DAMAPs incurred to compensate Resources for meeting the reliability needs of a local system.

6.1.10.1.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability DAMAP Charge}_{c,h} = \text{DAMAPCosts}_h \times \frac{\text{SZWithdrawalUnits}_{c,h}}{\text{SZTotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

Local Reliability DAMAP Charge$_{c,h}$ = The amount, in $, for which Transmission Customer c is responsible for hour h for the relevant Subzone.

DAMAPCosts$_h$ = The DAMAP costs, in $, for hour h in the relevant Subzone incurred to compensate Resources meeting the reliability needs of that Subzone.

SZWithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits$_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.10.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability DAMAP Charge}_{c,d} = \frac{\text{DAMAPCosts}_d}{\text{SZTotalWithdrawalUnits}_d} \times \text{SZStationPower}_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$\text{SZStationPower}_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c in day d in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.2 shall be determined for day d.

6.1.10.1.3 Local Reliability DAMAP Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.1.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

Local Reliability DAMAP $\text{Credit}_{c,d}$ =

$$\text{LocRelDAMAPCharge}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period.

Local Reliability DAMAP $\text{Credit}_{c,d}$ = The amount, in $, that Transmission Customer c will receive for day d for the relevant Subzone.

$\text{LocRelDAMAPCharge}_d$ = The sum of charges, in $, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.10.1.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.3 shall be determined for day d.

6.1.10.2 Recovery of Costs of All Remaining DAMAPs

Pursuant to this Section 6.1.10.2, the ISO shall recover the costs of all DAMAPs not recovered through Section 6.1.10.1 of this Rate Schedule 1 from all Transmission Customers.

6.1.10.2.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

$$\text{Remaining DAMAP Charge}_{c,h} = \text{RemainingDAMAPCosts}_h \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

Remaining DAMAP Charge$_{c,h}$ = The amount, in \$, for which Transmission Customer c is responsible for hour h.

RemainingDAMAPCosts$_h$ = The DAMAP costs, in \$, for hour h not recovered by the ISO through Section 6.1.10.1 of this Rate Schedule 1.

WithdrawalUnits$_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

TotalWithdrawalUnits$_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

6.1.10.2.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$\text{Remaining DAMAP Charge}_{c,d} = \frac{\text{RemainingDAMAPCosts}_d}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$\text{StationPower}_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.2 shall be determined for day d.

6.1.10.2.3 Remaining DAMAP Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.2.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$\text{Remaining DAMAP Credit}_{c,d} = \text{RemainingDAMAPCharge}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period.

$\text{Remaining DAMAP Credit}_{c,d}$ = The amount, in \$, that Transmission Customer c will receive for day d.

$RemainingDAMAPCharge_d$ = The sum of charges, in $, for all Transmission Customers as calculated in Section 6.1.10.2.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.3 shall be determined for day d.

6.1.11 Recovery of Import Curtailment Guarantee Payment Costs

6.1.11.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the hourly charges for the Transmission Customer, as calculated in accordance with the following formula, for each hour in the relevant Billing Period.

$$\text{Import Curtailment Guarantee Charge}_{c,h} = \text{ImportCurtGuarCosts}_h \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$\text{Import Curtailment Guarantee Charge}_{c,h}$ = The amount, in $, for which Transmission Customer c is responsible for hour h.

$ImportCurtGuarCosts_h$ = The costs, in $, for the Import Curtailment Guarantee Payments to Import Suppliers for hour h.

$WithdrawalUnits_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

$TotalWithdrawalUnits_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply

Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

6.1.11.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a charge for each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the daily charges for the Transmission Customer, as calculated in accordance with the following formula, for each day in the relevant Billing Period.

$$\text{Import Curtailment Guarantee Charge}_{c,d} = \frac{\text{ImportCurtGuarCosts}_d}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

$\text{StationPower}_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.2 shall be determined for day d.

6.1.11.3 Import Curtailment Guarantee Credit

The ISO shall credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.11.2 of this Rate Schedule 1 above for each Billing Period. This credit shall be equal to the sum of daily payments for the Transmission

Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

$$\text{Import Curtailment Guarantee Credit}_{c,d} = \text{ImpCurtGuarCharge}_{d} \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_{d}}$$

Where:

d = A given day in the relevant Billing Period.

Import Curtailment Guarantee $\text{Credit}_{c,d}$ = The amount, in $, that Transmission Customer c will receive for day d.

$\text{ImpCurtGuarCharge}_{d}$ = The sum of charges, in $, for all Transmission Customers as calculated in Section 6.1.11.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.3 shall be determined for day d.

6.1.12 Recovery of Bid Production Cost Guarantee Payment and Demand Reduction Incentive Payment Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of BPCG and Demand Reduction Incentive Payment costs for each Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.12.1 through 6.1.12.6 of this Rate Schedule 1, for each day in the relevant Billing Period and for each Subzone, where applicable.

6.1.12.1 Costs of Demand Reduction BPCGs and Demand Reduction Incentive Payments

After accounting for imbalance charges paid by Demand Reduction Providers, the ISO shall recover the costs associated with Demand Reduction Bid Production Cost guarantee payments and Demand Reduction Incentive Payments from Transmission Customers pursuant to the methodology established in Attachment R of this ISO OATT.

6.1.12.2 Costs of BPCGs for Additional Generating Units Committed to Meet Forecast Load

If the sum of all Bilateral Transaction schedules, excluding schedules of Bilateral Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO may commit Resources in addition to the reserves that it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load. The ISO shall recover a portion of the costs associated with Bid Production Cost guarantee payments for the additional Resources committed Day-Ahead to meet the Day-Ahead forecast of Load from Transmission Customers pursuant to the methodology established in Attachment T of this ISO OATT. The ISO shall recover the residual costs of such Bid Production Cost guarantee payments not recovered through the methodology in Attachment T of the ISO OATT pursuant to Section 6.1.12.6 of this Rate Schedule 1.

6.1.12.3 Costs of BPCGs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.3, the ISO shall recover the costs for Bid Production Cost guarantee payments incurred to compensate Suppliers for their Resources, other than Special Case Resources, that are committed or dispatched to meet the reliability needs of a local system.

