Attachment I

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 Member System'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.

Commenced Repair: As defined in the ISO Services 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.

Credible Repair Plan: As defined in the ISO Services Tariff.

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. CTS Interface Bids shall include a MW amount, a direction indicating whether the proposed Transaction is to Import Energy to, or Export Energy from, the New York Control Area, and a Bid Price.

CTS Sink: Representation of the location(s) within a Control Area where energy associated with a CTS Interface Bid is withdrawn.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

CTS Sink Price: The price at a CTS Sink.

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

CTS Source Price: The price at a CTS Source.

Curtailment or Curtail: A reduction in 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.

1.9 Definitions - I

ICAP Ineligible Forced Outage: As defined in the ISO Services Tariff.

Import Curtailment Guarantee Payment: A payment made in accordance with Section 4.5.3.2 and Attachment J of the ISO Services Tariff to compensate a Supplier whose Import is Curtailed by the ISO.

Imports: A Bilateral Transaction or sale to the LBMP Market where Energy is delivered to a NYCA Interconnection from another Control Area.

Imputed Revenue: The Congestion Rents that owners of Grandfathered Rights do not have to pay due to their own use of those Grandfathered Rights.

Inactive Reserves: As defined in the ISO Services Tariff.

Inadvertent Energy Accounting: The accounting performed to track and reconcile the difference between net actual Energy interchange and scheduled Energy interchange of a Control Area with adjacent Control Areas.

Incremental Energy Bid: A series of monotonically increasing constant cost incremental Energy steps that indicate the quantities of Energy for a given price that an entity is willing to supply to the ISO Administered Markets.

Incremental TCC: A set of point-to-point Transmission Congestion Contract(s) that is awarded pursuant to Section 19.2.2 of Attachment M to this ISO OATT.

Independent System Operator, Inc. ("ISO"): The New York Independent System Operator, a not-for-profit corporation established pursuant to the ISO Agreement.

Independent System Operator Agreement ("ISO Agreement"): The agreement that establishes the New York ISO.

Independent System Operator/New York State Reliability Council ("ISO/NYSRC Agreement"): The agreement between the ISO and the New York State Reliability Council governing the relationship between the two organizations.

Independent System Operator/Transmission Owner Agreement ("ISO/TO Agreement"): The agreement that establishes the terms and conditions under which the Member Systems transferred to the ISO Operational Control over designated transmission facilities.

Injection Billing Units: A Transmission Customer's Actual Energy Injections (for all internal injections) or Scheduled Energy Injections (for all Import Energy injections) in the New York Control Area, including injections for Wheels Through. For purposes of Rate Schedule 1 and Rate Schedule 11 of this ISO OATT, (i) a Limited Energy Storage Resource shall be responsible for charges or eligible for payments on the basis only of its Actual Energy Injections and (ii) a Day-Ahead Demand Reduction Provider's Demand Reduction shall be included as Injection

Billing Units. For purposes of recovering the ISO annual budgeted costs and the annual FERC fee pursuant to Rate Schedule 1 of this ISO OATT, Injection Billing Units shall include the absolute value of negative injections by pump storage facilities.

Installed Capacity: A Generator or Load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for Energy in the NYCA for the purpose of ensuring that sufficient Energy and Capacity are available to meet the Reliability Rules. The Installed Capacity requirement, established by the NYSRC, includes a margin of reserve in accordance with the Reliability Rules.

Interconnection or Interconnection Points ("IP"): The point(s) at which the NYCA connects with a distribution system or adjacent Control Area. The IP may be a single tie line or several tie lines that are operated in parallel.

Interface: A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas.

Interface MW - Mile Methodology: The procedure used to allocate Original Residual TCCs determined prior to the first Centralized TCC Auction to Transmission Owners.

Intermittent Power Resource: A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. In New York, resources that depend upon wind, or solar energy or landfill gas for their fuel have been classified as Intermittent Power Resources. Each Intermittent Power Resource that depends on wind as its fuel shall include all turbines metered at a single scheduling point identifier (PTID).

Internal: An entity (*e.g.*, Supplier, Transmission Customer) or facility (*e.g.*, Generator, Interface) located within the Control Area being referenced. Where a specific Control Area is not referenced, internal means the NYCA.

Internal Transactions: Purchases, sales or exchanges of Energy, Capacity or Ancillary Services where the Generator and Load are located within the NYCA.

Investment Grade Customer: As defined in the ISO Services Tariff.

Investor-Owned Transmission Owners: At the present time these include: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

ISO Administered Markets: The Day-Ahead Market and the Real-Time Market (collectively the LBMP Markets) and any other market administered by the ISO.

ISO-Committed Fixed: In the Day-Ahead, a bidding mode in which a Generator requests that the ISO commit and schedule it. In the Real-Time Market, a bidding mode in which a Generator, with ISO approval, requests that the ISO schedule it no more frequently than every 15 minutes. A Generator scheduled in the Day-Ahead Market as ISO-Committed Fixed will participate as a

Self-Committed Fixed Generator in the Real-Time Market unless it changes bidding mode, with ISO approval, to participate as an ISO-Committed Fixed Generator.

ISO-Committed Flexible: A bidding mode in which a Dispatchable Generator Demand Side Resource follows Base Point Signals and is committed by the ISO.

ISO Market Power Monitoring Program: The monitoring program approved by the Commission and administered by the ISO designed to monitor the possible exercise of market power in ISO Administered Markets.

ISO OATT (the "Tariff"): The ISO Open Access Transmission Tariff.

ISO Procedures: The procedures adopted by the ISO in order to fulfill its responsibilities under the ISO OATT, the ISO Services Tariff and the ISO Related Agreements.

ISO Related Agreements: Collectively, the ISO Agreement, the NYSRC Agreement, the ISO/NYSRC Agreement, the ISO/TO Agreement, and Operating Agreements.

NYISO Services Tariff: The ISO Market Administration and Control Area Services Tariff.

ISO Tariffs: The ISO OATT and the ISO Services Tariff, collectively.

1.13 Definitions - M

Major Emergency State: An Emergency accompanied by abnormal frequency, abnormal voltage and/or equipment overloads that create a serious risk that the reliability of the NYS Power System could be adversely affected.

Manual Dispatch: A dispatch of the NYS Transmission System performed by the ISO when the ISO's RTD is unavailable.

Marginal Losses: The NYS Transmission System Real Power Losses associated with each additional MWh of consumption by Load, or each additional MWh transmitted under a Bilateral Transaction as measured at the Points of Withdrawal.

Marginal Losses Component: The component of LBMP at a bus that accounts for the Marginal Losses, as measured between that bus and the Reference Bus.

Market Participant: An entity, excluding the ISO, that produces, transmits, sells, and/or purchases for resale Capacity, Energy and Ancillary Services in the Wholesale Market. Market Participants include: Transmission Customers under the ISO OATT, Customers under the ISO Services Tariff, Power Exchanges, Transmission Owners, Primary Holders, LSEs, Suppliers and their designated agents. Market Participants also include entities buying or selling TCCs.

Market Services: Services provided by the ISO under the ISO Services Tariff related to the ISO Administered Markets for Energy, Capacity and Ancillary Services.

Member Systems: The eight Transmission Owners that comprised the membership of the New York Power Pool, which are: (1) Central Hudson Gas & Electric Corporation, (2) Consolidated Edison Company of New York, Inc., (3) New York State Electric & Gas Corporation, (4) Niagara Mohawk Power Corporation d/b/a National Grid, (5) Orange and Rockland Utilities, Inc., (6) Rochester Gas and Electric Corporation, (7) the Power Authority of the State of New York, and (8) Long Island Lighting Company d/b/a Long Island Power Authority.

Minimum Generation Bid: A Bid parameter that identifies the payment a Supplier requires to operate a Generator at its specific minimum operating level or to provide a Demand Side Resource's specified minimum quantity of Demand Reduction.

Minimum Generation Level: For purposes of describing the eligibility of ten minute Resources to be committed by the Real Time Dispatch for pricing purposes pursuant to the Services Tariff, Section 4.4.3.3, an upper bound, established by the ISO, on the physical minimum generation limits specified by ten minute Resources. Ten minute Resources with physical minimum generation limits that exceed this upper bound will not be committed by the Real Time Dispatch for pricing purposes. The ISO shall establish a Minimum Generation Level based on its evaluation of the extent to which it is meeting its reliability criteria including Control Performance. The Minimum Generation Level, in megawatts, and the ISO's rationale for that level, shall be made available through the ISO's website or comparable means.

Modified Wheeling Agreements ("MWA"): A Transmission Wheeling Agreement between

Transmission Owners that was in existence at the time of ISO start-up, as amended and modified as described in Attachment K. Modified Wheeling Agreements are associated with Generators or power supply contracts existing at ISO start-up. All Modified Wheeling Agreements are listed in Attachment L, Table 1A, and are designated in the "Treatment" column of Table 1A, as "MWA."

Mothball Outage: As defined in the ISO Services Tariff.

1.15 Definitions - O

Off-Peak: The hours between 11:00 p.m. and 7:00 a.m., prevailing Eastern Time, Monday through Friday, and all day Saturday and Sunday, and NERC-defined holidays, or as otherwise decided by ISO.

On-Peak: The hours between 7:00 a.m. and 11:00 p.m. inclusive, prevailing Eastern Time, Monday through Friday, except for NERC-defined holidays, or as otherwise decided by the ISO.

Open Access Same-Time Information System ("OASIS"): The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Operating Agreement: An agreement between the ISO and a non-incumbent owner of transmission facilities in the New York Control Area concerning the operation of the transmission facilities in the form of the agreement set forth in Appendix H (Section 31.11) of Attachment Y.

Operating Capacity: Capacity that is readily converted to Energy and is measured in MW.

Operating Committee: A standing committee of the ISO created pursuant to the ISO Agreement, which coordinates operations, develops procedures, evaluates proposed system expansions and acts as a liaison to the NYSRC.

Operating Requirement: As defined in the ISO Services Tariff.

Operating Reserves: Capacity that is available to supply Energy, or to reduce demand and that meets the requirements of the ISO. The ISO will administer Operating Reserves markets, in the manner described in Article 4 and Rate Schedule 4 of this ISO Services Tariff, to satisfy the various Operating Reserves requirements, including locational requirements, established by the Reliability rules and other applicable reliability standards. The basic Operating Reserves products that will be procured by the ISO on behalf of the market are classified as follows:

(1) Spinning Reserve: Operating Reserves provided by Generators and Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff that are already synchronized to the NYS Power System and can respond to instructions to change their output level, or reduce their Energy usage, within ten (10) minutes. Spinning Reserves may not be provided by Demand Side Resources that are Local Generators;

(2) 10-Minute Non-Synchronized Reserve: Operating Reserve provided by Generators, or Demand Side Resources, including Demand Side Resources using Local Generators, that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can be started, synchronized and can change their output level within ten (10) minutes; and

(3) 30-Minute Reserve: Synchronized Operating Reserves provided by Generators and Demand Side Resources that are not Local Generators; or non-synchronized

Operating Reserves provided by Generators or Demand Side Resources that meet the eligibility criteria set forth in Rate Schedule 4 of this ISO Services Tariff and that can respond to instructions to change their output level within thirty (30) minutes, including starting and synchronizing to the NYS Power System.

Operating Reserve Demand Curve: A series of quantity/price points that defines the maximum Shadow Price for Operating Reserves meeting a particular Operating Reserve requirement corresponding to each possible quantity of Resources that the ISO's software may schedule to meet that requirement. A single Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for each of the ISO's twelve Operating Reserve requirements.

Operating Study Power Flow: A Power Flow analysis that is performed at least once before each Capability Period that is used to determine each Interface Transfer Capability for the Capability Period (See Attachment M).

Operational Control: Directing the operation of the Transmission Facilities Under ISO Operational Control to maintain these facilities in a reliable state, as defined by the Reliability Rules. The ISO shall approve operational decisions concerning these facilities, made by each Transmission Owner before the Transmission Owner implements those decisions. In accordance with ISO Procedures, the ISO shall direct each Transmission Owner to take certain actions to restore the system to the Normal State. Operational Control includes security monitoring, adjustment of generation and transmission resources, coordination and approval of changes in transmission status for maintenance, determination of changes in transmission status for reliability, coordination with other Control Areas, voltage reductions and Load Shedding, except that each Transmission Owner continues to physically operate and maintain its facilities.

Optimal Power Flow ("OPF"): The Power Flow analysis that is performed during the administration of the Centralized TCC Auction to determine the most efficient simultaneously feasible allocation of TCCs to bidders.

Original Residual TCC: A TCC converted from Residual Transmission Capacity estimated prior to the first Centralized TCC Auction and allocated among the Transmission Owners utilizing the Interface MW-Mile Methodology prior to the first Centralized TCC Auction.

Order Nos. 888 et seq.: The Final Rule entitled Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, issued by the Commission on April 24, 1996, in Docket Nos. RM95-8-000 and RM94-7-001, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31,036 (1996) ("Order No. 888"), on reh'g, III FERC Stats. & Regs. ¶ 31,048 (1997) ("Order No. 888-A"), on reh'g, 81 FERC ¶ 61,248 (1997) ("Order No. 888-B") (Order on reh'g 82 FERC ¶ 61,046 (1998) ("Order No. 888- C").

Order Nos. 889 et seq.: The Final Rule entitled Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, issued by the Commission on April 24, 1996, in Docket No. RM95-9-000, as modified on rehearing, or upon appeal. (See FERC Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31,035 (1996) ("Order No. 889"), on reh'g, III FERC Stats. & Regs. ¶ 31,049 (1997) ("Order No. 889-A"), on reh'g, 81 FERC ¶ 61,253 (1997) ("Order No. 889-B")).

Out-of-Merit Generation: Resources committed and/or dispatched by the ISO at specified output limits for specified time periods to meet Load and/or reliability requirements that differ from or supplement the ISO's security constrained economic commitment and/or dispatch.

1.18 Definitions - R

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

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

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

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

Real-Time Bid: A Bid submitted into the Real-Time Commitment before the close of the Real-Time Scheduling Window. A Real-Time Bid shall also include a CTS Interface Bid.

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

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

Services Tariff the term “RTD” will normally be used to refer to both the Real-Time Dispatch and to the specialized Real-Time Dispatch Corrective Action Mode software.

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

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

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

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

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

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

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

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

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

Repair Plan: As defined in the ISO Services Tariff.

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

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

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

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

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

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

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

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

GTR is the transmission capacity associated with Grandfathered Rights.

GTCC is the transmission capacity associated with Grandfathered TCCs.

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

TRM is the Transmission Reliability Margin.

CBM is the Capacity Benefit Margin.

Retired: As defined in the ISO Services Tariff.

RMR Agreement: An agreement of limited duration that provides for the continued operation of one or more RMR Generator(s) to satisfy one or more Reliability Need(s) entered into between the ISO and an entity or entities that own or have operational control over the RMR Generator(s).

RMR Avoidable Costs: The (a) fixed costs of an Initiating Generator that would be avoided if it were to exit the ISO-Administered Markets in the manner specified in its Generator Deactivation Notice, (b) the fixed costs of a Generator already in a Mothball Outage, an ICAP Ineligible Forced Outage, or that has been mothballed since before May 1, 2015 that would be incurred if it were to re-enter the ISO-Administered Markets pursuant to an RMR Agreement that would be avoided if it remained in such state, or (c) the costs necessary for a new Generator proposed as a Gap Solution to enter service. RMR Avoidable Costs include mandatory capital expenditures, fixed operating and maintenance costs, and forgone opportunity costs, determined by the ISO in accordance with Section 31.2.11.8 of Attachment Y, as modified by the

Commission. RMR Avoidable Costs do not include variable costs or any other type of cost that are included in the Generator's Energy or Ancillary Services reference levels, or that are ordinarily included in Energy or Ancillary Services reference levels.

RMR Generator: The Generator or Generators operating under an RMR Agreement.

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

1.20 Definitions - T

Tangible Net Worth: The value, determined by the ISO, of all of a Customer's assets less both: (i) the amount of the Customer's liabilities and (ii) all of the Customer's intangible assets, including, but not limited to, patents, trademarks, franchises, intellectual property, and goodwill.

Third Party Sale: Any sale for resale in interstate commerce to a power purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

Third Party Transmission Wheeling Agreements ("Third Party TWAs"): A Transmission Wheeling Agreement, as amended, between Transmission Owners or between a Transmission Owner and an entity that is not a Transmission Owner. Third Party TWAs are associated with the purchase (or sale) of Energy, Capacity, and/or Ancillary Services for the benefit of an entity that is not a Transmission Owner. All Third Party TWAs are listed in Attachment L, Table 1A, and are designated in the "Treatment "column of Table 1A, as "Third Party TWA."

Total Transfer Capability ("TTC"): The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner.

Trading Hub: A virtual location in a given Load Zone, modeled as a Generator bus and/or Load bus, for scheduling Bilateral Transactions in which both the POI and POW are located within the NYCA.

Trading Hub Energy Owner: A Customer who buys energy in a Bilateral Transaction in which the POW is a Trading Hub, or who sells energy in a Bilateral Transaction in which the POI is a Trading Hub.

Transaction: The purchase and/or sale of Energy or Capacity, or the sale of Ancillary Services. A Transaction bid into the Energy market to sell or purchase Energy or to schedule a Bilateral Transaction includes a Point of Injection and a Point of Withdrawal.

Transfer Capability: The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission facilities (or paths) between those areas under specified system conditions.

Transmission Congestion Contract Component ("TCC Component"): As defined in the ISO Services Tariff.

Transmission Congestion Contracts ("TCCs"): The right to collect or obligation to pay Congestion Rents in the Day-Ahead Market for Energy associated with a single MW of transmission between a specified POI and POW. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission.

Transmission Customer: Any Eligible Customer (or its designated agent) that (i) executes a Service Agreement, or (ii) requests in writing that the ISO file with the Commission a proposed unexecuted Service Agreement to receive Transmission Service under Part 3, 4 and/or 5 of the Tariff.

Transmission District: The geographic area in which a Transmission Owner, including LIPA, is obligated to serve Load, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York.

Transmission Facility Agreement ("TFA"): Agreements governing the use of specific or designated transmission facilities charges to cover all, or a portion, of the costs to install, own, operate, or maintain transmission facilities, to the customer under the agreement and that have provisions to provide Transmission Service utilizing said transmission facilities. All Transmission Facility Agreements are listed in Attachment L. Table 1A, and are designated in the "Treatment" column as "Facility Agmt. – MWA."

Transmission Facilities Under ISO Operational Control: The transmission facilities of the Transmission Owners listed in Appendix A-1 of the ISO/TO Agreement ("Listing of Transmission Facilities Under ISO Operational Control") and listed in Appendix A-1 of an Operating Agreement ("NTO Transmission Facilities Under ISO Operational Control") that are subject to the Operational Control of the ISO. This listing may be amended from time-to-time as specified in the ISO/TO Agreement and Operating Agreements.

Transmission Facilities Requiring ISO Notification: The transmission facilities of the Transmission Owners listed in Appendix A-2 of the ISO/TO Agreement ("Listing of Transmission Facilities Requiring ISO Notification") and listed in Appendix A-2 of an Operating Agreement ("NTO Transmission Facilities Requiring ISO Notification") whose status of operation must be provided to the ISO by the Transmission Owners (for the purposes stated in the ISO Tariffs and in accordance with the ISO OATT, ISO/TO Agreement, and/or Operating Agreements) prior to the Transmission Owners making operational changes to the state of these facilities. This listing may be amended from time-to-time as specified in the ISO/TO Agreement and Operating Agreements.

Transmission Fund: The mechanism used under the current NYPP Agreement to compensate the Member Systems for providing Transmission Service for economy Energy Transactions over their transmission systems. Each Member System is allocated a share of the economy Energy savings in dollars assigned to the fund that is based on the ratio of their investment in transmission facilities to the sum of investments in transmission and generation facilities.

Transmission Owner: The public utility or authority (or its designated agent) that owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff.

Transmission Owner's Monthly Transmission System Peak: The maximum hourly firm usage as measured in megawatts (MW) of the Transmission Owner's transmission system in a calendar month.

Transmission Plan: A plan developed by the ISO staff with Transmission Owner's support that is a compilation of transmission projects proposed by the Transmission Owners and others, that are found to meet all applicable criteria.

Transmission Reliability Margin ("TRM"): The amount of TTC reserved by the ISO to ensure the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Transmission Service: Point-To-Point, Network Integration or Retail Access Transmission Service provided under Parts 3, 4 and 5 of the Tariff.

Transmission Service Charge ("TSC"): A charge designed to ensure recovery of the embedded cost of a transmission system owned by a Member System.

Transmission Shortage Cost: A series of quantity/price points that defines the maximum Shadow Price of a particular Constraint that will be used in calculating LBMP. The Transmission Shortage Costs are set at $350/MWh for shortages above zero and less than or equal to 5MW, $2350/MWh for shortages above 5MW and less than or equal to 20MW, and $4000/MWh for shortages above 20MW.

Transmission System: The facilities operated by the ISO that are used to provide Transmission Services under Part 3, Part 4 or Part 5 of this Tariff.

Transmission Usage Charge ("TUC"): Payments made by the Transmission Customer to cover the cost of Marginal Losses and, during periods of time when the transmission system is Constrained, the marginal cost of Congestion. The TUC is equal to the product of: (1) the LBMP at the POW minus the LBMP at the POI (in $/MWh); and (2) the scheduled or delivered Energy (in MWh).

Transmission Wheeling Agreement ("TWA"): The agreements listed in Table 1A of Attachment L to the ISO OATT governing the use of specific or designated transmission facilities that are owned, controlled or operated by an entity for the transmission of Energy in interstate commerce. TWAs between Transmission Owners have been modified such that all TWAs between Transmission Owners are now MWAs.

2.1 Term and Effectiveness

2.1.1 Effectiveness:

This Tariff shall become effective on the latest of the following: (i) September 1, 1999; (ii) Commission approval of (a) this Tariff; (b) the ISO Services Tariff; (c) the ISO Agreement; (d) NYSRC Agreement; (e) the ISO/NYSRC Agreement; and (f) the ISO/TO Agreement; (iii) the date on which both the Commission and the PSC grant all necessary approvals to the Member Systems to transfer Operational Control of any facilities to the ISO or otherwise dispose of any of their property, including, without limitation, those approvals required under Section 70 of the New York Public Service Law ("PSL") and Section 203 of the Federal Power Act ("FPA"); (iv) the last date that any other approval or authorization is received, to the extent such additional approval or authorization is necessary; (v) execution of the ISO Related Agreements with the exception of any Operating Agreement; or (vi) such later date specified by the Commission.

2.1.2 Term and Termination:

This Tariff shall remain in effect until: (i) canceled by the ISO upon sixty (60) days prior written notice in accordance with applicable Commission regulations; or (ii) the effective date of, any law, order, rule, regulation, or determination of a body of competent jurisdiction requiring termination or a material modification of this Tariff and/or Service Agreements related to this Tariff that would be inconsistent with any term or provision of the ISO/TO Agreement. Any Transmission Customer may withdraw from this Tariff on thirty (30) days prior written notice to the ISO.

2.7 Billing and Payment

2.7.1 ISO as Counterparty; Right to Net or Set Off; ISO Clearing Account

2.7.1.1 ISO as Counterparty

The ISO shall be for all purposes the contracting counterparty, in its own name and right, to each Transmission Customer for any purchase or sale of any product or service, or for any other transaction, that is financially settled by the ISO under the ISO Tariffs.

2.7.1.2 Right to Net or Set Off Obligations Owed

Unless otherwise specifically set forth in this ISO OATT, if for any settlement period the ISO is required to pay any amount to the Transmission Customer and the Transmission Customer is required to pay any amount to the ISO under this ISO OATT or the ISO Services Tariff, such amounts shall be netted, and the party owing the greater aggregate amount shall pay to the other party the difference between the amounts owed. Additionally, all outstanding payment obligations under this ISO OATT and the ISO Services Tariff between the ISO and the Transmission Customer may be netted, offset, set off, or recouped, and payment shall be owed as set forth above.

2.7.1.3 ISO Clearing Account

The ISO will establish one or more accounts (the “ISO Clearing Account”) at a bank or other financial institution, and Transmission Customers shall make payments to the ISO or receive payments from the ISO through the ISO Clearing Account in accordance with their settlement information provided by the ISO as described in Section 2.7.3 of this ISO OATT.

The funds held by the ISO in the ISO Clearing Account shall not be commingled with funds held by the ISO in any other ISO accounts.

2.7.1.4 ISO Liability for Payment

The obligation of the ISO to pay Transmission Customers for monies owed for a given settlement period shall be limited so that the aggregate liability of the ISO for such payments does not exceed the sum of (i) the aggregate amount paid to or recovered by the ISO from Transmission Customers (including by applying a defaulting Transmission Customer's financial security) for that settlement period, and (ii) the amount of funds held by the ISO in the Working Capital Fund. The process for declaring and recovering bad debt losses is set forth in Attachment U to this ISO OATT.

2.7.2 Determination and Payment of Charges Associated with Transmission Service

This Section 2.7.2 applies to all Transmission Services except Transmission Service pursuant to Grandfathered Agreements listed in Attachment L. Charges applicable to Grandfathered Agreements are described in Attachment K.

2.7.2.1 Transmission Service Charge - General Applicability

The TSC charge is applied to all Actual Energy Withdrawals from the NYS Power System under Part 3 or Part 4 of this Tariff, except for withdrawals by a Transmission Owner to provide bundled retail service or scheduled withdrawals associated with grandfathered transactions as specified in Attachments K and L. The TSC charge also is applied to Transactions to destinations outside the NYCA (Export or Wheel-Through Transactions), except as provided for in Section 2.7.2.1.4 of this Tariff.

Subject to the foregoing, the TSC applies to all Actual Energy Withdrawals regardless of whether the withdrawals occur in conjunction with a Bilateral Transaction or through the purchase of Energy from an LBMP Market. The TSC is payable under this Section regardless of whether the withdrawal is scheduled under Part 3 or Part 4 of this Tariff. Customers buying Energy from a Transmission Owner as part of a bundled retail rate will pay a portion of the Transmission Owner's transmission revenue requirement as part of their retail rates. Sales to these customers will be included in the billing units used to calculate each Transmission Owner's TSC under this Tariff in accordance with Attachment H.

Transmission Customers who are parties to grandfathered agreements specified in Attachment L will pay the applicable contract rate in those agreements. Revenues from these agreements will be credited against the Transmission Owners' individual revenue requirements in calculating the TSC.

2.7.2.1.1 Payable to Transmission Owners: The TSC will be payable to Transmission Owners, in the manner described below in the remainder of Section 2.7.2.1.

2.7.2.1.2 Payable by Retail Access Customers: Retail access customers or LSEs scheduling on their behalf will pay a TSC to their respective Transmission Owners under the provisions described in Part 5 of this Tariff. The TSC is payable under Part 5 (Retail Access Service) regardless of whether the LSE takes service under Part 3 (Point-to-Point Service) or Part 4 (Network Integration Service) of this Tariff.

2.7.2.1.3 Payable by LSEs Serving Non-Retail Access Load in NYCA: LSEs serving NYCA Load that is not part of a retail access program, such as customers of municipal electric systems, will pay a TSC to the Transmission Owner in whose Transmission District the Load is located. The TSC shall apply to Actual Energy Withdrawals by the Load, regardless of whether such withdrawals are associated with Transmission Service under Part 3 or Part 4 of this Tariff or purchases from an LBMP Market, whether the withdrawals are scheduled or unscheduled, and regardless of whether the withdrawals were made on the Load's behalf by the LSE or by another Transmission Customer.

2.7.2.1.4 Payable by Transmission Customers Scheduling Export or Wheel-Through Transactions: Transmission Customers scheduling Transactions to destinations outside the NYCA (Export or Wheel-Through Transactions) are subject to a TSC as calculated in Attachment H. The TSC charge shall be eliminated on all Exports and Wheel-Through Transactions scheduled with the ISO to destinations within the New England Control Area; provided that the following conditions shall continue to be met: (1) a Commission approved tariff provision is in effect that provides for unconditional reciprocal elimination of charges on Exports and Wheel-Through Transactions from the New England Control Area to the New York Control Area; (2) no change in the provisions in this Tariff related to Local Furnishing Bonds and Other Tax Exempt Financing shall be required for the reciprocal elimination of charges on Export and Wheel-Through Transactions to the New York Control Area; and (3) the New York Transmission Owners have the ability to fully recover the revenues related to the charges on Export and Wheel-Through Transactions that are eliminated. The ISO and the New York Transmission Owners, jointly or separately, shall have the right to make a Section 205 filing with the Commission to reimpose the charge on Exports and Wheel-Through Transactions if at any time any of the foregoing conditions is no longer satisfied. The ISO will perform the requisite calculation and inform the Transmission Customer of the applicable Transmission Owner(s) of the TSC charge. The TSC will be payable by the Transmission Customer directly to the Transmission Owner(s).

2.7.2.2 Transmission Usage Charge (TUC)

2.7.2.2.1 Payable to the ISO: Transmission Usage Charges include Congestion Rents and charges for Marginal Losses. They are payable directly to the ISO. Attachment J explains the calculation of the TUC.

2.7.2.2.2 Payable by Transmission Customers Scheduling Transmission Service: All Transmission Customers scheduling Transmission Service under Part 3 or Part 4 of this Tariff shall pay the applicable TUC charge as calculated in the Attachment J hereto.

2.7.2.2.3 Payable by Transmission Owners Scheduling Bilateral Transactions on Behalf of Bundled Retail Customers: Transmission Owners scheduling Transmission Service to supply bundled retail customers shall pay the applicable TUC charge.

2.7.2.2.4 Payable by Customers Scheduling Direct LBMP Purchases from the LBMP Market: Any Customer purchasing from the LBMP Market to supply bundled retail customers, will pay the Congestion Rent and Marginal Losses charge applicable to its location. These Congestion Rent and Marginal Losses charges will be included in the calculation of the LBMP charged by the ISO for the purchase of Energy from the LBMP Market.

2.7.2.3 Ancillary Services

2.7.2.3.1 Payable to the ISO: All Ancillary Services charges are payable directly to the ISO.

2.7.2.3.2 Payable by LSEs: All LSEs scheduling Transmission Service under Part 3 or Part 4 or purchases from the LMBP Market to supply Load in the NYCA shall pay Ancillary Services charges as described in Schedules 1 through 6. The charges will be assessed on the basis of all Actual Energy Withdrawals by the Load, regardless of whether such withdrawals are scheduled or unscheduled, and regardless of whether they are scheduled on the Load's behalf by the LSE or by another Transmission Customer. As explained in Schedule 1, in certain circumstances the Schedule 1 charge may vary depending upon the Transmission District in which the Load is located.

2.7.2.3.3 Payable by Customers Scheduling External Transactions: Transmission Customers scheduling Export or Wheel-Through Transactions to destinations outside the NYCA, or purchases from the LBMP Market to serve Load outside the NYCA shall pay Ancillary Services charges under Schedules 1, 2, 4, and 5 of this Tariff. The charges will be assessed on the basis of all Scheduled Energy Withdrawals from the NYCA.

2.7.2.3.4 Payable by Transmission Owners Serving Bundled Retail Customers: Transmission Owners scheduling Transmission Service or purchases from the LBMP Market to serve of bundled retail customers shall pay the ISO Ancillary Services charges as described in Schedules 1 to 6 based on Actual Energy Withdrawals.

2.7.2.4 NYPA Transmission Adjustment Charge (NTAC)

2.7.2.4.1 Payable to the ISO: NTAC charges are calculated in Attachment H. All NTAC charges are payable to the ISO.

2.7.2.4.2 Payable by LSEs Serving Load in the NYCA: Each LSE serving Load in the NYCA shall pay an NTAC to the ISO based on the LSE's Actual Energy Withdrawals.

2.7.2.4.3 Payable by Transmission Customers Scheduling Export or Wheel-Through Transactions: Transmission Customers scheduling Export or Wheel-Through Transactions shall pay an NTAC based on their Transaction schedules. The NTAC charge shall not apply to Exports and Wheel-Through Transactions scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

2.7.2.5 Reliability Facilities Charge ("RFC") and LIPA RFC

2.7.2.5.1 Payable through the ISO: All RFC and LIPA RFC charges are calculated, collected and payable to the ISO pursuant to Rate Schedule 10.

2.7.3 Billing and Payment Procedures

For purposes of this Section 2.7.3:

(i) the term "Complete Week Settlement Period" shall mean the seven day period between Saturday and Friday for which all of the days are in the same month; and

(ii) the term "Stub Week Settlement Period" shall mean the six or fewer day period between Saturday and Friday for which all of the days are in the same month.

2.7.3.1 Billing and Settlement Information

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

2.7.3.2 Invoicing and Payment

2.7.3.2.1 Weekly Invoice

On or about each Wednesday, as set forth in ISO Procedures, the ISO shall submit an invoice to a Transmission Customer that indicates the net amount owed by or owed to the Transmission Customer for those services furnished under this ISO OATT or the ISO Services Tariff for the previous Complete Week Settlement Period or Stub Week Settlement Period that are designated as Weekly Invoice Components in ISO Procedures; *provided, however,* that the net amount owed by or owed to the Transmission Customer for those services furnished for a Stub Week Settlement Period that concludes a month shall be included in the next monthly invoice issued in accordance with Section 2.7.3.2.2 of this ISO OATT.

2.7.3.2.2 Monthly Invoice

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

(i) for those services furnished under this ISO OATT or the ISO Services Tariff for a Stub Week Settlement Period that concludes the previous month that are designated as Weekly Invoice Components in ISO Procedures;

(ii) for any adjustments to amounts contained in the weekly invoices issued in the previous month pursuant to Section 2.7.3.2.1 of this ISO OATT;

(iii) for those services furnished under this ISO OATT or the ISO Services Tariff in the previous month that are designated as Monthly Invoice Components in ISO Procedures;

(iv) for any adjustments to amounts contained in a previously issued monthly invoice that was issued on or about one hundred twenty (120) days prior to the issuance of this invoice; and

(v) for any adjustments to amounts contained in a previously issued monthly invoice as part of the Close-Out Settlement of that monthly invoice pursuant to Section 2.7.4.2.2 of this ISO OATT.

2.7.3.2.3 Payment by the Transmission Customer

A Transmission Customer owing payments on net in its weekly invoice or its monthly invoice shall make those payments to the ISO through the ISO Clearing Account by the second business day after the date on which the weekly invoice or monthly invoice is rendered by the ISO unless otherwise specified in ISO Procedures. In accordance with Section 2.7.1.2 of this ISO OATT, the ISO may net any overpayment by the Transmission Customer for past estimated charges against current amounts due from the Transmission Customer or, if the Transmission

Customer has no outstanding amounts due, the ISO may pay to the Transmission Customer an amount equal to the overpayment.

2.7.3.2.4 Payment by the ISO

Except as provided in Section 2.7.1.4 of this ISO OATT, the ISO shall pay all net monies owed to a Transmission Customer in its weekly invoice or its monthly invoice from the ISO Clearing Account by the second business day after the due date for Transmission Customer payments set forth in Section 2.7.3.2.3 of this ISO OATT unless otherwise specified in ISO Procedures.

2.7.3.3 Use of Estimated Data and Meter Data

The ISO may use estimates, including estimated meter data, in whole or in part to settle a weekly or monthly invoice in accordance with ISO Procedures. The ISO shall use meter data submitted to the ISO in accordance with Section 3.16 of this ISO OATT. Any charges based on estimates shall be subject to true-up in invoices subsequently issued by the ISO after the ISO has obtained the requisite actual information, provided that the ISO shall only true-up charges based on meter data prior to the deadline for finalizing the meter data established in Section 2.7.4.2 of this ISO OATT. A trued-up charge shall include interest amounts calculated at the rate set forth in Section 2.7.4 of this ISO OATT from the weekly or monthly due date for the charge until the date of payment of the trued-up amount for that charge.

2.7.3.4 Method of Payment

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

2.7.3.5 Verification of Payments

The ISO shall verify that all payments owed by Transmission Customers in accordance with this ISO OATT and the ISO Services Tariff have been paid to the ISO in a timely manner. If a Transmission Customer fails to make a payment within the time period established in Sections 2.7.3.2.1, 2.7.3.2.2, and 2.7.3.6 of this ISO OATT or pays less than the amount due, the ISO shall take measures pursuant to Section 2.7.5 of this ISO OATT. Except as provided in Section 2.7.1.4 of this ISO OATT, the ISO shall also ensure that monies owed to Transmission Customers in accordance with this ISO OATT and the ISO Services Tariff are paid through the ISO Clearing Account in a timely manner.

2.7.3.6 TCC Auction Settlements

Notwithstanding Sections 2.7.3.2.1 and 2.7.3.2.2 of this ISO OATT, the ISO shall make settlements related to the Centralized TCC Auction and the Reconfiguration Auction as set forth in this Section 2.7.3.6.

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

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

2.7.3.6.3 Except as provided in Section 2.7.1.4 of this ISO OATT, the ISO shall pay all net monies owed to Transmission Customers as a result of their activity in or related to a Centralized TCC Auction or a Reconfiguration Auction, pursuant to an award notice or a comparable invoice rendered by the ISO, from the ISO Clearing Account in accordance with ISO Procedures.

2.7.3.6.4 Sections 2.7.3.1, 2.7.3.3, 2.7.3.4 and 2.7.3.5 of this ISO OATT and Section 19.9.6 of Attachment M of this ISO OATT shall apply to settlements calculated in accordance with this Section 2.7.3.6.

2.7.3.7 Settlement Information and Billing Procedures for TSCs

The ISO shall provide each Member System with information to facilitate TSC billing. Settlement information and billing procedures for payments of the TSC by retail access customers or LSEs serving retail access customers in accordance with Section 5 of this ISO OATT shall be separately issued, paid and collected in accordance with Section 5 of this ISO OATT. Settlement information and billing procedures for payments for TSCs for customers other than retail access customers and LSEs serving retail access customers shall be separately issued, paid and collected in accordance with the terms and conditions set forth in Attachment H of this ISO OATT in accordance with Section 5 of this ISO OATT.

2.7.3.8 Billing Procedures for Retail Access Programs

The billing procedures for customers participating in retail access programs shall be in accordance with Section 5 of this ISO OATT.

2.7.4 Interest on Unpaid Balances:

Interest on any unpaid amount whether owed to a Transmission Customer or to the ISO (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a (a)-(2) (iii). Interest on unpaid amounts shall be calculated from the due date of the bill to the date of payment. Invoices shall be considered as having been paid on the date of receipt of payment by the ISO.

If the ISO is unable to provide settlement information on time due to the actions or inactions of the Transmission Customer, in addition to any other remedies the ISO may have at law or in equity, the Transmission Customer shall pay interest on amounts due, as calculated above, from the first day of the Billing Period following the Billing Period in which charges are accrued, to the time of payment of those charges.

2.7.4.1 Billing Disputes:

This Section 2.7.4.1 establishes the process and timeframe for review, challenge, and correction of Transmission Customer invoices. For purposes of this Section 2.7.4.1, any deadline that falls on a Saturday, Sunday, or holiday for which the ISO is closed shall be observed on the ISO's next business day.

For purposes of this Section 2.7.4.1, "finalized" data and invoices shall not be subject to further correction, including by the ISO, except as ordered by the Commission or a court of competent jurisdiction; *provided, however,* that nothing herein shall be construed to restrict any stakeholder's right to seek redress from the Commission in accordance with the Federal Power Act.

2.7.4.2 Settlement Cycle for Services Furnished On and After January 1, 2009

2.7.4.2.1 ISO Corrections or Adjustments and Transmission Customer Challenges to the Accuracy of Settlement Information

Settlement information for services furnished beginning January 1, 2009, and thereafter shall be subject to review, comment, and challenge by a Transmission Customer and correction or adjustment by the ISO for errors at any time for up to five (5) months from the date of the initial invoice for the month in which service is rendered as set forth in Section 2.7.3.2.2 of this ISO OATT and as further provided in Section 2.7.4.2.2, subject to the following requirements and limitations:

(i) A Supplier or meter authority may review, comment on, and challenge Generator, tie-line, and sub-zone Load metering data for fifty-five (55) days from the date of the initial invoice for the month in which service is rendered. Following this review period, the ISO shall then have five (5) days to process and correct Generator, tie-line, and sub-zone Load metering data, after which time it shall be finalized.

(ii) The meter authority shall provide to the ISO all LSE bus metering data then available within seventy (70) days from the date of the initial invoice and shall provide any necessary updates to the LSE bus metering data as soon as possible thereafter. The ISO shall post all available LSE bus metering data within approximately seventy-five (75) days from the date of the initial invoice and shall continue to post incoming LSE bus metering data as soon as practicable after it is received.

(iii) The ISO shall post advisory settlement information, including available LSE bus metering data, within ninety (90) days from the date of the initial invoice. Transmission Customers may review, comment on, and challenge this settlement information, except for Generator, tie-line, and sub-zone Load metering data, after which the ISO shall process and correct the data and issue a corrected invoice with the regular monthly invoice issued on or about one hundred twenty (120) days from the date of the initial invoice. Following the ISO's issuance of a corrected invoice, Transmission Customers may continue to review, comment on, and challenge their settlement information, excepting Generator, tie-line, and sub-zone Load metering data, until the end of the five-month review period.

(iv) The meter authority shall provide to the ISO any final updates or corrections to LSE bus metering data within one hundred thirty (130) days from the date of the initial invoice. The ISO shall then post any updated and corrected LSE bus metering data within one hundred thirty-five (135) days from the date of the initial invoice. Transmission Customers may then review, comment on, and challenge the LSE bus metering data for an additional ten (10) days. Following this review period, the ISO shall have five (5) days to process and correct the LSE bus metering data, after which it shall be finalized.

The ISO shall use reasonable means to post metering revisions for review by Transmission Customers and to notify Transmission Customers of the approaching expiration of review periods. To challenge settlement information contained in an invoice, a Transmission Customer shall first make payment in full, including any amounts in dispute. Transmission Customer challenges to settlement information shall: (i) be submitted to the ISO in writing, (ii) be clearly identified as a settlement challenge, (iii) state the basis for the Transmission Customer's challenge, and (iv) include supporting documentation, if applicable. The ISO shall notify all Transmission Customers of errors identified and the details of corrections or adjustments made pursuant to this Section 2.7.4.2.1.

2.7.4.2.2 Review and Correction of Challenged Invoices

The ISO shall evaluate a settlement challenge as soon as possible within two (2) months following the conclusion of the challenge period specified in Section 2.7.4.2.1; *provided, however,* the ISO may, upon notice to Transmission Customers within this time of extraordinary circumstances requiring a longer evaluation period, take up to six (6) months to evaluate a settlement challenge. The ISO shall not be limited to the scope of Transmission Customer challenges in its review of a challenged invoice and may, at its discretion, review and correct any other elements and intervals of a challenged invoice, except Load and meter data as specified in Section 2.7.4.2.1. Corrections to a challenged invoice shall be applied to all Transmission Customers that were or should have been affected by the original settlement and shall not be limited to the Transmission Customer challenging the invoice; *provided, however,* that the ISO may recover *de minimis* amounts or amounts that the ISO is unable to collect from individual Transmission Customers through Rate Schedule 1 of this ISO OATT.

Upon completing its evaluation, the ISO shall provide written notice to the challenging Transmission Customer of the ISO's final determination regarding the Transmission Customer's settlement challenge. If the ISO determines that corrections or adjustments to a challenged invoice are necessary and can quantify them with reasonable certainty, the ISO shall provide all Transmission Customers with the details of the corrections or adjustments within the timeframe established in this Section 2.7.4.2.2. The ISO shall then provide a period of twenty-five (25) days for Transmission Customers to review the corrected settlement information and provide comments to the ISO regarding the implementation of those corrections or adjustments; *provided, however,* that in the event of a dispute resolution proceeding conducted in accordance with Section 2.7.4.3 of this ISO OATT, this twenty-five (25) day period shall not start or, if it has already started, shall be suspended until the conclusion of the dispute resolution proceeding. Following the conclusion of the dispute resolution proceeding, the ISO shall make any corrections to Transmission Customers' settlement invoices that it determines to be necessary and shall then start or re-start the twenty-five (25) day Transmission Customer comment period.

If no errors in the implementation of corrections or adjustments are identified during the twenty-five (25) day Transmission Customer comment period, the ISO shall issue a finalized close-out settlement ("Close-Out Settlement"), clearly identified as such, in the next regular monthly billing invoice. If an error in the implementation of a correction or adjustment is identified during the twenty-five (25) day Transmission Customer comment period, the ISO shall have one (1) month to make such further corrections as are necessary to address the error and provide Transmission Customers with one additional period of twenty-five (25) days to review and comment on the implementation of those further corrections. If an error in the implementation of those further corrections is identified, the ISO shall then have one (1) month to make any final corrections that are necessary and shall issue a finalized Close-Out Settlement in the next regular monthly billing invoice.

2.7.4.3 Expedited Dispute Resolution Procedures for Unresolved Settlement Challenges

2.7.4.3.1 Applicability of Expedited Dispute Resolution Procedures

This Section 2.7.4.3 establishes expedited dispute resolution procedures applicable to address any dispute between a Transmission Customer and the ISO regarding a Transmission Customer settlement that was not resolved in the ordinary settlement review, challenge, and correction process; *provided, however*, that nothing herein shall restrict a Transmission Customer or the ISO from seeking redress from the Commission in accordance with the Federal Power Act.

A Transmission Customer may request expedited dispute resolution if it has previously presented a settlement challenge consistent with the requirements of Section 2.7.4.2.1 of this ISO OATT and has received from the ISO a final, written determination regarding the settlement challenge pursuant to Section 2.7.4.2.2 of this ISO OATT. The scope of an expedited dispute resolution proceeding shall be limited to the subject matter of the Transmission Customer's prior settlement challenge. Transmission Customer challenges regarding Generator, tie-line, sub-zone Load, and LSE bus metering data shall not be eligible for formal dispute resolution proceedings under this ISO OATT. To ensure consistent treatment of disputes, separate requests for expedited dispute resolution regarding the same issue and the same service month or months may be resolved on a consolidated basis, consistent with applicable confidentiality requirements.

2.7.4.3.2 Initiation of Expedited Dispute Resolution Proceeding

To initiate an expedited dispute resolution proceeding, a Transmission Customer shall submit a written request to the ISO Chief Financial Officer within eleven (11) business days from the date that the ISO issues a final, written determination regarding a Transmission Customer settlement challenge pursuant to Section 2.7.4.2.2 of this ISO OATT. A Transmission Customer's written request for expedited dispute resolution shall contain: (i) the name of the Transmission Customer making the request, (ii) an indication of other potentially affected parties, to the extent known, (iii) an estimate of the amount in controversy, (iv) a description of the Transmission Customer's claim with sufficient detail to enable the ISO to determine whether the claim is within the subject matter of a settlement challenge previously submitted by the Transmission Customer, (v) copies of the settlement challenge materials previously submitted by the Transmission Customer to the ISO, and (vi) citations to the ISO Tariffs and other relevant materials upon which the Transmission Customer's settlement challenge relies.

The ISO Chief Financial Officer shall acknowledge in writing receipt of the Transmission Customer's request to initiate an expedited dispute resolution proceeding. If the ISO determines that the proceeding would be likely to aid in the resolution of the dispute, the ISO shall accept the Transmission Customer's request and provide written notice of the proceeding to all Transmission Customers through the ordinary means of communication for settlement issues. The ISO shall provide written notice to the Transmission Customer in the event that the ISO declines its request for expedited dispute resolution.

2.7.4.3.3 Participation by Other Interested Transmission Customers

Any Transmission Customer with rights or interests that would be materially affected by the outcome of an expedited dispute resolution proceeding may participate; *provided, however*, that a Transmission Customer seeking or supporting a change to the NYISO's determination regarding a Transmission Customer settlement challenge must have previously raised the issue in a settlement challenge consistent with the requirements of Section 2.7.4.2.1 of this ISO OATT. To participate, such Transmission Customer shall submit to the ISO Chief Financial Officer a written request to participate that meets the requirements for an initiating request for expedited dispute resolution within eleven (11) business days from the date that the ISO issues notice of the expedited dispute resolution proceeding. If the ISO determines that the Transmission Customer has met the requirements of this Section 2.7.4.3.3, the ISO will accept the Transmission Customer's request to participate in the dispute resolution proceeding.

2.7.4.3.4 Selection of a Neutral

As soon as reasonably possible following the ISO's acceptance of a Transmission Customer's request for expedited dispute resolution under Section 2.7.4.3.2, the ISO shall appoint a neutral to preside over the proceeding by randomly selecting from a list (i) provided to the ISO by the American Arbitration Association or (ii) developed by the ISO with input from the appropriate stakeholder committee, until an available neutral is found. To the extent possible, the neutral shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues and the financial settlement of electric markets.

No person shall be eligible to act as a neutral who is a past or present officer, employee, or consultant to any of the disputing parties, or of an entity related to or affiliated with any of the disputing parties, or is otherwise interested in the matter in dispute except upon the express written consent of the parties. Any individual appointed as a neutral shall make known to the disputing parties any such disqualifying relationship or interest and a new neutral shall be appointed, unless express written consent is provided by each party.

2.7.4.3.5 Conduct of the Expedited Dispute Resolution Proceeding

The neutral shall schedule the initial meeting of the disputing parties within five (5) business days of appointment. Except as otherwise provided in this Section 2.7.4.3, the neutral shall have discretion over the conduct of the dispute resolution process including, but not limited to: (i) requiring the disputing parties to meet for discussion, (ii) allowing or requiring written submissions, (iii) establishing guidelines for such written submissions, and (iv) allowing the participation of Transmission Customers that have requested an opportunity to be heard.

Within sixty (60) days of the appointment of the neutral, if the dispute has not been resolved, the neutral shall provide the disputing parties with a written, confidential, and non-binding recommendation for resolving the dispute. The disputing parties shall then meet in an attempt to resolve the dispute in light of the neutral's recommendation. If the disputing parties have not resolved the dispute within ten (10) days of receipt of the neutral's recommendation, the dispute resolution process will be concluded.

Neither the recommendation of the neutral, nor statements made by the neutral or any party, including the ISO, or their representatives, nor written submissions prepared for the dispute resolution process, shall be admissible for any purpose in any proceeding.

2.7.4.3.6 Allocation of Costs

Each party to a dispute resolution proceeding shall be responsible for its own costs incurred during the process and for a pro rata share of the costs of a neutral.

2.7.5 Customer Default

2.7.5.1 Events of Default

A Transmission Customer shall be in default, upon written notice from the ISO, in the event that: (i) the Transmission Customer fails to timely make a payment due to the ISO, regardless of whether such payment obligation is in dispute, (ii) the Transmission Customer fails to comply with the ISO's creditworthiness requirements, or (iii) the Transmission Customer fails to cure its default in another independent system operator/regional transmission organization market. In the event of a billing dispute between the ISO and the Transmission Customer, the ISO will continue to provide service under the Service Agreement as long as the Transmission Customer continues to make all payments.

2.7.5.2 Cure

Unless otherwise provided in Attachment W to this OATT, a Transmission Customer shall have one (1) business day to cure a default resulting from its failure to timely make a payment due to the ISO. A Transmission Customer shall have two (2) business days to cure a default resulting from its failure to comply with the ISO's creditworthiness requirements; *provided, however*, that a Transmission Customer shall have one (1) business day to cure a default resulting from its failure to comply with the ISO's creditworthiness requirements following termination of a Prepayment Agreement.

2.7.5.3 ISO Remedies

In addition to any and all other remedies available under the ISO Tariffs or pursuant to law or equity, the ISO shall have the following remedies:

(i) **Event of Default.** Upon an event of default and expiration of the relevant cure period, the ISO may terminate service to a Transmission Customer immediately upon notice to the Commission. In addition, in the event of a payment default, the ISO shall have the sole and exclusive right to initiate debt collection procedures against a Transmission Customer on account of any such default. The process for declaring and recovering bad debt losses is set forth in Attachment U to this OATT.

(ii) **Financial Distress.** In the event of a reduction in the amount of a Transmission Customer's Unsecured Credit (a) by fifty percent (50%) or more as determined in accordance with Section 26.5 of Attachment K to the ISO Services Tariff, or (b) as a result of a material adverse change as determined in accordance with Section 26.14 of Attachment K to the ISO Services Tariff, then the ISO shall have the right to: (1) immediately issue an invoice to such Transmission Customer requiring payment within two (2) business days from the invoice date for initial settlements representing the sum of that Billing Period's daily billing data available as of the invoice date, and/or (2) require such Transmission Customer to prepay estimated charges weekly for up to twelve months in accordance with ISO Procedures.

(iii) **Default in Another ISO/RTO.** In the event a Transmission Customer fails to cure its default in another independent system operator/regional transmission organization market, then the ISO shall have the right to: (1) demand immediate payment by the Transmission Customer to the ISO for any amounts owed as of the date of the demand, and/or (2) require the Transmission Customer to prepay estimated charges weekly for a minimum of twelve months in accordance with ISO Procedures, and/or (3) reduce or eliminate the amount of the Transmission Customer's Unsecured Credit.

(iv) **Two Late Payments.** In the event a Transmission Customer fails to pay its invoice when due on two occasions within a rolling twelve (12) month period, then the ISO shall have the right to: (1) require the Transmission Customer to prepay estimated charges weekly, based on the charges incurred by the Transmission Customer in the previous week, for up to twelve months, and/or (2) reduce or eliminate the amount of the Transmission Customer's Unsecured Credit for up to twelve (12) months.

2.7.5.4 Notice to Transmission Customers

The ISO shall notify all Transmission Customers in the event that a Transmission Customer is in default and shall also notify all Transmission Customers in the event that the Transmission Customer subsequently cures the default or the ISO terminates the Transmission Customer due to the default. In the event of a payment default or creditworthiness default, the ISO will disclose in its notice to Transmission Customers the approximate amount of the default as follows:

Default Amount	Type of Default	
Range	Payment	Creditworthiness
$0 to $100,000		
$100,001 to $500,000		
$500,001 to $1,000,000		
$1,000,001 to $5,000,000		
$5,000,001 to $10,000,000		
> $10,000,000		

In addition, in the event of a payment default, unless otherwise precluded, the ISO will also disclose the amount and type of collateral, if any, held by the ISO to secure the defaulting Transmission Customer's obligations to the ISO.

2.7.6 Stranded Costs

The Transmission Owners other than NYPA may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in Commission Order No. 888. However, the Transmission Owners must separately file any proposal to recover stranded costs under Section 205 of the FPA. This provision shall not supersede or otherwise affect a Transmission Owner’s right to recover stranded costs under other authority. To the extent that LIPA’s rates for service are established by LIPA’s Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s and are not subject to Commission and/or PSC jurisdiction, LIPA’s recovery of stranded costs will not be subject to the foregoing requirements.

Upon filing of a proposal to recover stranded costs under the FPA, the Transmission Owner shall immediately provide the ISO with a copy of the appropriate rate schedule which will be incorporated as a new Stranded Service and Point-to-Point Service Customers and remit the collected amounts to the applicable Transmission Owner(s). Any SIRC rate schedule developed by LIPA under this Tariff will be effective upon receipt by the ISO, subject to any applicable laws and orders.

2.12 Back-Up Operation

2.12.1 Back-Up Operation Procedures:

The ISO shall maintain Back-Up Operation procedures that will carry out the intent and purposes of this ISO OATT, to the extent practical, in circumstances under which the normal communications or computer systems of the ISO are not fully functional. Such procedures shall include testing requirements and training for the ISO staff, and Transmission Owners. If a communication or computer system malfunction results in the ISO's inability to operate the NYCA in accordance with ISO Procedures or under approved testing procedures, the ISO will direct the Transmission Owners to assume the responsibility to operate their respective systems, including facilities that a Transmission Owner has agreed to operate in accordance with an operation and maintenance agreement, in accordance with Good Utility Practice to facilitate the operation of the NYCA in a safe and reliable manner.

The Transmission Owners will continue to operate their respective systems, including facilities that a Transmission Owner has agreed to operate in accordance with an operation and maintenance agreement, until such time that the ISO is ready to resume control. During Back-Up Operation, the Transmission Owner control centers will operate to maintain the Desired Net Interchange ("DNI") within each Transmission District. Generator Bid curves will be provided by the ISO to the individual Transmission Owners in order to permit dispatch by the Transmission Owners, subject to the Transmission Owner code of conduct to the extent applicable. Normal Day-Ahead Market and Real-Time Market operations may be halted if required.

2.12.2 Market Participant and Transmission Customer Obligations:

During Back-Up Operation, Transmission Customers and other Market Participants shall comply with any and all instructions and orders issued by the ISO or the Transmission Owners.

2.12.3 Billing and Settlement:

In the event that Back-Up Operation is implemented, the billing and settlement procedures contained in Section 2.7 of this ISO OATT shall apply only to the extent they can be implemented by the Back-Up Operation procedures. The ISO will develop and apply as necessary modified billing and settlement procedures for use under the specific circumstances that required Back-Up Operation. The ISO shall gather necessary information, manually reconstruct the billing information as soon as practical, and submit invoices to Transmission Customers. The ISO shall be under no obligation to comply with the billing procedure time limits specified in Article 2.7. Neither the ISO nor the Transmission Owners shall be liable, under any circumstances, for any economic losses suffered by any Transmission Customer, Market Participant, or third party, resulting from the implementation by the ISO of Back-Up Operation or from compliance with orders issued by the ISO or Transmission Owners that were necessary to operate the NYCA in a safe and reliable manner. Such orders may include, without limitation, instructions to generation facilities to increase or decrease output, and instructions to Load to reduce or interrupt service.

4 Network Integration Transmission Service

Preamble

The ISO will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in this Tariff and Service Agreement over the transmission facilities of the parties to the ISO/TO Agreement or an Operating Agreement. Network Integration Transmission Service will be provided when the Network Customer agrees to pay the Congestion Rent associated with its requested service. The Network Customer may fix the price of its Network Integration Transmission Service by purchasing TCCs corresponding with designated Network Resources and its Network Load. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the individual Transmission Owner utilizes their respective transmission systems to serve their Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy Energy purchases to its Network Load from non-designated resources on an as-available basis (i.e. when there is no Congestion) without additional charge. Transmission Service for sales to non-designated Loads will be provided pursuant to the applicable terms and conditions of Part 3 of this Tariff.

6.10 Schedule 10 - Rate Mechanism for the Recovery of the Reliability Facilities Charge ("RFC")

6.10.1 Applicability.

This rate mechanism establishes the Reliability Facilities Charge ("RFC") for the recovery of costs related to: (i) a regulated backstop transmission solution identified by the NYISO pursuant to Section 31.2.4.3.1 of Attachment Y of the ISO OATT and the NYISO/TO Reliability Agreement or an Operating Agreement, (ii) an alternative regulated transmission solution provided that the ISO has selected such project pursuant to Section 31.2.6.5.2 of Attachment Y of the ISO OATT as the more efficient or cost effective solution to the identified Reliability Need, or (iii) a regulated transmission Gap Solution proposed by a Responsible Transmission Owner or an alternative regulated Gap Solution proposed by an Other Developer or Transmission Owner that has been determined by the appropriate state regulatory agency(ies) as the preferred solution(s) to the identified Reliability Need. The rate mechanism shall not apply to projects undertaken by Transmission Owners pursuant to Local Transmission Owner Planning Processes pursuant to Section 31.1.3 and Section 31.2.1 of Attachment Y of the NYISO OATT. The RFC shall be comprised of the revenue requirements related to: (i) each regulated reliability transmission project filed with FERC by a Transmission Owner pursuant to the provisions of this Attachment; (ii) any costs incurred by NYPA and filed with FERC by the NYISO pursuant to the provisions of this Attachment; and (iii) any FERC approved costs incurred by an Other Developer under Section 6.10.5 and filed with FERC by the NYISO or Other Developer pursuant to the provisions of this Attachment. Any costs incurred by LIPA and allocable to other Transmission Districts will be collected under a separate LIPA RFC as set forth in Section 6.10.4.3 and filed with FERC by the NYISO pursuant to the provisions of Section 6.10.4.3. This RFC will provide for full recovery of all reasonably incurred costs related to the preparation of proposals for, and the development, construction, operation and maintenance of any regulated reliability transmission project undertaken pursuant to Attachment Y of this tariff, including all reasonable costs related to such a project that is halted in accordance with the provisions of the NYISO's tariff and the NYISO/TO Reliability Agreement or an Operating Agreement. Subject to regulatory acceptance, the RFC shall include a reasonable return on investment and any applicable incentives. The RFC established under this Attachment shall be separate from the Transmission Service Charge ("TSC") and the NYPA Transmission Adjustment Charge ("NTAC") determined in accordance with Attachment H of the NYISO OATT. With respect to the recovery of costs incurred by LIPA and NYPA, the provisions of Sections 6.10.1, and 6.10.2 through 6.10.3.4 of this Attachment shall not apply to LIPA or NYPA, except as provided for in Sections 6.10.4.3 and 6.10.4.4 of this Attachment. The recovery of costs related to development, construction, operation and maintenance of a regulated reliability transmission project undertaken by LIPA or NYPA shall be pursuant to the provisions of Sections 6.10.4.3 and 6.10.4.4 of this Attachment**.** The recovery of costs related to development, construction, operation and maintenance of an alternative regulated solution proposed by an Other Developer shall be pursuant to the provisions of Section 6.10.5 of this Attachment.

6.10.2 Recovery of Transmission Owner's Costs Related to Regulated Reliability Transmission Solutions.

Each Transmission Owner shall have on file at FERC the rate treatment that will be used to derive and determine the revenue requirement to be included in the RFC, and for the LIPA RFC as applicable, for regulated transmission projects undertaken pursuant to a determination by the NYISO that a regulated solution is needed to address Reliability Needs identified by the NYISO in its reliability planning process in accordance with Section 31.2.8 of Attachment Y of the NYISO OATT. The filing will provide for the recovery of the full revenue requirement for a regulated reliability transmission project consistent with FERC regulations including but not limited to any incentives for the construction of transmission projects provided for in Section 219 of the Federal Power Act and the FERC regulations implementing that section. Pursuant to a determination by the NYISO that a regulated solution is needed to address Reliability Needs identified by the NYISO in its reliability planning process in accordance with Section 31.2.8 of Attachment Y of the NYISO OATT, (i) the Responsible Transmission Owner(s) proceeding with a regulated transmission backstop solution or (ii) a Transmission Owner proceeding with an alternative regulated transmission solution that the ISO has selected as the more efficient or cost effective solution, will proceed with the approval process for all necessary federal, state and local authorizations for the requested project to which this RFC applies.

6.10.2.1 Upon receipt of all necessary federal, state, and local authorizations, including FERC acceptance of the rate treatment, the Transmission Owner(s) shall commence construction of the project.

6.10.2.2 Upon completion of the project, the Transmission Owner(s) or the NYISO as applicable, will make an informational filing with FERC to provide the final project cost and resulting revenue requirement to be recovered pursuant to this Attachment. The final project cost and resulting revenue requirement will be reduced by any amounts that, pursuant to Section 25.7.12.3.3 of Attachment S to the NYISO OATT, have been previously committed by or collected from Developers for the installation of System Deliverability Upgrades required for the interconnection of generation or merchant transmission projects. The resulting revenue requirement will become effective and recovery of project costs pursuant to this Attachment will commence upon the making of the information filing with FERC, and shall not require and shall not be dependent upon a re-opening or review of the Transmission Owner(s)' revenue requirements for the TSCs and NTAC set forth in Attachment H of the NYISO OATT. This Section 6.10.2.2 also applies to the recovery of all reasonably incurred costs related to either (i) a regulated backstop transmission project or (ii) an alternative regulated transmission project that the ISO has selected as the more efficient or cost effective solution and that is later halted, including but not limited to reasonable and necessary expenses incurred to implement an orderly termination of the project, in accordance with the provisions of the NYISO OATT and the NYISO/TO Reliability Agreement or an Operating Agreement. Following the information filing, the NYISO will bill the RFC or LIPA RFC, as applicable.

6.10.2.3 The Transmission Owners may propose a non-transmission solution subject to state jurisdiction to address a Reliability Need included in the Comprehensive Reliability Plan, provided that the appropriate state agency(ies) has established procedures to ensure full and prompt recovery of all reasonably incurred costs related to a project, comparable to those set forth in this tariff for cost recovery for regulated reliability transmission projects.

6.10.3 RFC Revenue Requirement Recovery.

The RFC is to be billed by the NYISO and paid by the LSEs located in load zones to which the cost of the transmission facilities have been allocated in accordance with Attachment Y of the NYISO OATT. All LSEs in the load zones to which costs have been allocated, including Transmission Owners, competitive LSEs and municipal systems, will be billed by the NYISO.

6.10.3.1 The revenue requirement filed pursuant to Section 6.10.2.2 will be the basis for the RFC Rate ($/MWh) for the Billing Period, and shall be applied by the NYISO to each LSE based on its Actual Energy Withdrawals as set forth in Section 6.10.3.4.

6.10.3.2 To the extent that incremental transmission rights owned by the Transmission Owner sponsoring the project are created as a result of a transmission project implemented in accordance with Attachment Y of the NYISO OATT, those incremental transmission rights that can be sold will be auctioned or otherwise sold by the NYISO. The NYISO will disburse the associated revenues to the Transmission Owner(s). The associated revenues will be used in the calculation of the RFC as set forth in Section 6.10.3.4. The incremental transmission rights will continue to be sold for the depreciable life of the project, and the revenues offset discussed above will commence upon the first payment of revenues related to a sale of incremental transmission rights on or after the RFC is implemented for a specific project. These incremental revenues shall not require and shall not be dependent upon any reopening or any review of the Transmission Owner(s) TSCs or NTAC under Attachment H of the NYISO OATT.

6.10.3.3 The NYISO will collect the appropriate RFC revenues each Billing Period and remit those revenues to the appropriate Transmission Owner(s) in accordance with the NYISO's billing and settlement procedures pursuant to Section 2.7.2.5 of the NYISO OATT.

6.10.3.4 The Billing Units for the RFC Rate for the Billing Period shall be based on the Actual Energy Withdrawals available for the prior Billing Period for those zones determined to be allocated the costs of the project in accordance with Attachment Y of the NYISO OATT.

Step 1: Calculate the $ assigned to each Zone

$$RFC_{z,B} = \sum_{p \in P} \left(\left(AnnualRR_{p,B} - IncrementalTransmissionRightsRevenue_{p,B} \right) * \left(ZonalCostAllocation\%_{P} \right) \right)$$

Step 2: Calculate a per-MWh Rate for each Zone

$$RFCRate_{z,B} = RFC_{z,B} / MWh_{z,B}$$

Step 3: Calculate charge for each Billing Period for each LSE in each Zone

$$Charge_{B,1,z} = RFCRate_{z,B} * MWh_{1,z,B}$$

Step 4: Calculate charge for each Billing Period for each LSE across all Zones

$$Charge_{B,1} = \sum_{z \in Z} \left(Charge_{B,1,z} \right)$$

Where,

P = set of Projects.

Z = set of NYISO Zones

B = the relevant Billing Period.

$MWh_{z,B}$ = Actual Energy Withdrawals in zone, z aggregated across all hours in Billing Period B.

$MWh\ l, z, B_{1,z,B}$ = Actual Energy Withdrawals for LSE l in zone z aggregated across all hours in Billing Period B.

$AnnualRR_{p,B}$ = the pro rata share of the annual Revenue Requirement for each Project as discussed in Section 6.10.2.2 above allocated for Billing Period B.

$IncrementalTransmissionRightsRevenue_{p,B}$ = the pro rata share of the Incremental Transmission Rights Revenue for each Project as discussed in Section 6.10.3.2 above allocated for Billing Period B.

6.10.4 Recovery of Costs by an Unregulated Transmitting Utility.

An Unregulated Transmitting Utility is a Transmission Owner that, pursuant to Section 201(f) of the FPA is not subject to the Commission's jurisdiction under Sections 205 and 206 of the FPA. The recovery of costs related to the preparation of proposals for, and the development, construction, operation and maintenance of, a regulated reliability transmission project undertaken pursuant to Attachment Y of the NYISO OATT by LIPA, as an Unregulated Transmitting Utility, shall be conducted as follows:

6.10.4.1 Upon the request of the NYISO, an Unregulated Transmitting Utility will proceed with the process of receiving any necessary authorization for the requested project.

6.10.4.2 Upon receipt of all necessary federal, state and local authorizations, the Unregulated Transmitting Utility shall commence with construction of the project.

6.10.4.3 Cost Recovery for LIPA

Transmission Owners other than LIPA that propose an alternative regulated transmission project on Long Island would recover any costs per Sections 6.10.2 through 6.10.3.4 of this Attachment. Other Developers that propose an alternative regulated transmission project on Long Island would recover any costs per Section 6.10.5 of this Attachment.

6.10.4.3.1 Any costs incurred for a regulated backstop reliability transmission project or an alternative regulated transmission project undertaken by LIPA, as an Unregulated Transmitting Utility, shall be recovered as follows:

6.10.4.3.1.1 For costs to LIPA customers: Cost will be recovered pursuant to a rate recovery mechanism approved by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Upon approval of the rate recovery mechanism, LIPA shall provide to the NYISO, for purposes of inclusion within the NYISO OATT and filing with FERC on an informational basis only, a description of the rate recovery mechanism and the rate that LIPA will charge and collect from responsible entities within the Long Island Transmission District in accordance with the NYISO cost allocation methodology pursuant to Section 31.5.3.2 of Attachment Y of the NYISO OATT.

6.10.4.3.1.2 For Costs to Other Transmission Districts: Where the NYISO determines that there are responsible entities outside of the Long Island Transmission District that should be allocated a portion of the costs of the regulated backstop reliability transmission solution or an alternative regulated transmission solution undertaken by LIPA, LIPA shall inform the NYISO of the amount of such costs. Such costs will be an allocable amount of the cost base recovered through the recovery mechanism described in Section 6.10.4.3.1.1 in accordance with the formula set forth in Section 6.10.3.4. The costs of a LIPA regulated backstop reliability transmission project or an alternative regulated transmission solution, allocable to responsible entities outside of the Long Island Transmission District shall constitute the "revenue requirement" that the NYISO shall include and, and recover through, a separate "LIPA RFC". The NYISO shall file the LIPA RFC with the Commission as an informational filing. The NYISO will file such RFC for Commission review under the same “comparability” standard as is applied to review of changes in LIPA’s TSC under Attachment H of this tariff. LIPA shall intervene in support of such filing at the Commission and shall take the responsibility to resolve all concerns about the contents of the filing that might be raised in such proceeding. The NYISO shall bill for LIPA the LIPA RFC to responsible entities in Transmission Districts other than the Long Island Transmission District consistent with Sections 6.10.3.1 through 6.10.3.4 and shall remit the revenues collected to LIPA each Billing Period.

6.10.4.4 Savings Clause. The inclusion in the NYISO OATT or in a FERC filing on an informational basis of the charges for recovery of costs incurred by LIPA or NYPA related to a regulated project undertaken pursuant to Attachment Y into the NYISO OATT, as provided for in Sections 6.10.4.3 and 6.10.4.4, or the inclusion of such charges in the NYISO RFC pursuant to Section 6.10.4.3.1.2, shall not be deemed to modify the treatment of such rates as non-jurisdictional pursuant to Section 201(f) of the FPA.

6.10.5 Recovery of Costs Incurred by an Other Developer Related to an Alternative Regulated Solution.

6.10.5.1 The RFC shall be used as the cost recovery mechanism for the recovery of the costs of an alternative regulated transmission solution that has been selected by the ISO as the more efficient or cost effective solution to the identified Reliability Need, and is authorized by FERC to recover costs under this rate mechanism. Provided however, nothing in this cost recovery mechanism shall be deemed to create any additional rights for an Other Developer to proceed with a regulated transmission project that such Other Developer does not otherwise have at law. The provisions of Sections 6.10.3 through 6.10.3.4 of this Attachment shall be applicable to the recovery of the costs incurred by an Other Developer for proposing, developing, constructing, operating, maintaining, and financing an alternative regulated transmission project that the ISO has selected as the more efficient or cost effective solution to the identified Reliability Need .

6.10.5.2 Upon receipt of all necessary federal, state, and local authorizations, including FERC acceptance of a Section 205 filing authorizing cost recovery under the NYISO tariff, the Other Developer shall commence construction of the project . Upon completion of the project, the Other Developer and/or the NYISO, as applicable, will make a filing with FERC to provide the final project cost and resulting revenue requirement to be recovered pursuant to this Attachment. The resulting revenue requirement will become effective and recovery of project costs pursuant to this Attachment will commence upon the acceptance of the filing by FERC. This Section 6.10.5.2 also applies to the recovery of all reasonably incurred costs related to a project that the ISO has selected as the more efficient or cost effective solution, and is later halted in accordance with the provisions of the NYISO OATT, including but not limited to reasonable and necessary expenses incurred to implement an orderly termination of the project.

6.10.5.3 Other Developers may also propose a non-transmission solution subject to state jurisdiction to address a Reliability Need included in the Comprehensive Reliability Plan.

12.1 Introduction

This Code of Conduct shall apply to the ISO's Directors, Officers, and Employees (collectively, "ISO Employees") and provides policies, rules and procedures to be followed in carrying out the ISO's responsibilities. The provisions relating to covered contractors and consultants are set forth in Section 12.13 below.

The ISO Employees shall take all reasonable actions within their authority under the ISO Tariffs and Agreements[1] necessary to:

(1) comply with all laws including, without limitation, the following: federal and state environmental laws; Federal Power Act, FERC Rules and Regulations, FERC Order Nos. 888 et. seq. and 889 et seq.; 18 C.F.R. § 37.1-37.4; federal securities laws; and copyright, trademark and patent laws; Attachment F

(2) provide Transmission Service pursuant to the ISO Open Access Transmission Tariff ("OATT"), acting as the Responsible Party,[2] as defined in Order Nos. 889 et. seq. for all Transmission Owners and operate the OASIS in accordance with Section 12.2, below;

(3) refrain from Energy Transactions in accordance with Section 12.3, below;

(4) treat commercially sensitive, proprietary, or regulated information as Confidential Information in accordance with Section 12.4, below;

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[1] The "ISO Tariffs and Agreements" consist of the ISO OATT, the ISO Services Tariff, the ISO Agreement, the NYSRC Agreement, the ISO/NYSRC Agreement, the ISO/TO Agreement, and Operating Agreements. The term "ISO Tariffs" consists of the ISO OATT and the ISO Services Tariff.