6.1.12.3.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability BPCG Charge}_{c,d} = \text{BPCGCosts}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

Local Reliability BPCG Charge$_{c,d}$ = The amount, in \$, for which Transmission Customer c is responsible for day d for the relevant Subzone.

BPCGCosts$_d$ = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Resources for day d in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone, except for the Bid Production Cost guarantee payments made to Suppliers for Special Case Resources.

SZWithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits$_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.3.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability BPCG Charge}_{c,d} = \frac{\text{BPCGCosts}_d}{\text{SZTotalWithdrawalUnits}_d} \times \text{SZStationPower}_{c,d}$$

Where:

SZStationPower$_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c in day d in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.3.1 above,

6.1.12.3.3 Local Reliability BPCG Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.3.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$\text{Local Reliability BPCG Credit}_{c,d} = \text{LocRelBPCGCharge}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

Local Reliability BPCG Credit$_{c,d}$ = The amount, in \$, that Transmission Customer c will receive for day d for the relevant Subzone.

LocRelBPCGCharge$_d$ = The sum of charges, in \$, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.12.3.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.3.1 above.

6.1.12.4 Cost of BPCGs for Special Case Resources Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.4, the ISO shall recover the costs of Bid Production Cost guarantee payments incurred to compensate Special Case Resources called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Special Case Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability SCR BPCG Charge}_{c,d} = \text{BPCGCosts}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

Local Reliability SCR BPCG Charge$_{c,d}$ = The amount, in \$, for which Transmission Customer c is responsible for day d for the relevant Subzone.

BPCGCosts$_d$ = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Special Case Resources for day d in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone.

SZWithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits$_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.5 Cost of BPCG for Special Case Resources Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.12.5, the ISO shall recover the costs for Bid Production Cost guarantee payments to compensate Special Case Resources called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used except for Withdrawal Billing Units for Wheels ~~t~~Through, Exports or to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$\text{NYCA Reliability SCR BPCG Charge}_{c,d} = \text{BPCGCosts}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

NYCA Reliability SCR BPCG Charge$_{c,d}$ = The amount, in \$, for which Transmission Customer c is responsible for day d.

BPCGCosts$_d$ = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Special Case Resources called to meet the reliability needs of the NYCA for day d.

WithdrawalUnits$_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d, except for the Withdrawal Billing Units for Wheels ~~t~~Through, Exports or to supply Station Power as a third-party provider.

TotalWithdrawalUnits$_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units for Wheels-~~t~~Through, Exports or to supply Station Power as third-party providers.

6.1.12.6 Costs of All Remaining BPCGs

Pursuant to this Section 6.1.12.6, the ISO shall recover the costs of all Bid Production Cost guarantee payments not recovered through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, 6.1.12.4, and 6.1.12.5 of this Rate Schedule 1, including the residual costs of Bid Production Cost guarantee payments for additional Resources not recovered through the methodology in Attachment T of this ISO OATT, from all Transmission Customers.

6.1.12.6.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$\text{Remaining BPCG Charge}_{c,d} = \text{RemainingBPCGCosts}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

Remaining BPCG $\text{Charge}_{c,d}$ = The amount, in $, for which Transmission Customer c is responsible for day d.

$\text{RemainingBPCGCosts}_d$ = The BPCG costs, in $, for day d not recovered by the ISO through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, 6.1.12.4, and 6.1.12.5 of this Rate Schedule 1.

$\text{WithdrawalUnits}_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d, except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

$\text{TotalWithdrawalUnits}_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units to supply Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

6.1.12.6.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$\text{Remaining BPCG Charge}_{c,d} = \frac{\text{RemainingBPCGCosts}_d}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

$\text{StationPower}_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.6.1 of this Rate Schedule 1 above.

6.1.12.6.3 Remaining BPCG Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.6.2 of this Rate

Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$\text{Remaining BPCG Credit}_{c,d} = \text{RemainingBPCGCharge}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

Remaining BPCG Credit$_{c,d}$ = The amount, in $, that Transmission Customer c will receive for day d.

RemainingBPCGCharge$_d$ = The sum of charges, in $, for all Transmission Customers as calculated in Section 6.1.12.6.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.6.1 of this Rate Schedule 1 above.

6.1.13 Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or charge in accordance with Section 6.1.13.1 of this Rate Schedule 1 for the distribution of funds received by the ISO or the recovery of funds incurred by the ISO in the settlement of a dispute.

6.1.13.1 Calculation of the Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or a dispute resolution charge for each Billing Period as calculated according to the following formula.

$$\text{Dispute Resolution Payment/ Charge}_{c,P} = \text{DisputeResolutionCosts}_P \times \frac{\text{WithdrawalUnits}_{c,P}}{\text{TotalWithdrawalUnits}_P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

Dispute Resolution Payment/Charge$_{c,P}$ = The amount, in $, for Billing Period P that (i) Transmission Customer c will receive if the ISO is distributing funds that it has collected in the settlement of a dispute, or (ii) Transmission Customer c will be responsible for if the ISO is recovering funds that it has incurred in the settlement of a dispute.

DisputeResolutionCosts$_{P}$ = The amount, in $, for Billing Period P that (i) the ISO has collected in the settlement of a dispute or (ii) the ISO has incurred in the settlement of a dispute.

WithdrawalUnits$_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

TotalWithdrawalUnits$_{P}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in Billing Period P, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

6.1.14 Credit for Financial Penalties

The ISO shall distribute to each Transmission Customer each Billing Period in accordance with the following formula any payments that it has collected from Transmission Customers to satisfy: (i) Financial Impact Charges issued pursuant to Sections 4.5.3.2 and 4.5.4.2 of the ISO Services Tariff; (ii) ICAP sanctions issued pursuant to Section 5.12.12 of the ISO Services Tariff; (iii) ICAP deficiency charges pursuant to Section 5.14.3.1 of the ISO Services Tariff, except as provided in Section 5.14.3.2 of the ISO Services Tariff; (iv) market power mitigation financial penalties pursuant to Section 23.4.3.6 of Attachment H of the ISO Services Tariff, except as provided in Section 23.4.4.3.2 of Attachment H of the ISO Services Tariff; and (v) any other financial penalties set forth in the ISO Services Tariff or this ISO OATT. The ISO will perform this calculation separately for the allocation of the revenue from each financial penalty.

$$\text{Financial Penalties Credit}_{c,P} = \text{PenaltyRevenue}_{P} \times \frac{\text{WithdrawalUnits}_{c,P}}{\text{TotalWithdrawalUnits}_{P}}$$

Where:

c = Transmission Customer.