[2] The term "Responsible Party" as defined in Order No. 889 means the Transmission Owner or an agent to whom the Transmission Owner has delegated the responsibility of meeting the requirements of 18 C.F.R. §37 concerning the operation of the OASIS.

(5) protect the integrity of ISO Records[3] in accordance with Section 12.7, below;

(6) protect the ISO's assets including property, facilities, equipment and supplies in accordance with Section 12.12, below; and

(7) avoid contact with Market Participants[4] which could cause or appear to cause a conflict of interest under Section 12.8, below.

[3] ISO Records consist of all documents submitted to, or generated by, the ISO that pertain to ISO business. Examples of ISO Records include, without limitation, requests for Transmission and Ancillary Services, service agreements, system impact studies and facilities studies developed by the Transmission Owners and forwarded to the ISO, audit records, and ISO annual reports.

[4] Market Participant is any person (natural or legal) transacting with the ISO to buy, sell or schedule electric generating Capacity and/or Energy, Ancillary Services or Transmission Services. The term includes, but is not limited to, Power Exchanges, power brokers, power marketers, Buyers, Sellers, Transmission Owners, Non-Utility Generators, Independent Power Producers, load aggregators, Load Serving Entities, and municipalities or groups of these entities.

14.2 Attachment 1 to Attachment H

14.2.1 Schedules

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Niagara Mohawk Power Corporation | **Attachment 1**

Calculation of RR Pursuant to Attachment H, Section 14.1.9.2 | Year | **Schedule 1**

Calculation of RR

14.1.9.2 The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the formula below.

Historical Transmission Revenue Requirement (Historical TRR)

Line No.			Reference		
1		**Historical Transmission Revenue Requirement (Historical TRR)**			
2					
3	14.1.9.2 (a)	Historical TRR shall equal the sum of NMPC's (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C)			
4		Transmission Related Real Estate Tax Expense, (D) Transmission Related Amortization of Investment Tax Credits,			
5		(E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission			
6		Related Payroll Tax Expense, (H) Billing Adjustments, and (I) Transmission Related Bad Debt Expense less			
7		(J) Revenue Credits, and (K) Transmission Rents, all determined for the most recently ended calendar year as of the beginning of the update year.			
8			Reference		
9			*Section:*	**0**	
10		Return and Associated Income Taxes	(A)	#DIV/0!	Schedule 8, line 64
11		Transmission-Related Depreciation Expense	(B)	#DIV/0!	Schedule 9, Line 6, column 5
12		Transmission-Related Real Estate Taxes	(C)	#DIV/0!	Schedule 9, Line 12, column 5
13		Transmission - Related Investment Tax Credit	(D)	#DIV/0!	Schedule 9, Line 16, column 5 times minus 1
14		Transmission Operation & Maintenance Expense	(E)	$0	Schedule 9, Line 23, column 5
15		Transmission Related Administrative & General Expense	(F)	#DIV/0!	Schedule 9, Line 38, column 5
16		Transmission Related Payroll Tax Expense	(G)	$0	Schedule 9, Line 44, column 5
17		Sub-Total (sum of Lines 10 - Line 16)		#DIV/0!	
18					
19		Billing Adjustments	(H)	$0	Schedule 10, Line 1
20		Bad Debt Expenses	(I)	$0	Schedule 10, Line 4
21		Revenue Credits	(J)	$0	Schedule 10, Line 7
22		Transmission Rents	(K)	$0	Schedule 10, Line 14
23					
24		Total Historical Transmission Revenue Requirement (Sum of Line 17 - Line 22)		#DIV/0!	
25					

0

Shading denotes an input

Line No.			Period	Reference			Source
1	14.1.9.2 (b)	**FORECASTED TRANSMISSION REVENUE REQUIREMENTS**					
2		Forecasted TRR shall equal (1) the Forecasted Transmission Plant Additions (FTPA) multiplied by the Annual FTRRF, plus (2) the Mid-Year Trend					
3		Adjustment (MYTA), plus (3) the Tax Rate Adjustment (TRA), as shown in the following formula:					
4							
5		Forecasted TRR = (FTPA * FTRRF) + MYTA + TRA					
6							
7			Period	Reference			Source
8							
9							
10	(1)	Forecasted Transmission Plant Additions (FTPA)				$0	Workpaper 8, Section I, Line 16
11		Annual Transmission Revenue Requirement Factor (FTRRF)			#DIV/0!		Line 35
12		Sub-Total (Lines 10*11)			#DIV/0!		
13		Plus Mid-Year Trend Adjustment (2) (MYTA)			$0		Workpaper 9, line 31, variance column
14		Less Impact of Transmission Support Payments on Historical Transmission Revenue Requirement			$0		Worpaper 9A
15		Forecasted Transmission Revenue Requirement (Line 12 + Line 13-Line 14)			**#DIV/0!**		
16	(2)	**MID YEAR TREND ADJUSTMENT (MYTA)**					
17		The Mid-Year Trend Adjustment shall be the difference, whether positive or negative, between					
18							
19		(i) the Historical TRR Component (E) excluding Transmission Support Payments, based on actual data for the first three months of the Forecast Period, and (ii) the Historical TRR Component (E) excluding Transmission Support Payments, based on data for the first three months of the year prior to the Forecast Period.					
20							
21	(3)	**The Tax Rate Adjustment (TRA)**					
22		The Tax Rate Adjustment shall be the amount, if any, required to adjust Historical TRR Component (A) for any change in the Federal Income Tax Rate					
23		and/or the State Income Tax Rate that takes effect during the first five months of the Forecast Period.					
24							
25	14.1.9.2(c)	**ANNUAL FORECAST TRANSMISSION REVENUE REQUIREMENT FACTOR**					
26		The Annual Forecast Transmission Revenue Requirement Factor (Annual FTRRF) shall equal the sum of Historical TRR components (A) through (C),					
27		divided by the year-end balance of Transmission Plant in Service determined in accordance with Section 14.1.9.2 (a), component (A)1(a).					
28							
29							
30		Investment Return and Income Taxes		(A)	#DIV/0!		Schedule 1, Line 10
31		Depreciation Expense		(B)	#DIV/0!		Schedule 1, Line 11
32		Property Tax Expense		(C)	#DIV/0!		Schedule 1, Line 12

33	Total Expenses (Lines 30 thru 32)		#DIV/0!	
34	Transmission Plant	(a)	#DIV/0!	Schedule 6, Page 1, Line 12
35	Annual Forecast Transmission Revenue Requirement Factor (Lines 33/ Line 34)		#DIV/0!	

Niagara Mohawk Power Corporation **Attachment 1**
Annual True-up (ATU) **Schedule 3**
Attachment H Section 14.1.9.2 (c)

Line No.			0 Year	**Source:**
1				
2	14.1.9.2(d)	The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year		
3		Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs		
4		and Prior Year Scheduling, System Control and Dispatch costs, plus (3) the difference between the Prior Year Billing Units and the Actual Year		
5		Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.		
6				
7	(1)	Revenue Requirement (RR) of rate effective July 1 of prior year	$0	Schedule 4, Line 1, Col (d)
8		Less: Annual True-up (ATU) from rate effective July 1 of prior year	$0	Schedule 4, Line 1, Col (c)
9		Prior Year Transmission Revenue Requirement	$0	Line 7 - Line 8
10				
11		Actual Transmission Revenue Requirement	#DIV/0!	Schedule 4, Line 2, Col (a)
12		Difference	#DIV/0!	Line 11 - Line 9
13				
14	(2)	Prior Year Scheduling, System Control and Dispatch costs (CCC)	$0	Schedule 4, Line 1, Col (e)
15		Actual Scheduling, System Control and Dispatch costs (CCC)	$0	Schedule 4, Line 2, Col (e)
16		Difference	$0	Line 15 - Line 14
17				
18	(3)	Prior Year Billing Units (MWH)	$0	Schedule 4, Line 1, Col (f)
19		Actual Billing Units	-	Schedule 4, Line 2, Col (f)
20		Difference	-	Line 18 - Line 19
21		Prior Year Indicative Rate	#DIV/0!	Schedule 4, Line 1, Col (g)
22		Billing Unit True-Up	#DIV/0!	Line 20 * Line 21
23				
24		Total Annual True-Up before Interest	#DIV/0!	(Line 12 + Line 16 + Line 22)
25				
26	(4)	Interest	#DIV/0!	Line 57
27				
28		Annual True-up RR Component	#DIV/0!	(Line 24 + Line 26)
29				

Line No.									
30	Interest Calculation per 18 CFR § 35.19a								
31	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
32	Quarters	Annual	Accrued Prin	Monthly	Days			Accrued Prin	Accrued
33		Interest	& Int. @ Beg	(Over)/Under	in	Period		& Int. @ End	Int. @ End
34		Rate (a)	Of Period	Recovery	Period	Days	Multiplier	Of Period	Of Period
35									
36	3rd QTR '07		0		92	92	1.0000	$0	$0
37	July	0.00%		#DIV/0!	31	92	1.0000	#DIV/0!	#DIV/0!
38	August	0.00%		#DIV/0!	31	61	1.0000	#DIV/0!	#DIV/0!
39	September	0.00%		#DIV/0!	30	30	1.0000	#DIV/0!	#DIV/0!
40									

41	4th QTR '07		#DIV/0!		92	92	1.0000	#DIV/0!	#DIV/0!
42	October	0.00%		#DIV/0!	31	92	1.0000	#DIV/0!	#DIV/0!
43	November	0.00%		#DIV/0!	30	61	1.0000	#DIV/0!	#DIV/0!
44	December	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
45									
46	1st QTR '08		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!
47	January	0.00%		#DIV/0!	31	91	1.0000	#DIV/0!	#DIV/0!
48	February	0.00%		#DIV/0!	29	60	1.0000	#DIV/0!	#DIV/0!
49	March	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
50									
51	2nd QTR '08		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!
52	April	0.00%		#DIV/0!	30	91	1.0000	#DIV/0!	#DIV/0!
53	May	0.00%		#DIV/0!	31	61	1.0000	#DIV/0!	#DIV/0!
54	June	0.00%		#DIV/0!	30	30	1.0000	#DIV/0!	#DIV/0!
55									
56									
57	Total (over)/under Recovery			#DIV/0!	(line 24)	#DIV/0!			#DIV/0!

(a) Interest rates shall be the interest rates as reported on the FERC Website http://www.ferc.gov/legal/acct-matts/interest-rates.asp

Niagara Mohawk Power Corporation Wholesale TSC Calculation Information

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Historical Transmission Revenue Requirement (Historical TRR)	Forecasted Transmission Revenue Requirement	Annual True Up (**)	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate $/MWh (*)
1	Prior Year Rates Effective ________	-	-	-	-	-	-	#DIV/0!
2	Current Year Rates Effective July 1, _______	#DIV/0!	#DIV/0!		#DIV/0!	-	-	#DIV/0!
3	Increase/(Decrease)							#DIV/0!
4	Percentage Increase/(Decrease)							#DIV/0!

1.) Information directly from Niagara Mohawk Prior Year Informational Filing
2.)
(a) Schedule 1, Line 24
(b) Schedule 2, Line 14
(c) Schedule 3, Line 28
(d) Attachment H, Section 14.1.9.2 The RR Component shall equal Col (a) Historical Transmission Revenue Requirement plus Col (b) the Forecasted Transmission Revenue Requirement which shall exclude Transmission Support Payments, plus Col (c) the Annual True-Up plus Col (c) the Annual True-Up
(e) Schedule 11 - Annual Scheduling, System Control and Dispatch Costs. (i.e. the Transmission Component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts from the prior calendar year excluding any NY Independent System Operating (NYISO) system control and load dispatch expenses already recovered under Schedule 1 of the NYISO Tariff.
(f) Schedule 12 - Billing Units shall be the total Niagara Mohawk load as reported to the NYISO for the calendar year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR, and Reserved components of Attachment H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.
(g) (Col (d) + Col (e)) / Col (f)

(*) The rate column represents the unit rate prior to adjustments; the actual rate will be determined pursuant to the applicable TSC formula rate.
(**)

Niagara Mohawk Power Corporation
Allocation Factors - As calculated pursuant to Section 14.1.9.1

Attachment 1
Schedule 5

		0	

Shading denotes an input

Line No.				Source	Definition
1	14.1.9.1 1.	**Electric Wages and Salaries Factor**	**83.5000%**		Fixed per settlement
2					
3	14.1.9.1 3.	**Transmission Wages and Salaries Allocation Factor**	**13.0000%**		Fixed per settlement
4					
5					
6					
7					
8	14.1.9.1 2.	**Gross Transmission Plant Allocation Factor**			
9		Transmission Plant in Service	#DIV/0!	Schedule 6, Page 2, Line 3, Col 5	Gross Transmission Plant Allocation Factor shall equal the total investment in
10		Plus: Transmission Related General	$0	Schedule 6, Page 2, Line 5, Col 5	Transmission Plant in Service, Transmission Related Electric General Plant,
11		Plus: Transmission Related Common	$0	Schedule 6, Page 2, Line 10, Col 5	Transmission Related Common Plant and Transmission Related Intangible Plant
12		Plus: Transmission Related Intangible Plant	$0	Schedule 6, Page 2, Line 15, Col 5	divided by Gross Electric Plant.
13		Gross Transmission Investment	#DIV/0!	Sum of Lines 9 - 13	
14					
15		Total Electric Plant		FF1 207.104	
16		Plus: Electric Common	$0	Schedule 6, Page 2, Line 10, Col 3	
17		Gross Electric Plant in Service	$0	Line 15 + Line 16	
18					
19		**Percent Allocation**	**#DIV/0!**	Line 13 / Line 17	
20					
21	14.1.9.1 4.	**Gross Electric Plant Allocation Factor**			
22					
23		Total Electric Plant in Service	$0	Line 15	Gross Electric Plant Allocation Factor shall equal
24		Plus: Electric Common Plant	$0	Schedule 6, Page 2, Line 10, Col 3	Gross Electric Plant divided by the sum of Total Gas Plant,
25		Gross Electric Plant in Service	$0	Line 23 + Line 24	Total Electric Plant, and Total Common Plant
26					
27		Total Gas Plant in Service		FF1 201.8d	
28		Total Electric Plant in Service	$0	Line 15	
29		Total Common Plant in Service	$0	Schedule 6, Page 2, Line 10, Col 1	
30		Gross Plant in Service (Gas & Electric)	-	Sum of Lines 27-Lines 29	
31					
32		**Percent Allocation**	**#DIV/0!**	Line 25 / Line 30	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H, section 14.1.9.2

Line No.

1 14.1.9.2 (a) <u>Transmission Investment Base</u>

2

3 A.1. Transmission Investment Base shall be defined as (a) Transmission Plant in Service, plus (b) Transmission Related Electric General Plant, plus
4 (c) Transmission Related Common Plant, plus (d) Transmission Related Intangible Plant, plus (e) Transmission Related Plant Held for Future Use, less
5 (f) Transmission Related Depreciation Reserve, less (g) Transmission Related Accumulated Deferred Taxes, plus (h) Transmission Related
6 Regulatory Assets net of Regulatory Liabilities, plus (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies,
7 plus (k) Transmission Related Cash Working Capital.

8

9

Line No.		Reference	**2007**	Reference
10		Reference	**2007**	Reference
11		*Section:*		
12	Transmission Plant in Service	(a)	#DIV/0!	Schedule 6, page 2, line 3, column 5
13	General Plant	(b)	$0	Schedule 6, page 2, line 5, column 5
14	Common Plant	(c)	$0	Schedule 6, page 2, line 10, column 5
15	Intangible Plant	(d)	$0	Schedule 6, page 2, line 15, column 5
16	Plant Held For Future Use	(e)	$0	Schedule 6, page 2, line 19, column 5
17	Total Plant (Sum of Line 12 - Line 16)		#DIV/0!	
18				
19	Accumulated Depreciation	(f)	#DIV/0!	Schedule 6, page 2, line 29, column 5
20	Accumulated Deferred Income Taxes	(g)	#DIV/0!	Schedule 7, line 6, column 5
21	Other Regulatory Assets	(h)	#DIV/0!	Schedule 7, line 11, column 5
22	Net Investment (Sum of Line 17 -Line 21)		#DIV/0!	
23				
24	Prepayments	(i)	#DIV/0!	Schedule 7, line 15, column 5
25	Materials & Supplies	(j)	#DIV/0!	Schedule 7, line 21, column 5
26	Cash Working Capital	(k)	$0	Schedule 7, line 28, column 5
27				
28	Total Investment Base (Sum of Line 22 - Line 26)		#DIV/0!	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Attachment 1
Schedule 6

Transmission Investment Base (Part 1 of 2)

Attachment H Section 14.1. 9.2 (a) A. 1.

0

Shading denotes an input

Line No.		(1) Total	(2) Allocation Factor		(3) = (1)*(2) Electric Allocated	(4) Allocation Factor		(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Plant								FF1 207.58g	14.1.9.2(a)A.1.(a)	Transmission Plant in Service shall equal the
2	Wholesale Meter Plant							#DIV/0!	Workpaper 1		balance of total investment in Transmission Plant
3	Total Transmission Plant in Service (Line 1+ Line 2)							#DIV/0!			plus Wholesale Metering Investment
4											
5	General Plant		100.00%		$0	13.00%	(c)	$0	FF1 207.99g	14.1.9.2(a)A.1.(b)	Transmission Related Electric General Plant shall
6											equal the balance of investment in Electric General
7											Plant mulitplied by the Transmission Wages and
8											Salaries Allocation Factor
9											
10	Common Plant		83.50%	(a)	$0	13.00%	(c)	$0	FF1 201. 8h	14.1.9.2(a)A.1.(c)	Transmission Related Common Plant shall equal Common
11											Plant multiplied by the Electric Wages and Salaries
12											Allocation Factor and further multiplied by the
13											Transmission Wages and Salaries Allocation Factor.
14											
15	Intangible Plant		100.00%		-	13.00%	(c)	$0	FF1 205.5g	14.1.9.2(a)A.1.(d)	Transmission Related Intangible Plant shall equal Intangible
16											Electric Plant multiplied by the Transmission Wages and
17											Salaries Allocation Factor.
18											
19	Transmission Plant Held for Future Use	$0						$0	Workpaper	14.1.9.2(a)A.1.(e)	Transmission Related Plant Held

									10		for Future Use shall equal
											the balance in Plant Held for
20											Future Use associated with
											property planned to be used for
21											transmission service within
22											five years
	Transmission Accumulated										
23	Depreciation										
											Transmission Related
											Depreciation Reserve shall
24	Transmission Accum. Depreciation							$0	FF1 219.25b	14.1.9.2(a)A.1.(f)	equal the
											balance of: (i) Transmission
25	General Plant Accum.Depreciation		100.00%		$0	13.00%	(c)	$0	FF1 219.28b		Depreciation Reserve, plus (ii)
											the product of Electric General
26	Common Plant Accum Depreciation		83.50%	(a)	$0	13.00%	(c)	$0	FF1 356.1 end of year balance		Plant Depreciation Reserve
											multiplied by the Transmission
27	Amortization of Other Utility Plant		100.00%		$0	13.00%	(c)	$0	FF1 200.21c		Wages and Salaries
											Allocation Factor, plus (iii) the
28	Wholesale Meters	#DIV/0!						#DIV/0!	Workpaper 1		product of Common Plant
											Depreciation Reserve multiplied
29	Total Depreciation (Sum of line 24 - Line 28)							#DIV/0!			by the Electric Wages and
											Salaries Allocation Factor and
30											further multiplied by the
											Transmission Wages and
											Salaries Allocation Factor plus
31											(iv)
											the product of Intangible
											Electric Plant Depreciation
32											Reserve
											multiplied by the Transmission
33											Wages and Salaries
											Allocation Factor plus (v)
											depreciation reserve associated
34											with
											the Wholesale Metering
35											Investment
36											

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32 - not used on this Schedule
(c) Schedule 5, line 3
(d) Schedule 5, line 19 - not used on this Schedule

Transmission Investment Base (Part 2 of 2)

Attachment H Section 14.1.9.2 (a) A. 1.

Shading denotes an input

0

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor		(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)		Definition
1	Transmission Accumulated Deferred Taxes									
2	Accumulated Deferred Taxes (281-282)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 275.2k	14.1.9.2(a)A.1.(g)	Transmission Related Accumulated Deferred Income Taxes
3	Accumulated Deferred Taxes (283)	$0	100.00%	$0	#DIV/0!	(d)	#DIV/0!	Workpaper 2, Line 5		shall equal the electric balance of Total Accumulated Deferred
4	Accumulated Deferred Taxes (190)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 234.8c		Income Taxes (FERC Accounts 190, 55,281, 282, and 283 net of
5	Accumulated Deferred Inv. Tax Cr (255)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 267.8h		stranded costs), multiplied by the Gross Transmission Plant
6	Total (Sum of line 2 - Line 5)			$0			#DIV/0!			Allocation Factor.
7										
8	Other Regulatory Assets									
9	FAS 109 (Asset Account 182.3)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 232 lines 2,4,9,17	14.1.9.2(a)A.1.(h)	Transmission Related Regulatory Assets shall be Regulatory
10	FAS 109 (Liability Account 254)		100.00%	$0	#DIV/0!	(d)	#DIV/0!	FF1 278.1 lines 4&21(f)		Assets net of Regulatory Liabilities multiplied by the Gross
11	Total (line 9 + Line 10)	$0		$0			#DIV/0!			Transmission Plant Allocation Factor.
12										
13	Transmission Prepayments							FF1 111.57c	14.1.9.2(a)A.1.(i)	Transmission Related Prepayments shall be the product of
14	Less: Prepaid State and Federal Income Tax							FF1 263 lines 2 & 9 (h)		Prepayments excluding Federal and State taxes multiplied by
15	Total Prepayments	$0	#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!			the Gross Electric Plant Allocation Factor and further
16										multiplied by the Gross Transmission Plant Allocation Factor.
17										
18	Transmission Material and Supplies								14.1.9.2(a)A.1.(j)	Transmission Related Materials and Supplies shall equal: (i)
19	Trans. Specific O&M Materials and Supplies						$0	FF1 227.8		the balance of Materials and Supplies assigned to
20	Construction Materials and Supplies		#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!	FF1 227.5		Transmission plus (ii) the product of Material and Supplies
21	Total (Line 19 + Line 20)						#DIV/0!			assigned to Construction multiplied by the Gross Electric
22										Plant Allocation Factor and further multiplied by Gross
23										Transmission Plant Allocation Factor.

24					
25	<u>Cash Working Capital</u>			14.1.9.2(a)A.1.(k)	Transmission Related Cash Working Capital shall be an
26	Operation & Maintenance Expense	$0	Schedule 9, Line 23		allowance equal to the product of: (i) 12.5% (45 days/ 360 days = 12.5%)
27		0.1250	x 45 / 360		multiplied by (ii) Transmission Operation and Maintenance Expense.
28	Total (line 26 * line 27)	$0			
29					
30					

Allocation Factor Reference
(a) Schedule 5, line 1 - not used on this Schedule
(b) Schedule 5, line 32
(c) Schedule 5, line 3 - not used on this Schedule
(d) Schedule 5, line 19

Niagara Mohawk Power Corporation **Attachment 1**
Annual Revenue Requirements of Transmission Facilities **Schedule 8**
Cost of Capital Rate

Shading denotes an input | **0**

Line No.

1 **The Cost of Capital Rate shall equal the proposed Weighted Costs of Capital plus Federal Income Taxes and State Income Taxes.**

2 The Weighted Costs of Capital will be calculated for the Transmission Investment Base using NMPC's actual capital structure and will equal the sum of (i), (ii), and (iii) below:

3

4 (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's long-term debt outstanding during the year and the sum of (a) the ratio of actual long-term debt to total capital at year-end; and

5 (b) the extent, if any, by which the ratio of NMPC's actual common equity to total capital at year-end exceeds fifty percent (50%). Long term debt shall be defined as the average of the beginning of the year and end of year balances of the following: long term debt less the unamortized

6 Discounts on Long-Term Debt less the unamortized Loss on Reacquired Debt plus unamortized Gain on Reacquired Debt. Cost to maturity of NMPC's long-term debt shall be defined as the cost of long term debt included in the debt discount expense and

7 any loss or gain on reacquired debt.

8 (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's preferred stock then outstanding and the ratio of actual preferred stock to total capital at year-end;

9

10 (iii) the return on equity component shall be the product of the allowed return on equity of 10.3% and the ratio of NMPC's actual common equity to total capital at year-end, provided that such ratio

11 shall not exceed fifty percent (50%).

12

Line No.			CAPITALIZATION	Source:	CAPITALIZATION RATIOS	COST OF CAPITAL	Source:	WEIGHTED COST OF CAPITAL	EQUITY PORTION
13									
14									
15									
16									
17	(i)	Long-Term Debt	$0	Workpaper. 6, Line 16b	#DIV/0!	#DIV/0!	Workpaper 6, Line 17c	#DIV/0!	
18	(ii)	Preferred Stock		FF1 112.3c	#DIV/0!	#DIV/0!	Workpaper 6, Line 24d	#DIV/0!	#DIV/0!
19	(iii)	Common Equity		FF1 112.16c - FF1 112.3,12,15c	#DIV/0!	10.30%		#DIV/0!	#DIV/0!
20									
21		Total Investment Return	$0		#DIV/0!			#DIV/0!	#DIV/0!

22

23

24

25

26 14.1.9.2.2.(b) Federal Income Tax shall equal = (A. + [B / C] X Federal Income Tax Rate)

27 Federal Income
(1 - Tax Rate)

28

29 where A is the sum of the preferred stock component and the return on equity component, each as determined in Sections (a)(ii) and for the ROE set forth in (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for

30 Transmission Plant in Service as defined at Section 14.1.9.1.16 (FF1 117.38c), and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.

31

32 =
(#DIV/0! +($0) / #DIV/0! X)

33 (1 - 0)

34

35 = #DIV/0!

36

37

38 14.1.9.2.2.(c) State Income Tax shall equal = (A. + [B / C] + Federal Income Tax Rate) X State Income Tax Rate

39 (1 - State Income Tax Rate)

40

41 where A is the sum of the preferred stock component and the return on equity component as determined in (a)(ii) and (a)(iii) above , B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in

42 Service as defined at Section 14.1.9.1.16 above, and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.

43

44

45

46 = (#DIV/0! +($ 0) / #DIV/0! + #DIV/0!) X

47 (1 - 0)

48

49 = #DIV/0!

50

51

52

53 (a)+(b)+(c) Cost of Capital Rate = #DIV/0!

54

55

56 **14.1.9.2(a) A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate**

57

58

59

60	Transmission Investment Base	#DIV/0!	Schedule 6, page 1 of 2, Line 28
61			
62	Cost of Capital Rate	#DIV/0!	Line 53
63			
64	= Investment Return and Income Taxes	#DIV/0!	Line 60 X Line 62

Niagara Mohawk Power Corporation | **Attachment 1**
Annual Revenue Requirements of Transmission Facilities | **Schedule 9**
Transmission Expenses

Attachment H Section 14.1.9.2 | **0**

Shading denotes an input

Line No.		(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1/ PSC Report Reference for col (1)		Definition
	Depreciation Expense								
1	Transmission Depreciation					$0	FF1 336.7f	14.1.9.2.B.	Transmission Related Depreciation Expense shall equal the sum of:
2	General Depreciation		100.0000%	$0	13.0000% (c)	$0	FF1 336.10f		(i) Depreciation Expense for Transmission Plant in Service, plus (ii)
3	Common Depreciation		83.5000% (a)	$0	13.0000% (c)	$0	FF1 356.1		the product of Electric General Plant Depreciation Expense multiplied
4	Intangible Depreciation		100.0000%	$0	13.0000% (c)	$0	FF1 336.1f		by the Transmission Wages and Salaries Allocation Factor plus (iii)
5	Wholesale Meters					#DIV/0!	Workpaper 1		Common Plant Depreciation Expense multiplied by the Electric
6	Total (line 1+2+3+4+5)					#DIV/0!			Wages and Salaries Allocation Factor, further multiplied by the
7									Transmission Wages and Salaries Allocation Factor plus (iv)
8									Intangible Electric Plant Depreciation Expense multiplied by the
9									Transmission Wages and Salaries Factor plus (v) depreciation
10									expense associated with the Wholesale Metering Investment.
11									
12	Real Estate Taxes		100.0000%	$0	#DIV/0! (d)	#DIV/0!	FF1 263.25i	14.1.9.2.C.	Transmission Related Real Estate Tax Expense shall equal the
13									electric Real Estate Tax Expenses multiplied by the Gross
14									Transmission Plant Allocation Factor.
15									
16	Amortization of Investment Tax Credits		#DIV/0! (b)	#DIV/0!	#DIV/0! (d)	#DIV/0!	FF1 117.58c	14.1.9.2.D.	Transmission Related Amortization of Investment Tax Credits shall
17									equal the product of Amortization of Investment Tax Credits multiplied
18									by the Gross Electric Plant Allocation Factor and further multiplied by
19									the Gross Transmission Plant Allocation Factor.
20	Transmission Operation and Maintenance								
21	Operation and Maintenance					$0	FF1 321.112b	14.1.9.2.E.	Transmission Operation and Maintenance Expense shall equal
22	less Load Dispatching - #561					$0	FF1 321.84-92b		the sum of electric expenses as recorded in
23	O&M (Line 21 - Line 22)	$0				$0			FERC Account Nos. 560, 562-574.
24									
25	Transmission Administrative and General							14.1.9.2.F.	Transmission Related Administrative and General Expenses shall
26	Total Administrative and General						FF1 323.197b		equal the product of electric Administrative and General Expenses,
27	less Property Insurance (#924)						FF1 323.185b		excluding the sum of Electric Property Insurance, Electric Research and
28	less Pensions and Benefits (#926)						FF1 323.187b		Development Expense and Electric Environmental Remediation

										Expense,
29	less: Research and Development Expenses (#930)	$0					Workpaper 12			and 50% of the NYPSC Regulatory Expense
30	Less: 50% of NY PSC Regulatory Expense						50% of Workpaper 15			multiplied by the Transmission Wages and Salaries Allocation Factor,
31	Less: 18a Charges (Temporary Assessment						Workpaper 15			
32	less: Environmental Remediation Expense	$0					Workpaper 11			plus the sum of Electric Property Insurance multiplied by the Gross
33	Subtotal (Line 26-27-28-29-30-31-32)	$0	100.0000 %	$0	13.0000% (c)	$0				Transmission Plant Allocation Factor, plus transmission-specific Electric
34	PLUS Property Insurance alloc. using Plant Allocation	$0	100.0000 %	$0	#DIV/0! (d)	#DIV/0!	Line 27			Research and Development Expense, and transmission-specific
35	PLUS Pensions and Benefits	$88,644,000	100.0000 %	$88,644,000	13.0000% (c)	$11,523,720	Workpaper 3			Electric Environmental Remediation Expense. In addition, Administrative
36	PLUS Transmission-related research and development	$0				$0	Workpaper 12			and General Expenses shall exclude the actual Post-Employment
37	PLUS Transmission-related Environmental Expense	$0				$0	Workpaper 11			Benefits Other than Pensions ("PBOP") included in FERC Account 926,
38	Total A&G (Line 33+34+35+36+37)	$88,644,000		$88,644,000		#DIV/0!				and shall add back in the amounts shown on Workpaper 3, page 1,
39										or other amount subsequently approved by FERC under Section 205 or 206.
40	<u>Payroll Tax Expense</u>								14.1.9.2.G.	Transmission Related Payroll Tax Expense shall equal the product of
41	Federal Unemployment						FF1 263.4i			electric Payroll Taxes multiplied by the Transmission Wages and Salaries Allocation Factor.
42	FICA						FF1 263.3i			
43	State Unemployment						FF1 263.17i			
44	Total (Line 41+42+43)	$0	100.0000 %	$0	13.0000% (b)	$0				

Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32
(c) Schedule 5, line 3
(d) Schedule 5, line 19

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Billing Adjustments, Revenue Credits, Rental Income

Attachment 1
Schedule 10

0

Attachment H Section
14.1.9.2 (a)

Shading denotes an input

Line No.		(1) Total	Source		Definition
1	Billing Adjustments			14.1.9.2.H.	Billing Adjustments shall be any adjustments made in accordance with Section 14.1.9.4.4 below.
2					( ) indicates a refund or a reduction to the revenue requirement on Schedule 1.
3					
4	Bad Debt Expense	$0	Workpaper 4	14.1.9.2.I.	Transmission Related Bad Debt Expense shall equal
5					Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.
6					
7	Revenue Credits	$0	Workpaper 5	14.1.9.2.J.	Revenue Credits shall equal all Transmission revenue recorded in FERC account 456
8					excluding (a) any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved
9					components in Attachment H of the NYISO TSC rate; (b) any revenues associated
10					with expenses that have been excluded from NMPC’s revenue requirement; and (c) any
11					revenues associated with transmission service provided under this TSC rate, for which the
12					load is reflected in the calculation of BU.
13					
14	Transmission Rents	$0	Workpaper 7	14.1.9.2.K.	Transmission Rents shall equal all Transmission-related rental income recorded in FERC
15					account 454.615
16					
17				14.1.9.4(d)	
18				1	Any changes to the Data Inputs for an Annual Update, including but not limited to
19					revisions resulting from any FERC proceeding to consider the Annual Update, or
20					as a result of the procedures set forth herein, shall take effect as of the beginning
21					of the Update Year and the impact of such changes shall be incorporated into the
22					charges produced by the Formula Rate (with interest determined in accordance
23					with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
24					Year. This mechanism shall apply in lieu of mid-Update Year adjustments and
25					any refunds or surcharges, except that, if an error in a Data Input is discovered
26					and agreed upon within the Review Period, the impact of such change shall be
27					incorporated prospectively into the charges produced by the Formula Rate during
28					the remainder of the year preceding the next effective Update Year, in which case
29					the impact reflected in subsequent charges shall be reduced accordingly.
30				2	The impact of an error affecting a Data Input on charges collected during the
31					Formula Rate during the five (5) years prior to the Update Year in which the error
32					was first discovered shall be corrected by incorporating the impact of the error on

the charges produced by the Formula Rate during the five-year period into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update Year. Charges collected before the five-year period shall not be subject to correction.

(b)	List of Items excluded from the Revenue Requirement	Reason

Niagara Mohawk Power Corporation
System, Control, and Load Dispatch Expenses (CCC)
Attachment H, Section 14.1.9.5

The CCC shall equal the annual Scheduling, System Control and Dispatch Costs (i.e., the transmission component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts using information from the prior calendar year, excluding NYISO system control and load dispatch expense already recovered under Schedule 1 of the NYISO Tariff.

1	**Scheduling and Dispatch Expenses**			**0**	**Source**
2					
3	Accounts	561	Load Dispatching		FF1 321.84b
4	Accounts	561.1	Reliability		FF1 321.85b
5	Accounts	561.2	Monitor and Operate Transmission System		FF1 321.86b
6	Accounts	561.3	Transmission Service and Schedule		FF1 321.87b
7	Accounts	561.4	Scheduling System Control and Dispatch		FF1 321.88b
8	Accounts	561.5	Reliability, Planning and Standards Development		FF1 321.89b
9	Accounts	561.6	Transmission Service Studies		FF1 321.90b
10	Accounts	561.7	Generation Interconnection Studies		FF1 321.91b
11	Accounts	561.8	Reliability, Planning and Standards Dev. Services		FF1 321.92b
12					
13		Total Load Dispatch Expenses (sum of Lines 3 - 11)			sum lines 3 - 11
14					
15	Less Account 561 directly recovered under Schedule 1 of the NY ISO Tariff				
16					
17	Accounts	561.4	Scheduling System Control and Dispatch		line 7
18	Accounts	561.8	Reliability, Planning and Standards Dev. Services		line 11
19		Total NYISO Schedule 1			line 17 + line 18
20					
21	Total CCC Component				line 13 - line 19

Niagara Mohawk Power Corporation
Billing Units - MWH
Attachment H, Section 14.1.9.6

BU shall be the total Niagara Mohawk load as reported to the NYISO for the calendar billing year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC Rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR and Reserved components of Workpaper H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.

Line No.			**SOURCE**
1	Subzone 1		NIMO TOL (transmission owner load)
2	Subzone 2		NIMO TOL (transmission owner load)
3	Subzone 3		NIMO TOL (transmission owner load)
4	Subzone 4		NIMO TOL (transmission owner load)
5	Subzone 29		NIMO TOL (transmission owner load)
6	Subzone 31		NIMO TOL (transmission owner load)
7	Total NIMO Load report to NYISO	**0.000**	sum lines 1-6
8	LESS: All non-retail transactions		
9	Watertown		FF1 page 329.11.j
10	Disputed Station Service		NIMO TOL (transmission owner load)
11	Other non-retail transactions		All other non-retail transactions (Sum of 300,000 series PTID's from TOL)
12	Total Deductions	**0.000**	sum lines 9 - 11
13	PLUS: TSC Load		
14	NYMPA Muni's, Misc. Villages, Jamestown (X1)		FF1 page 329.19.j
15	NYPA Niagara Muni's (X2)		FF1 page 329.1.j
16	Total additions	**0.000**	sum lines 15 -17
17	Total Billing Units	**0.000**	line 7 - line 12 + line 16

14.2.2 NYPA Transmission Adjustment Charge ("NTAC")

14.2.2.1 Applicability of the NYPA Transmission Adjustment Charge

Each Billing Period, the ISO shall charge, and each Transmission Customer shall pay, the applicable NYPA Transmission Adjustment Charge ("NTAC") calculated in accordance with Section 14.2.2.2.2 of this Attachment for the first two (2) months of LBMP and in accordance with Section 14.2.2.2.1 of this Attachment thereafter. The NTAC shall apply to Transmission Service:

14.2.2.1.1 from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area ("Wheels Through");[1] or

14.2.2.1.2 from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection ("Exports");1 or

14.2.2.1.3 to serve Load within the NYCA.