P = A given day in the relevant Billing Period.

$Financial\ Penalties\ Credit_{c,P}$ = The amount, in $, that Transmission Customer c will receive for Billing Period P.

$PenaltyRevenue_{P}$ = The sum, in $, of revenue that the ISO has collected for Billing Period P from a Transmission Customer for one of the financial penalties indicated in this Article 6.1.14 of this Rate Schedule 1.

$WithdrawalUnits_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c for Billing Period P, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

$TotalWithdrawalUnits_{P}$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers for Billing Period P, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

6.2 Schedule 2 - Charges for Voltage Support Service

In order to maintain transmission voltages on the NYS Transmission System within acceptable limits, generation facilities under the control of the ISO, synchronous condensers, and Qualified Non-Generator Voltage Support Resources, are operated to produce (or absorb) reactive power. Thus, Voltage Support Service must be provided for each Transaction on the NYS Transmission System. The amount of Voltage Support Service that must be supplied will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the ISO.

Voltage Support Service is to be provided directly by the ISO. The methodologies that the ISO will use to obtain Voltage Support Service and the associated charges for such service are set forth below.

6.2.1 Responsibilities

The ISO shall coordinate the Voltage Support Service provided by generation facilities, synchronous condensers, and Qualified Non-Generator Voltage Support Resources that qualify to provide such services as described in Section 15.2.1.1 of Rate Schedule 2 of the ISO Services Tariff.

6.2.1.1 Wheels Through, Exports and Purchases from the LBMP Market

Transmission Customers engaging in Wheels Through, and Transmission Customers or Customers engaged in Export Transactions, except for Export Transactions resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England, shall purchase Voltage Support Service from the ISO at the rates described in the formula contained in Section 6.2.2.1 of this Rate Schedule.

6.2.1.2 Load-Serving Entities

LSEs serving Load in the NYCA shall purchase Voltage Support Service from the ISO at the rates described in the formula contained in Section 6.2.2.1 of this Rate Schedule.

6.2.2 Payments

6.2.2.1 Payments made by Transmission Customers and LSEs

Transmission Customers, Customers, and LSEs shall pay the ISO for Voltage Support Service. The ISO shall compute the Voltage Support Service Rate based on forecast data using the following equation

$$Rate_{VSS} = \frac{\sum NYISO_{VSSPmts} + PYA_{VSS}}{Energy_{NYISO}}$$

Where:

$Rate_{VSS}$ = Voltage Support Service Rate ($/MWh)

$Energy_{ISO}$ = The annual forecasted transmission usage for the year as projected by the ISO including Load within the NYCA, Exports and Wheels Through (MWh).

$\Sigma\ NYISO_{VSSPmts}$ = The sum of the projected ISO payments to generation facilities, synchronous condensers, and Qualified Non-Generator Voltage Support Resources providing Voltage Support Service based on Sections 15.2.2.1, 15.2.2.2 and 15.2.2.3 of Rate Schedule 2 of the ISO Services Tariff ($).

PYA_{VSS} = "Prior year adjustment" for Voltage Support Service which is the total of prior year payments to generation facilities, synchronous condensers, and Qualified Non-Generator Voltage Support Resources supplying Voltage Support Service as defined in the ISO Services Tariff less the total of payments received by the ISO from Transmission Customers , Customers and LSEs in the prior year for Voltage Support Service (including all payments for penalties) ($).

Transmission Customers engaging in Wheels Through and Transmission Customers or Customers engaged in Export Transactions, except for Export Transactions resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England, shall pay to the ISO a charge for this service equal to the rate as determined in Section 6.2.1 of this Rate Schedule multiplied by their Energy scheduled in the hour. LSEs shall pay to the ISO a charge for this service equal to the rate as determined in Section 6.2.1 of this Rate Schedule multiplied by the Energy consumed by the LSE's Load located in the NYCA in the hour provided, however, LSEs taking service under Section 5 of the OATT to supply Station Power as a third-party provider shall pay to the ISO a charge for this service equal to the rate as determined in Section 6.2.1 of this Rate Schedule multiplied by the LSE's Station Power provided under Section 5 of the OATT. For LSEs and all Wheels Through and Exports, the ISO shall calculate the payment hourly. The ISO shall bill each Transmission Customer or LSE each Billing Period.

6.2.3 Self-Supply

All Voltage Support Service shall be purchased from the ISO.

6.5 Schedule 5 - Charges for Operating Reserve Service

The ISO must offer this service when Transmission Service is used to serve Load within the NYCA. Transmission Customers and LSEs must either purchase this service from the ISO. The charges for Operating Reserve Service are set forth below.

The NYSRC shall be responsible for evaluating the adequacy of the criteria for determining the required level of Operating Reserves and shall modify such criteria from time to time as required. The ISO shall establish additional categories of Operating Reserves if necessary to ensure reliability.

The ISO will ensure that Suppliers that are compensated for using Capacity to provide one Operating Reserve product are not simultaneously compensated for providing another Operating Reserve product, or Regulation Service, using the same Capacity (consistent with the additive nature of the market clearing price calculation formulae in Sections 15.4.5.1 and 15.4.6.1 of Rate Schedule 4 of the ISO Services Tariff).