In summary, the NTAC will be applied to all Energy Transactions, including internal New York State Loads and Wheels Through and Exports out of the NYCA at a uniform, non-discountable rate.

14.2.2.2 NTAC Calculation

14.2.2.2.1 NTAC Formula

Beginning with January 2001, NYPA shall calculate the NTAC applicable to Transmission Service to serve New York State Load, Wheels Through and Exports as follows:

---

[1] The NTAC shall not apply to Wheels Through or Exports scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

$NTAC = \{(ATRR_{NTAC} \div 12) - (EA) - (IR \div 12) - SR - CRN - WR - ECR - NR - NT\}/(BU \div 12)$

Where:

$ATRR_{NTAC}$ = NYPA's Annual Transmission Revenue Requirement for costs not recoverable through project-specific transmission revenue requirements, which includes the Scheduling, System Control and Dispatch Costs of NYPA's control center, all as determined in accordance with the Formula Rate Template provided in Section 14.2.3.1 of this Attachment, and as reflected on SCH - Summary, line 11 of the Formula Rate Template;

EA = Monthly Net Revenues from Modified Wheeling Agreements, Facility Agreements and Third Party TWAs, and Deliveries to directly connected Transmission Customers;

SR = $SR_1 + SR_2$

SR_1 will equal the revenues from the Direct Sale by NYPA of Original Residual TCCs, and Grandfathered TCCs associated with ETAs, the expenses for which are included in NYPA's $ATRR_{NTAC}$ where NYPA is the Primary Owner of said TCCs.

SR_2 will equal NYPA's revenues from the Centralized TCC Auction allocated pursuant to Attachment M; this includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; and (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for these ETAs are included in NYPA's $ATRR_{NTAC}$.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Providers sell through the Centralized TCC

Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N).

SR_1 shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (i.e., January actual data will be used in February to calculate the NTAC effective in March). SR_1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that NYPA will receive under each applicable TCC sold in a Direct Sale divided by the duration of the TCC (in months).

SR_2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR_2 shall be adjusted after each Centralized TCC Auction, and the revised SR_2 shall be effective at the start of each Capability Period;

ECR = NYPA's share of Net Congestion Rents in a month, calculated pursuant to Attachment N. The computation of ECR is exclusive of any Congestion payments or Rents included in the CRN term;

CRN = Monthly Day-Ahead Congestion Rents in excess of those required to offset Congestion paid by NYPA's SENY governmental customers associated with the NYPA OATT Niagara/St. Lawrence Service reservations, net of the Initial Cost.

IR = A. The amount that NYPA will credit to its $ATRR_{NTAC}$ assessed to the SENY Load on account of the foregoing NYPA Niagara/St. Lawrence OATT reservations for SENY governmental customers. Such annual revenues will be computed as the product ("Initial Cost") of NYPA's current OATT system rate of \$2.23 per kilowatt per month and the 600 MW of TCCs (or the amount of TCCs reduced by Paragraph C below). In the event NYPA sells these TCCs (or any part thereof), all revenues from these sales will offset the NTAC and the Initial Cost will be concomitantly reduced to reflect the net amount of Niagara/St. Lawrence OATT Reservations, if any, retained by NYPA for the SENY Load. The parties hereby agree that the revenue offset to NTAC will be the greater of the actual sale price obtained by NYPA for the TCCs sold or that computed at the applicable system rate in accordance with Paragraph B below;

B. The system rate of \$2.23 per kilowatt per month will be benchmarked to the $ATRR_{NTAC}$ for NYPA transmission initially accepted by FERC ("Base Period $ATRR_{NTAC}$") for the purposes of computing the Initial Cost. Whenever an amendment to the $ATRR_{NTAC}$ is accepted by FERC or the $ATRR_{NTAC}$ is updated pursuant to the procedures set forth in Section 14.2.3.2 of this Attachment ("Amended $ATRR_{NTAC}$"), the system rate for the purpose of computing the Initial Cost will be increased (or decreased) by the ratio of the Amended $ATRR_{NTAC}$ to the Base Period $ATRR_{NTAC}$ and the effect of Paragraph A on NTAC will be amended accordingly.

C. If prior to the Centralized TCC Auction all Grandfathered Transmission Service including NYPA's 600 MW Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers are found not to be feasible, then such OATT reservations will be reduced until feasibility is assured. A reduction, subject to a 200 MW cap on the total reduction as described in Attachment M, will be applied to the NYPA Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers.

WR = NYPA's revenues from external sales (Wheels Through and Exports) not associated with Existing Transmission Agreements in Attachment L, Tables 1 and 2 and Wheeling revenues from OATT reservations extending beyond the start-up of the ISO;

NR = NYPA Reserved1 + NYPA Reserved2

NYPA Reserved1 will equal NYPA's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for NYPA's RCRR TCCs.

NYPA Reserved2 will equal the value that NYPA receives for the sale of RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the months remaining until the expiration of that RCRR TCC.

NT = The amount of actual NYPA transmission revenues minus NYPA's monthly revenue requirement.

BU = Annual Billing Units are New York State Loads and Loads associated with Wheels Through and Exports in megawatt-hours ("MWh").

The $ATRR_{NTAC}$ and SR will not include expenses for NYPA's purchase of TCCs or revenues from the sale of such purchased TCCs or from the collection of Congestion Rents for such TCCs.

The ECR, EA, CRN, WR, NR, and NT shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (i.e., January actual data will be used in February to calculate the NTAC effective in March).

The NTAC shall be calculated as a $/MWh charge and shall be applied to Actual Energy Withdrawals, except for Wheels Through and Exports in which case the NTAC shall be applied to scheduled Energy quantities. The NTAC shall not apply to scheduled quantities that are Curtailed by the ISO.

14.2.2.2.2 Implementation of NTAC

At the start of LBMP implementation certain variables of the NTAC equation will not be available. For the first and second months of LBMP implementation, the only terms in the NTAC equation that will be known by NYPA are its historical Annual Transmission Revenue Requirement ($ATRR_{NTAC}$) and the historical Billing Units (BU), which have been approved by or filed with FERC. For these two months NYPA shall calculate the NTAC using the following equation:

$$NTAC = \{(ATRR_{NTAC} \div 12) - (EA) - (IR \div 12)\}/(BU \div 12)$$

SR_2 shall not be available until after the first Centralized TCC Auction. For the third month of LBMP implementation until the second month of the Capability Period corresponding to the first Centralized TCC Auction, NYPA shall recalculate the NTAC using the following equation:

$$NTAC = \{(ATRR_{NTAC} \div 12) - (EA) - (IR \div 12) - WR - CRN - SR_1 - ECR\}/(BU \div 12)$$

Prior to and during implementation of LBMP those current NYPA transmission customers wishing to terminate their Third Party TWAs shall notify the ISO. The ISO shall duly inform NYPA of such conversion so that NYPA can calculate revenues (EA) to be derived from Existing Transmission Wheeling Agreements.

14.2.2.2.3

NYPA's recovery pursuant to NTAC initially is limited to expenses and return associated with its transmission system as that system exists at the time of FERC approval of the NTAC ("base period revenue requirement"). Additions to its system may be included in the computation of NTAC only if: a) upgrades or expansions do not exceed $5 million on an annual basis; or b) such upgrades or expansions have been unanimously approved by the Member Systems. Notwithstanding the above, NYPA may invest in transmission facilities in excess of $5 million annually without unanimous Member Systems' authorization outside the NTAC recovery mechanism. In that case, NYPA cannot recover any expenses or return associated with such additions under NTAC and any TCC or other revenues associated with such additions will not be considered NYPA transmission revenue for purposes of developing the NTAC nor be used as a credit in the allocation of NTAC to transmission system users.

14.2.2.3 Filing and Posting of NTAC

NYPA shall coordinate with the ISO to update certain components of the NTAC formula on a monthly or Capability Period basis. NYPA may update the NTAC calculation to change the $ATRR_{NTAC}$, initially approved by FERC, and such updates shall be submitted to FERC each year as part of NYPA's informational filing pursuant to Section 14.2.3.2.6 of this Attachment. An integral part of the agreement between the other Member Systems and NYPA is NYPA's consent to the submission of its $ATRR_{NTAC}$ for FERC review and approval on the same basis and subject to the same standards as the Revenue Requirements of the Investor-Owned Transmission Owners. Each January, beginning with January 2001, the ISO shall inform NYPA of the prior year's actual New York internal Load requirements and the actual Wheels Through and Exports and shall post this information on the OASIS. NYPA shall change the BU component of the NTAC formula to reflect the prior calendar year's information, with such change to take effect beginning with the March NTAC of the current year. NYPA will calculate the monthly NTAC and provide this information to the ISO by no later than the fourteenth day of each month, for posting on the OASIS to become effective on the first day of the next calendar month. Beginning with LBMP implementation, the monthly NTAC shall be posted on the OASIS by the ISO no later than the fifteenth day of each month or as soon thereafter as is reasonably possible but in no event later than the 20th of the month to become effective on the first day of the next calendar month.

14.2.2.4 NTAC Calculation Information

NYPA's $ATRR_{NTAC}$ for facilities owned as of January 31, 1997, and Annual Billing Units (BU) of the NTAC are:

$ATRR_{NTAC}$ = $165,449,297

BU = 133,386,541MWh

NYPA's $ATRR_{NTAC}$ is subject to FERC review because it is collected through the ISO's jurisdictional rates, and will be filed, together with any project-specific revenue requirements, with the Commission each year for informational purposes pursuant to Section 14.2.3.2.6 of this Attachment.

14.2.2.5 Billing

The New York State Loads, Wheels Through, and Exports will be billed based on the product of: (i) the NTAC; and (ii) the Customer's billing units for the Billing Period. The billing units will be based on the metered energy for all Transactions to supply Load in the NYCA during the Billing Period, and hourly Energy schedules for the Billing Period for all Wheels Through and Exports.

19.5 Reservation of Transmission Capacity in a Centralized TCC Auction through RCRR TCCs

19.5.1 Before each Centralized TCC Auction, the ISO shall, subsequent to performing the reduction process pursuant to Section 19.8.2 of this Attachment M, determine the number of RCRRs between each of the following contiguous pairs of Load Zones within the NYCA that the ISO shall allocate to each Member System: West – Genesee; Genesee – Central; North – Mohawk Valley; Central - Mohawk Valley; Mohawk Valley – Capital; Capital - Hudson Valley; Hudson Valley – Millwood; Millwood – Dunwoodie; Dunwoodie - New York City; Dunwoodie - Long Island.

The ISO shall determine the number of RCRRs that the ISO shall allocate for each of these Load Zone pairs by maximizing the number of RCRRs between each Load Zone pair that are simultaneously feasible with all TCCs and Grandfathered Rights listed in Section 19.8.2 (i), and Table 1 ETCNL/TCCs that remain~~s~~ after reduction pursuant to Section 19.8.2 of this Attachment M.

To do so, the ISO will use the same optimization model that is used in determining the award of TCCs in a Centralized TCC Auction, and will represent each TCC and Grandfathered Right listed in Section 19.8.2 (i), Table 1 ETCNL/TCCs remaining after reduction pursuant to Section 19.8.2, and a large number of RCRRs in the model as fixed injections and withdrawals. The Centralized TCC Auction software will determine the maximum number of RCRRs for each Load Zone pair by maximizing the area under the bid curve $Bids_j$ as expressed by the following formula, subject to the constraint that the injections and withdrawals corresponding to the TCCs, Grandfathered Rights listed in Section 19.8.2 (i) and Table 1 ETCNL/TCCs remaining after reduction pursuant to Section 19.8.2, and potential RCRRs must correspond to a simultaneously feasible Power Flow:

$$\sum_{j \in N} \int_{0}^{A_j} Bids_j$$

Where,

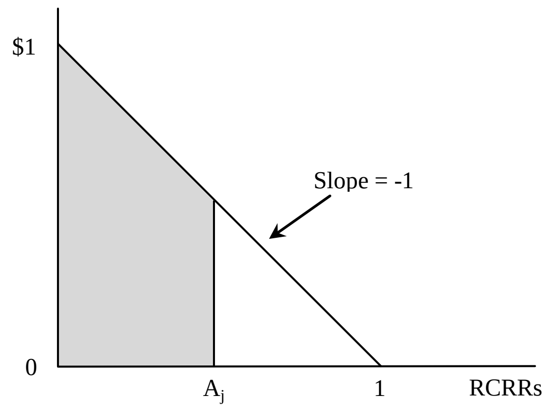
j = A Load Zone pair

N = The set of all Load Zone pairs for which the ISO shall calculate RCRRs

A_j = The number of RCRRs defined between Load Zone pair *j*

$Bids_j$ = The line that intersects the y-axis at \$1/TCC and which intersects the x-axis at 1 MW, as illustrated in the bid curve illustrated below.

Bid Curve $Bids_j$ for $RCRR_j$



The ISO shall determine the POI and POW of each RCRR by assigning the POI and POW that the ISO expects, based on the ISO's review of historical and other information available to the ISO, to produce positive Congestion payments to a Member System that converts the RCRR into an RCRR TCC for the majority of the duration, in hours, of the longest duration TCCs to be sold in the relevant Centralized TCC Auction.

19.5.2 The ISO shall allocate RCRRs between each Load Zone pair to each Member System in an amount equal to the product of (i) the number of RCRRs between the Load Zone pair for the Centralized TCC Auction as calculated pursuant to Section 19.5.1 of this Attachment M, and (ii) the Member System's allocation factor for that Load Zone pair, which shall be calculated pursuant to the following formula:

$$\text{Allocation Factor}_{\text{t,j}} = \frac{\sum_{a\in A}\left(\text{Interface Revenue}_{t,j,a}\right)}{\sum_{\substack{t\in T\\ a\in A}}\left(\text{Interface Revenue}_{t,j,a}\right)}$$

Where,

Allocation $\text{Factor}_{t,j}$	=	The allocation factor used by the ISO to allocate a share of RCRRs between Load Zone pair *j* to Member System *t* for a Centralized TCC Auction
Interface $\text{Revenue}_{t,j,a}$	=	The revenue from the sale of TCCs (excluding those TCCs for which revenue is allocated to a Member System pursuant to Sections 20.3.3 through 20.3.5 of Attachment N) associated with the Interface between Load Zone pair *j* in Centralized TCC Auction *a* assigned to Member System *t*

t	=	A Member System
T	=	The set of all Member Systems
a	=	A Centralized TCC Auction
A	=	The set of Centralized TCC Auctions beginning with the Centralized TCC Auction held for the 2000 Summer Capability Period and ending with the Centralized TCC Auction held for the 2003-2004 Winter Capability Period
j	=	A Load Zone pair.

19.5.3 Subject to the limitations set forth in Section 19.5.4 of this Attachment M, a Member System allocated an RCRR pursuant to Section 19.5.2 of this Attachment M shall have a right prior to each Centralized TCC Auction to convert each RCRR into an RCRR TCC. Each RCRR TCC will have a duration of 6 months and will have the same POW and POI as the RCRR from which it was converted. If a Member System fails to exercise its right to convert an RCRR into an RCRR TCC in the manner and by the date specified in this Section 19.5.0, the Member System shall forfeit the RCRR. Each RCRR shall be valid only for the Centralized TCC Auction for which it was allocated.

19.5.4 Notwithstanding any other provisions of this Section 19.5.0, a Member System shall not convert an amount greater than the Capacity Reservation Cap of the Member System's RCRRs into RCRR TCCs.

RCRRs may be converted only into whole RCRR TCCs. If the Capacity Reservation Cap multiplied by the number of RCRR does not yield a whole number, then the number of RCRR TCCs that a Member System shall have a right to convert from RCRRs will be reduced to the nearest integer and the number of RCRRs that a Member System shall not have a right to convert to RCRR TCCs will be increased to the nearest integer.

19.5.5 Before each Centralized TCC Auction, the ISO shall, subsequent to performing the reduction process pursuant to Section 19.8.2 of this Attachment M, determine the number of RCRRs that each Member System shall have a right to convert to RCRR TCCs. The ISO shall notify each Member System of the ISO's determination with regard to its RCRRs in a written notice to be received by the Member System on or before the date specified in the timeline for the relevant Centralized TCC Auction posted on the ISO's website, as that timeline may be revised from time to time.

19.5.6 A Member System may exercise its right to convert its RCRRs into RCRR TCCs by notifying the ISO of the number of the Member System's RCRRs that the Member System elects to convert to RCRR TCCs. The Member System shall make the notification in a written notice, in accordance with ISO Procedures, to be received by the ISO on or before the date specified in the timeline for the relevant Centralized TCC Auction posted on the ISO's website, as that timeline may be revised from time to time. After receipt by the ISO, the Member System's notification shall not be modified or revoked, except by permission of the ISO.

19.5.7 A Member System shall not transfer (by sale or otherwise) its RCRR TCCs except through a Centralized TCC Auction or Reconfiguration Auction, and shall not sell its RCRR TCCs through Direct Sales or through Secondary Markets.

19.8 Auctions for TCCs

19.8.1 Overview

The ISO will conduct Centralized TCC Auctions before each Capability Period. Winning bidders in each such auction will purchase TCCs that will be valid for one or more Capability Periods, beginning with the first Capability Period that begins after the conclusion of the auction. The ISO will also conduct Reconfiguration Auctions each month. Winning bidders in each such auction will purchase TCCs that will be valid for the calendar month that follows the conclusion of the auction.

19.8.2 Description of the Reduction Process For Reducible ETCNL/GFTCCs

Before each Centralized TCC Auction, the ISO shall ensure that all of the following correspond to a simultaneously feasible security constrained Power Flow: (i) existing TCCs and Grandfathered Rights that are valid for any part of the duration of any TCCs to be sold in the Centralized TCC Auction, including but not limited to Fixed Price TCCs that were created pursuant to Section 19.2.1 or 19.2.2.of this Attachment M and Incremental TCCs awarded pursuant to Section 19.2.4 of this Attachment M; Grandfathered TCCs not subject to reduction and Original Residual TCCs to the extent not previously used to support the purchase of TCCs that are valid for any part of the duration of any TCCs to be sold in the Centralized TCC Auction (henceforth "TCCs and Grandfathered Rights listed in Section 19.8.2 (i)"); and (ii) ETCNL (to the extent not previously used to support the purchase of TCCs that are valid for any part of the duration of any TCCs to be sold in the Centralized TCC Auction) and Grandfathered TCCs subject to reduction as listed in Table 1 of this Attachment M (henceforth "Table 1 ETCNL/TCCs"). In some cases, the total set of all the TCCs, Grandfathered Rights, and Table 1 ETCNL/TCCs listed in (i) through (ii) above may not correspond to a simultaneously feasible

Power Flow in some period of time. In such cases, Table 1 ETCNL/TCCs, will be reduced for that period in order to make the total set of TCCs and Grandfathered Rights listed in Section 19.8.2 (i), and Table 1 ETCNL/TCCs remaining after reduction correspond to a simultaneously feasible Power Flow.

This reduction procedure will use the same optimization model that will be used in the Centralized TCC Auction to determine the amount by which Table 1 ETCNL/TCCs will be reduced. Each of the TCCs and Grandfathered Rights listed in Section 19.8.2 (i) above will be represented in the Centralized TCC Auction model by a fixed injection of 1 MW at its Point of Injection, and a fixed withdrawal of 1 MW at its Point of Withdrawal. In addition, Table 1 ETCNL/TCCs will be represented in the model, but they will be represented in such a way as to allow their reduction. To do so, bids for each Table 1 ETCNL/TCC will consist of a line which intersects the y-axis at $1/TCC (or any other value selected by the ISO, so long as that value is constant for each bid curve for all of these Table 1 ETCNL/TCCs) and which intersects the x-axis at 1 MW. An example of the bid curve B_j for a representative Table 1 ETCNL/TCC is illustrated in the diagram below.

The TCC auction software will determine the amount of each Table 1 ETCNL/TCC that will remain after reduction, which is designated as A_j in the diagram. The objective function that the TCC auction software will use to determine these coefficients A_j will be to maximize:

$$\sum_{j \in N} \int_{0}^{A_j} \mathrm{B}_j$$

Where:

N = The set of Table 1 ETCNL/TCCs

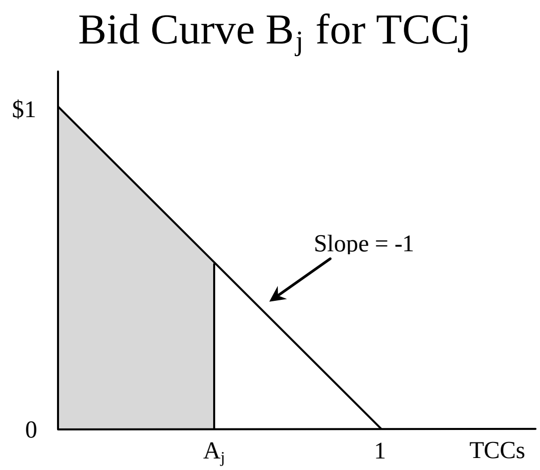
j = Any individual Table 1 ETCNL/TCC

A_j = Any amount of each Table 1 ETCNL/TCC(j) remaining

B_j = As defined by the diagram

subject to the constraint that injections and withdrawals corresponding to the TCCs and Grandfathered Rights listed in Section 19.8.2 and Table 1 ETCNL/TCCs remaining after reduction must be simultaneously feasible in a Power Flow.

As a result, the objective function will maximize the area under the bid curve for each Table 1 ETCNL/TCC that remains after reduction, summed over all Table 1 ETCNL/TCCs, subject to the simultaneous feasibility constraint. This area for one Table 1 ETCNL/TCC is illustrated in the following diagram:



The ISO shall apply this methodology as follows:

19.8.2.1 first, on the Table 1 ETCNL/TCCs (prior to the conversion of any ETCNL to ETCNL TCCs), and

19.8.2.2 second, on the Table 1 ETCNL/TCCs remaining after conversion into ETCNL TCCs of ETCNL included in such Table 1 ETCNL/TCCs.

For purpose of the second reduction, a holder of ETCNL may elect to disaggregate the ETCNL in accordance with ISO Procedures prior to conducting the reduction process. If a TO elects to have its ETCNL disaggregated, the number of MW of ETCNL allocated to that TO specifying each Load Zone as its POW shall be replaced by the same number of MW of ETCNL, specifying the same POI as the original ETCNL, but specifying various buses within that Load Zone as the POWs, as determined in accordance with ISO Procedures.

To the extent more than one model is used in a given Centralized TCC Auction (*e.g.* to reflect different summer / winter ratings), the ISO shall retest the Table 1 ETCNL/TCCs remaining after reduction so as to avoid reducing the Table 1 ETCNL/TCCs more than is necessary to prevent infeasibility in a given Sub-Auction. However, any Table 1 ETCNL/TCC that is deemed infeasible in one Centralized TCC Auction may be deemed reduced and not eligible for retesting in a subsequent Centralized TCC Auction.

19.8.3 Transmission Capacity Sold in Centralized Auctions for TCCs

Transmission Owners with ETCNL will release that transmission Capacity to support the sale of TCCs in each Centralized TCC Auction, unless the Transmission Owner has converted the ETCNL into ETCNL TCCs pursuant to Section 19.4 of this Attachment M. Transmission Owners which have not sold their Original Residual TCCs through a Direct Sale on the OASIS prior to the Centralized TCC Auction, shall sell them through the Centralized TCC Auction. Transmission Owners may retain their Grandfathered TCCs. If it sells Grandfathered TCCs, a Transmission Owner shall do so either through Direct Sales or through Centralized TCC Auctions or Reconfiguration Auctions.

Capacity associated with the termination of ETAs in effect on November 19, 1999, listed in Table 1A of Attachment L to this OATT (as it may be amended), that conferred transmission rights on an LSE and is not used to create Fixed Price TCCs, pursuant to Section 19.2.1 of this Attachment M shall be converted into Residual Transmission Capacity.

In each Centralized TCC Auction, the following transmission Capacity not required to support already-outstanding TCCs or Grandfathered Rights and not withheld pursuant to Section 19.1.1 of this Attachment M shall be available to support TCCs that can be purchased in that Centralized TCC Auction:

19.8.3.1 following any reduction pursuant to Section 19.8.2 of this Attachment M, all of the transmission Capacity associated with ETCNL (a) that the Transmission Owners do not sell through a Direct Sale in advance of the Auction, (b) that the Transmission Owners do not convert to ETCNL TCCs, and (c) that has not been used to support the sale of existing TCCs that are valid for any part of the duration of any TCCs sold in the Centralized TCC Auction;

19.8.3.2 all of the transmission Capacity associated with Original Residual TCCs, that the Transmission Owners do not sell through a Direct Sale in advance of the Auction and that has not been used to support the sale of existing TCCs that are valid for any part of the duration of any TCCs sold in the Centralized TCC Auction;

19.8.3.3 all of the transmission Capacity associated with TCCs offered for sale by TCC Primary Holders; and

19.8.3.4 any Residual Transmission Capacity.

19.8.4 Centralized TCC Auctions

TCCs with durations of 6 months and 1 year shall be available in each Centralized TCC Auction. TCCs with durations of 2 years, 3 years, 4 years, or 5 years may also be available in this Auction, at the ISO’s discretion.

The final decision concerning the percentage of the transmission Capacity that will be available in the Centralized TCC Auction to support TCCs of different durations will be made by the ISO. The ISO will conduct a polling process to assess the market demand for TCCs with different durations, which it will take into consideration when making this determination. The ISO may elect not to sell any TCCs with one or more of the above durations. However, all transmission Capacity not associated with ETAs or outstanding TCCs or not reserved through conversion of ETCNL to ETCNL TCCs or RCRRs to RCRR TCCs must be available to support TCCs of some duration sold in the Centralized TCC Auction.

The Centralized TCC Auction will consist of a series of Sub-Auctions, which will be conducted consecutively. In each Sub-Auction, TCCs of a single duration will be available (*e.g.*, only TCCs with a five-year duration might be available in one Sub-Auction). Sub-Auctions will be conducted in decreasing order of the length of the period for which TCCs sold in the Sub-Auction are valid. Therefore, if the ISO were to determine that five years would be the maximum length of TCCs available in the Centralized TCC Auction, then the Sub-Auction for TCCs with a duration of five years would be held first. All TCCs sold in the 5-year TCC Sub-Auction (other than those offered for sale in the next Sub-Auction, as described in Section 19.9.1) would then be modeled as fixed injections and withdrawals in the next Sub-Auction, in which TCCs of the next longest duration, as determined by the ISO (*e.g.*, four years), would be available for purchase. Following that Sub-Auction, TCCs sold in either of the first two Sub-Auction (other than those offered for sale in the next Sub-Auction) would then be modeled as fixed injections and withdrawals in the third Sub-Auction (*e.g.*, a Sub-Auction for TCCs with a duration of three years), etc.

Each Sub-Auction shall normally consist of at least four rounds unless the Transmission Owners that are subject to Attachment N of this Tariff unanimously consent to fewer rounds. The ISO shall have the authority to determine the percentage of the available transmission Capacity that will be available to support TCCs sold in each round of each Sub-Auction such that all of the transmission Capacity offered for sale in that Sub-Auction shall be offered by the last round of that Sub-Auction. The ISO shall announce these percentages before the Sub-Auctions. The "scaling factor" for each round shall equal the percentage of available transmission Capacity that has not yet been made available to support the sale of TCCs in previous rounds, divided by the percentage of available transmission Capacity that will be made available to support the sale of TCCs in that round.

The ISO shall also determine the maximum duration of TCCs sold in the Centralized TCC Auction, and whether the TCCs sold in the Centralized TCC Auction shall be separately available for purchase as on-peak and off-peak TCCs. (For purposes of this Attachment, the on-peak period will include the hours from 7 a.m. to 11 p.m. Prevailing Eastern Time Monday through Friday. The remaining hours in each week will be included in the off-peak period.)

19.8.5 Reconfiguration Auctions

A Reconfiguration Auction is an auction in which monthly TCCs may be offered and purchased. This will allow Market Participants to purchase and sell short-term TCCs. Reconfiguration Auctions will also capture short-term changes in transmission Capacity. The ISO will conduct Reconfiguration Auctions monthly and TCCs purchased in Reconfiguration Auctions will be valid for the month following the Reconfiguration Auction. A Reconfiguration Auction will consist of a single round. Any Primary Holder of a TCC that is valid for the month in which TCCs are being sold in the Reconfiguration Auction, including a purchaser of a TCC in a Centralized TCC Auction that has not sold that TCC and a Transmission Owner that is the Primary Owner of an ETCNL TCC or a Member System that is the Primary Holder of a RCRR TCC, may offer that TCC for sale in a Reconfiguration Auction; provided however that the sale of TCCs in a Reconfiguration Auction shall be subject to the limitations and prohibitions set forth in this ISO OATT including the limitation on the sale or transfer of Fixed Price TCCs and the limitation on the sale or other transfer of Incremental TCCs. The transmission Capacity used to support these TCCs, as well as any other transmission Capacity not required to support already-outstanding TCCs or Grandfathered Rights, will be available to support TCCs purchased in the Reconfiguration Auction.

Transmission Capacity made available for transmission rights in durations of no more than one month pursuant to Section 19.1.1 shall be released in Reconfiguration Auctions.

19.9 Procedures for Sales of TCCs in Each Auction

19.9.1 Auction Structure

Participation in a Sub-Auction-TCCs may be offered for sale in each Sub-Auction round of the Centralized TCC Auction.

TCCs purchased in any round of any Sub-Auction may be resold in a subsequent round of that Sub-Auction. For example, the purchaser of a 5-year TCC purchased in the 5 year Sub-Auction may release a 4-year TCC with the same Point of Injections and Point of Withdrawal for sale in the 4-year Sub-Auction. Similarly, that purchaser could instead release a corresponding 3-year TCC for sale in the 3-year Sub-Auction.

The following holders of TCCs may offer to sell TCCs in any round of a Sub-Action appropriate to their duration (i) Primary Holders who did not sell those TCCs in a Direct Sale or in a previous round of the Centralized TCC Auction ; (ii) purchasers of TCCs in previous rounds of that Centralized TCC Auction or in previous Auctions who have not subsequently sold those TCCs through an Auction; and (iii) purchasers of TCCs through a Direct Sale who qualify to become Primary Holders and have not already sold those TCCs through an Auction or through a Direct Sale, provided however that the sale of TCCs shall be subject to the limitations and prohibitions set forth in this ISO OATT including the limitation on the sale or transfer of Fixed Price TCCs and the limitation on the sale or other transfer of Incremental TCCs.

19.9.1.1 Bid Requirements

Bidders shall submit Bids into the Auction in accordance with this Attachment and ISO Procedures. Bidders shall submit Bids such that the sum of the value of its Bids (excluding Bids for TCCs already held by that bidder) shall not exceed that bidder’s ability to pay for TCCs, as determined by ISO Procedures.

19.9.1.2 Bidding Rounds

Bidders shall be awarded TCCs in each round of the Auction and shall be charged the market clearing price for that round, as defined in this Attachment, for all TCCs they purchase.

19.9.1.3 Reconfiguration Auctions

All rules stated in this Section 19.9 for the auction rounds of a Centralized TCC Auction shall also apply to Reconfiguration Auctions unless otherwise stated or the context otherwise requires it. The scaling factor for the single round of a Reconfiguration Auction shall be one.

19.9.2 Responsibilities of the ISO

The ISO shall establish the Auction rules and procedures consistent with this Tariff. The ISO shall conduct the Optimal Power Flows in each round of the Centralized TCC Auction. The ISO will verify that the Optimal Power Flows calculated in each round of the Centralized TCC Auction corresponds to a simultaneously feasible Power Flow as described in Section 19.9.7 of this Attachment M. The ISO shall notify the Transmission Owners if: (1) the Optimal Power Flow results calculated are inaccurate; or (2) the Optimal Power Flow is not calculated in accordance with the correct procedure.

Additionally, the ISO will determine the information pertaining to the Auction to be made available to Centralized TCC Auction participants over the OASIS and publish information on its OASIS accordingly. The ISO may develop a list of POIs and POWs between which TCCs may not be purchased and shall post such list on its OASIS. The ISO will identify the details to be included in development of the Auction software and arrange for development of the software.

The ISO will apply the credit requirements established in this ISO OATT and Attachment K of the Services tariff to Primary Holders of TCCs and to bidders in the Centralized TCC Auctions and Reconfiguration Auctions.

The ISO shall not reveal the Bid Prices submitted by any bidder in the Auction until three months after the Bids were submitted. When these Bid Prices are posted, the names of the bidders shall not be publicly revealed, but the data shall be posted in a way that permits third parties to track each individual bidder's Bids over time.

The ISO will settle all Centralized TCC Auctions and Reconfiguration Auctions, and will settle all Congestion settlements related to the Day-Ahead Market, pursuant to Attachment N.

19.9.3 Additional Responsibilities of the ISO

The ISO shall be capable of completing the Centralized TCC Auction within the time frame specified in this Attachment M.

The ISO will establish an auditable information system to facilitate analysis and acceptance or rejection of Bids, and to provide a record of all Bids and the award of Fixed Price TCCs. The ISO shall also provide all necessary assistance in the resolution of disputes that arise from questions regarding the acceptance, rejection, award and recording of Bids, or the award of Fixed Price TCCs, pursuant to Sections 19.2.1 or 19.2.2.above. The ISO will establish a system to communicate Auction-related information to all Auction participants between rounds of the Auction. (This last requirement will not apply to single-round Auctions.)

The ISO will receive Bids to buy TCCs from any entity that meets the eligibility criteria established in this ISO OATT and will implement the Auction bidding rules previously established by the ISO. In accordance with ISO Procedures, the ISO shall unbundle TCCs in accordance with a request made by a Transmission Customer awarded a TCC. Unbundling

TCCs shall consist of replacing that TCC with an equivalent set of TCCs. In all cases, the amount payable to (or by) the Primary Holder of such a set of TCCs will be equal to the amount payable to (or by) the Primary Holder of the original TCC.

The ISO will be required to solve Optimum Power Flows for the NYS Transmission System; properly utilize an Optimum Power Flow program to determine the set of winning Bids for each round of the Centralized TCC Auction; and calculate the market clearing price of all TCCs at the conclusion of each round of the Centralized TCC Auction, in the manner described in this Attachment M.

19.9.4 Responsibilities of each Bidder

To qualify to submit Bids and offers in a Centralized TCC Auction, a party shall register as a Customer or Transmission Customer and shall otherwise comply with all applicable registration requirements established in ISO Procedures. All Customers and Transmission Customers seeking to submit Bids and Offers in a Centralized TCC Auction shall comply with all applicable credit requirements as set forth in Attachment K of the Services tariff.

Each bidder shall submit Bids to purchase and sell TCCs into the Centralized TCC Auction in accordance with this Attachment M and ISO Procedures. Each bidder shall submit the following information with its Bids to purchase TCCs: (i) the number of TCCs for which an offer to purchase is made, (ii) the Bid Price (in $/TCC) which represents the maximum amount the bidder is willing to pay for the TCC (Bid Prices may be negative, indicating that a bidder would have to be paid in order to accept a TCC); (iii) the location of the Point of Injection and the Point of Withdrawal for the TCC to which the Bid applies (these locations may be any locations for which the ISO calculates an LBMP and which is otherwise available as a TCC POI or POW); and (iv) if the Auction is a Centralized TCC Auction, the duration in multiples of

Capability Periods of the TCC for which the bidder is bidding. Additionally, if the ISO offers TCCs for sale that are valid in sub-periods (e.g., on-peak or off-peak TCCs), this information must also be provided by the Bidder.

Each bidder must submit such information to the ISO regarding the bidder's or LSE's creditworthiness as the ISO may require, along with a statement signed by the bidder, or LSE representing that the bidder or LSE is financially able and willing to pay for the TCCs for which it is bidding or converting. The aggregate value of the Bids submitted by any bidder into the Auction shall not exceed that bidder's ability to pay or the maximum value of Bids that bidder is permitted to place, as determined by the ISO (based on an analysis of that bidder's creditworthiness).

19.9.5 Selection of Winning Bids and Determination of the Market Clearing Price

The ISO shall determine the winning set of Bids in each round of the Centralized TCC Auction as follows: (i) the ISO shall use an Optimal Power Flow program with the initial assumptions identified by the ISO; (ii) the Optimal Power Flow shall use the same Reference Bus and system security constraints assumptions as used by the ISO subject to ISO Procedures; (iii) the ISO shall select the set of Bids that maximizes the value of the TCCs awarded to the winning bidders; (iv) the aggregate market value of the TCCs awarded to each bidder shall not exceed that bidder's ability to pay, since each bidder is not allowed to Bid more than its ability to pay as determined by the ISO; and (v) the selected set of Bids must be simultaneously feasible as described in this Attachment.