6.5.1 Operating Reserves Charges

Transmission Customers and Customers engaging in Export Transactions, except for Export Transactions resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England, and LSEs shall pay an hourly charge equal to the product of (A) the cost to the ISO of providing all Operating Reserves for a given hour; and (B) the ratio of (i) the LSE's hourly Load or the Transmission Customer's hourly scheduled Export Transactions, except for Export Transactions resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England, to (ii) the sum of all Load in the NYCA and all scheduled Export Transactions, except for Export Transactions resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England, for a given hour. The cost to the ISO of providing Operating Reserves in each hour will equal the total amount that the ISO pays to procure Operating Reserves on behalf of the market in the Day-Ahead Market and the Real-Time Market, less payments collected from entities that are scheduled to provide less Operating Reserves in the Real-Time Market than in the Day-Ahead Market during that hour, under Rate Schedule 4 of the ISO Services Tariff. The ISO shall aggregate the hourly charges to produce a total charge for a given Dispatch Day.

LSEs taking service under Section 5 of the OATT to supply Station Power as third-party providers shall pay to the ISO a daily charge for this service equal to the product of (A) the cost to the ISO of providing all Operating Reserves for the day and (B) the ratio of (i) the LSE's Station Power supplied under Section 5 of the OATT for the day to (ii) the sum of all Load in the NYCA and all scheduled Exports, except for Export Transactions resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England, for the day. The ISO shall credit the daily charges paid for Operating Reserves by LSEs taking service under Section 5 of the OATT to supply Station Power as third-party providers on a Load ratio share basis to the Load in the NYCA for that day and all scheduled Exports for the day except for Export Transactions resulting from CTS Interface Bids at a CTS Enabled Interface with ISO New England.

6.5.2 Self-Supply

Transmission Customers, including LSEs, may provide for Self-Supply of Operating Reserve by placing Resources supplying any one of the Operating Reserves under ISO Operational Control. The Resources must meet ISO rules for acceptability, pursuant to Rate Schedule 4 of the Services Tariff. The specified Resources will receive the market value of the Operating Reserves services provided by the specified Resource as determined in the ISO Services Tariff. In addition, Transmission Customers, including LSEs, may enter into Day-

Ahead bilateral financial transactions, *e.g.*, contracts-for-differences, in order to hedge against price volatility in the Operating Reserves markets.

16.3 Transmission Service, Schedules and Curtailment

16.3.1 Requests for Bilateral Transaction Schedules

Only Firm Point-to-Point Transmission Service shall be available for internal Bilateral Transactions and for CTS Interface Bids for Bilateral Transactions~~.~~. Firm and Non-Firm Point-to-Point Transmission Service shall be available for Import and Export Bilateral Transactions and Wheel-Through Transactions. Except as specified in Services Tariff section 4.4.1.2.2, 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~~At Variably Scheduled Proxy Generator Buses that are not CTS Enabled Proxy Generator Buses, 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 indicates that the ISO may vary schedules associated with those Bids within the hour.~~; *provided however*, t~~ The ISO will subject all CTS Interface Bids to variable scheduling in accordance with Services Tariff section 4.4.4. 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; or a CTS Interface Bid for Transactions other than Wheels Through at CTS Enabled Proxy Generator Buses;

(7) A direction for the desired flow for CTS Interface Bids submitted at the CTS Enabled Proxy Generator Buses; and

(8) 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 and Wheels Through, (ii) Bids from entities engaged in Imports to the LBMP Market,; (iii) CTS Interface Bids from entities engaged in Imports and Exports at CTS Enabled Proxy Generator Buses; (iv) Energy Bids from internal Generators; (v) Sink Price Cap Bids from entities engaged in Bilateral Export Transactions; and (vi) Bids from entities engaged in 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 (vi) 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 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 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 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 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 for any Transaction at a CTS Enabled Proxy Generator Bus or, at any other Proxy Generator Bus, 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, the Linden VFT Scheduled Line, and the HTP 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 prohibited 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.

The ISO may add additional prohibited scheduling paths to the above list when the ISO, acting in consultation with its Market Monitoring Unit, determines that one or more scheduling paths are being used to schedule External Transactions in a manner that is not consistent with the manner in which power is actually expected to flow. The ISO shall inform its Market Participants of the additional prohibited scheduling path or paths by providing notice at least one week in advance of the implementation of any such prohibition. At the time the NYISO provides notice to its Market Participants the ISO shall submit a compliance filing in FERC Docket No. ER13-780 requesting authority to update the above list to reflect the additional prohibited scheduling path or paths. Any such compliance filing will include: (1) an explanation of the scheduling behavior the ISO has identified and why that behavior presents a concern to the ISO and its Market Monitoring Unit; and (2) an explanation of why the ISO believes that the problem it has identified can be remedied or mitigated by adding one or more new prohibited scheduling paths. The compliance filing will also include, or be accompanied by, a discussion of the Market Monitoring Unit's position regarding the ISO's proposal to add a new prohibited scheduling path or new prohibited scheduling paths. Unless FERC acts on the ISO's compliance filing, the ISO shall implement the new scheduling path prohibition(s) on the date proposed in its compliance filing.

The responsibilities of the Market Monitoring Unit that are addressed in this Section are also addressed in Section 30.4.6.8.1 of the Market Monitoring Plan, Attachment O to the ISO Services Tariff.

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, the Linden VFT Scheduled Line, and the HTP 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, the Linden VFT Scheduled Line, and the HTP 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 Bilateral Transaction, 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 , including committing additional resources, if necessary;

16.3.4.4.4 Adjust the DNI associated with External Transactions: Curtail External Firm Transactions until the Constraint is relieved by (1) Curtailing based on , CTS Interface 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.

35.2 Abbreviations, Acronyms, Definitions and Rules of Construction

In this Agreement, the following words and terms shall have the meanings (such meanings to be equally applicable to both the singular and plural forms) ascribed to them in this Section 35.2. Any undefined, capitalized terms used in this Agreement shall have the meaning given under industry custom and, where applicable, in accordance with Good Utility Practices or the meaning given to those terms in the tariffs of PJM and NYISO on file at FERC.

Schedule C to this Agreement contains the Operating Protocol for the Implementation of Con Ed – PJM Transmission Service Agreements. Schedule C was accepted by FERC as a multi-party settlement to a long-running dispute. To the extent Schedule C contains definitions that differ from those set forth below (see, e.g., Appendix 8 to Schedule C), the definitions contained in Schedule C shall supersede the definitions set forth below, for purposes of interpreting Schedule C (including all of the appendices thereto), but shall not be used to interpret any other part of this Agreement.

35.2.1 Abbreviations, Acronyms and Definitions

"AC" shall mean alternating current.

"Affected Party" shall mean the electric system of the Party other than the Party to which a request for interconnection or long-term firm delivery service is made and that may be affected by the proposed service.

"Agreement" shall mean this document, as amended from time to time, including all attachments, appendices, and schedules.

"Area Control Error" or **"ACE" shall** mean the instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

"Available Flowgate Capability" or **"AFC"** shall mean the rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

"Available Transfer Capability" or **"ATC"** shall mean a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

"Balancing Authority" or **"BA"** shall mean the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real-time.

"Balancing Authority Area" or **"BAA"** shall mean the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area..

"Bulk Electric System" shall have the meaning provided for in the NERC Glossary of Terms used in Reliability Standards, as it may be amended, supplemented, or restated from time to time.

"Capacity Benefit Margin" or **"CBM"** shall mean the amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities ("LSEs"), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

"CIM" shall mean Common Infrastructure Model.

"Confidential Information" shall have the meaning stated in Section 35.8.1.

"Control Area(s)" shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied.

"Control Performance Standard" or **"CPS"** shall mean the reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.

"Coordinated Transaction Scheduling" or **"CTS"** shall mean the market rules that allow transactions to be scheduled based on a bidder's willingness to purchase energy from a source in either the NYISO or PJM Control Area and sell it at a sink in the other Control Area if the forecasted price at the sink minus the forecasted price at the corresponding source is greater than or equal to the dollar value specified in the bid.

“Coordination Committee” shall mean the jointly constituted PJM and NYISO committee established to administer the terms and provisions of this Agreement pursuant to Section 35.3.2.

“Delivery Point” shall mean each of the points of direct Interconnection between PJM and the NYISO Balancing Authority Areas. Such Delivery Point(s) shall include the Interconnection Facilities between the PJM and the New York Balancing Authority Areas.

“DC” shall mean direct current.

“Disclosing Party” shall have the meaning stated in Section 35.8.7.

“Dispute” shall have the meaning stated in Section 35.15.

“Disturbance Control Standard” or **“DCS”** shall mean the reliability standard that sets the time limit following a disturbance within which a balancing authority must return its Area Control Error to within a specified range.

“Economic Dispatch” shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

“Effective Date” shall have the meaning stated in Section 35.19.1.

“Emergency” shall mean any abnormal system condition that requires remedial action to prevent or limit loss of transmission or generation facilities that could adversely affect the reliability of the electricity system.

“Emergency Energy” shall mean energy supplied from Operating Reserve or electrical generation available for sale in New York or PJM or available from another Balancing Authority Area. Emergency Energy may be provided in cases of sudden and unforeseen outages of generating units, transmission lines or other equipment, or to meet other sudden and unforeseen circumstances such as forecast errors, or to provide sufficient Operating Reserve. Emergency Energy is provided pursuant to this Agreement and the Inter Control Area Transactions Agreement dated May 1, 2000 and priced according to Section 35.6.4 of this agreement and said Inter Control Area Transactions Agreement.

“EMS” shall mean the respective Energy Management Systems utilized by the Parties to manage the flow of energy within their Regions.

“External Capacity Resource” shall mean: (1) for NYISO, (a) an entity (e.g., Supplier, Transmission Customer) or facility (e.g., Generator, Interface) located outside the NYCA with the capability to generate or transmit electrical power, or the ability to control demand at the direction of the NYISO, measured in megawatts or (b) a set of Resources owned or controlled by an entity within a Control Area, not the NYCA, that also is the operator of such Control Area; and (2) for PJM, a generation resource located outside the metered boundaries of the PJM Region (as defined in the PJM Tariff) that meets the definition of Capacity Resource in the PJM Tariff or PJM's governing agreements filed with the Commission.

"FERC" or **"Commission"** shall mean the Federal Energy Regulatory Commission or any successor agency thereto.

"Flowgate" shall mean a representative modeling of facilities or groups of facilities that may act as potential constraint points.

"*Force Majeure*" shall mean an event of *force majeure* as described in Section 35. 20.1.

"Generator to Load Distribution Factor" or **"GLDF"** shall mean a generator's impact on a Flowgate while serving load in that generator's Balancing Authority Area.

"Good Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the North American electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted by NERC.

"Governmental Authority" shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power.

"ICCP", **"ISN"** and **"ICCP/ISN"** shall mean those common communication protocols adopted to standardize information exchange.

"IDC" shall mean the NERC Interchange Distribution Calculator used for identifying and requesting congestion management relief.

"Indemnifying Party" shall have the meaning stated in Section 35.20.3.

"Indemnitee" shall have the meaning stated in Section 35.20.3

"Intellectual Property" shall mean (i) ideas, designs, concepts, techniques, inventions, discoveries, or improvements, regardless of patentability, but including without limitation patents, patent applications, mask works, trade secrets, and know-how; (ii) works of authorship, regardless of copyright ability, including copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

"Intentional Wrongdoing" shall mean an act or omission taken or omitted by a Party with knowledge or intent that injury or damage could reasonably be expected to result.

"Interconnected Reliability Operating Limit" or **"IROL"** shall mean the value (such as MW, MVAR, Amperes, Frequency, or Volts) derived from, or a subset of, the System Operating Limits, which if exceeded, could expose a widespread area of the bulk electrical system to instability, uncontrolled separation(s) or cascading outages.

"Interconnection" shall mean a connection between two or more individual Transmission Systems that normally operate in synchronism and have interconnecting intertie(s).

"Interconnection Facilities" shall mean the Interconnection facilities described in Schedule A.