In the Centralized TCC Auction, if the ISO elects to perform separate Auctions for on-peak and off-peak TCCs, the procedure used to select winning Bids in an on-peak Auction will not depend on winning Bids selected in an off-peak Auction; nor shall the procedure used to select winning Bids in an off-peak Auction depend on winning Bids selected in an on-peak Auction.

The market clearing price for each TCC in each round of a Centralized TCC Auction shall be determined using a similar algorithm to that used to determine LBMPs (refer to Attachment J and ISO Procedures). The market clearing price for each TCC shall be based on the lowest winning Bid made in that round for that TCC (or for other TCCs if injections and withdrawals corresponding to those TCCs would have the same impact on flows over congested Interfaces as injections and withdrawals corresponding to that TCC).

19.9.6 Settlements, Billing, Payment, and Disputes

Each bidder must pay the market clearing price for each TCC it is awarded in the Centralized TCC Auction.

Charges for TCCs awarded in the Centralized TCC Auction, shall be billed upon completion of the Centralized TCC Auction or Reconfiguration Auction process through the delivery of an award notice by the ISO. The ISO shall establish a dispute period following the conclusion of the Centralized TCC Auction during which challenges to awards may be made and mistakes in the calculation of market clearing prices may be corrected. Notice of the dispute period established by the ISO and of procedures to be employed in bringing a dispute or correcting a market clearing price shall be provided by the ISO on its OASIS.

Following the resolution of challenges, if any, to Centralized TCC Auction or Reconfiguration Auction awards, or mistakes in the calculation of market clearing prices, raised during the dispute period, charges and payments for TCCs awarded or sold in the Centralized TCC Auction and Reconfiguration Auction shall be final as provided in the award notices provided by the ISO and shall not be subject to revision.

19.9.7 Simultaneous Feasibility

The set of winning Bids selected in each round of a Sub-Auction shall correspond to a simultaneously feasible Power Flow.

The Power Flow must be able to accommodate in each round injections and withdrawals corresponding to each of the following TCCs and Grandfathered Rights: (i) TCCs not offered for sale in that round, including Grandfathered TCCs, Original Residual TCCs, or any other existing TCCs whether purchased in a previous Auction, an earlier round of the current Auction or otherwise acquired that are valid for any part of the duration of any TCCs to be sold in that round; (ii) Grandfathered Rights; and (iii) TCCs awarded in the current round. Each injection and withdrawal associated with TCCs and Grandfathered Rights will be multiplied by a scaling factor which apportions the transmission Capacity available among each of the rounds.

A set of injections and withdrawals shall be judged simultaneously feasible if it would not cause any thermal, voltage, or stability violations within the NYCA for base case conditions or any monitored contingencies.

When performing Power Flows for the purpose of determining simultaneous feasibility, injections for TCCs that specify a Load Zone as the Point of Injection will be modeled as a set of injections at each Load bus in the Load Zone containing the Point of Injection equal to the product of the number of TCCs and the ratio of Load served at each bus to Load served in the Load Zone, based on the bus Loads used in calculating zonal LBMPs.

When performing the above Power Flows, withdrawals for TCCs that specify a Load Zone as the Point of Withdrawal will be modeled as a set of withdrawals at each Load bus in the Load Zone containing the Point of Withdrawal equal to the product of the number of TCCs and the ratio of the Load served at each bus to the total Load served in the Load Zone based on the ISO’s estimate of the bus Loads used in calculating the Zonal LBMPs.

The Power Flow simulations shall take into consideration the effects of parallel flows on the transmission Capacity of the NYS Transmission System when determining which sets of injections and withdrawals are simultaneously feasible.

19.9.8 Information to be Made Available to Bidders

The ISO shall provide over the ISO's OASIS the expected non-simultaneous Total Transfer Capability for each Interface (as displayed on the OASIS).

The ISO shall make the following information available before each Centralized TCC or Reconfiguration Auction:

19.9.8.1 for each Generator bus, external bus and Load Zone for the previous ten (10) Capability Periods, if available, (a) the average Congestion Component of the LBMP, relative to the Reference Bus, and (b) the average Marginal Losses Component of the LBMP, relative to the Reference Bus;

19.9.8.2 for the previous two Capability Periods, (a) data from which the following can be determined: historical flow for each of the closed Interfaces, and (b) historically, the number of hours that the most limiting facilities were physically constrained;

19.9.8.3 Subject to a Transmission Customer's completion of a non-disclosure agreement in the form required by ISO procedures: (a) Power Flow data to be used as the starting point for the Centralized TCC Auction or Reconfiguration Auction, including all assumptions, (b) all limits associated with transmission facilities, contingencies, thermal, voltage and stability to be monitored as constraints in the Optimum Power Flow determination;

19.9.8.4 (a) assumptions made by the ISO relating to transmission maintenance outage schedules, and (b) the ISO summer and winter operating study results (non-simultaneous Interface Transfer Capabilities);

19.9.8.5 on its website no fewer than five (5) business days prior to the date on which a Centralized TCC Auction will begin, the number of megawatts of each set of ETCNL that each Transmission Owner has elected to convert to ETCNL TCCs for the Centralized TCC Auction and the RCRRs that each Member System has elected to convert to RCRR TCCs for the Centralized TCC Auction;

19.9.8.6 between each round of bidding during the Centralized TCC Auction, for all bidders bidding in subsequent rounds, the Market-Clearing Price, stated relative to the Reference Bus for each Generator bus, External bus and Load Zone; and

19.9.8.7 for each TCC awarded in each round, (a) the number of TCCs awarded, (b) the Point of Injection and Point of Withdrawal for that TCC, (c) the market clearing price for the TCC, and (d) the Auction participant awarded the TCC.

Items 19.9.8.1, 19.9.8.2, 19.9.8.3, 19.9.8.4(b), and 19.9.8.6 above shall be made available separately for on-peak and off-peak periods, if on-peak and off-peak TCCs will be separately available for purchase in the upcoming Auction.

The ISO will make available information about Secondary Market transactions, and all sales of TCCs by Direct Sale, to the extent received by the ISO.

20.1 Overview and Definitions

20.1.1 Overview

This Attachment N describes the Congestion settlements related to the Day-Ahead Market and the settlements related to Centralized TCC Auctions and Reconfiguration Auctions. Congestion Rent settlements for Real-Time Market Energy Transactions or Bilateral Transactions scheduled in the Real-Time Market are not addressed in this Attachment N.

Section 20.2 addresses the Congestion settlements related to each hour of the Day-Ahead Market. These settlements include, as applicable pursuant to this Attachment N, charges or payments for Congestion Rents for Energy Transactions in the Day-Ahead Market and for Bilateral Transactions scheduled in the Day-Ahead Market, and settlements with Primary Holders of TCCs. In addition, these settlements include, as applicable pursuant to this Attachment N, O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Congestion Rent Surplus Payments, and U/D Congestion Rent Surplus Payments. The ISO shall allocate to Transmission Owners the net of all of these settlements as Net Congestion Rents as described in this Attachment N.

Section 20.3 addresses the settlements in each round of each Centralized TCC Auction and in each Reconfiguration Auction. These settlements include, as applicable pursuant to this Attachment N, charges or payments to purchasers of TCCs, charges or payments to Primary

Holders selling TCCs, payments to Transmission Owners in a Centralized TCC Auction for ETCNL released into the Centralized TCC Auction, and payments to Transmission Owners for Original Residual TCCs that are released into the Centralized TCC Auction. In addition, these settlements include, as applicable pursuant to this Attachment N, O/R-t-S Auction Revenue Shortfall Charges, U/D Auction Revenue Shortfall Charges, O/R-t-S Auction Revenue Surplus

Payments, and U/D Auction Revenue Surplus Payments. The ISO shall allocate to Transmission Owners the net of all of these settlements as Net Auction Revenue as described in this Attachment N.

Provisions of this Attachment N applicable to a transmission facility outage or return-to-service shall not apply to a transmission facility derating or uprating. Charges and payments under this Attachment N shall be made to a Transmission Owner for a transmission facility derating or uprating only as specified in Sections 20.2.4.3 and 20.3.6.3.

This Attachment N shall not apply to the obligation to pay an outage charge which obligation attaches to persons or entities not otherwise subject to Section 20.2.5 of this Attachment N that own an Expansion (or a portion of an Expansion) associated with a temporary or final award of Incremental TCCs or which has been assigned Incremental TCCs related to an Expansion which Expansion is modeled as wholly or partially out of service for any hour in the Day-Ahead Market which obligation to pay to the ISO an outage charge shall be determined pursuant to Attachment M to the OATT.

Unless expressly provided for otherwise in the ISO Tariffs, such as in a rate schedule, this Attachment N shall apply to the Member Systems. This Attachment N shall only apply to Transmission Owners other than the Member Systems to the extent that the ISO Tariffs, such as in a rate schedule, do not provide otherwise.

20.1.2 Defined Terms Used in Attachment N

Capitalized terms used in this Attachment N shall have the meaning specified below in this Section 20.1.2, and capitalized terms used in this Attachment N but not defined below shall have the meaning given to them in Section 1 of the OATT:

Actual Qualifying Auction Derating: As defined in Section 20.3.6.3.1.

Actual Qualifying Auction Outage: As defined in Section 20.3.6.2.1.

Actual Qualifying Auction Return-to-Service: As defined in Section 20.3.6.2.1.

Actual Qualifying Auction Uprating: As defined in Section 20.3.6.3.1.

Actual Qualifying DAM Derating: As defined in Section 20.2.4.3.1.

Actual Qualifying DAM Outage: As defined in Section 20.2.4.2.1.

Actual Qualifying DAM Return-to-Service: As defined in Section 20.2.4.2.1.

Actual Qualifying DAM Uprating: As defined in Section 20.2.4.3.1.

Auction Status Change: Any of the following: Qualifying Auction Outage, Qualifying Auction Derating, Qualifying Auction Return-to-Service, or Qualifying Auction Uprating.

Centralized TCC Auction Interface Uprate/Derate Table: The interface derate table posted on the ISO website prior to a given Centralized TCC Auction specifying the impact on transfer limits of Qualifying DAM Outages and Qualifying DAM Returns-to-Service for a Sub-Auction of a Centralized TCC Auction.

DAM Constraint Residual: The dollar value associated with a Constraint that is binding for an hour of the Day-Ahead Market, which is calculated pursuant to Section 20.2.4.1.

DAM Status Change: Any of the following: Qualifying DAM Outage, Qualifying DAM Derating, Qualifying DAM Return-to-Service, or Qualifying DAM Uprating.

DCR Allocation Threshold: Five thousand dollars ($5,000), except that this amount shall be reduced for any given month to the extent necessary so that the sum of all DAM Constraint Residuals for the month (for all binding constraints and for all hours of the month) that are less than the DCR Allocation Threshold is not greater than either two hundred and fifty thousand dollars ($250,000) or five percent (5%) of the sum of all DAM Constraint Residuals for the month (for all binding constraints and for all hours of the month) that would have been calculated if the DCR Allocation Threshold were set equal to zero.

Deemed Qualifying Auction Derating: As defined in Section 20.3.6.3.1.

Deemed Qualifying Auction Outage: As defined in Section 20.3.6.2.1.

Deemed Qualifying Auction Return-to-Service: As defined in Section 20.3.6.2.1.

Deemed Qualifying Auction Uprating: As defined in Section 20..3.6.3.1.

Deemed ISO-Directed Auction Status Change: Any of the following: (1) an Actual Qualifying Auction Return-to-Service for a Reconfiguration Auction that occurs for a transmission facility that, in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction, was a Qualifying Auction Outage that qualified as an ISO-Directed Auction Status Change; (2) an Actual Qualifying Auction Uprating for a

Reconfiguration Auction that occurs as a result of an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service of a transmission facility that, in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction, qualified as a Qualifying Auction Outage or Qualifying Auction Return-to-Service that was an ISO-Directed Auction Status Change; or (3) an Actual Qualifying Auction Derating for a Reconfiguration Auction that occurs as a result of an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service of a transmission facility that, in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction, qualified as an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service that was an ISO-Directed Auction Status Change.

Deemed ISO-Directed DAM Status Change: Any of the following: (1) an Actual Qualifying DAM Return-to-Service for an hour of the Day-Ahead Market that occurs for a transmission facility that, in the last Reconfiguration Auction held for TCCs valid for the relevant hour or the last 6-month Sub-Auction of a Centralized TCC Auction held for TCCs valid for the relevant hour, was an Actual Qualifying Auction Outage that qualified as an ISO-Directed Auction Status Change; (2) an Actual Qualifying DAM Uprating for an hour of the Day-Ahead Market that occurs for a transmission facility that, in the last Reconfiguration Auction held for TCCs valid for the relevant hour or the last 6-month Sub-Auction of a Centralized TCC Auction held for TCCs valid for the relevant hour, qualified as an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service that was an ISO-Directed Auction Status Change; or (3) an Actual Qualifying DAM Derating for an hour of the Day-Ahead Market that occurs for a transmission facility that, in the last Reconfiguration Auction held for TCCs valid for the relevant hour or the last 6-month Sub-Auction of a Centralized TCC Auction held for TCCs valid for the relevant hour, qualified as an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service that was an ISO-Directed Auction Status Change. (The terms "Actual Qualifying Auction Outage" and "ISO-Directed Auction Status Change" shall, if not defined in this Section 20.1.2, have the meaning given in the ISO's March 17, 2006, filing.)

Deemed Qualifying DAM Derating: As defined in Section 20.2.4.3.1.

Deemed Qualifying DAM Outage: As defined in Section 20.2.4.2.1.

Deemed Qualifying DAM Return-to-Service: As defined in Section 20.2.4.2.1.

Deemed Qualifying DAM Uprating: As defined in Section 20.2.4.3.1.

ISO-Directed Auction Status Change: Either of the following: (1) an Actual Qualifying Auction Outage for a Reconfiguration Auction or a round of a Centralized TCC Auction that is directed by the ISO or results from an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service directed by the ISO; or (2) an Actual Qualifying Auction Derating or an Actual Qualifying Auction Uprating for a Reconfiguration Auction or a round of a Centralized TCC Auction that results from an Actual Qualifying Auction Outage directed by the ISO.

ISO-Directed DAM Status Change: Either of the following: (1) an Actual Qualifying DAM Outage for an hour of the Day-Ahead Market that is directed by the ISO or results from an

Actual Qualifying DAM Outage or an Actual Qualifying DAM Return-to-Service directed by the ISO; or (2) an Actual Qualifying DAM Derating or an Actual Qualifying DAM Uprating for an hour of the Day-Ahead Market that results from an Actual Qualifying DAM Outage directed by the ISO.

Normally Out-of-Service Equipment: Transmission facilities that are normally operated as out-of-service by mutual agreement of the transmission facility owner and the ISO and that appear on the list of such equipment posted on the ISO website.

Outage/Return-to-Service Auction Constraint Residual ("O/R-t-S Auction Constraint Residual"): The portion of an Auction Constraint Residual that is deemed to be attributable to Qualifying Auction Outages or Qualifying Auction Returns-to-Service, which O/R-t-S Auction Constraint Residual shall be calculated pursuant to Section 20.3.6.1.

Outage/Return-to-Service Auction Revenue Shortfall Charge ("O/R-t-S Auction Revenue Shortfall Charge"): A charge to a Transmission Owner that is created as a result of the allocation of an O/R-t-S Auction Constraint Residual pursuant to Section 20.3.6.2.

Outage/Return-to-Service Auction Revenue Surplus Payment ("O/R-t-S Auction Revenue Surplus Payment"): A payment to a Transmission Owner that is created as a result of the allocation of an O/R-t-S Auction Constraint Residual pursuant to Section 20.3.6.2.

Outage/Return-to-Service Congestion Rent Shortfall Charge ("O/R-t-S Congestion Rent Shortfall Charge"): A charge to a Transmission Owner that is created as a result of the allocation of an O/R-t-S DAM Constraint Residual pursuant to Section 20.2.4.2.

Outage/Return-to-Service Congestion Rent Surplus Payment ("O/R-t-S Congestion Rent Surplus Payment"): A payment to a Transmission Owner that is created as a result of the allocation of an O/R-t-S DAM Constraint Residual pursuant to Section 20.2.4.2.

Outage/Return-to-Service DAM Constraint Residual ("O/R-t-S DAM Constraint Residual"): The portion of a DAM Constraint Residual that is deemed to be attributable to Qualifying DAM Outages or Qualifying DAM Returns-to-Service, which O/R-t-S DAM Constraint Residual shall be calculated pursuant to Section 20.2.4.1.

Qualifying Auction Derating: As defined in Section 20.3.6.3.1.

Qualifying Auction Outage: As defined in Section 20.3.6.2.1.

Qualifying Auction Return-to-Service: As defined in Section 20.3.6.2.1.

Qualifying Auction Uprating: As defined in Section 20.3.6.3.1.

Qualifying DAM Derating: As defined in Section 20.2.4.3.1.

Qualifying DAM Outage: As defined in Section 20.2.4.2.1.

Qualifying DAM Return-to-Service: As defined in Section 20.2.4.2.1.

Qualifying DAM Uprating: As defined in Section 20.2.4.3.1.

Reconfiguration Auction Interface Uprate/Derate Table: The interface derate table posted on the ISO website prior to a Reconfiguration Auction specifying the impact on transfer limits of Qualifying DAM Outages and Qualifying DAM Returns-to-Service for the Reconfiguration Auction.

Uprate/Derate Auction Constraint Residual ("U/D Auction Constraint Residual"): The portion of an Auction Constraint Residual that is deemed to be attributable to Qualifying Auction Deratings or Qualifying Auction Upratings, which U/D Auction Constraint Residual shall be calculated pursuant to Section 20.3.6.1.

Uprate/Derate Auction Revenue Shortfall Charge ("U/D Auction Revenue Shortfall Charge"): A charge to a Transmission Owner that is created as a result of the allocation of a U/D Auction Constraint Residual pursuant to Section 20.3.6.3.

Uprate/Derate Auction Revenue Surplus Payment ("U/D Auction Revenue Surplus Payment"): A payment to a Transmission Owner that is created as a result of the allocation of a U/D Auction Constraint Residual pursuant to Section 20.3.6.3.

Uprate/Derate Congestion Rent Shortfall Charge ("U/D Congestion Rent Shortfall Charge"): A charge to a Transmission Owner that is created as a result of the allocation of a U/D DAM Constraint Residual pursuant to Section 20.2.4.3.

Uprate/Derate Congestion Rent Surplus Payment ("U/D Congestion Rent Surplus Payment"): A payment to a Transmission Owner that is created as a result of the allocation of a U/D DAM Constraint Residual pursuant to Section 20.2.4.3.

Uprate/Derate DAM Constraint Residual ("U/D DAM Constraint Residual"): The portion of a DAM Constraint Residual that is deemed to be attributable to a Qualifying DAM Derating or a Qualifying DAM Uprating, which U/D DAM Constraint Residual shall be calculated pursuant to Section 20.2.4.1.

For purposes of this Attachment N, the term "transmission facility" shall mean any transmission line, phase angle regulator, transformer, series reactor, circuit breaker, or other type of transmission equipment.

For the purposes of this Attachment N, a "constraint" shall refer to a monitored transmission facility and a transmission facility that is out of service in the contingency being evaluated (including the base case).

All references in this Attachment N to Sections shall be construed to be references to a section of this Attachment N.

20.2 Congestion Settlements Related to the Day-Ahead Market

20.2.1 Overview of Congestion Settlements Related to the Day-Ahead Market; Calculation of Net Congestion Rents

Overview of DAM Related Congestion Settlements. For each hour *h* of the Day-Ahead Market, the ISO shall settle all Congestion settlements related to the Day-Ahead Market. These Congestion settlements include, as applicable pursuant to the provisions of this Attachment N: (i) Congestion Rent charges or payments for Energy Transactions in the Day-Ahead Market and Bilateral Transactions scheduled in the Day-Ahead Market; (ii) Congestion payments or charges to Primary Holders of TCCs; (iii) O/R-t-S Congestion Rent Shortfall Charges and U/D Congestion Rent Shortfall Charges; and (iv) O/R-t-S Congestion Rent Surplus Payments and U/D Congestion Rent Surplus Payments. Each of these settlements is represented by a variable in Formula N-1.

Calculation of Net Congestion Rents for an Hour. In each hour *h* of the Day-Ahead Market, the ISO shall calculate Net Congestion Rents pursuant to Formula N-1.

Formula N-1

$$NetCongestionRents_h = (Congestion\ Rents_h - TCC\ Payments_h - O/R\text{-}t\text{-}S\&U/D\ CRSC\&CRSP_h)$$

Where,

$NetCongestionRents_h$	=	The total Net Congestion Rents for hour *h* of the Day-Ahead Market
h	=	An hour of the Day-Ahead Market
$Congestion\ Rents_h$	=	The sum of Congestion Rents for (i) Energy Transactions scheduled in hour *h* of the Day-Ahead Market, and (ii) Bilateral Transactions scheduled in hour *h* of the Day-Ahead Market, each as calculated pursuant to Section 20.2.2
$TCC\ Payments_h$	=	The sum for all TCCs of all payments and charges made pursuant to Section 20.2.3 to Primary Holders of TCCs in hour *h*

O/R-t-S&U/D $CRSC\&CRSP_h$	=	The sum of all O/R-t-S Congestion Rent Shortfall Charges (O/R-t-S $CRSC_{a,t,h}$), U/D Congestion Rent Shortfall Charges (U/D $CRSC_{a,t,h}$), O/R-t-S Congestion Rent Surplus Payments (O/R-t-S $CRSP_{a,t,h}$), and U/D Congestion Rent Surplus Payments (U/D $CRSP_{a,t,h}$) for all Transmission Owners *t* (which sum is calculated for each Transmission Owner as $NetDAMAllocations_{t,h}$ pursuant to Formula N-14), reduced by any zeroing out of such charges or payments pursuant to Section 20.2.4.5

The ISO shall allocate the Net Congestion Rents calculated in each hour to Transmission Owners pursuant to Section 20.2.5.

20.2.2 Congestion Rents Charged in the Day-Ahead Market

In each hour of the Day-Ahead Market, the ISO shall collect or pay Congestion Rents through Energy Transactions in the Day-Ahead Market and through Bilateral Transactions scheduled in the Day-Ahead Market.

Day-Ahead Market Energy Transactions. The ISO shall charge or pay Congestion Rents as part of the Congestion Component of the LBMP applicable to Energy injections and withdrawals scheduled in the Day-Ahead Market, as described in Attachment J of this Tariff. The total Congestion Rents for all Energy Transactions scheduled in the Day-Ahead Market in hour *h* are calculated pursuant to Formula N-2.

Formula N-2

$$\sum_{W} MWh_{W,h} * CCPOW_{W,h} - \sum_{I} MWh_{I,h} * CCPOI_{I,h}$$

Where,

$MWh_{W,h}$	=	Energy, in MWh, scheduled to be withdrawn in hour *h* pursuant to Day-Ahead Market schedule *W*
$CCPOW_{W,h}$	=	Congestion Component, in \$/MWh, at the Point of Withdrawal for Energy withdrawn in hour *h* pursuant to schedule *W*
$MWh_{I,h}$	=	Energy, in MWh, scheduled to be injected in hour *h* pursuant to Day-Ahead Market schedule *I*

$CCPOI_{I,h}$ = Congestion Component, in $/MWh, at the Point of Injection for Energy injected in hour *h* pursuant to schedule *I*.

Bilateral Transactions. The ISO shall charge or pay Congestion Rents as part of the Transmission Usage Charge applied to Bilateral Transaction *B* scheduled in the Day-Ahead Market, as described in Section 2.7.2.2 of this Tariff. Total Congestion Rents for all Bilateral Transactions scheduled in the Day-Ahead Market in hour *h* are calculated pursuant to Formula N-3.

Formula N-3

$$\sum_{B} MWh_{B,h} * CCTUC_{B,h}$$

Where,

$MWh_{B,h}$ = Energy, in MWh, of Bilateral Transaction *B* scheduled in the Day-Ahead Market in hour *h*

$CCTUC_{B,h}$ = Congestion Component of the TUC, in $/MWh, for scheduled Bilateral Transaction *B*, in hour *h*, which is equal to $CCPOW_{B,h}$ - $CCPOI_{B,h.}$

$CCPOW_{B,h}$ = Congestion Component, in $/MWh, at the Point of Withdrawal for Energy withdrawn in hour *h* pursuant to Bilateral Transaction *B*

$CCPOI_{B,h}$ = Congestion Component, in $/MWh, at the Point of Injection for Energy injected in hour *h* pursuant to Bilateral Transaction *B*.

20.2.3 Congestion Payments Made To Primary Holders

For each hour *h* of the Day-Ahead Market, the ISO shall charge or pay Congestion payments to the Primary Holders, as follows:

Formula N-4

$$Congestion\ Payment\ (\$/\text{hr}) = (CCPOW - CCPOI) * TCCMW$$

Where,

CCPOW = Congestion Component ($/MWh) at the Point of Withdrawal (POW)

CCPOI = Congestion Component ($/MWh) at the Point of Injection (POI)

TCCMW = The number of TCCs in MW from POI to POW.

(See Attachment J for the calculation of the Congestion Component of the LBMP price at either the POI or the POW.)

The ISO shall pay Primary Holders for the Congestion payments from revenues collected from: (i) Congestion Rents, (ii) O/R-t-S Congestion Rent Shortfall Charges and U/D Congestion Rent Shortfall Charges, and (iii) Net Congestion Rents in accordance with Section 20.2.5.

The ISO shall assess a “Shortfall Reimbursement Surcharge” each month on monthly net positive Congestion payments to Primary Holders of TCCs sold in or after the Autumn 2004 Centralized TCC Auction. The Shortfall Reimbursement Surcharge shall be 0.5% of Congestion payments associated with TCCs that have a Point of Withdrawal outside of Load Zone J and 2.5% of Congestion payments associated with TCCs that have a Point of Withdrawal at, or inside of, Load Zone J.

The Shortfall Reimbursement Surcharge shall not be assessed on Congestion payments to Primary Holders of TCCs that produce net negative Congestion payments, *i.e.*, that oblige the Primary Holder to make payments, in a given month, on Congestion payments to Primary Holders of Grandfathered TCCs, or on Congestion payments to Primary Holders of ETCNL TCCs or RCRR TCCs. The Shortfall Reimbursement Surcharge also shall not be assessed on Congestion payments to Primary Holders of TCCs sold before the Autumn 2004 Centralized TCC Auction, except to the extent that such TCCs are unbundled or reconfigured at the request of a Primary Holder, and sold, in or after that auction, in which case the Congestion payments associated with them shall be subject to the Shortfall Reimbursement Surcharge.

The ISO shall cease to impose the Shortfall Reimbursement Surcharge when it has collected sufficient funds to: (i) pay refunds for all of the “Historic Shortfall” plus interest pursuant to Article III of the July 13, 2004 Settlement Agreement that was approved by the

Commission in Docket Nos. EL04-110, EL04-113, EL04-115, and ER04-983; and (ii) replenished the ISO Working Capital Fund pursuant to Article IV of that Settlement Agreement.

20.2.4 Charges and Payments to Transmission Owners for DAM Outages and Returns-to-Service

The ISO shall charge O/R-t-S Congestion Rent Shortfall Charges and U/D Congestion Rent Shortfall Charges and pay O/R-t-S Congestion Rent Surplus Payments and U/D Congestion Rent Surplus Payments pursuant to this Section 20.2.4. To do so, the ISO shall calculate the DAM Constraint Residual for each binding constraint for each hour of the Day-Ahead Market and then determine the amount of each DAM Constraint Residual that is O/R-t-S DAM Constraint Residual and the amount that is U/D DAM Constraint Residual, as specified in Section 20.2.4.1. The ISO shall use the O/R-t-S DAM Constraint Residual to allocate O/R-t-S Congestion Rent Shortfall Charges and O/R-t-S Congestion Rent Surplus Payments to Transmission Owners pursuant to Sections 20.2.4.2 and 20.2.4.4, each of which shall be subject to being reduced to zero pursuant to Section 20.2.4.5. The ISO shall use the U/D DAM Constraint Residual to allocate U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments to Transmission Owners pursuant to Sections 20.2.4.3 and 20.2.4.4, each of which shall be subject to being reduced to zero pursuant to Section 20.2.4.5.

20.2.4.1 Measuring the Impact of DAM Outages and Returns-to-Service: Calculation of DAM Constraint Residuals and Division of DAM Constraint Residuals into O/R-t-S DAM Constraint Residuals and U/D DAM Constraint Residuals

For each hour *h* of the Day-Ahead Market, the ISO shall identify all constraints that are binding in the Power Flow solution for the final schedules for hour *h* of the Day-Ahead Market. For each binding constraint *a* identified for each hour *h*, the ISO shall calculate the DAM

Constraint Residual, $DCR_{a,h}$, using Formula N-5; *provided*, *however*, where $DCR_{a,h}$ calculated using Formula N-5 is not greater than the DCR Allocation Threshold or less than the negative of the DCR Allocation Threshold, then $DCR_{a,h}$ shall be set equal to zero.

Formula N-5

$$DCR_{a,h} = ShadowPrice_{a,h} * \begin{bmatrix} (FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction}) \\ +(UprateDerate_{a,h} * SCUCSignChange_{a,h}) \\ +(UnsoldCapacity_{a,h,RA} * SCUCSignChange_{a,h}) \end{bmatrix}$$

Where,

$DCR_{a,h}$	=	The DAM Constraint Residual, in dollars, for binding constraint *a* in hour *h* of the Day-Ahead Market
$ShadowPrice_{a,h}$	=	The Shadow Price, in dollars/MWh, of binding constraint *a* in hour *h* of the Day-Ahead Market, which Shadow Price is calculated in a manner so that if relaxation of constraint *a* would permit a reduction in the associated Bid Production Cost, $ShadowPrice_{a,h}$ is negative
$FLOW_{a,h,DAM}$	=	The Energy flow, in MWh, on binding constraint *a* for hour *h* for a set of injections and withdrawals that corresponds[1] to the set of TCCs and Grandfathered Rights represented in the solution to the most recent auction in which TCCs valid in hour *h* were sold (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction), which Energy flow will be determined using Shift Factors produced in scheduling hour *h* of the Day-Ahead Market applied to these injections and withdrawals and the phase angle regulator schedules fixed in the last auction held for TCCs valid for hour *h*
$FLOW_{a,h,TCC\ Auction}$	=	The Energy flow, in MWh, on binding constraint *a* for hour *h* determined as described in the definition of $FLOW_{a,h,DAM}$ above, except that the Shift Factors applied will be those produced in a simulated run of SCUC (run using the Transmission System model used in the most recent auction in which TCCs valid in hour *h* were sold); *provided*, *however*, special rules (1) through (3) below shall instead be used to calculate $FLOW_{a,h,TCC\ Auction}$ if they apply, and rule (4) below shall be used to calculate $FLOW_{a,h,TCC\ Auction}$ if $FLOW_{a,h,TCC\ Auction}$ cannot be calculated using any other rule set forth in this definition of $FLOW_{a,h,TCC\ Auction}$ because a simulated run of SCUC does not produce Shift Factors to calculate $FLOW_{a,h,TCC\ Auction}$:

[1] A set of injections and withdrawals corresponds to a set of TCCs and Grandfathered Rights if the quantity of Energy injected at each location matches the number of TCCs and Grandfathered Rights specifying that location as a POI, and the quantity of Energy withdrawn at each location matches the number of TCCs and Grandfathered Rights specifying that location as a POW.

(1) in the event that a maintenance contingency is binding in the Day-Ahead Market but was not applied in the most recent auction in which TCCs valid in hour *h* were sold, $FLOW_{a,h,TCC\ Auction}$ shall be equal to the Energy flow in MWh on the monitored transmission facility of binding constraint *a* for the contingency resulting in the highest flows on constraint *a* in the most recent auction in which TCCs valid in hour *h* were sold, which Energy flow shall be calculated using the set of injections and withdrawals that corresponds to the set of TCCs and Grandfathered Rights represented in the solution to that auction (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction) and using Shift Factors from a simulated run of SCUC as first set forth in this definition of $FLOW_{a,h,TCC\ Auction}$

(2) in the event that the monitored transmission facility for constraint *a* was modeled as out-of-service in the most recent auction in which TCCs valid in hour *h* were sold and that transmission facility returns to service for hour *h* of the Day-Ahead Market, $FLOW_{a,h,TCC\ Auction}$ shall be equal to:

(i) the rating limit, in MWh, for the monitored transmission facility of binding constraint *a* applicable in hour *h* of the Day-Ahead Market, <u>multiplied</u> by

(ii) negative $SCUCSignChange_{a,h}$

(3) in the event that the transmission facility that is the contingency element for constraint *a* was modeled as out-of-service in the most recent auction in which TCCs valid in hour *h* were sold and that transmission facility returns to service for hour *h* of the Day-Ahead Market, $FLOW_{a,h,TCC\ Auction}$ shall be equal to the Energy flow, in MWh, on the monitored transmission facility of binding constraint *a* for

the contingency resulting in the highest flows on the monitored transmission facility of constraint *a* in the most recent auction in which TCCs valid in hour *h* were sold, which Energy flow shall be calculated using the set of injections and withdrawals that corresponds to the set of TCCs and Grandfathered Rights represented in the solution to that auction (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction) and using Shift Factors from a simulated run of SCUC as first set forth in this definition of $FLOW_{a,h,TCC\ Auction}$

(4) in the event that a simulated run of SCUC does not produce Shift Factors to calculate $FLOW_{a,h,TCC\ Auction}$, $FLOW_{a,h,TCC\ Auction}$ shall be equal to:

(i) the Energy flow on constraint *a* as determined in the most recent auction in which TCCs valid in hour *h* were sold, multiplied by

(ii) $OPF/SCUCAdjust_a$

$UprateDerate_{a,h}$ = Zero, except that in the event of a Qualifying DAM Uprating or Qualifying DAM Derating for constraint *a* in hour *h* that is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction), $UprateDerate_{a,h}$ shall equal the interface uprating or derating impact reflected in such table. Notwithstanding the definition above, $UprateDerate_{a,h}$ shall always equal zero in the event that the monitored transmission facility for binding constraint *a* in the Day-Ahead Market was modeled as out-of-service in the most recent auction in which TCCs valid in hour *h* were sold and that transmission facility returns to service for hour *h*.

$UnsoldCapacity_{a,h,RA}$ = Zero, except that if $ShadowPrice_{a,h}$ * ($FLOW_{a,h,DAM}$ – $FLOW_{a,h,TCCAuction}$) + ($UprateDerate_{a,h}$ * $SCUCSignChange_{a,h}$) is less than zero, then $UnsoldCapacity_{a,h,RA}$ shall be equal to the lesser of (1) the amount of transmission Capacity for constraint *a* that was available for sale in the most recent auction in which TCCs valid in hour *h* were sold but which transmission Capacity was not sold; or (2) the absolute value of

$(FLOW_{a,h,DAM} – FLOW_{a,h,TCCAuction}) + (UprateDerate_{a,h} * SCUCSignChange_{a,h})$.

$SCUCSignChange_{a,h}$ = 1 if $ShadowPrice_{a,h}$ is greater than zero; otherwise, -1.

$OPF/SCUCAdjust_a$ = 1 if the directional orientation of constraint *a* used by the ISO in SCUC is the same as that used by the ISO in the Optimal Power Flow program used to select winning Bids in TCC auctions; otherwise, -1.

Following calculation of the DAM Constraint Residual for each constraint *a* for each hour *h*, the ISO shall calculate the amount of each O/R-t-S DAM Constraint Residual and the amount of each U/D DAM Constraint Residual for each constraint *a* for each hour *h*. The amount of each O/R-t-S DAM Constraint Residual for hour *h* and for constraint *a* shall be determined by applying Formula N-6. The amount of each U/D DAM Constraint Residual for hour *h* and for constraint *a* shall be determined by applying Formula N-7.

Formula N-6

$$O/R\text{-}t\text{-}S\ DCR_{a,h} = DCR_{a,h} * \left[\frac{(FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction})}{(FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction}) + (UprateDerate_{a,h} * SCUCSignChange_{a,h})} \right]$$

Where,

O/R-t-S $DCR_{a,h}$ = The amount of the O/R-t-S DAM Constraint Residual, in dollars, for hour *h* and for constraint *a*

and each of the other variables are as defined in Formula N-5.

Formula N-7

$$U/D\ \ DCR_{a,h} = DCR_{a,h} * \left[\frac{(UprateDerate_{a,h} * SCUCSignChange_{a,h})}{(FLOW_{a,h,DAM} - FLOW_{a,h,TCCAuction}) + (UprateDerate_{a,h} * SCUCSignChange_{a,h})} \right]$$

Where,

U/D $DCR_{a,h}$ = The amount of the U/D DAM Constraint Residual for hour *h* for constraint *a*

and each of the other variables are as defined in Formula N-5.