"Intermediate Term Security Constrained Economic Dispatch" shall mean PJM's algorithm that performs various functions, including but not limited to forecasting dispatch and LMP solutions based on current and projected system conditions for up to several hours into the future.

"ISO" shall mean Independent System Operator.

"kV" shall mean kilovolt of electric potential.

"LEC Adjusted Market Flow" shall mean the real-time Market Flow incorporating the observed operation of the PARs at the Michigan-Ontario border.

"Locational Marginal Price" or **"LMP"** shall mean the market clearing price for energy at a given location in a Party's RC Area, and "Locational Marginal Pricing" shall mean the processes related to the determination of the LMP.

"Losses" shall have the meaning stated in Section 35.20.3.

"M2M" shall mean the market-to-market coordination process set forth in Schedule D to this Agreement.

"**M2M Entitlement**" shall mean a Non-Monitoring RTO's share of a M2M Flowgate's total capability to be used for settlement purposes that is calculated pursuant to Section 6 of Schedule D to this Agreement.

“M2M Event” shall mean the period when both Parties are operating under M2M as defined and set forth in Schedule D to this Agreement.

“M2M Flowgate” shall mean Flowgates where constraints are jointly monitored and coordinated as defined and set forth in Schedule D to this Agreement.

“Market Flows” shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving load within an RTO’s market.

“Market Participant” shall mean an entity that, for its own account, produces, transmits, sells, and/or purchases for its own consumption or resale capacity, energy, energy derivatives and ancillary services in the wholesale power markets. Market Participants include transmission service customers, power exchanges, Transmission Owners, load serving entities, loads, holders of energy derivatives, generators and other power suppliers and their designated agents.

“Metered Quantity” shall mean apparent power, reactive power, active power, with associated time tagging and any other quantity that may be measured by a Party’s Metering Equipment and that is reasonably required by either Party for Security reasons or revenue requirements.

“Metering Equipment” shall mean the potential transformers, current transformers, meters, interconnecting wiring and recorders used to meter any Metered Quantity.

“Monitoring RTO” shall mean the Party that has operational control of a M2M Flowgate.

“Multiregional Modeling Working Group” or **“MMWG”** shall mean the NERC working group that is charged with multi-regional modeling.

“Mutual Benefits” shall mean the transient and steady-state support that the integrated generation and Transmission Systems in PJM and New York provide to each other inherently by virtue of being interconnected as described in Section 35.4 of this Agreement.

“MVAR” shall mean megavolt ampere of reactive power.

“MW” shall mean megawatt of capacity.

“NAESB” shall mean North American Energy Standards Board or its successor organization.

“NERC” shall mean the North American Electricity Reliability Corporation or its successor organization.

“Network Resource” shall have the meaning as provided in the NYISO OATT, for such resources located in New York, and the meaning as provided in the PJM OATT, for such resources located in PJM.

“New Year Market Flow” shall mean the Market Flow incorporating the transmission topology that includes all pre-existing Transmission Facilities and all new or upgraded Transmission Facilities whose impact on M2M Entitlements has been previously evaluated and incorporated, *and* all new or upgraded Transmission Facilities whose impact on M2M Entitlements is being evaluated in the current evaluation step.

“Non-Monitoring RTO” shall mean the Party that does not have operational control of a M2M Flowgate.

“Notice” shall have the meaning stated in Section 35. 20.22.

“NPCC” shall mean the Northeast Power Coordinating Council, Inc., including the NPCC Cross Border Regional Entity (“CBRE”), or their successor organizations.

“NYISO” shall have the meaning stated in the preamble of this Agreement.

“NYISO Code of Conduct” shall mean the rules, procedures and restrictions concerning the conduct of the ISO directors and employees, contained in Attachment F to the NYISO OATT.

“NYISO Market Monitoring Plan” shall refer to Attachment O to the NYISO Services Tariff.

“NYISO Tariffs” shall mean the NYISO OATT and the NYISO Market Administration and Control Area Services Tariff (“Services Tariff”), collectively.

“NYSRC” shall mean the New York State Reliability Council.

“NYSRC Reliability Rules” shall mean the rules applicable to the operation of the New York Transmission System. These rules are based on Reliability Standards adopted by NERC and NPCC, but also include more specific and more stringent rules to reflect the particular requirements of the New York Transmission System.

“OASIS” shall mean the Open Access Same-Time Information System required by FERC for the posting of market and transmission data on the Internet websites of PJM and NYISO.

“OATT” shall mean the applicable Open Access Transmission Tariffs on file with FERC for PJM and NYISO.

“Operating Entity” shall mean an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

“Operating Instructions” shall mean the operating procedures, steps, and instructions for the operation of the Interconnection Facilities established from time to time by the Coordination Committee or the PJM and NYISO individual procedures and processes and includes changes from time to time by the Coordination Committee to such established procedures, steps and instructions exclusive of the individual procedures.

"Operating Reserve" shall mean generation capacity or load reduction capacity which can be called upon on short notice by either Party to replace scheduled energy supply which is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies.

"Operational Control" shall mean Security monitoring, adjustment of generation and transmission resources, coordinating and approval of changes in transmission status for maintenance, determination of changes in transmission status for reliability, coordination with other Balancing Authority Areas and Reliability Coordinators, voltage reductions and load shedding, except that each legal owner of generation and transmission resources continues to physically operate and maintain its own facilities.

"**OTDF**" shall mean the electric PTDF with one or more system facilities removed from service (*i.e.*, outaged) in the post-contingency configuration of a system under study.

"Outages" shall mean the planned unavailability of transmission and/or generation facilities dispatched by PJM or the NYISO, as described in Section 35.9 of this Agreement.

"PAR" shall mean phase angle regulator.

"PAR Shift Factor" or **"PSF"**, shall mean the PAR's impact on a Flowgate measured as the ratio of Flowgate flow change in MW to PAR schedule change in MW.

"Party" or **"Parties"** refers to each party to this Agreement or both, as applicable.

"PJM" has the meaning stated in the preamble of this Agreement.

"PJM Code of Conduct" shall mean the code of ethical standards, guidelines and expectations for PJM's employees, officers and Board Members in their transactions and business dealings on behalf of PJM as posted on the PJM website and as may be amended from time to time.