20.2.4.2 Charges and Payments for the Direct Impact of DAM Outages and Returns-to-Service

The ISO shall use O/R-t-S DAM Constraint Residuals to allocate O/R-t-S Congestion

Rent Shortfall Charges and O/R-t-S Congestion Rent Surplus Payments, as the case may be, among Transmission Owners pursuant to this Section 20.2.4.2. Each O/R-t-S Congestion Rent Shortfall Charge and each O/R-t-S Congestion Rent Surplus Payment allocated to a Transmission Owner pursuant to this Section 20.2.4.2 is subject to being set equal to zero pursuant to Section 20.2.4.5.

20.2.4.2.1 Identification of Outages and Returns-to-Service Qualifying for Charges and Payments

For each hour of the Day-Ahead Market, the ISO shall identify each Qualifying DAM Outage and each Qualifying DAM Return-to-Service, as described below. The Transmission Owner responsible, as determined pursuant to Section 20.2.4.4, for a Qualifying DAM Outage or Qualifying DAM Return-to-Service shall be allocated an O/R-t-S Congestion Rent Shortfall Charge or an O/R-t-S Congestion Rent Surplus Payment pursuant to Sections 20.2.4.2.2 or 20.2.4.2.3.

20.2.4.2.1.1 Definition of Qualifying DAM Outage

A "**Qualifying DAM Outage**" shall be defined to mean either an Actual Qualifying DAM Outage or a Deemed Qualifying DAM Outage. For purposes of this Attachment N, "*o*" shall refer to a single Qualifying DAM Outage.

An "**Actual Qualifying DAM Outage**" shall be defined as a transmission facility that, for a given hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the facility exists but is not modeled as in-service for the Day-Ahead Market for hour *h*;

(ii) the facility existed and was modeled as in-service in the last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last auction held for TCCs valid for hour *h*.

A "**Deemed Qualifying DAM Outage**" shall be defined as a transmission facility that, for a given hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service for the last auction held for TCCs valid for hour *h*;

(ii) the facility existed but was not modeled as in-service in hour *h* as a result of a DAM Status Change or external event described in Section 20.2.4.4.3 for which responsibility was assigned pursuant to Section 20.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.2.4.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service for the last auction held for TCCs valid for hour *h*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last auction held for TCCs valid for hour *h*.

A transmission facility shall not qualify as an Actual Qualifying DAM Outage if the facility is modeled as in-service for hour *h* of the Day-Ahead Market as a result of a Transmission Owner's use of spare or alternative transmission equipment to bring the facility back in-service so long as the Transmission Owner has notified the ISO in advance of or contemporaneously with the use of such spare or alternative equipment and the estimated duration of its use.

20.2.4.2.1.2 Definition of Qualifying DAM Return-to-Service

A "**Qualifying DAM Return-to-Service**" shall be defined to mean either an Actual

Qualifying DAM Return-to-Service or a Deemed Qualifying DAM Return-to-Service. For purposes of this Attachment N, "*o*" shall refer to a single Qualifying DAM Return-to-Service.

An "**Actual Qualifying DAM Return-to-Service**" shall be defined as a transmission facility that, for a given hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the facility exists and is modeled as in-service in the Day-Ahead Market for hour *h*;

(ii) the facility existed but was not modeled as in-service for the last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last auction held for TCCs valid for hour *h*.

A "**Deemed Qualifying DAM Return-to-Service**" shall be defined as a transmission facility that, for a given hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service for the last auction held for TCCs valid for hour *h*;

(ii) the facility existed but was not modeled as in-service in the Day-Ahead Market for hour *h* as a result of a DAM Status Change or external event described in Section 20.2.4.4.3 for which responsibility is assigned pursuant to Section 20.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.2.4.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service for the last auction held for TCCs valid for hour *h*; and

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last auction held for TCCs valid for hour *h*.

20.2.4.2.2 Allocation of an O/R-t-S DAM Constraint Residual When Only One Transmission Owner is Responsible for All of the Relevant Outages and Returns-to-Service

This Section 20.2.4.2.2 describes the allocation of an O/R-t-S DAM Constraint Residual for a given hour and a given constraint when only one Transmission Owner is responsible, as determined pursuant to Section 20.2.4.4, for all of the Qualifying DAM Outages and all of the Qualifying DAM Returns-to-Service for that hour that contribute to that constraint.

If the same Transmission Owner is responsible, as determined pursuant to Section 20.2.4.4, for all of the Qualifying DAM Outages *o* and Qualifying DAM Returns-to-Service *o* for hour *h* that contribute to constraint *a*, then the ISO shall allocate the O/R-t-S DAM Constraint Residual for that hour and that constraint, O/R-t-S $DCR_{a,h}$, to that Transmission Owner in the form of either: (i) an O/R-t-S Congestion Rent Shortfall Charge in the amount of O/R-t-S $DCR_{a,h}$ if O/R-t-S $DCR_{a,h}$ is negative, or (ii) an O/R-t-S Congestion Rent Surplus Payment in the amount of O/R-t-S $DCR_{a,h}$ if O/R-t-S $DCR_{a,h}$ is positive.

20.2.4.2.3 Allocation of an O/R-t-S DAM Constraint Residual When More Than One Transmission Owner is Responsible for the Relevant Outages and Returns-to-Service

This Section 20.2.4.2.3 describes the allocation of an O/R-t-S DAM Constraint Residual for a given hour and a given constraint when more than one Transmission Owner is responsible, as determined pursuant to Section 20.2.4.4, for the Qualifying DAM Outages and the Qualifying DAM Returns-to-Service for that hour that contribute to that constraint.

If more than one Transmission Owner is responsible, as determined pursuant to Section 20.2.4.4, for the Qualifying DAM Outages and the Qualifying DAM Returns-to-Service for hour *h* that contribute to constraint *a*, the ISO shall allocate the O/R-t-S DAM Constraint Residual for constraint *a* for hour *h*, O/R-t-S $DCR_{a,h}$, in the form of an O/R-t-S Congestion Rent Shortfall Charge or O/R-t-S Congestion Rent Surplus Payment to the Transmission Owners responsible for the Qualifying DAM Outages *o* and Qualifying DAM Returns-to-Service *o* for hour *h* by first determining the net total impact on the constraint for hour *h* of all Qualifying DAM Outages and Qualifying DAM Returns-to-Service for hour *h* with an impact on the Energy flow across that constraint of 1 MWh or more by applying Formula N-8, and then applying either Formula N-9 or Formula N-10, as specified herein, to assess O/R-t-S Congestion Rent Shortfall Charges and O/R-t-S Congestion Rent Surplus Payments.

Formula N-8

$$O/R\text{-}t\text{-}S\ NetDAMImpact_{a,h} = \left(\sum_{for\ all\ o \in O_h} FlowImpact_{a,h,o} * ShadowPrice_{a,h} \right) * OPF/SCUCAdjust_a$$

Where,

O/R-t-S $NetDAMImpact_{a,h}$ = The net impact, in dollars, on constraint *a* in hour *h* of all Qualifying DAM Outages and Qualifying DAM Returns-to-Service for hour *h* having an impact of more than 1 MWh on Energy flow across constraint *a*; *provided, however,* O/R-t-S $NetDAMImpact_{a,h}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula N-8

$FlowImpact_{a,h,o}$ = The Energy flow impact of a Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o*, in MWh, on binding constraint *a* determined for hour *h*, which shall either:

(a) if Qualifying DAM Outage *o* is a Deemed Qualifying DAM Outage, be equal to the negative of $FlowImpact_{a,h,o}$ calculated for the corresponding Deemed Qualifying DAM Return-to-Service as described in part (b) of this definition of $FlowImpact_{a,h,o}$; or

(b) if Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* is an Actual Qualifying DAM Outage, an Actual Qualifying DAM Return-to-Service, or a Deemed Qualifying DAM Return-to-Service, be calculated pursuant to the following formula:

$$FlowImpact_{a,h,o} = One\text{-}OffFlow_{a,h,o} - BaseCaseFlow_{a,h}$$

Where,

$BaseCaseFlow_{a,h}$ = The Energy flow on binding constraint *a* resulting from a Power Flow or similar analysis using (1) the set of injections and withdrawals corresponding to the TCCs and Grandfathered Rights represented in the solution to the most recent auction in which TCCs valid in hour *h* were sold (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction); (2) the phase angle regulator schedule determined in the Optimal Power Flow solution for the final round of the last auction held for TCCs valid in hour *h*; and (3) the Transmission System model for the last auction held for TCCs valid in hour *h*;

$One\text{-}OffFlow_{a,h,o}$ = Either

(1) if Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* is an Actual Qualifying DAM Outage or an Actual Qualifying DAM Return-to-Service, the Energy flow on binding constraint *a* resulting from a Power Flow or similar analysis using each element of the base case data set used in the calculation of $BaseCaseFlow_{a,h}$ above (*provided*, *however*, if a transmission facility was modeled as free-flowing in hour *h* of the Day-Ahead Market because of the outage of any transmission facility, the ISO shall appropriately adjust the phase angle regulator schedule and related variables to model the transmission facility as free flowing), but in each case with the Transmission System model modified so as to, as the case may be, either (i) model as out-of-service Actual Qualifying DAM Outage *o*, or (ii) model as in-service Actual Qualifying DAM Return-to-Service *o*; or

(2) if Qualifying DAM Return-to-Service *o* is a Deemed Qualifying DAM Return-to-Service, the Energy flow on binding constraint *a* resulting from a Power Flow or

similar analysis using each element of the base case data set used in the calculation of $BaseCaseFlow_{a,h}$ above (*provided, however*, if a transmission facility was modeled as free-flowing in hour *h* of the Day-Ahead Market because of the outage of any transmission facility, the ISO shall appropriately adjust the phase angle regulator schedule and related variables to model the transmission facility as free flowing), but with the Transmission System model modified so as to model as in-service the transmission facility that is Deemed Qualifying DAM Return-to-Service *o*

provided, however, where the absolute value of $FlowImpact_{a,h,o}$ calculated using the procedures set forth above is less than 1 MWh, then $FlowImpact_{a,h,o}$ shall be set equal to zero;

provided further, $FlowImpact_{a,h,o}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula N-8

O_h = The set of all Qualifying DAM Outages *o* and Qualifying DAM Returns-to-Service *o* in hour *h*

and the variables $ShadowPrice_{a,h}$ and $OPF/SCUCAdjust_a$ are defined as set forth in Formula N-5.

After calculating O/R-t-S $NetDAMImpact_{a,h}$ pursuant to Formula N-8, the ISO shall determine whether O/R-t-S $NetDAMImpact_{a,h}$ for constraint *a* in hour *h* has a different sign than O/R-t-S $DCR_{a,h}$ for constraint *a* in hour *h*. If the sign is different, the ISO shall (i) recalculate O/R-t-S $NetDAMImpact_{a,h}$ pursuant to Formula N-8 after setting equal to zero each $FlowImpact_{a,h,o}$ for which $FlowImpact_{a,h,o}$ * $ShadowPrice_{a,h}$ * $OPF/SCUCAdjust_a$ has a different sign than O/R-t-S $DCR_{a,h}$, and then (ii) use this recalculated O/R-t-S $NetDAMImpact_{a,h}$ and reset value of $FlowImpact_{a,h,o}$ to allocate O/R-t-S Congestion Rent Shortfall Charges and O/R-t-S Congestion Rent Surplus Payments pursuant to Formula N-9 or Formula N-10, as specified below.

If the absolute value of the net impact (O/R-t-S $NetDAMImpact_{a,h}$) on constraint *a* of all Qualifying DAM Outages and Qualifying DAM Returns-to-Service for hour *h* as calculated using Formula N-8 (or recalculated pursuant to Formula N-8 using a reset value of $FlowImpact_{a,h,o}$ as described in the prior paragraph) is greater than the absolute value of the O/R-t-S DAM Constraint Residual (O/R-t-S $DCR_{a,h}$), in dollars, for constraint *a* in hour *h*, then the ISO shall allocate the O/R-t-S DAM Constraint Residual in the form of an O/R-t-S Congestion Rent Shortfall Charge, O/R-t-S $CRSC_{a,t,h}$, or O/R-t-S Congestion Rent Surplus Payment, O/R-t-S $CRSP_{a,t,h}$, by using Formula N-9. If the absolute value of the net impact (O/R-t-S $NetDAMImpact_{a,h}$) on constraint *a* of all Qualifying DAM Outages and Qualifying DAM Returns-to-Service for hour *h* as calculated using Formula N-8 (or recalculated pursuant to Formula N-8 using a reset value of $FlowImpact_{a,h,o}$ as described in the prior paragraph) is less than or equal to the absolute value of the O/R-t-S DAM Constraint Residual (O/R-t-S $DCR_{a,h}$), in dollars, for constraint *a* in hour *h*, then the ISO shall allocate the O/R-t-S DAM Constraint Residual in the form of an O/R-t-S Congestion Rent Shortfall Charge or O/R-t-S Congestion Rent Surplus Payment by using Formula N-10.

Formula N-9

$$O/R\text{-}t\text{-}S\,Allocation_{a,t,h} = \left(\frac{\sum_{\substack{o \in O_h \\ and\ q=t}} \left(FlowImpact_{a,h,o} * Responsibility_{h,q,o}\right)}{\sum_{for\ all\ o \in O_h} FlowImpact_{a,h,o}} \right) * O/R\text{-}t\text{-}S\,DCR_{a,h}$$

Where,

O/R-t-S $Allocation_{a,t,h}$ = Either an O/R-t-S Congestion Rent Shortfall Charge or an O/R-t-S Congestion Rent Surplus Payment, as specified in (a) and (b) below:

(a) If O/R-t-S $Allocation_{a,t,h}$ is negative, then O/R-t-S $Allocation_{a,t,h}$ shall be an O/R-t-S Congestion Rent Shortfall Charge, O/R-t-S $CRSC_{a,t,h}$, charged to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market; or

(b) If O/R-t-S $\text{Allocation}_{a,t,h}$ is positive, then O/R-t-S $\text{Allocation}_{a,t,h}$ shall be an O/R-t-S Congestion Rent Surplus Payment, O/R-t-S $\text{CRSP}_{a,t,h}$, paid to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market

$\text{Responsibility}_{h,q,o}$ = The amount, as a percentage, of responsibility borne by Transmission Owner *q* (which shall include the ISO when it is deemed a Transmission Owner for the purpose of applying Sections 20.2.4.4.2, 20.2.4.4.3, or 20.2.4.4.4) for Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* in hour *h*, as determined pursuant to Section 20.2.4.4

and the variable O/R-t-S $\text{DCR}_{a,h}$ is defined as set forth in Formula N-6 and the variables $\text{FlowImpact}_{a,h,o}$ and O_h are defined as set forth in Formula N-8.

Formula N-10

$$O/R\text{-}t\text{-}S\,Allocation_{a,t,h} = \left(\sum_{\substack{o \in O_h \\ and\ q=t}} FlowImpact_{a,h,o} * ShadowPrice_{a,h} * Responsibility_{h,q,o} \right) * OPF/SCUCAdjust_a$$

Where,

the variables $\text{ShadowPrice}_{a,h}$ and OPF/SCUCAdjust_a are defined as set forth in Formula N-5, the variables O/R-t-S $\text{Allocation}_{a,t,h}$ and $\text{Responsibility}_{h,q,o}$ are defined as set forth in Formula N-9, and the variables $\text{FlowImpact}_{a,h,o}$ and O_h are defined as set forth in Formula N-8.

20.2.4.3 Charges and Payments for the Secondary Impact of DAM Outages and Returns-to-Service

The ISO shall use U/D DAM Constraint Residuals to allocate U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments, as the case may be, among Transmission Owners pursuant to this Section 20.2.4.3. Each U/D Congestion Rent Shortfall Charge and each U/D Congestion Rent Surplus Payment allocated to a Transmission Owner pursuant to this Section 20.2.4.3 is subject to being set equal to zero pursuant to Section 20.2.4.5.

20.2.4.3.1 Identification of Upratings and Deratings Qualifying for Charges and

Payments

For each hour of the Day-Ahead Market and for each constraint, the ISO shall identify each Qualifying DAM Derating and each Qualifying DAM Uprating, as described below. The Transmission Owner responsible, as determined pursuant to Section 20.2.4.4, for the Qualifying DAM Derating shall be allocated a U/D Congestion Rent Shortfall Charge and the Transmission Owner responsible, as determined pursuant to Section 20.2.4.4, for the Qualifying DAM Uprating shall be allocated a U/D Congestion Rent Surplus Payment pursuant to Section 20.2.4.3.2.

20.2.4.3.1.1 Definition of Qualifying DAM Derating

A "**Qualifying DAM Derating**" shall be defined to mean either an Actual Qualifying DAM Derating or a Deemed Qualifying DAM Derating. For purposes of this Attachment N, "*r*" shall refer to a single Qualifying DAM Derating.

An "**Actual Qualifying DAM Derating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* and hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the constraint has a lower rating in hour *h* than it would have if all transmission facilities were modeled as in-service in hour *h*;

(ii) this lower rating is in whole or in part the result of an Actual Qualifying DAM Outage *o* or an Actual Qualifying DAM Return-to-Service *o* for hour *h*;

(iii) this lower rating resulting from Actual Qualifying DAM Outage *o* or Actual Qualifying DAM Return-to-Service *o* for hour *h* was not modeled in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating is included in the Reconfiguration Auction Interface

Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); and

(v) the constraint is binding in the Day-Ahead Market for hour *h*.

A "**Deemed Qualifying DAM Derating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* and hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the constraint has a lower rating in hour *h* than it would have if all transmission facilities were modeled as in-service in hour *h*;

(ii) this lower rating is in whole or in part the result of a Deemed Qualifying DAM Outage *o* or Deemed Qualifying DAM Return-to-Service *o* for hour *h*;

(iii) the lower rating resulting from Deemed Qualifying DAM Outage *o* or Deemed Qualifying DAM Return-to-Service *o* for hour *h* was modeled in the last auction held for TCCs valid for hour *h*, but responsibility for Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* resulting in the lower rating for hour *h* is assigned pursuant to Section 20.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.2.4.4) other than the Transmission Owner responsible for the lower rating in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); and

(v) the constraint is binding in the Day-Ahead Market for hour *h*.

20.2.4.3.1.2 Definition of Qualifying DAM Uprating

A “**Qualifying DAM Uprating**” shall be defined to mean either an Actual Qualifying DAM Uprating or a Deemed Qualifying DAM Uprating. For purposes of this Attachment N, “*r*” shall refer to a single Qualifying DAM Uprating.

An “**Actual Qualifying DAM Uprating**” shall be defined as a change in the rating of a constraint that, for a given constraint *a* in hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the constraint has a higher rating for hour *h* than it would have absent an Actual Qualifying DAM Outage *o* or Actual Qualifying DAM Return-to-Service *o* for hour *h*;

(ii) this higher rating resulting from Actual Qualifying DAM Outage *o* or Actual Qualifying Return-to-Service *o* for hour *h* was not modeled in the last auction held for TCCs valid for hour *h*;

(iii) this higher rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); and

(iv) the constraint is binding in the Day-Ahead Market for hour *h*.

A “**Deemed Qualifying DAM Uprating**” shall be defined as a change in the rating of a constraint that, for a given constraint *a* and hour *h* of the Day-Ahead Market, meets each of the following requirements:

(i) the constraint has a lower rating in hour *h* than it would have if all transmission facilities were modeled as in-service in hour *h*;

(ii) this lower rating is in whole or in part the result of a Deemed Qualifying DAM Outage *o* or Deemed Qualifying DAM Return-to-Service *o* for hour *h*;

(iii) this lower rating resulting from Deemed Qualifying DAM Outage *o* or Deemed Qualifying DAM Return-to-Service *o* for hour *h* was modeled in the last auction held for TCCs valid for hour *h*, but responsibility for Qualifying DAM Outage *o* or Qualifying DAM Return-to-Service *o* resulting in the lower rating for hour *h* is assigned pursuant to Section 20.2.4.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner for the purpose of applying Section 20.2.4.4) other than the Transmission Owner responsible for the lower rating in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating for hour *h* is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the last Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); and

(v) the constraint is binding in the Day-Ahead Market for hour *h*.

20.2.4.3.2 Allocation of U/D DAM Constraint Residuals

This Section 20.2.4.3.2 describes the allocation of U/D DAM Constraint Residuals to Qualifying DAM Deratings and Qualifying DAM Upratings.

When there are Qualifying DAM Deratings or Qualifying DAM Upratings for constraint *a* in hour *h*, the ISO shall allocate a U/D DAM Constraint Residual in the form of a U/D Congestion Rent Shortfall Charge, U/D $CRSC_{a,t,h}$, or U/D Congestion Rent Surplus Payment, U/D $CRSP_{a,t,h}$, by first determining the net total impact on the constraint for hour *h* of all Qualifying DAM Upratings r and Qualifying DAM Deratings *r* for constraint *a* in hour *h* pursuant to Formula N-11 and then applying either Formula N-12 or Formula N-13, as specified herein, to assess U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments.

Formula N-11

$$U/D\ NetDAMImpact_{a,h} = \left(\sum_{for\ all\ r \in R_{a,h}} RatingChange_{a,h,r} * ShadowPrice_{a,h} \right) * SCUCSignChange_{a,h}$$

Where,

U/D $NetDAMImpact_{a,h}$ = The net impact, in dollars, on constraint *a* of all Qualifying DAM Upratings and Qualifying DAM Deratings for constraint *a* in hour *h*; *provided*, *however*, U/D $NetDAMImpact_{a,h}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula N-11

$RatingChange_{a,h,r}$ = Either

(a) If Qualifying DAM Derating *r* or Qualifying DAM Uprating *r* is a Deemed Qualifying DAM Derating or a Deemed Qualifying DAM Uprating, $RatingChange_{a,h,r}$ shall be equal to the amount, in MWh, of the decrease or increase in the rating of binding constraint *a* in hour *h* resulting from a Deemed Qualifying DAM Return-to-Service or Deemed Qualifying DAM Outage for constraint *a* in hour *h*, as shown in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); or

(b) If Qualifying DAM Derating *r* or Qualifying DAM Uprating *r* is an Actual Qualifying DAM Derating or an Actual Qualifying DAM Uprating, $\text{RatingChange}_{a,h,r}$ shall be equal to the amount, in MWh, of the decrease or increase in the rating of binding constraint *a* in hour *h* resulting from an Actual Qualifying DAM Return-to-Service or an Actual Qualifying DAM Outage for constraint *a* in hour *h*, as shown in the Reconfiguration Auction Interface Uprate/Derate Table in effect for the Reconfiguration Auction in which TCCs valid in hour *h* were sold (or if no Reconfiguration Auction was held for TCCs valid in hour *h*, then the Centralized TCC Auction Interface Uprate/Derate Table in effect for the last Centralized TCC Auction held for TCCs valid in hour *h*); *provided, however*, $\text{RatingChange}_{a,h,r}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula N-11

$R_{a,h}$ = The set of all Qualifying DAM Deratings *r* or Qualifying DAM Upratings *r* for binding constraint *a* in hour *h*

and the variables $\text{SCUCSignChange}_{a,h}$ and $\text{ShadowPrice}_{a,h}$ are defined as set forth in Formula N-5.

After calculating U/D $\text{NetDAMImpact}_{a,h}$ pursuant to Formula N-11, the ISO shall determine whether U/D $\text{NetDAMImpact}_{a,h}$ for constraint *a* in hour *h* has a different sign than U/D $\text{DCR}_{a,h}$ for constraint *a* in hour *h*. If the sign is different, the ISO shall (i) recalculate U/D $\text{NetDAMImpact}_{a,h}$ pursuant to Formula N-11 after setting equal to zero each $\text{RatingChange}_{a,h,r}$ for which $\text{RatingChange}_{a,h,r}$ * $\text{ShadowPrice}_{a,h}$ * $\text{SCUCSignChange}_{a,h}$ has a different sign than U/D $\text{DCR}_{a,h}$, and then (ii) use this recalculated U/D $\text{NetDAMImpact}_{a,h}$ and reset value of

$RatingChange_{a,h,r}$ to allocate U/D Congestion Rent Shortfall Charges and U/D Congestion Rent Surplus Payments pursuant to Formula N-12 or Formula N-13, as specified below.

If the absolute value of the net impact (U/D $NetDAMImpact_{a,h}$) on constraint *a* of all Qualifying DAM Deratings and Qualifying DAM Upratings for constraint *a* in hour *h* as calculated using Formula N-11 (or recalculated pursuant to Formula N-11 using a reset value of $RatingChange_{a,h,r}$ as described in the prior paragraph) is greater than the absolute value of the U/D DAM Constraint Residual (U/D $DCR_{a,h}$) for constraint *a* in hour *h*, then the ISO shall allocate the U/D DAM Constraint Residual in the form of a U/D Congestion Rent Shortfall Charge, U/D $CRSC_{a,t,h}$, or U/D Congestion Rent Surplus Payment, U/D $CRSP_{a,t,h}$, by using Formula N-12. If the absolute value of the net impact (U/D $NetDAMImpact_{a,h}$) on constraint *a* of all Qualifying DAM Deratings and Qualifying DAM Upratings for constraint *a* in hour *h* as calculated using Formula N-11 (or recalculated pursuant to Formula N-11 using a reset value of $RatingChange_{a,h,r}$ as described in the prior paragraph) is less than or equal to the absolute value of the U/D DAM Constraint Residual (U/D $DCR_{a,h}$) for constraint *a* in hour *h*, then the ISO shall allocate the U/D DAM Constraint Residual in the form of a U/D Congestion Rent Shortfall Charge, U/D $CRSC_{a,t,h}$, or U/D Congestion Rent Surplus Payment, U/D $CRSP_{a,t,h}$, by using Formula N-13.

Formula N-12

$$U/D\,Allocation_{a,t,h} = \left(\frac{\sum_{\substack{r \in R_{a,h} \\ and\ q=t}} \left(RatingChange_{a,h,r} * Responsibility_{h,q,r}\right)}{\sum_{for\ all\ r \in R_{a,h}} RatingChange_{a,h,r}} \right) * U/D\,DCR_{a,h}$$

Where,

U/D $Allocation_{a,t,h}$ = Either a U/D Congestion Rent Shortfall Charge or a U/D Congestion Rent Surplus Payment, as specified in (a) and (b) below:

(a) If U/D $Allocation_{a,t,h}$ is negative, then U/D $Allocation_{a,t,h}$ shall be a U/D Congestion Rent Shortfall Charge, U/D $CRSC_{a,t,h}$, charged to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market; or

(b) If U/D $Allocation_{a,t,h}$ is positive, then U/D $Allocation_{a,t,h}$ shall be a U/D Congestion Rent Surplus Payment, U/D $CRSP_{a,t,h}$, paid to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market

$Responsibility_{h,q,r}$ = The amount, as a percentage, of responsibility borne by Transmission Owner *q* (which shall include the ISO when it is deemed a Transmission Owner for the purpose of applying Sections 20.2.4.4.2, 20.2.4.4.3, or 20.2.4.4.4) for Qualifying DAM Derating *r* or Qualifying DAM Uprating *r* in hour *h*, as determined pursuant to Section 20.2.4.4

and the variable U/D $DCR_{a,h}$ is defined as set forth in Formula N-7 and the variables $RatingChange_{a,h,r}$ and $R_{a,h}$ are defined as set forth in Formula N-11.

Formula N-13

$$U/D\ Allocation_{a,t,h} = \left(\sum_{\substack{r \in R_{a,h} \\ and\ q=t}} RatingChange_{a,h,r} * ShadowPrice_{a,h} * Responsibility_{h,q,r} \right) * SCUCSignChange_{a,h}$$

Where,

the variables $ShadowPrice_{a,h}$ and $SCUCSignChange_{a,h}$ are defined as set forth in Formula N-5, the variables U/D $Allocation_{a,t,h}$ and $Responsibility_{h,q,r}$ are defined as set forth in Formula N-12, and the variables $RatingChange_{a,h,r}$ and $R_{a,h}$ are defined as set forth in Formula N-11.

20.2.4.4 Assigning Responsibility for Outages, Returns-to-Service, Deratings, and Upratings

20.2.4.4.1 General Rule for Assigning Responsibility; Presumption of Causation

Unless the special rules set forth in Sections 20.2.4.4.2 through 20.2.4.4.4 apply, a Transmission Owner shall for purposes of this Section 20.2.4 be deemed responsible for a DAM Status Change to the extent that the Transmission Owner has caused the DAM Status Change by changing the in-service or out-of-service status of its transmission facility; *provided, however,* that where a DAM Status Change results from a change to the in-service or out-of-service status of a transmission facility owned by more than one Transmission Owner, responsibility for such DAM Status Change shall be assigned to each owning Transmission Owner based on the percentage of the transmission facility that is owned by the Transmission Owner (as determined in accordance with Section 20.2.4.6.1) during the hour for which the DAM Status Change occurred. For the sake of clarity, a Transmission Owner may, by changing the in-service or out-of-service status of its transmission facility, cause a DAM Status Change of another transmission facility if the Transmission Owner’s change in the in-service or out-of-service status of its transmission facility causes (directly or as a result of Good Utility Practice) a change in the in-service or out-of-service status of the other transmission facility.

The Transmission Owner that owns a transmission facility that qualifies as a DAM Status Change shall be deemed to have caused the DAM Status Change of that transmission facility unless (i) the Transmission Owner that owns the facility informs the ISO that another Transmission Owner caused the DAM Status Change or that responsibility is to be shared among Transmission Owners in accordance with Sections 20.2.4.4.2, 20.2.4.4.3, or 20.2.4.4.4, and no party disputes such claim; (ii) in case of a dispute over the assignment of responsibility, the ISO determines a Transmission Owner other than the owner of the transmission facility caused the DAM Status Change or that responsibility is to be shared among Transmission Owners in accordance with Sections 20.2.4.4.2, 20.2.4.4.3, or 20.2.4.4.4; or (iii) FERC orders otherwise.

20.2.4.4.2 Shared Responsibility For Outages, Returns-to-Service, and Ratings Changes Directed by the ISO or Caused by Facility Status Changes Directed by the ISO

A Transmission Owner shall not be responsible for any DAM Status Change that qualifies as an ISO-Directed DAM Status Change or Deemed ISO-Directed DAM Status

Change. Instead, the ISO shall allocate any revenue impacts resulting from a DAM Status Change that qualifies as an ISO-Directed DAM Status Change or Deemed ISO-Directed DAM Status Change as part of Net Congestion Rents for hour *h*. To do so, the ISO shall be treated as a Transmission Owner when allocating DAM Constraint Residuals pursuant to Section 20.2.4.2 and Section 20.2.4.3, and any DAM Status Change that qualifies as an ISO-Directed DAM Status Change or Deemed ISO-Directed DAM Status Change shall be attributed to the ISO when performing the calculations described in Section 20.2.4.2 and Section 20.2.4.3; *provided, however*, any O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment allocable to the ISO pursuant to this Section 20.2.4.4.2 shall ultimately be allocated to the Transmission Owners as Net Congestion Rents pursuant to Section 20.2.5.

Responsibility for a Qualifying DAM Return-to-Service or Qualifying DAM Uprating that is directed by the ISO but does not qualify as a Deemed ISO-Directed DAM Status Change shall be assigned to the Transmission Owner that was responsible for the Qualifying Auction Outage or Qualifying Auction Derating in the last Reconfiguration Auction held for TCCs valid for the relevant hour or the last 6-month Sub-Auction of a Centralized TCC Auction held for TCCs valid for the relevant hour.

20.2.4.4.3 Shared Responsibility for External Events

A Transmission Owner shall not be responsible for a DAM Status Change occurring inside the NYCA that is caused by a change in the in-service or out-of-service status or rating of a transmission facility located outside the NYCA. Instead, the ISO shall allocate any revenue impacts resulting from a DAM Status Change caused by such an event outside the NYCA as part of Net Congestion Rents for hour *h*. To do so, the ISO shall be treated as a Transmission Owner when allocating DAM Constraint Residuals pursuant to Section 20.2.4.2 and Section 20.2.4.3 and any DAM Status Change caused by such an event outside the NYCA shall be attributed to the ISO when performing the calculations described in Section 20.2.4.2 and Section 20.2.4.3; *provided, however,* any O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment allocable to the ISO pursuant to this Section 20.2.4.4.3 shall ultimately be allocated to the Transmission Owners as Net Congestion Rents pursuant to Section 20.2.5.

20.2.4.4.4 Shared Responsibility For Returns-to-Service and Upratings During a Transitional Period

Notwithstanding any other provision of this Attachment N, a Transmission Owner shall be deemed to be not responsible for a Qualifying DAM Return-to-Service, Qualifying DAM Derating, or Qualifying DAM Uprating for an hour of the Day-Ahead Market if this Attachment N was not in effect at the time of the last Reconfiguration Auction held for TCCs valid for the hour. Instead, the ISO shall allocate any revenue impacts resulting from such a Qualifying DAM Return-to-Service, Qualifying DAM Derating, or Qualifying DAM Uprating as part of Net Congestion Rents for hour *h*. To do so, the ISO shall be treated as a Transmission Owner when allocating DAM Constraint Residuals pursuant to Section 20.2.4.2 and Section 20.2.4.3, and any such Qualifying DAM Return-to-Service, Qualifying DAM Derating, or Qualifying DAM Uprating during this transitional period shall be attributed to the ISO when performing the calculations described in Section 20.2.4.2 and Section 20.2.4.3; *provided, however*, any O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment allocable to the ISO pursuant to this Section 20.2.4.4.4 shall ultimately be allocated to the Transmission Owners as Net Congestion Rents pursuant to Section 20.2.5.

20.2.4.5 Exceptions: Setting Charges and Payments to Zero

20.2.4.5.1 Zeroing Out of Charges and Payments When Outages and Deratings Lead to Net Payments or Returns-to-Service and Upratings Lead to Net Charges

The ISO shall use Formula N-14 to calculate the total O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Congestion Rent Surplus Payments, and U/D Congestion Rent Surplus Payments, $\text{NetDAMAllocations}_{t,h}$, for Transmission Owner *t* in hour *h*. Based on this calculation, the ISO shall set equal to zero all O/R-t-S $\text{CRSC}_{a,t,h}$, U/D $\text{CRSC}_{a,t,h}$, O/R-t-S $\text{CRSP}_{a,t,h}$, and U/D $\text{CRSP}_{a,t,h}$ (each as defined in Formula N-14) for Transmission Owner *t* for all constraints for hour *h* if (i) $\text{NetDAMAllocations}_{t,h}$ is positive and Transmission Owner *t* is not responsible (as determined pursuant to Section 20.2.4.4) for any Qualifying DAM Returns-to-Service or Qualifying DAM Upratings during hour *h*, or (ii) $\text{NetDAMAllocations}_{t,h}$ is negative and Transmission Owner *t* is not responsible (as determined pursuant to Section 20.2.4.4) for any Qualifying DAM Outages or Qualifying DAM Deratings during hour *h*; *provided*, *however*, the ISO shall not set equal to zero pursuant to this Section 20.2.4.5.1 any O/R-t-S $\text{CRSC}_{a,t,h}$, U/D $\text{CRSC}_{a,t,h}$, O/R-t-S $\text{CRSP}_{a,t,h}$, or U/D $\text{CRSP}_{a,t,h}$ arising from an ISO-Directed DAM Status Change or Deemed ISO-Directed DAM Status Change described in Section 20.2.4.4.2, an external event described in Section 20.2.4.4.3, or an event occurring during a transitional period as described in Section 20.2.4.4.4.

Formula N-14

$$NetDAMAllocations_{t,h} = \sum_{for\ all\ a} \left(O/R\text{-}t\text{-}S\ CRSC_{a,t,h} + U/D\,\mathrm{CRSC}_{\,a,t,h} + O/R\text{-}t\text{-}S\ CRSP_{\mathrm{a,t,h}} + U/D\ CRSP_{\mathrm{a,t,h}} \right)$$

Where,

$\text{NetDAMAllocations}_{t,h}$ = The total of the O/R-t-S Congestion Rent Shortfall Charges, U/D Congestion Rent Shortfall Charges, O/R-t-S Congestion Rent Surplus Payments, and U/D Congestion Rent Surplus Payments allocated to Transmission Owner *t* in hour *h*

O/R-t-S $CRSC_{a,t,h}$ = An O/R-t-S Congestion Rent Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market, calculated pursuant to Section 20.2.4.2

U/D $CRSC_{a,t,h}$ = A U/D Congestion Rent Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market, calculated pursuant to Section 20.2.4.3

O/R-t-S $CRSP_{a,t,h}$ = An O/R-t-S Congestion Rent Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market, calculated pursuant to Section 20.2.4.2

U/D $CRSP_{a,t,h}$ = A U/D Congestion Rent Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in hour *h* of the Day-Ahead Market, calculated pursuant to Section 20.2.4.3.

20.2.4.5.2 Zeroing Out of Charges and Payments Resulting from Formula Failure

Notwithstanding any other provision of this Attachment N, the ISO shall set equal to zero any O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment allocated to a Transmission Owner for an hour of the Day-Ahead Market if either:

(i) data necessary to compute such a charge or payment, as specified in the formulas set forth in Section 20.2.4, is not known by the ISO and cannot be computed by the ISO (in interpreting this clause, equipment failure shall not preclude computation by the ISO unless necessary data is irretrievably lost); or

(ii) both (a) the charge or payment is clearly and materially inconsistent with cost causation principles; and (b) this inconsistency is the result of factors not taken into account in the formulas used to calculate the charge or payment;

provided, *however*, if the amount of charges or payments set equal to zero as a result of the unknown data or inaccurate formula is greater than twenty five thousand dollars ($25,000) in any given month or greater than one hundred thousand dollars ($100,000) over multiple months, the ISO will inform the Transmission Owners of the identified problem and will work with the

Transmission Owners to determine if an alternative allocation method is needed and whether it will apply to all months for which the intended formula does not work. Alternate methods would be subject to market participant review and subsequent filing with FERC, as appropriate.