"PJM Tariffs" shall mean the PJM OATT and the PJM Amended and Restated Operating Agreement, collectively.

"**Power Transfer Distribution Factor**" or "**PTDF**" shall mean a measure of the responsiveness or change in electrical loadings on Transmission Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer in the pre-contingency configuration of a system under study.

“Real-Time Commitment” shall mean NYISO’s multi-period security constrained unit commitment and dispatch model, as defined in the NYISO Tariffs.

“Reference Year Market Flow” shall mean the Market Flow based on a transmission topology that includes all pre-existing Transmission Facilities and all new or upgraded Transmission Facilities whose impact on M2M Entitlements has been previously evaluated and incorporated.

“Region” shall mean the Control Areas and Transmission Facilities with respect to which a Party serves as RTO or Reliability Coordinator under NERC policies and procedures.

“Regulatory Body” shall have the meaning stated in Section 35.20.21.

“Reliability Coordinator” or **“RC”** shall mean the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the wide area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator’s vision.

“Reliability Coordinator Area” shall mean that portion of the Bulk Electric System under the purview of the Reliability Coordinator.

“Reliability Standards” shall mean the criteria, standards, rules and requirements relating to reliability established by a Standards Authority.

“RFC” shall mean ReliabilityFirst Corporation.

“RTO” shall mean Regional Transmission Organization. For ease of reference, the New York Independent System Operator, Inc., may be referred to as an RTO in this Agreement and the NYISO and PJM may be referred to collectively as the “RTOs” or the “participating RTOs.”

“Schedule” shall mean a schedule attached to this Agreement and all amendments, supplements, replacements and additions hereto.

“SDX System” shall mean the system used by NERC to exchange system data.

“Security” shall mean the ability of the electric system to withstand sudden disturbances including, without limitation, electric short circuits or unanticipated loss of system elements.

“Security Limits” shall mean operating electricity system voltage limits, stability limits and thermal ratings.

“SERC” shall mean SERC Reliability Corporation or its successor organization.

“Shadow Price” shall mean the marginal value of relieving a particular constraint which is determined by the reduction in system cost that would result from an incremental relaxation of that constraint.

“Standards Authority” shall mean NERC, and the NERC regional entities with governance over PJM and NYISO, any successor thereof, or any other agency with authority over the Parties regarding standards or criteria to either Party relating to the reliability of Transmission Systems.

“Standards Authority Standards” shall have the meaning stated in Section 35.5.2.

“State Estimator” shall mean a computer model that computes the state (voltage magnitudes and angles) of the Transmission System using the network model and real-time measurements. Line flows, transformer flows, and injections at the busses are calculated from the known state and the transmission line parameters. The State Estimator has the capability to detect and identify bad measurements.

“Supplying Party” shall have the meaning stated in Section 35.8.2.

“System Operating Limit” or **“SOL”** shall mean the value (such as MW, MVAR, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

“**Target Value**” shall have the meaning stated in Section 7.2 of Schedule D to this Agreement.

“Third Party” refers to any entity other than a Party to this Agreement.

“TLR” shall mean the NERC Transmission Loading Relief Procedures used in the Eastern Interconnection as specified in NERC Operating Policies.

“Transmission Adjusted Market Flow” shall mean the result of applying the M2M Entitlement Transmission Adjusted Market Flow Calculation to the New Year Market Flow. The resulting Transmission Adjusted Market Flow is then used as the Reference Year Market Flow in all subsequent, iterative, evaluations.

“Transmission Operator” shall mean the entity responsible for the reliability of its “local” Transmission System, and that operates or directs the operations of the Transmission Facilities.

“Transmission Owner” shall mean an entity that owns Transmission Facilities.

“Transmission System” shall mean the facilities controlled or operated by PJM or NYISO as designated by each in their respective OATTs.

“Transmission Facility” shall mean a facility for transmitting electricity, and includes any structures, equipment or other facilities used for that purpose as defined in the Parties respective OATTs.

“Transmission Reliability Margin” or **“TRM”** shall mean the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

“Total Transfer Capability” or **“TTC”** shall mean the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected Transmission Systems by way of all transmission lines (or paths) between those areas under specified system conditions.

“Voltage and Reactive Power Coordination Procedures” are the procedures under Section 35.11 for coordination of voltage control and reactive power requirements.

35.2. 2 Rules of Construction.

35.2. 2.1 No Interpretation Against Drafter.

In addition to their roles as RTOs/ISOs and Reliability Coordinators, and the functions and responsibilities associated therewith, the Parties agree that each Party participated in the drafting of this Agreement and was represented therein by competent legal counsel. No rule of construction or interpretation against the drafter shall be applied to the construction or in the interpretation of this Agreement.

35.2. 2.2 Incorporation of Preamble and Recitals.

The Preamble and Recitals of this Agreement are incorporated into the terms and conditions of this Agreement and made a part thereof.

35.2. 2.3 Meanings of Certain Common Words.

The word “including” shall be understood to mean “including, but not limited to.” The word “Section” refers to the applicable section of this Agreement and, unless otherwise stated, includes all subsections thereof. The word “Article” refers to articles of this Agreement.

35.2. 2.4 Standards Authority Standards, Policies, and Procedures.

All activities under this Agreement will meet or exceed the applicable Standards Authority standards, policies, or procedures as revised from time to time.

35.2. 2.5 Scope of Application.

Each Party will perform this Agreement in accordance with its terms and conditions with respect to each Control Area for which it serves as ISO or RTO and, in addition, each Control Area for which it serves as Reliability Coordinator.