For the sake of clarity, the ISO shall not pursuant to this Section 20.2.4.5.2 set equal to zero any O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment that fails to meet these conditions, even if another O/R-t-S Congestion Rent Shortfall Charge, U/D Congestion Rent Shortfall Charge, O/R-t-S Congestion Rent Surplus Payment, or U/D Congestion Rent Surplus Payment is set equal to zero pursuant to this Section 20.2.4.5.2 in the same hour of the Day-Ahead Market.

20.2.4.6 Information Requirements

20.2.4.6.1 Information Regarding Facility Ownership

A Transmission Owner shall be responsible for informing the ISO of any change in the ownership of a transmission facility. The ISO shall allocate responsibility for DAM Status Changes based on the transmission facility ownership information available to it at the time of initial settlement.

20.2.4.6.2 Calculation of Settlements Without DCR Allocation Threshold

One month each year, the ISO shall, for informational purposes only, calculate the DAM Constraint Residuals for each constraint for each hour without applying the DCR Allocation Threshold and shall calculate all O/R-t-S Congestion Rent Shortfall Charges, O/R-t-S Congestion Rent Surplus Payments, U/D Congestion Rent Shortfall Charges, and U/D Congestion Rent Surplus Payments. Before choosing the month for which it will perform these calculations, the ISO will consult with the Transmission Owners.

20.2.5 Allocation of Net Congestion Rents to Transmission Owners

The Net Congestion Rents for each hour of month *m* shall be summed over the month, so that positive and negative values net to a monthly total, NCR_m. The ISO shall allocate NCR_m each month to the Transmission Owners by allocating to each Transmission Owner *t* an amount equal to the product of (i) NCR_m, and (ii) the allocation factor for Transmission Owner *t* for month *m*, as calculated pursuant to Formula N-15.

Formula N-15

$$AllocationFactor_{t,m} = \frac{\left(OriginalResidual_{t,m} + ETCNL_{t,m} + NARs_{t,m} + GFR\&GFTCC_{t,m}\right)}{\sum_{q \in T}\left(OriginalResidual_{q,m} + ETCNL_{q,m} + NARs_{q,m} + GFR\&GFTCC_{q,m}\right)}$$

Where,

Allocation $Factor_{t,m}$	=	The allocation factor used by the ISO to allocate a share of the Net Congestion Rents to Transmission Owner *t* for month *m*
Original $Residual_{q,m}$	=	The one-month portion of the revenue imputed to the Direct Sale or the sale in any Centralized TCC Auction Sub-Auction of Original Residual TCCs that are valid in month *m*. The one-month portion of the revenue imputed to the Direct Sale of these Original Residual TCCs shall be the market clearing price of the TCCs in the Reconfiguration Auction held for month *m* (or one-sixth of the average market clearing price in the rounds of the 6-month Sub-Auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for month *m*. For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds.). The one-month portion of the revenue imputed to the sale in any Centralized TCC Auction Sub-Auction of these Original Residual TCCs shall be calculated by dividing the revenue received from the sale of these Original Residual TCCs in the Centralized TCC Auction Sub-Auction by the duration in months of the TCCs sold in that Centralized TCC Auction Sub-Auction.
$ETCNL_{q,m}$	=	The sum of the one-month portion of the revenue the Transmission Owner has received as payment for the Direct Sale of ETCNL or for its ETCNL released in the Centralized TCC Auction Sub-Auction held for TCCs valid for month *m*. Each one-month portion of the revenue for ETCNL released in such Centralized TCC Auction shall be calculated by dividing the revenue received in a

Centralized TCC Auction Sub-Auction from the sale of the ETCNL by the duration in months of the TCCs corresponding to the ETCNL sold in the Centralized TCC Auction Sub-Auction.[2] The one-month portion of the revenue imputed to the Direct Sale of ETCNL shall be the value of the TCCs corresponding to that ETCNL in the Reconfiguration Auction held for month *m* (or one-sixth of the average market clearing price of such TCCs in the rounds of the 6-month Sub-Auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for month *m*). For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds.

$NARs_{q,m}$ = The one-month portion of the Net Auction Revenues the Transmission Owner has received in Centralized TCC Auction Sub-Auction and Reconfiguration Auctions held for TCCs valid for month *m* (which shall not include any revenue from the sale of Original Residual TCCs). The one-month portion of the revenues shall be calculated by summing (i) the revenue Transmission Owner *q* received in each Centralized TCC Auction Sub-Auction or Reconfiguration Auction from the allocation of Net Auction Revenue pursuant to Section 20.3.7, divided by the duration in months of the TCCs sold in the Centralized TCC Auction Sub-Auction or Reconfiguration Auction (or, to the extent TCC auction revenues were allocated pursuant to a different methodology, the amount of such revenues allocated to Transmission Owner *q*), minus (ii) the sum of $NetAuctionAllocations_{t,n}$ as calculated pursuant to Formula N-27 (as adjusted for any charges or payments that are zeroed out) for Transmission Owner *q* for all 6-month Sub-Auction rounds *n* of all Centralized TCC Auctions held for TCCs valid in month *m*, divided in each case by the duration in months of the TCCs sold in each Centralized TCC Auction Sub-Auction (or, to the extent that the revenue impact of transmission facility outages, returns-to-service, upratings, and deratings were settled pursuant to a different methodology, the net of such revenue impacts for Transmission Owner *q*), minus (iii) $NetAuctionAllocations_{t,n}$ as calculated pursuant to Formula N-27 and as adjusted for any charges or payments that are zeroed out for Transmission Owner *q* for the Reconfiguration Auction *n* held for month *m* (or, to the extent that the revenue impact of transmission facility outages, returns-to-service, upratings, and deratings were settled pursuant to a different methodology, the net of such revenue impacts for Transmission Owner *q*). For Centralized TCC Auctions conducted before May 1, 2010, the calculation of (ii) shall

2 A TCC corresponds to ETCNL if it has the same POI and POW as the ETCNL.

incorporate only Stage 1 six month rounds.

$GFR\&GFTCC_{q,m}$ = The one-month portion of the imputed value of Grandfathered TCCs and Grandfathered Rights, valued at their market clearing prices in the Reconfiguration Auction for month *m* (or one-sixth of the average market clearing price for rounds in the 6-month Sub-Auction of the last Centralized TCC Auction if no Reconfiguration Auction was held for month *m*), provided that the Transmission Owner is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in month *m*. For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds.

t = Transmission Owner *t*

T = The set of all Transmission Owners *q*.

Each Transmission Owner's share of Net Congestion Rents allocated pursuant to this Section 20.2.5 shall be incorporated into, or otherwise accounted for as part of, its TSC, NTAC, or other applicable rate mechanism under the ISO Tariffs used to assess charges for Transmission Service provided by the Transmission Owner pursuant to this Tariff, as the case may be.

20.3 Settlement of TCC Auctions

20.3.1 Overview of TCC Auction Settlements; Calculation of Net Auction Revenue

Overview of TCC Auction Settlements. For each round *n* of a Centralized TCC Auction and for each Reconfiguration Auction *n*, the ISO shall settle all settlements for round *n* or for Reconfiguration Auction *n*. These settlements include, as applicable pursuant to the provisions of this Attachment N: (i) the market clearing price charged or paid to purchasers of TCCs; (ii) payments to Transmission Owners that released ETCNL; (iii) payments or charges to Primary Holders selling TCCs; (iv) payments to Transmission Owners that released Original Residual TCCs; (v) O/R-t-S Auction Revenue Shortfall Charges and U/D Auction Revenue Shortfall Charges; and (vi) O/R-t-S Auction Revenue Surplus Payments and U/D Auction Revenue Surplus Payments. Each of these settlements is represented by a variable in Formula N-16.

Calculation of Net Auction Revenues for a Round or a Reconfiguration Auction. In each Centralized TCC Auction round *n* and in each Reconfiguration Auction *n*, the ISO shall calculate Net Auction Revenue pursuant to Formula N-16.

Formula N-16

$$Net\ Auction\ Revenue_n = \begin{bmatrix} TCC\ Auction\ Revenue_n \\ -ETCNL_n \\ -Primary\ Holder\ TCCs\ Sold_n \\ -Original\ Residual\ TCCs_n \\ -O/R\text{-}t\text{-}S\&U/D\ ARSC\&ARSP_n \end{bmatrix}$$

Where,

n	=	A round of a Centralized TCC Auction (which may be either a round of a 6-month Sub-Auction , a round of a Sub-Auction in which TCCs with a duration greater than 6 months are sold,) or a Reconfiguration Auction, as the case may be
Net Auction Revenue$_n$	=	Net Auction Revenue for the round *n* of a Centralized TCC Auction or for Reconfiguration Auction *n*, as the case may be

TCC Auction $Revenue_n$	=	The gross amount of revenue that the ISO collects from the award of TCCs to purchasers in round *n* or in Reconfiguration Auction *n*, which results from the charges and payments allocated pursuant to Section 20.3.2
$ETCNL_n$	=	Either (i) if round *n* is a round of a Centralized TCC Auction, the total of all payments that the ISO makes to Transmission Owners releasing ETCNL into the round pursuant to Section 20.3.3; or (ii) for Reconfiguration Auction *n*, 0
Primary Holder TCCs $Sold_n$	=	The net of the total payments and charges the ISO allocates to Primary Holders selling TCCs in round *n* or in Reconfiguration Auction *n* pursuant to Section 20.3.4
Original Residual $TCCs_n$	=	Either (i) if round *n* is a round of a Centralized TCC Auction, the total payments the ISO makes in round *n* pursuant to Section 20.3.5 to Transmission Owners that release into round *n* Original Residual TCCs; or (ii) for Reconfiguration Auction *n*, 0
O/R-t-S&U/D $ARSC\&ARSP_n$	=	Either (i) if round *n* is a round of a Centralized TCC Auction in which 6-month TCCs are sold, the sum of the total O/R-t-S Auction Revenue Shortfall Charges, U/D Auction Revenue Shortfall Charges, O/R-t-S Auction Revenue Surplus Payments, and U/D Auction Revenue Surplus Payments (calculated as $NetAuctionAllocations_{t,n}$ pursuant to Formula N-27) for all Transmission Owners *t*, reduced by any zeroing out of such charges or payments pursuant to Section 20.3.6.5; (ii) if round *n* is a round of a Centralized TCC Auction Sub-Auction in which TCCs with durations longer than 6 months are sold, 0; or (iii) for Reconfiguration Auction *n*, the sum of the total O/R-t-S Auction Revenue Shortfall Charges(O/R-t-S $ARSC_{a,t,n}$), U/D Auction Revenue Shortfall Charges (U/D $ARSC_{a,t,n}$), O/R-t-S Auction Revenue Surplus Payments (O/R-t-S $ARSP_{a,t,n}$), and U/D Auction Revenue Surplus Payments (U/D $ARSP_{a,t,n}$) for all Transmission Owners *t* (which sum is calculated for each Transmission Owner as $NetAuctionAllocations_{t,n}$ pursuant to Formula N-27), reduced by any zeroing out of such charges or payments pursuant to Section 20.3.6.5

The ISO shall allocate the Net Auction Revenue calculated in each round of a Centralized TCC Auction Sub-Auction and in each Reconfiguration Auction to Transmission Owners pursuant to Section 20.3.7.

20.3.2 Charges for TCCs Purchased

All bidders awarded TCCs in round *n* of a Centralized TCC Auction or in

Reconfiguration Auction *n* shall pay or be paid the market clearing price in round *n* or in Reconfiguration Auction *n*, as determined pursuant to Attachment M of this Tariff, for the TCCs purchased.

20.3.3 Payments for ETCNL

The ISO shall, in each round of a Centralized TCC Auction in which ETCNL is released, pay the market clearing price determined in that round for TCCs that correspond to that ETCNL to the Transmission Owner that releases the ETCNL.

If a Transmission Owner releases ETCNL for sale in a round of the Centralized TCC Auction, and the market-clearing price for those TCCs corresponding to that ETCNL in that round is negative, the value of those TCCs will not be included in the determination of payments to the Transmission Owners for ETCNL released into the Centralized TCC Auction. If the market-clearing price is negative for TCCs corresponding to any ETCNL, the value will be set to zero for purposes of allocating auction revenues from the sale of ETCNL. If the total value of the auction revenues available for payment to the Transmission Owners for ETCNL released into the Centralized TCC Auction is insufficient to fund payments at market-clearing prices, the total payments to each Transmission Owner for ETCNL will be reduced proportionately. Notwithstanding any other provision in this Tariff, ETCNL that is offered in any Centralized TCC Auction and that is assigned a negative market clearing price or value shall not give rise to a payment obligation by the Transmission Owner that released it.

20.3.4 Payments to Primary Holders Selling TCCs; Distribution of Revenues from Sale of Certain Grandfathered TCCs (excluding ETCNL) in a Centralized TCC Auction

The ISO shall distribute to or collect from each Primary Holder of a TCC selling that TCC in the Centralized TCC Auction or Reconfiguration Auction the market clearing price of that TCC in the round of the Centralized TCC Auction or in the Reconfiguration Auction in which that TCC was sold.

In the event a Grandfathered TCC[1] is terminated by mutual agreement of the parties to the grandfathered ETA prior to the conditions specified within Attachments K and L, then the ISO shall distribute the revenues from the sale of the TCCs that correspond to the terminated Grandfathered TCCs in a round of a Centralized TCC Auction directly back to the Transmission Owner identified in Attachment L, until such time as the conditions specified within Attachments K and L are met. Upon such time that the conditions within Attachments K and L are met, the ISO shall allocate the revenues from the sale of the TCCs that correspond to terminated Grandfathered TCCs in the Centralized TCC Auction as Net Auction Revenues in accordance with Section 20.3.7 of this Attachment.

20.3.5 Allocation of Revenues from the Sale of Original Residual TCCs

Revenues associated with Original Residual TCCs shall be distributed directly to each Primary Holder for the duration of the LBMP Transition Period. The Primary Holder of such an Original Residual TCC shall be paid the market clearing price of the Original Residual TCC in the round of the Sub-Auction in which that Original Residual TCC was sold.

If a Transmission Owner releases an Original Residual TCC for sale in a round of the Centralized TCC Auction, and the market-clearing price for those TCCs in that round is negative, the value of those TCCs will not be included in the determination of payments to the Transmission Owners for Original Residual TCCs released into the Centralized TCC Auction. If the market-clearing price is negative for any Original Residual TCC, the value will be set to zero for purposes of allocating auction revenues from the sale of Residual TCCs. If the total value of

[1] These TCCs include TCCs, if any, associated with those rate schedules to which footnote 9 of Attachment L pertains, whether by mutual agreement or otherwise.

the auction revenues available for payment to the Transmission Owners for Original Residual TCCs released into the Centralized TCC Auction is insufficient to fund payments at market-clearing prices, the total payments to each Transmission Owner for Original Residual TCCs will be reduced proportionately. This proportionate reduction would include a reduction in payments reflecting a proportionate reduction in the auction value of Original Residual TCCs sold in a Direct Sale. Notwithstanding any other provision in this Tariff, Original Residual TCCs that are offered in any Centralized TCC Auction and that are assigned a negative market clearing price or value shall not give rise to a payment obligation by the Transmission Owner that released them.

20.3.6 Charges and Payments to Transmission Owners for Auction Outages and Returns-to-Service

The ISO shall charge O/R-t-S Auction Revenue Shortfall Charges and U/D Auction Revenue Shortfall Charges and pay O/R-t-S Auction Revenue Surplus Payments and U/D Auction Revenue Surplus Payments pursuant to this Section 20.3.6. To do so, the ISO shall calculate the Auction Constraint Residual for each constraint for each round *n* of a Centralized TCC Auction 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, pursuant to Section 20.3.6.1 and then determine the amount of each Auction Constraint Residual that is O/R-t-S Auction Constraint Residual and the amount that is U/D Auction Constraint Residual, as specified in Section 20.3.6.1. The ISO shall use the O/R-t-S Auction Constraint Residual to allocate O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments to Transmission Owners pursuant to Sections 20.3.6.2 and 20.3.6.4, each of which shall be subject to being reduced to zero pursuant to Section 20.3.6.5. The ISO shall use the U/D Auction Constraint Residual to allocate U/D Auction Revenue Shortfall Charges and U/D Auction Revenue Surplus Payments to Transmission Owners pursuant to Sections 20.3.6.3 and 20.3.6.4, each of which shall be subject to being reduced to zero pursuant to Section 20.3.6.5.

The ISO shall not calculate an Auction Constraint Residual, O/R-t-S Auction Constraint Residual, or U/D Auction Constraint Residual for any rounds of a Centralized TCC Auction except for rounds of the 6-month Sub-Auction.

20.3.6.1 Measuring the Impact of Auction Outages and Returns-to-Service: Calculation of Auction Constraint Residuals and Division of Auction Constraint Residuals into O/R-t-S Auction Constraint Residuals and U/D Auction Constraint Residuals

The ISO shall identify all constraints that are binding in the final Optimal Power Flow solution for round *n* of a 6-month Sub-Auction of a Centralized TCC Auction or for Reconfiguration Auction *n*, as the case may be. For each binding constraint *a* and for each round *n* of a 6-month Sub-Auction of a Centralized TCC Auction or Reconfiguration Auction *n*, the ISO shall calculate the Auction Constraint Residual, $ACR_{a,n}$, using Formula N-17; *provided, however*, the ISO shall recalculate $ACR_{a,n}$ using Formula N-18 if (i) $ACR_{a,n}$ is positive based on the calculation using Formula N-17, and (ii) constraint *a* was not binding in the Power Flow used to determine the Energy flow on constraint *a* in calculating the variable $FLOW_{a,n,basecase}$ in Formula N-17.

Formula N-17

$$ACR_{a,n} = ShadowPrice_{a,n} * \begin{bmatrix} (FLOW_{a,n,actual} - FLOW_{a,n,basecase}) \\ +(ISORatingChange_{a,n} * OPFSignChange_{a,n}) \end{bmatrix} * \%Sold_n$$

Where,

$ACR_{a,n}$ = The Auction Constraint Residual, in dollars, for binding constraint *a* in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*

$ShadowPrice_{a,n}$ = The Shadow Price, in dollars/MW-*p*, of binding constraint *a* in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, where *p* is a one-month period for Reconfiguration Auction *n* and *p* is a six-month period for round *n* of a 6-month Sub-Auction, which Shadow Price is calculated in a manner so that if relaxation of constraint *a* would permit an increase in the objective function used for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* as described in Attachment M of this tariff, then $ShadowPrice_{a,n}$ is positive

$FLOW_{a,n,actual}$ = The Energy flow, in MW-*p*, on binding constraint *a* resulting from a Power Flow using, as the case may be:

(a) For Reconfiguration Auction *n*, (i) the Transmission System model for Reconfiguration Auction *n*, (ii) the set of TCCs and Grandfathered Rights represented in the solution to Reconfiguration Auction *n* (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction), and (iii) the phase angle regulator schedules determined in the Optimal Power Flow solution for Reconfiguration Auction *n*; or

(b) For round *n* of a 6-month Sub-Auction, (i) the Transmission System model for round *n*, (ii) the set of TCCs (scaled appropriately) and Grandfathered Rights represented in the solution to round *n* (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction), and (iii) the phase angle regulator schedule produced in the Optimal Power Flow solution for round *n*

$FLOW_{a,n,basecase}$= The Energy flow, in MW-*p*, on binding constraint *a* produced in, as the case may be:

(a) For Reconfiguration Auction *n*, a Power Flow using the following base case data set: (i) the Transmission System model for Reconfiguration Auction *n*, (ii) the set of TCCs and Grandfathered Rights represented in the solution to the final round of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n* (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction), and (iii) the phase angle regulator schedules determined in the Optimal Power Flow solution for the final round of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; or (b)

For round *n* of a 6-month Sub-Auction, a Power Flow run using the following base case data set: (i) the Transmission System model for the actual 6-month Sub-Auction, and (ii) the base case set of TCCs (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in the simulated auction) and the phase angle regulator schedule produced in a single simulated TCC auction administered for all rounds of the 6-month Sub-Auction using the Transmission System model for the actual 6-month Sub-Auction modified so as to model as in-service all transmission facilities that were out-of-service in the Transmission System model used for the Sub-Auction and model as fully rated all transmission facilities that were derated in the Transmission System model used for the Sub-Auction, the pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in the Sub-Auction, and all bids to purchase and offers to sell made into all rounds of the Sub-Auction that includes round *n*

$ISORatingChange_{a,n}$ = The total change in the rating of constraint *a* for round *n* or Reconfiguration Auction *n* resulting from ISO-Directed Auction Status Changes or Deemed ISO-Directed Auction Status Changes described in Section 20.3.6.4.2, external events described in Section 20.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for round *n* or Reconfiguration Auction *n*, which shall be calculated as follows:

(a) For Reconfiguration Auction *n*, zero, except that in the event of a change in the rating of constraint *a* resulting from ISO-Directed Auction Status Changes or Deemed ISO-Directed Auction Status Changes described in Section 20.3.6.4.2, external events described in Section 20.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for round *n* or Reconfiguration Auction *n*, $ISORatingChange_{a,n}$ shall be equal to the amount, in MW-*p*, of the change in the rating limit of constraint *a* as shown in the Reconfiguration Auction Interface Uprate/Derate Table applicable for Reconfiguration Auction *n*

(b) For round *n* of a 6-month Sub-Auction, zero, except that in the event of a change in the rating of a transmission facility resulting from ISO-Directed Auction Status Changes or Deemed ISO-Directed Auction Status Changes described in Section 20.3.6.4.2, external events described in Section 20.3.6.4.3, or reasons determined by the ISO to be unrelated to Qualifying Auction Outages or Qualifying Auction Returns-to-Service for round *n* or Reconfiguration Auction *n*, $\text{ISORatingChange}_{a,n}$ shall be equal to the amount, in MW-*p*, of the change in the rating limit of constraint *a* as shown in the Centralized TCC Auction Interface Uprate/Derate Table applicable for round *n*

$\text{OPFSignChange}_{a,n}$=1 if $\text{ShadowPrice}_{a,n}$ is greater than zero; otherwise, -1

$\text{\%Sold}_n$ = Either (i) for round *n* of a 6-month Sub-Auction, the percentage of transmission Capacity sold in round *n*, divided by the percentage of transmission Capacity sold in all rounds of the Sub-Auction of which round *n* is a part; or (ii) for Reconfiguration Auction *n*, 1.

Formula N-18

$$ACR_{a,n} = ShadowPrice_{a,n} * \begin{bmatrix} (FLOW_{a,n,actual} - FLOW_{a,n,basecase}) \\ +(ISORatingChange_{a,n} * OPFSignChange_{a,n}) \\ -(UnsoldCapacity_{a,n,PriorAuction} * OPFSignChange_{a,n}) \end{bmatrix} * \%Sold_n$$

Where,

$\text{UnsoldCapacity}_{a,n,\text{PriorAuction}}$ = Either:

(a) For Reconfiguration Auction *n*, the rating limit for binding constraint *a* applied in the model used in the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, minus the Energy flow, in

MW-*p*, on binding constraint *a* produced in the Optimal Power Flow in the last round of that Centralized TCC Auction; or

(b) For round *n* of a 6-month Sub-Auction, the rating limit for binding constraint *a* applied in the model used in the simulated auction run to determine $FLOW_{a,n,basecase}$ in Formula N-17, minus the Energy flow, in MW-*p*, on binding constraint *a* produced in the Optimal Power Flow in the simulated auction run to determine $FLOW_{a,n,basecase}$ in Formula N-17

and each of the other variables is as set forth in Formula N-17; *provided, however*, if $ACR_{a,n}$ is less than zero when calculated using this Formula N-18, $ACR_{a,n}$ shall be set equal to zero.

Following calculation of the Auction Constraint Residual for each constraint *a* for each round *n* of a 6-month Sub-Auction or each Reconfiguration Auction *n*, the ISO shall calculate the amount of each O/R-t-S Auction Constraint Residual and the amount of each U/D Auction Constraint Residual for each constraint *a* for each ound *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be. The amount of each O/R-t-S Auction Constraint Residual for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, for constraint *a* shall be determined by applying Formula N-19. The amount of each U/D Auction Constraint Residual for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, for constraint *a* shall be determined by applying Formula N-20.

Formula N-19

$$O/R\text{-}t\text{-}S\,ACR_{a,n} = ACR_{a,n} * \left[\frac{\left(FLOW_{a,n,actual} - FLOW_{a,n,basecase}\right) + \left(TotalRatingChange_{a,n} * OPFSignChange_{a,n}\right)}{\left(FLOW_{a,n,actual} - FLOW_{a,n,basecase}\right) + \left(ISORatingChange_{a,n} * OPFSignChange_{a,n}\right)}\right]$$

Where:

$O/R\text{-}t\text{-}S\ ACR_{a,n}$ = The amount of the O/R-t-S Auction Constraint Residual for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, for constraint *a*

$TotalRatingChange_{a,n}$ = The total change in the rating of constraint *a*, which shall be calculated as follows:

(a) For Reconfiguration Auction *n*, $TotalRatingChange_{a,n}$ shall be equal to (1) the rating limit, in MW-*p*, of constraint *a* in the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, minus (2) the rating limit, in MW-*p*, of constraint *a* applicable in Reconfiguration Auction *n*

(b) For round *n* of a 6-month Sub-Auction, $TotalRatingChange_{a,n}$ shall be equal to (1) the rating limit, in MW-*p*, of constraint *a* in a case where all transmission facilities are in-service and fully rated, minus (2) the rating limit, in MW-*p*, of constraint *a* in round *n*

and the variable $ACR_{a,n}$ is as calculated pursuant to Formula N-17 or, if required, pursuant to Formula N-18, and each of the other variables are as defined in Formula N-17.

Formula N-20

$$U/D\,ACR_{a,n} = ACR_{a,n} * \left[\frac{-\left(TotalRatingChange_{a,n} - ISORatingChange_{a,n}\right) * \ OPFSignChange_{a,n}}{\left(FLOW_{a,n,actual} - FLOW_{a,n,basecase}\right) + \left(ISORatingChange_{a,n} * OPFSignChange_{a,n}\right)}\right]$$

Where,

$U/D\ ACR_{a,n}$ = The amount of the U/D Auction Constraint Residual for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, for constraint *a*

and the variable $ACR_{a,n}$ is as calculated pursuant to Formula N-17 or, if required, pursuant to Formula N-18, the variable $TotalRatingChange_{a,n}$ is defined as set forth in Formula N-19 and each of the other variables are defined as set forth in Formula N-17.

20.3.6.2 Charges and Payments for the Direct Impact of Auction Outages and Returns-to-Service

The ISO shall use O/R-t-S Auction Constraint Residuals to allocate O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments, as the case may be, among Transmission Owners pursuant to this Section 3.6.2. Each O/R-t-S Auction Revenue Shortfall Charge and each O/R-t-S Auction Revenue Surplus Payment allocated to a Transmission Owner pursuant to this Section 20.3.6.2 is subject to being set equal to zero pursuant to Section 20.3.6.5.

20.3.6.2.1 Identification of Outages and Returns-to-Service Qualifying for Charges and Payments

For each round of a 6-month Sub-Auction or Reconfiguration Auction, as the case may be, the ISO shall identify each Qualifying Auction Outage and each Qualifying Auction Return-to-Service, as described below. The Transmission Owner responsible, as determined pursuant to Section 20.3.6.4, for the Qualifying Auction Outage or Qualifying Auction Return-to-Service shall be allocated an O/R-t-S Auction Revenue Shortfall Charge or an O/R-t-S Auction Revenue Surplus Payment pursuant to Sections 20.3.6.2.2 or 20.3.6.2.3.

20.3.6.2.1.1 Definition of Qualifying Auction Outage

A "**Qualifying Auction Outage**" (which term shall apply to round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be) shall be defined to mean either an Actual Qualifying Auction Outage or a Deemed Qualifying Auction Outage. For purposes of this Attachment N, "*o*" shall refer to a single Qualifying Auction Outage.

An "**Actual Qualifying Auction Outage**" (which term shall apply to round *n* of a 6-month ub-Auction or Reconfiguration Auction *n*, as the case may be) shall be defined as a transmission facility that, for a given round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be:

(a) For Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed and was modeled as in-service in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and

(ii) the facility exists but is not modeled as in-service for Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; or

(b) For round *n* of a 6-month Sub-Auction, meets each of the following requirements:

(i) the facility exists but is not modeled as in-service for round *n* of a 6-month Sub-Auction; and

(ii) the facility was not Normally Out-of-Service Equipment at the time of stage 1 round *n* of that 6-month Sub-Auction.

A "**Deemed Qualifying Auction Outage**" (which term shall apply only to a Reconfiguration Auction *n*) shall be defined as a transmission facility that, for Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(ii) the facility existed but was not modeled as in-service in Reconfiguration Auction *n* as a result of an Auction Status Change or external event described in Section 20.3.6.4.3 in Reconfiguration Auction *n* for which responsibility was assigned pursuant to Section 20.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.3.6.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*.

20.3.6.2.1.2 Definition of Qualifying Auction Return-to-Service

A "**Qualifying Auction Return-to-Service**" shall be defined to mean either an Actual Qualifying Auction Return-to-Service or a Deemed Qualifying Auction Return-to-Service. For purposes of this Attachment N, "*o*" shall refer to a single Qualifying Auction Return-to-Service.

An "**Actual Qualifying Auction Return-to-Service**" shall be defined as a transmission facility that, for a given Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service for the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and

(ii) the facility exists and is modeled as in-service in Reconfiguration Auction *n*;

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*.

Notwithstanding any other provision of this Attachment N, a transmission facility returning to service for round *n* of a 6-month Sub-Auction shall not be an Actual Qualifying Auction Return-to-Service for that round *n* and shall not qualify a Transmission Owner for an O/R-t-S Auction Revenue Shortfall Charge or O/R-t-S Auction Revenue Surplus Payment for that round *n*.

A “**Deemed Qualifying Auction Return-to-Service**” shall be defined as a transmission facility that, for a given Reconfiguration Auction *n*, meets each of the following requirements:

(i) the facility existed but was not modeled as in-service in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(ii) the facility existed but was not modeled as in-service in Reconfiguration Auction *n* as a result of an Auction Status Change or external event described in Section 20.3.6.4.3 in Reconfiguration Auction *n* for which responsibility was assigned pursuant to Section 20.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.3.6.4) other than the Transmission Owner assigned responsibility for the facility not being modeled as in-service for the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and

(iii) the facility was not Normally Out-of-Service Equipment at the time of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*.

20.3.6.2.2 Allocation of an O/R-t-S Auction Constraint Residual When Only One Transmission Owner is Responsible for All of the Relevant Outages and Returns-to-Service

This Section 20.3.6.2.2 describes the allocation of an O/R-t-S Auction Constraint Residual for a given round of a 6-month Sub-Auction or Reconfiguration Auction, as the case may be, and a given constraint when only one Transmission Owner is responsible, as determined pursuant to Section 20.3.6.4, for all of the Qualifying Auction Outages and all of the Qualifying Auction Returns-to-Service for that round of a 6-month Sub-Auction or Reconfiguration Auction that contribute to that constraint.

If the same Transmission Owner is responsible, as determined pursuant to Section 20.3.6.4, for all of the Qualifying Auction Outages *o* and Qualifying Auction Returns-to-Service *o* for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* that contribute to constraint *a*, then the ISO shall allocate the O/R-t-S Auction Constraint Residual for that round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* and that constraint, O/R-t-S $ACR_{a,n}$, to that Transmission Owner in the form of either (i) an O/R-t-S Auction Revenue Shortfall Charge in the amount of O/R-t-S $ACR_{a,n}$ if O/R-t-S $ACR_{a,n}$ is negative, or (ii) an O/R-t-S Auction Revenue Surplus Payment in the amount of O/R-t-S $ACR_{a,n}$ if O/R-t-S $ACR_{a,n}$ is positive.

20.3.6.2.3 Allocation of an O/R-t-S Auction Constraint Residual When More Than One Transmission Owner is Responsible for the Relevant Outages and Returns-to-Service

This Section 20.3.6.2.3 describes the allocation of an O/R-t-S Auction Constraint Residual for a given round of a 6-month Sub-Auction or Reconfiguration Auction, as the case may be, and a given constraint when more than one Transmission Owner is responsible, as determined pursuant to Section 20.3.6.4, for the Qualifying Auction Outages and the Qualifying Auction Returns-to-Service for the round of a 6-month Sub-Auction or Reconfiguration Auction that contribute to the constraint.

If more than one Transmission Owner is responsible, as determined pursuant to Section 20.3.6.4, for the Qualifying Auction Outages and the Qualifying Auction Returns-to-Service for round n of a 6-month Sub-Auction or Reconfiguration Auction n that contribute to constraint a, the ISO shall allocate the O/R-t-S Auction Constraint Residual for constraint a for round n of a 6-month Sub-Auction or for Reconfiguration Auction n, O/R-t-S $ACR_{a,n}$, in the form of an O/R-t-S Auction Revenue Shortfall Charge or O/R-t-S Auction Revenue Surplus Payment to the

Transmission Owners responsible for the Qualifying Auction Outages o and Qualifying Auction Returns-to-Service o for round n of a 6-month Sub-Auction or Reconfiguration Auction n by first determining the net total impact on the constraint of all Qualifying Auction Outages and Qualifying Auction Returns-to Service for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* with an impact on the Energy flow across that constraint of 1 MW-*p* or more by applying Formula N-21, and then applying either Formula N-22 or Formula N-23, as specified herein, to assess O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments.

Formula N-21

$$O/R\text{-}t\text{-}SNetAuctionImpact_{a,n} = \sum_{for\ all\ o \in O_n} FlowImpact_{a,n,o} * ShadowPrice_{a,n}$$

Where,

$O/R\text{-}t\text{-}SNetAuctionImpact_{a,n}$ = The net impact, in dollars, for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, on constraint *a* of all Qualifying Auction Outages and Qualifying Auction Returns-to-Service for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* having an impact of more than 1 MW-*p* on Energy flow across constraint *a; provided, however,* $O/R\text{-}t\text{-}SNetAuctionImpact_{a,n}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula N-21

$FlowImpact_{a,n,o}$ = The Energy flow impact, in MW-*p*, of a Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* on binding constraint *a* determined for Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, which shall either:

(a) if Qualifying Auction Outage *o* is a Deemed Qualifying Auction Outage, be equal to the negative of $FlowImpact_{a,n,o}$ calculated for the corresponding Deemed Qualifying Auction Return-to-Service as described in part (b) of this definition of $FlowImpact_{a,n,o}$, or

(b) if Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* is an Actual Qualifying Auction Outage, an Actual Qualifying Auction Return-to-

Service, or a Deemed Qualifying Auction Return-to-Service, be calculated pursuant to the following formula:

$$FlowImpact_{a,n,o} = BaseCaseFlow_{a,n} - One\text{-}OffFlow_{a,n,o}$$

Where,

$BaseCaseFlow_{a,n}$ = Either, as the case may be:

(i) for a Reconfiguration Auction, the Energy flow on constraint *a* resulting from a Power Flow using (1) the set of injections and withdrawals corresponding to the actual TCCs and Grandfathered Rights represented in the solution to the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n* (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction); (2) the phase angle regulator schedule determined in the Optimal Power Flow solution for the final round of the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; and (3) the Transmission System model for the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*; or

(ii) for any round of a 6-month Sub-Auction, the Energy flow on constraint *a* resulting from a Power Flow run using the following base case data set: (1) the Transmission System model for the actual 6-month Sub-Auction, modified so as to model as in-service all transmission facilities that were out-of-service for the actual 6-month Sub-Auction, and (2) the set of injections and withdrawals corresponding to the base case set of TCCs (including those pre-existing TCCs and Grandfathered Rights that are represented as fixed injections and withdrawals in the 6-month Sub-Auction) and the phase angle regulator schedule produced in the Optimal Power Flow used to calculate the Energy flow on constraint *a* for round *n* of a 6-month Sub-Auction, as described in the definition of $FLOW_{a,n,basecase}$ in Formula N-17

$One\text{-}OffFlow_{a,n,o}$ = Either

(i) if Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* is an Actual Qualifying Auction Outage or an Actual Qualifying Auction Return-to-Service, the Energy flow on constraint *a* resulting from a Power Flow using each element of the base case data set used in the calculation of $BaseCaseFlow_{a,n}$ above (*provided*, *however*, if a transmission facility was modeled as free-flowing in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, as the case may be, because of the outage of any transmission facility, the ISO shall appropriately adjust the phase angle regulator schedule and related variables to model the transmission facility as free flowing), but in each case with the Transmission System model modified so as to, as the case may be, either (i) model as out-of-service Actual Qualifying Auction Outage *o*, or (ii) model as in-service Actual Qualifying Auction Return-to-Service *o*; or

(ii) if Qualifying Auction Return-to-Service *o* is a Deemed Qualifying Auction Return-to-Service, the Energy flow on constraint *a* resulting from a Power Flow using each element of the base case data set used in the calculation of $BaseCaseFlow_{a,n}$ above (*provided*, however, if a transmission facility was modeled as free-flowing in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, as the case may be, because of the outage of any transmission facility, the ISO shall appropriately adjust the phase angle regulator schedule and related variables to model the transmission facility as free flowing), but with the Transmission System model modified so as to model as in-service the facility that is Deemed Qualifying Auction Return-to-Service *o*; *provided, however*, where the absolute value of $\text{FlowImpact}_{a,n,o}$ calculated using the procedures set forth above is less than 1 MW-*p*, then $\text{FlowImpact}_{a,n,o}$ shall be set equal to zero *provided further*, $\text{FlowImpact}_{a,n,o}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula N-21

O_n = The set of all Qualifying Auction Outages *o* and Qualifying Auction Returns-to-Service *o* in round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*

p = A one-month period for Reconfiguration Auction *n*, or a six-month period for round *n* of a 6-month Sub-Auction

and the variable $\text{ShadowPrice}_{a,n}$ is defined as set forth in Formula N-17.