35.7 Exchange of Information

35.7.1 Exchange of Operating Data

PJM and NYISO agree to exchange and share such information as may be required from time to time for the Parties to perform their duties and fulfill their obligations under this Agreement, subject to the requirements of existing confidentiality agreements or rules binding upon either of the Parties, including the NYISO Code of Conduct as set forth in Attachment F to the NYISO OATT, Article 6 of the NYISO Services Tariff, the PJM Code of Conduct and PJM Data Confidentiality Regional Stakeholder Group. Such information may consist of the following:

35.7.1.1 Information required to develop Operating Instructions;

35.7.1.2 Transmission System facility specifications and modeling data required to perform Security analysis;

35.7.1.2.1 The Parties will exchange their detailed EMS models in CIM format or another mutually agreed upon electronic format, and include the ICCP/ISN mapping files, identification of individual bus loads, seasonal equipment ratings and one-line drawings to expedite the model conversion process, upon request. The Parties will also exchange updates that represent the incremental changes that have occurred to the EMS model since the most recent update in an agreed upon electronic format;

35.7.1.3 Functional descriptions and schematic diagrams of Transmission System protective devices and communication facilities;

35.7.1.4 Ratings data and associated ratings methodologies for the Interconnection Facilities;

35.7.1.5 Telemetry points, equipment alarms and status points required for real-time monitoring of Security dispatch;

35.7.1.6 Data required to reconcile accounts for inadvertent energy, and for Emergency Energy transactions;

35.7.1.7 Transmission System information that is consistent with the information sharing requirements imposed by the Standards Authority;

35.7.1.8 Such other information as may be required for the Parties to maintain the reliable operation of their interconnected Transmission Systems and fulfill their obligations under this Agreement and to any Standards Authority of which either Party is a member, provided, however, that this other information will be exchanged only if that can be done in accordance with applicable restrictions on the disclosure of information to any Market Participant; ~~and~~

35.7.1.9 Additional information required for the Parties to administer the M2M coordination process set forth in Schedule D to this Agreement, including:

a. actual flows on M2M Flowgates;

b. actual limits for M2M Flowgates;

c. *ex ante* Shadow Prices on constrained M2M Flowgates;

d. requested relief during a M2M Event;

e. Market Flow calculation data (generator shift factors, load shift factors, interchange PTDFs, phase angle regulator OTDFs, generator output, load, net interchange);

f. Market Flows on M2M Flowgates; and

g. binding constraint thresholds (the shift factor thresholds used to identify the resource(s) available to relieve a transmission constraint).

35.7.1.10 Additional information required for the Parties to administer CTS, including:

a. interchange transaction offer attributes (frequency of scheduling, offer type, source and sink);

b. forecasted interchange schedules;

c. forecasted prices; and

d. CTS interface limits.

35.7.2 Confidentiality

The Party receiving information pursuant to this Section 35.7 shall treat such information as confidential subject to the terms and conditions of set forth in Section 35.8 of this Agreement. The obligation of each Party under this Section 35.7.2 continues and survives the termination of this Agreement by seven (7) years.

35.7.3 Data Exchange Contact

To facilitate the exchange of all such data, each Party will designate to the other Party's Vice President of Operations a contact to be available twenty-four (24) hours each day, seven (7) days per week, and an alternate contact to act in the absence or unavailability of the primary contact, to respond to any inquiries. With respect to each contact and alternate, each Party shall provide the name, telephone number, e-mail address, and fax number. Each Party may change a designee from time to time by Notice to the other Party's Vice President of Operations.

The Parties agree to exchange data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. Each Party shall provide notification to the other Party thirty (30) days prior to modifying an established data exchange format.

35.7.4 Cost of Data and Information Exchange

Each Party shall bear its own cost of providing information to the other Party.

35.7.5 Other Data

The Parties may share other data not listed in this Section 35.7 as mutually agreed upon by the Parties.

35.12 M2M Coordination Process and Coordinated Transaction Scheduling

35.12.1 M2M Coordination Process

The fundamental philosophy of the M2M transmission congestion coordination process that is set forth in the attached Market-to-Market Coordination Schedule is to allow any transmission constraints that are significantly impacted by generation dispatch changes in both the NYISO and PJM markets or by the operation of the Ramapo PARs to be jointly managed in the real-time security-constrained economic dispatch models of both Parties. This joint real-time management of transmission constraints near the market borders will provide a more efficient and lower cost transmission congestion management solution and coordinated pricing at the market boundaries.

Under normal system operating conditions, the Parties utilize the M2M coordination process on defined M2M Flowgates that experience congestion. The Party that is responsible for monitoring a M2M Flowgate will initiate and terminate the redispatch component of the M2M coordination process. The Party that is responsible for monitoring a M2M Flowgate is expected to bind that Flowgate when it becomes congested, and to initiate market-to-market redispatch to utilize the more cost effective generation between the two markets to manage the congestion in accordance with Section 7.1.2 of the attached Market-to-Market Coordination Schedule. Ramapo PAR coordination need not be formally invoked by either Party. It is ordinarily in effect.

The Market-to-Market coordination process includes a settlement process that applies when M2M coordination is occurring.

35.12.2 Coordinated Transaction Scheduling

Coordinated Transaction Scheduling or "CTS" are real time market rules implemented by NYISO and PJM that allow transactions to be scheduled based on a bidder's willingness to purchase energy at a source (in the PJM Control Area or the NYISO Control Area) and sell it at a sink (in the other Control Area) if the forecasted price at the sink minus the forecasted price at the corresponding source is greater than or equal to the dollar value specified in the bid.

CTS transactions are ordinarily evaluated on a 15--minute basis consistent with forecasted real--time prices from NYISO's Real-Time Commitment run and the forecasted price information from PJM's Intermediate Term Security Constrained Economic Dispatch solution. Coordinated optimization with CTS improves interregional scheduling efficiency by: (i) better ensuring that scheduling decisions take into account relative price differences between the regions; and (ii) moving the evaluation of bids and offers closer to the time scheduling decisions are implemented.

NYISO and PJM may suspend the scheduling of CTS transactions when NYISO or PJM are not able to adequately implement schedules as expected due to: (1) a failure or outage of the data link between NYISO and PJM prevents the exchange of accurate or timely data necessary to implement the CTS transactions; (2) a failure or outage of any computational or data systems preventing the actual or accurate calculation of data necessary to implement the CTS transactions; or (3) when necessary to ensure or preserve system reliability.