After calculating O/R-t-S $\text{NetAuctionImpact}_{a,n}$ pursuant to Formula N-21, the ISO shall determine whether O/R-t-S $\text{NetAuctionImpact}_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* has a different sign than O/R-t-S $\text{ACR}_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*. If the sign is different, the ISO shall (i) recalculate O/R-t-S $\text{NetAuctionImpact}_{a,n}$ pursuant to Formula N-21 after setting equal to zero each $\text{FlowImpact}_{a,n,o}$ for which $\text{FlowImpact}_{a,n,o}$ * $\text{ShadowPrice}_{a,n}$ has a different sign than O/R-t-S $\text{ACR}_{a,n}$, and then (ii) use this recalculated O/R-t-S $\text{NetAuctionImpact}_{a,n}$ and reset value of $\text{FlowImpact}_{a,n,o}$ to allocate O/R-t-S Auction Revenue Shortfall Charges and O/R-t-S Auction Revenue Surplus Payments pursuant to Formula N-22 or Formula N-23, as specified below.

If the absolute value of the net impact (O/R-t-S $\text{NetAuctionImpact}_{a,n}$) on constraint *a* of all Qualifying Auction Outages and Qualifying Auction Returns-to-Service for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* as calculated using Formula N-21 (or recalculated pursuant to Formula N-21 using a reset value of $\text{FlowImpact}_{a,n,o}$ as described in the prior paragraph) is greater than the absolute value of the O/R-t-S Auction Constraint Residual (O/R-t-S $\text{ACR}_{a,n}$) for constraint *a* in round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, then the ISO shall allocate the O/R-t-S Auction Constraint Residual in the form of an O/R-t-S Auction Revenue Shortfall Charge, O/R-t-S $\text{ARSC}_{a,t,n}$, or O/R-t-S Auction Revenue Surplus Payment, O/R-t-S $\text{ARSP}_{a,t,n}$, by using Formula N-22. If the absolute value of the net impact (O/R-t-S $\text{NetAuctionImpact}_{a,n}$) on constraint *a* of all Qualifying Auction Outages and Qualifying Auction Returns-to-Service for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* as calculated using Formula N-21 (or recalculated pursuant to Formula N-21 using a reset value of $\text{FlowImpact}_{a,n,o}$ as described in the prior paragraph) is less than or equal to the absolute value of the O/R-t-S Auction Constraint Residual (O/R-t-S $\text{ACR}_{a,n}$) for constraint *a* in round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, then the ISO shall allocate the O/R-t-S Auction Constraint Residual in the form of an O/R-t-S Auction Revenue Shortfall Charge, O/R-t-S $\text{ARSC}_{a,t,n}$, or O/R-t-S Auction Revenue Surplus Payment, O/R-t-S $\text{ARSP}_{a,t,n}$, by using Formula N-23.

Formula N-22

$$O/R\text{-}t\text{-}S\ Allocation_{a,t,n} = \left(\frac{\sum_{\substack{o \in O_n \\ and\ q=t}} \left(FlowImpact_{a,n,o} * Responsibility_{n,q,o} \right)}{\sum_{for\ all\ o \in O_n} FlowImpact_{a,n,o}} \right) * O/R\text{-}t\text{-}S\ ACR_{a,n}$$

Where,

O/R-t-S $\text{Allocation}_{a,t,n}$ = Either an O/R-t-S Auction Revenue Shortfall Charge or an O/R-t-S Auction Revenue Surplus Payment, as specified in (a) and (b) below:

(a) If O/R-t-S $\text{Allocation}_{a,t,n}$ is negative, then O/R-t-S $\text{Allocation}_{a,t,n}$ shall be an O/R-t-S Auction Revenue Shortfall Charge, O/R-t-S $\text{ARSC}_{a,t,n}$, charged to Transmission Owner *t* for binding constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction;

or

(b) If O/R-t-S $\text{Allocation}_{a,t,n}$ is positive, then O/R-t-S $\text{Allocation}_{a,t,n}$ shall be an O/R-t-S Auction Revenue Surplus Payment, O/R-t-S $\text{ARSP}_{a,t,n}$, paid to Transmission Owner *t* for binding constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction

$\text{Responsibility}_{n,q,o}$ = The amount, as a percentage, of responsibility borne by Transmission Owner *q* (which shall include the ISO when it is deemed a Transmission Owner for the purpose of applying Sections 20.3.6.4.2 or 20.3.6.4.3) for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, as determined pursuant to Section 20.3.6.4

and the variable O/R-t-S $\text{ACR}_{a,n}$ is defined as set forth in Formula N-19 and the variables $\text{FlowImpact}_{a,n,o}$ and O_n are defined as set forth in Formula N-21.

Formula N-23

$$O/R\text{-}t\text{-}S\,Allocation_{a,t,n} = \sum_{\substack{o \in O_n \\ and\ q=t}} FlowImpact_{a,n,o} * ShadowPrice_{a,n} * Responsibility_{n,q,o}$$

Where,

the variable $\text{ShadowPrice}_{a,n}$ is defined as set forth in Formula N-17, the variables O/R-t-S $\text{Allocation}_{a,t,n}$ and $\text{Responsibility}_{n,q,o}$ are defined as set forth in Formula N-22, and the variables $\text{FlowImpact}_{a,n,o}$ and O_n are defined as set forth in Formula N-21.

20.3.6.3 Charges and Payments for the Secondary Impact of Auction Outages and Returns-to-Service

The ISO shall use U/D Auction Constraint Residuals to allocate U/D Auction Revenue Shortfall Charges and U/D Auction Revenue Surplus Payments, as the case may be, among Transmission Owners pursuant to this Section 20.3.6.3. Each U/D Auction Revenue Shortfall Charge and each U/D Auction Revenue Surplus Payment allocated to a Transmission Owner pursuant to this Section 20.3.6.3 is subject to being set equal to zero pursuant to Section 20.3.6.5.

20.3.6.3.1 Identification of Upratings and Deratings Qualifying for Charges and Payments

For each constraint for each round of a 6-month Sub-Auction or Reconfiguration Auction, the ISO shall identify each Qualifying Auction Derating and each Qualifying Auction Uprating, as described below. The Transmission Owner responsible, as determined pursuant to Section 20.3.6.4, for a Qualifying Auction Derating or Qualifying Auction Uprating shall be allocated a U/D Auction Revenue Shortfall Charge or a U/D Auction Revenue Surplus Payment, as the case may be, pursuant to Section 20.3.6.3.2.

20.3.6.3.1.1 Definition of Qualifying Auction Derating

A "**Qualifying Auction Derating**" (which term shall apply to round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be) shall be defined to mean an Actual Qualifying Auction Derating or a Deemed Qualifying Auction Derating. For purposes of this Attachment N, "*r*" shall refer to a single Qualifying Auction Derating.

An "**Actual Qualifying Auction Derating**" (which term shall apply to round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be) shall be defined as a change in the rating of a constraint that, for a given constraint *a* and a given round *n* or Reconfiguration Auction *n* meets each of the following requirements:

For Reconfiguration Auction *n*:

(i) the constraint has a lower rating in Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service in Reconfiguration Auction *n*;

(ii) this lower rating is in whole or in part the result of an Actual Qualifying Auction Outage *o* or an Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n*;

(iii) the lower rating resulting from Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was not modeled in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iv) this lower rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint was binding in Reconfiguration Auction *n*.

For round *n* of a 6-month Sub-Auction:

(i) the constraint has a lower rating in round *n* of the 6-month Sub-Auction than that constraint would have in a case where all transmission facilities are in-service and fully rated;

(ii) this lower rating is the result of an Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for round *n* of the 6-month Sub-Auction;

(iii) this lower rating is included in the Centralized TCC Auction Interface Uprate/Derate Table in effect for round *n* of the 6-month Sub-Auction; and

(iv) the constraint is binding in round *n* of the 6-month Sub-Auction.

A "**Deemed Qualifying Auction Derating**" (which term shall apply to Reconfiguration Auction *n*) shall be defined as a change in the rating of a constraint that, for a given constraint *a* and a given Reconfiguration Auction *n* meets each of the following requirements:

(i) the constraint has a lower rating in Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service in Reconfiguration Auction *n*;

(ii) this lower rating is in whole or in part the result of a Deemed Qualifying Auction

Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n*;

(iii) this lower rating resulting from Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was modeled in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, but responsibility for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* resulting in the lower rating for Reconfiguration Auction *n* is assigned pursuant to Section 20.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.3.6.4) other than the Transmission Owner responsible for the lower rating in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iv) this lower rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint is binding in Reconfiguration Auction *n*.

20.3.6.3.1.2 Definition of Qualifying Auction Uprating

A "**Qualifying Auction Uprating**" shall be defined to mean either an Actual Qualifying Auction Uprating or a Deemed Qualifying Auction Uprating. For purposes of this Attachment N, "*r*" shall refer to a single Qualifying Auction Uprating.

An "**Actual Qualifying Auction Uprating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* and Reconfiguration Auction *n*, as the case may be, meets each of the following requirements:

(i) the constraint has a higher rating for Reconfiguration Auction *n* than it would have absent an Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n*;

(ii) this higher rating resulting from Actual Qualifying Auction Outage *o* or Actual Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was not modeled in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*;

(iii) this higher rating is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(iv) the constraint is binding in Reconfiguration Auction *n*.

Notwithstanding any other provision of this Attachment N, a transmission facility uprating for a round of a 6-month Sub-Auction shall not be a Qualifying Auction Uprating and shall not qualify a Transmission Owner for a U/D Auction Revenue Shortfall Charge or U/D Auction Revenue Surplus Payment.

A "**Deemed Qualifying Auction Uprating**" shall be defined as a change in the rating of a constraint that, for a given constraint *a* and Reconfiguration Auction *n*, as the case may be, meets each of the following requirements:

(i) the constraint has a lower rating in Reconfiguration Auction *n* than it would have if all transmission facilities were modeled as in-service in Reconfiguration Auction *n*;

(ii) this lower rating is in whole or in part the result of a Deemed Qualifying Auction Outage *o* or Deemed Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n*;

(iii) this lower rating resulting from Deemed Qualifying Auction Outage *o* or Deemed

Qualifying Auction Return-to-Service *o* for Reconfiguration Auction *n* was modeled in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, but responsibility for Qualifying Auction Outage *o* or Qualifying Auction Return-to-Service *o* resulting in the lower rating for Reconfiguration Auction *n* is assigned pursuant to Section 20.3.6.4 to a Transmission Owner (including the ISO when it is deemed a Transmission Owner pursuant to Section 20.3.6.4) other than the Transmission Owner responsible for the lower rating in the last auction held for TCCs valid for hour *h*;

(iv) this lower rating in Reconfiguration Auction *n* is included in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*; and

(v) the constraint is binding in Reconfiguration Auction *n*.

20.3.6.3.2 Allocation of U/D Auction Constraint Residuals

This Section 20.3.6.3.2 describes the allocation of U/D Auction Constraint Residuals to Qualifying Auction Deratings and Qualifying Auction Upratings.

When there are Qualifying Auction Deratings or Qualifying Auction Upratings in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction for constraint *a*, the ISO shall allocate a U/D Auction Constraint Residual in the form of a U/D Auction Revenue Shortfall Charge, U/D $ARSC_{a,t,n}$, or U/D Auction Revenue Surplus Payment, U/D $ARSP_{a,t,n}$, by first determining the net total impact on the constraint for the round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* of all Qualifying Auction Deratings *r* and Qualifying Auction Upratings *r* for constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction pursuant to Formula N-24 and then applying either Formula N-25 or Formula N-26, as specified herein, to assess U/D Auction Revenue Shortfall Charges and U/D Auction Revenue Surplus Payments.

Formula N-24

$$U/D\ NetAuctionImpact_{a,n} = \left(\sum_{r \in R_{a,n}} RatingChange_{a,n,r} * ShadowPrice_{a,n} \right) * OPFSignChange_{a,n}$$

Where,

$U/D\ NetAuctionImpact_{a,n}$ = The net impact, in dollars, on constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction of all Qualifying Auction Deratings or Qualifying Auction Upratings for constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction; *provided, however*, $U/D\ NetAuctionImpact_{a,n}$ shall be subject to recalculation as specified in the paragraph immediately following this Formula N-24

$RatingChange_{a,n,r}$= Either:

(a) If Qualifying Auction Derating *r* or Qualifying Auction Uprating *r* is a Deemed Qualifying Auction Derating or a Deemed Qualifying Auction Uprating, $RatingChange_{a,n,r}$ shall be equal to the amount, in MW-*p*, of the decrease or increase in the rating of binding constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction resulting from a Deemed Qualifying Auction Outage or Deemed Qualifying Auction Return-to-Service for constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, which in the case of Reconfiguration Auction *n* shall be as shown in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*, and which in the case of round *n* of a 6-month Sub-Auction shall be as shown in the Centralized TCC Auction Interface Uprate/Derate Table in effect for round *n* of a 6-month Sub-Auction; or

(b) If Qualifying Auction Derating *r* or Qualifying Auction Uprating *r* is an Actual Qualifying Auction Derating or an Actual Qualifying Auction Uprating, $RatingChange_{a,n,r}$ shall be equal to the amount, in MW-*p*, of the decrease or increase in the rating of binding constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction resulting from an Actual Qualifying Auction Outage or Actual Qualifying Auction Return-to-Service for constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, which in the case of Reconfiguration Auction *n* shall be as shown in the Reconfiguration Auction Interface Uprate/Derate Table in effect for Reconfiguration Auction *n*, and which in the case of round *n* of a 6-month Sub-Auction shall be as shown in the Centralized TCC Auction Interface Uprate/Derate Table in effect for round *n* of a 6-month Sub-Auction;

provided, however, $RatingChange_{a,n,r}$ shall be subject to being set equal to zero as specified in the paragraph immediately following this Formula N-24

$R_{a,n}$	=	The set of all Qualifying Auction Deratings *r* or Qualifying Auction Upratings *r* for binding constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction

and the variables $ShadowPrice_{a,n}$ and $OPFSignChange_{a,n}$ are defined as set forth in Formula N-17.

After calculating U/D $NetAuctionImpact_{a,n}$ pursuant to Formula N-24, the ISO shall determine whether U/D $NetAuctionImpact_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n* has a different sign than U/D $ACR_{a,n}$ for constraint *a* in round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*. If the sign is different, the ISO shall (i) recalculate U/D $NetAuctionImpact_{a,n}$ pursuant to Formula N-24 after setting equal to zero each $RatingChange_{a,n,r}$ for which $RatingChange_{a,n,r}$ * $ShadowPrice_{a,n}$ * $OPFSignChange_{a,n}$

has a different sign than U/D $ACR_{a,n}$, and then (ii) use this recalculated U/D $NetAuctionImpact_{a,n}$ and reset value of $RatingChange_{a,n,r}$ to allocate U/D Auction Revenue Shortfall Charges and U/D Auction Revenue Surplus Payments pursuant to Formula N-25 or Formula N-26, as specified below.

If the absolute value of the net impact (U/D $NetAuctionImpact_{a,n}$) on constraint *a* for Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction of all Qualifying Auction Deratings or Qualifying Auction Upratings for constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction as calculated using Formula N-24 (or recalculated pursuant to Formula N-24 using a reset value of $RatingChange_{a,n,r}$ as described in the prior paragraph) is greater than the absolute value of the U/D Auction Constraint Residual (U/D $ACR_{a,n}$) for constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, as the case may be, then the ISO shall allocate the U/D Auction Constraint Residual in the form of a U/D Auction Revenue Shortfall Charge, U/D $ARSC_{a,t,n}$, or U/D Auction Revenue Surplus Payment, U/D $ARSP_{a,t,n}$, by using Formula N-25. If the absolute value of the net impact (U/D $NetAuctionImpact_{a,n}$) on constraint *a* for Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction of all Qualifying Auction Deratings or Qualifying Auction Upratings for constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction as calculated using Formula N-24 (or recalculated pursuant to Formula N-24 using a reset value of $RatingChange_{a,n,r}$ as described in the prior paragraph) is less than or equal to the absolute value of the U/D Auction Constraint Residual (U/D $ACR_{a,n}$) for constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, as the case may be, then the ISO shall allocate the U/D Auction Constraint Residual in the form of a U/D Auction Revenue Shortfall Charge, U/D $ARSC_{a,t,n}$, or U/D Auction Revenue Surplus Payment, U/D $ARSP_{a,t,n}$, by using Formula N-26.

Formula N-25

$$U/D\,Allocation_{a,t,n} = \left(\frac{\sum_{\substack{r \in R_{a,n} \\ and\ q=t}} \left(RatingChange_{a,n,r} * Responsibility_{n,q,r} \right)}{\sum_{for\ all\ r \in R_{a,n}} RatingChange_{a,n,r}} \right) * U/D\,ACR_{a,n}$$

Where,

$U/D\ Allocation_{a,t,n}$ = Either a U/D Auction Revenue Shortfall Charge or a U/D Auction Revenue Surplus Payment, as specified in (a) and (b) below:

(a) If $U/D\ Allocation_{a,t,n}$ is negative, then $U/D\ Allocation_{a,t,n}$ shall be a U/D Auction Revenue Shortfall Charge, $U/D\ ARSC_{a,t,n}$, charged to Transmission Owner *t* for binding constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction; or

(b) If $U/D\ Allocation_{a,t,n}$ is positive, then $U/D\ Allocation_{a,t,n}$ shall be a U/D Auction Revenue Surplus Payment, $U/D\ ARSP_{a,t,n}$, paid to Transmission Owner *t* for binding constraint *a* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction

$Responsibility_{n,q,r}$ = The amount, as a percentage, of responsibility borne by Transmission Owner *q* (which shall include the ISO when it is deemed a Transmission Owner for the purpose of applying Sections 20.3.6.4.2 or 20.3.6.4.3) for Qualifying Auction Derating *r* or Qualifying Auction Uprating *r* in Reconfiguration Auction *n* or round *n* of a 6-month Sub-Auction, as determined pursuant to Section 20.3.6.4

and the variable $U/D\ ACR_{a,n}$ is defined as set forth in Formula N-20 and the variables $RatingChange_{a,n,r}$ and $R_{a,n}$ are defined as set forth in Formula N-24.

Formula N-26

$$U/D\,Allocation_{a,t,n} = \sum_{\substack{r \in R_{a,n} \\ and\ q=t}} RatingChange_{a,n,r} * ShadowPrice_{a,n} * Responsibility_{n,q,r}$$

Where,

the variables $U/D\ Allocation_{a,t,n}$ and $Responsibility_{n,q,r}$ are defined as set forth in Formula N-25, the variable $ShadowPrice_{a,n}$ is defined as set forth in Formula N-17, and the variables $RatingChange_{a,n,r}$ and $R_{a,n}$ are defined as set forth in Formula N-24.

20.3.6.4 Assigning Responsibility for Outages, Returns-to-Service, Deratings, and

Upratings

20.3.6.4.1 General Rule for Assigning Responsibility; Presumption of Causation

Unless the special rules set forth in Sections 20.3.6.4.2 or 20.3.6.4.3 apply, a Transmission Owner shall for purposes of this Section 20.3.6 be deemed responsible for an Auction Status Change to the extent that the Transmission Owner has caused the Auction Status Change by changing the in-service or out-of-service status of its transmission facility; *provided, however*, that where an Auction Status Change results from a change to the in-service or out-of-service status of a transmission facility owned by more than one Transmission Owner, responsibility for such Auction Status Change shall be assigned to each owning Transmission Owner based on the percentage of the transmission facility that is owned by the Transmission Owner (as determined in accordance with Section 20.3.6.6.3) during the hour for which the DAM Status Change occurred. For the sake of clarity, a Transmission Owner may, by changing the in-service or out-of-service status of its transmission facility, cause an Auction Status Change of another transmission facility if the Transmission Owner's change in the in-service or out-of-service status of its transmission facility causes (directly or as a result of Good Utility Practice) a change in the in-service or out-of-service status of the other transmission facility.

The Transmission Owner that owns a transmission facility that qualifies as an Auction Status Change shall be deemed to have caused the Auction Status Change of that transmission facility unless (i) the Transmission Owner that owns the facility informs the ISO that another Transmission Owner caused the Auction Status Change or that responsibility is to be shared among Transmission Owners in accordance with Sections 20.3.6.4.2 or 20.3.6.4.3, and no party disputes such claim; (ii) in case of a dispute over the assignment of responsibility, the ISO determines a Transmission Owner other than the owner of the transmission facility caused the Auction Status Change or that responsibility is to be shared among Transmission Owners in accordance with Section 20.3.6.4.2 or Section 20.3.6.4.3; or (iii) FERC orders otherwise.

20.3.6.4.2 Shared Responsibility For Outages, Returns-to-Service, and Ratings Changes Directed by the ISO or Caused by Facility Status Changes Directed by the ISO

A Transmission Owner shall not be responsible for any Auction Status Change that qualifies as an ISO-Directed Auction Status Change or Deemed ISO-Directed Auction Status Change. Instead, the ISO shall allocate any revenue impacts resulting from an Auction Status Change that qualifies as an ISO-Directed Auction Status Change or Deemed ISO-Directed Auction Status Change as part of Net Auction Revenues for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*. To do so, the ISO shall be treated as a Transmission Owner when allocating Auction Constraint Residuals pursuant to Section 20.3.6.2 and Section 20.3.6.3, and any Auction Status Change that qualifies as an ISO-Directed Auction Status Change or Deemed ISO-Directed Auction Status Change shall be attributed to the ISO when performing the calculations described in Section 20.3.6.2 and Section 20.3.6.3; *provided, however*, any O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment allocable to the ISO pursuant to this Section 20.3.6.4.2 shall ultimately be allocated to the Transmission Owners as Net Auction Revenues pursuant to Section 20.3.7.

Responsibility for a Qualifying Auction Return-to-Service or Qualifying Auction Uprating that is directed by the ISO but does not qualify as a Deemed ISO-Directed Auction Status Change shall be assigned to the Transmission Owner that was responsible for the Qualifying Auction Outage or Qualifying Auction Derating in the last 6-month Sub-Auction held for TCCs valid during the month corresponding to the relevant Reconfiguration Auction.

The ISO shall not direct that a transmission facility be modeled as in-service or out-of-service for purposes of a Reconfiguration Auction without the unanimous consent of the Transmission Owner(s), if any, that will be allocated a resulting O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment in accordance with this Section 20.3.6.4.2.

20.3.6.4.3 Shared Responsibility for External Events

A Transmission Owner shall not be responsible for an Auction Status Change occurring inside the NYCA that is caused by a change in the in-service or out-of-service status or rating of a transmission facility located outside the NYCA. Instead, the ISO shall allocate any revenue impacts resulting from an Auction Status Change caused by such an event outside the NYCA as part of Net Auction Revenues for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*. To do so, the ISO shall be treated as a Transmission Owner when allocating Auction Constraint Residuals pursuant to Section 20.3.6.2 and Section 20.3.6.3 and any Auction Status Change caused by such an event outside the NYCA shall be attributed to the ISO; *provided, however,* any O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment allocable to the ISO pursuant to this Section 20.3.6.4.3 shall ultimately be allocated to the Transmission Owners as Net Auction Revenues pursuant to Section 20.3.7.

20.3.6.5 Exceptions: Setting Charges and Payments to Zero

20.3.6.5.1 Zeroing Out of Charges and Payments When Outages and Deratings Lead to Net Payments or Returns-to-Service and Upratings Lead to Net Charges

The ISO shall use Formula N-27 to calculate the total O/R-t-S Auction Revenue Shortfall Charges, U/D Auction Revenue Shortfall Charges, O/R-t-S Auction Revenue Surplus Payments, and U/D Auction Revenue Surplus Payments, $NetAuctionAllocations_{t,n}$, for Transmission Owner *t* in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, as the case may be. Based on this calculation, the ISO shall set equal to zero all O/R-t-S $ARSC_{a,t,n}$, U/D $ARSC_{a,t,n}$, O/R-t-S $ARSP_{a,t,n}$, and U/D $ARSP_{a,t,n}$ (each as defined in Formula N-27) for Transmission Owner *t* for all constraints for round *n* of a 6-month Sub-Auction or Reconfiguration Auction *n*, as the case may be, if (i) $NetAuctionAllocations_{t,n}$ is positive and Transmission Owner *t* is not responsible (as determined pursuant to Section 20.3.6.4) for any Qualifying Auction Returns-to-Service or Qualifying Auction Upratings in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, as the case may be, or (ii) $NetAuctionAllocations_{t,n}$ is negative and Transmission Owner *t* is not responsible (as determined pursuant to Section 20.3.6.4) for any Qualifying Auction Outages or Qualifying Auction Deratings in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, as the case may be; *provided*, *however*, the ISO shall not set equal to zero pursuant to this Section 20.3.6.5.1 any O/R-t-S $ARSC_{a,t,n}$, U/D $ARSC_{a,t,n}$, O/R-t-S $ARSP_{a,t,n}$, or U/D $ARSP_{a,t,n}$ arising from an ISO-Directed Auction Status Change or Deemed ISO-Directed Auction Status Change described in Section 20.3.6.4.2 or external events described in Section 20.3.6.4.3.

Formula N-27

$$NetAuctionAllocations_{t,n} = \sum_{for\ all\ a} \left(O/R\text{-}t\text{-}S\,ARSC_{a,t,n} + U/D\,ARSC_{a,t,n} + O/R\text{-}t\text{-}S\,ARSP_{a,t,n} + U/D\,ARSP_{a,t,n} \right)$$

Where,

$NetAuctionAllocations_{t,n}$ = The total of the O/R-t-S Auction Revenue Shortfall Charges, U/D Auction Revenue Shortfall Charges, O/R-t-S Auction Revenue Surplus Payments, and U/D Auction Revenue Surplus Payments allocated to Transmission Owner *t* in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*

O/R-t-S $ARSC_{a,t,n}$ = An O/R-t-S Auction Revenue Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.2

U/D $ARSC_{a,t,n}$ = A U/D Auction Revenue Shortfall Charge allocated to Transmission Owner *t* for binding constraint *a* in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.3

O/R-t-S $ARSP_{a,t,n}$ = An O/R-t-S Auction Revenue Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.2

U/D $ARSP_{a,t,n}$ = A U/D Auction Revenue Surplus Payment allocated to Transmission Owner *t* for binding constraint *a* in round *n* of a 6-month Sub-Auction or in Reconfiguration Auction *n*, calculated pursuant to Section 20.3.6.3.

20.3.6.5.2 Zeroing Out of Charges and Payments Resulting from Formula Failure

Notwithstanding any other provision of this Attachment N, the ISO shall set equal to zero any O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment allocated to a Transmission Owner for a Reconfiguration Auction or a round of a Centralized TCC Auction if either:

(i) data necessary to compute such a charge or payment, as specified in the formulas set forth in Section 20.3.6, is not known by the ISO and cannot be computed by the ISO (in interpreting this clause, equipment failure shall not preclude computation by the ISO unless necessary data is irretrievably lost); or

(ii) both (a) the charge or payment is clearly and materially inconsistent with cost causation principles; and (b) this inconsistency is the result of factors not taken into account in the formulas used to calculate the charge or payment;

provided, *however*, if the amount of charges or payments set equal to zero as a result of the unknown data or inaccurate formula is greater than twenty five thousand dollars ($25,000) in any given month or greater than one hundred thousand dollars ($100,000) over multiple months, the ISO will inform the Transmission Owners of the identified problem and will work with the Transmission Owners to determine if an alternative allocation method is needed and whether it will apply to all months for which the intended formula does not work. Alternate methods would be subject to market participant review and subsequent filing with FERC, as appropriate.

For the sake of clarity, the ISO shall not pursuant to this Section 20.3.6.5.2 set equal to zero any O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment that fails to meet these conditions, even if another O/R-t-S Auction Revenue Shortfall Charge, U/D Auction Revenue Shortfall Charge, O/R-t-S Auction Revenue Surplus Payment, or U/D Auction Revenue Surplus Payment is set equal to zero pursuant to this Section 20.3.6.5.2 in the same round of a Centralized TCC Auction or the same Reconfiguration Auction, as the case may be.

20.3.6.6 Information Requirements

20.3.6.6.1 Posting of Uprate/Derate Tables

Prior to each Reconfiguration Auction, the ISO shall post on its website the Reconfiguration Auction Interface Uprate/Derate Table, which table shall specify the expected impact (at the time of the Reconfiguration Auction based on all information available to the ISO) of all transmission facility outages and returns-to-service on interface transfer limits for the period for which TCCs are to be sold in the Reconfiguration Auction.

Prior to each Centralized TCC Auction, the ISO shall post on its website the Centralized TCC Auction Interface Uprate/Derate Table, which table shall specify the expected impact (at the time of the Centralized TCC Auction based on all information available to the ISO) of all transmission facility outages and returns-to-service on interface transfer limits for the period for which TCCs are to be sold in each Sub-Auction of the Centralized TCC Auction.

20.3.6.6.2 Posting of List of Normally Out-of-Service Equipment

The ISO shall maintain on its website a list of Normally Out-of-Service Equipment and update such list prior to each Reconfiguration Auction and each Centralized TCC Auction.

20.3.6.6.3 Information Regarding Facility Ownership

A Transmission Owner shall be responsible for informing the ISO of any change in the ownership of a transmission facility. The ISO shall allocate responsibility for Auction Status Changes based on the transmission facility ownership information available to it at the time of initial settlement.

20.3.7 Allocation of Net Auction Revenue to Transmission Owners

In Centralized TCC Auction round *n* or in Reconfiguration Auction *n*, as the case may be, the ISO shall use the Facility Flow-Based Methodology to allocate Net Auction Revenue to each Transmission Owner *t* in an amount equal to the product of (i) the Facility Flow-Based Methodology coefficient, $FFB_{t,n}$, and (ii) the Net Auction Revenue for the round or for the Reconfiguration Auction; *provided, however,* where the Net Auction Revenue is negative for a Reconfiguration Auction, the ISO shall allocate Net Auction Revenue to each Transmission Owner *t* in an amount equal to the product of (i) the negative Net Auction Revenue coefficient, $NNAR_{t,n}$, and (ii) the negative Net Auction Revenue for the Reconfiguration Auction.

Calculation of Facility Flow-Based Methodology Coefficient. The Facility Flow-Based Methodology coefficient for Transmission Owner *t* for Centralized TCC Auction round *n* or Reconfiguration Auction *n* is calculated pursuant to Formula N-28.

Formula N-28

$$FFB_{t,n} = \frac{\sum_{l \in L_{t,n}} \left| \left(FLOW_{l,n} - FLOW_{l,IC}\right) * \left(Price_{y,l} - Price_{x,l}\right) * Share_{n,t,l} \right|}{\sum_{l \in L_n} \left| \left(FLOW_{l,n} - FLOW_{l,IC}\right) * \left(Price_{y,l} - Price_{x,l}\right) \right|}$$

Where,

$FFB_{t,n}$ = The Facility Flow-Based Methodology coefficient for Transmission Owner for Centralized TCC Auction round *n* or Reconfiguration Auction *n*, as the case may be

L_n = The set of all transmission facilities modeled in the Transmission System model for round *n* or for Reconfiguration Auction *n*, as the case may be

$L_{t,n}$ = The set of all transmission facilities owned by Transmission Owner *t* that are modeled in the Transmission System model applied in round *n* or in Reconfiguration Auction *n*, as the case may be

l = A transmission facility from bus *x* to bus *y*

$FLOW_{l,n}$ = The Energy flow, in MW-*p*, on transmission facility *l* from the set of TCCs and Grandfathered Rights represented in the solution to round *n* or to Reconfiguration Auction *n*, as the case may be (including those pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in that auction).

$FLOW_{l,IC}$ = The Energy flow, in MW-*p*, on transmission facility *l* from (i) the set of pre-existing TCCs and Grandfathered Rights represented as fixed injections and withdrawals in administering the TCC auction held for round *n* or Reconfiguration Auction *n*, as the case may be, (ii) ETCNL not sold in prior Centralized TCC Auctions or through a Direct Sale, and (iii) Original Residual TCCs not sold in prior Centralized TCC Auctions or through a Direct Sale

$Price_{y,l}$ = The market clearing price at bus *y* on transmission facility *l* in the Optimal Power Flow solution to round *n* or Reconfiguration Auction *n*, as the case may be

$Price_{x,l}$ = The market clearing price at bus *x* on transmission facility *l* in the Optimal Power Flow solution to round *n* or Reconfiguration Auction *n*, as the case may be

$Share_{n,t,l}$ = The percentage of transmission facility *l* owned by Transmission Owner *t* on the effective date of the TCCs sold in round *n* or in Reconfiguration Auction *n*

p = A one-month period for Reconfiguration Auction *n*, or the effective period of TCCs sold in round *n* for round *n*.

Calculation of Negative Net Auction Revenue Coefficient. The negative Net Auction Revenue coefficient for Transmission Owner *t* for Reconfiguration Auction *n* is calculated pursuant to Formula N-29.

Formula N-29

$$NNAR_{t,n} = \frac{(Original\ Residual_{t,n} + ETCNL_{t,n} + NARs_{t,n} + GFR\&GFTCC_{t,n})}{\sum_{q \in T}(Original\ Residual_{q,n} + ETCNL_{q,n} + NARs_{q,n} + GFR\&GFTCC_{q,n})}$$

Where,

$NNAR_{t,n}$ = The negative Net Auction Revenue coefficient for Transmission Owner *t* for Reconfiguration Auction *n*

Original $Residual_{q,n}$ = The one-month portion of the revenue imputed to the Direct Sale or the sale in any Centralized TCC Auction Sub-Auction of Original Residual TCCs that are valid during the month corresponding to Reconfiguration Auction *n*. The one-month portion of the revenue imputed to the Direct Sale of these Original Residual TCCs shall be one-sixth of the average market clearing price in the rounds of the 6-month Sub-Auction of the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*. For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds. The one-month portion of the revenue imputed to the sale in any Centralized TCC Auction Sub-Auction of these Original Residual TCCs shall be calculated by dividing the revenue received from the sale of these Original Residual TCCs in the Centralized TCC Auction Sub-Auction by the duration in months of the TCCs sold in that Centralized TCC Auction Sub-Auction

$ETCNL_{q,n}$ = The sum of the one-month portion of the revenues the Transmission Owner has received as payment for the Direct Sale of ETCNL or for its ETCNL released in the Centralized TCC Auction Sub-Auction held for TCCs valid for the month corresponding to Reconfiguration Auction *n*. Each one-month portion of the revenue for ETCNL released in such Centralized TCC Auction shall be calculated by dividing the revenue received in a Centralized TCC Auction Sub-Auction from the sale of the ETCNL by the duration in months of the TCCs corresponding to the ETCNL sold in the Centralized TCC Auction Sub-Auction.[2] The one-month portion of the revenue imputed to the Direct Sale of ETCNL shall be one-sixth of the average market clearing price of the TCCs corresponding to that ETCNL in the rounds of the 6-month Sub-Auction of the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n.* For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate only Stage 1 six month rounds.

$NARs_{q,n}$ = The one-month portion of the Net Auction Revenues the Transmission Owner has received in Centralized TCC Auction Sub-Auction and Reconfiguration Auctions held for TCCs valid for the month corresponding to Reconfiguration Auction *n* (which shall not include any revenue from the sale of Original Residual TCCs).

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[4] **A TCC corresponds to ETCNL if it has the same POI and POW as the ETCNL.**

The one-month portion of the revenues shall be calculated by summing (i) the revenue Transmission Owner *q* received in each Centralized TCC Auction Sub-Auction from the allocation of Net Auction Revenue pursuant to Section 20.3.7, divided by the duration in months of the TCCs sold in the Centralized TCC Auction Sub-Auction (or, to the extent TCC auction revenues were allocated pursuant to a different methodology, the amount of such revenues allocated to Transmission Owner *q*), minus (ii) the sum of $\text{NetAuctionAllocations}_{t,n}$ as calculated pursuant to Formula N-27 (as adjusted for any charges or payments that are zeroed out) for Transmission Owner *q* for all rounds *n* of a 6-month Sub-Auction for all Centralized TCC Auctions held for TCCs valid in the month corresponding to Reconfiguration Auction *n*, divided in each case by the duration in months of the TCCs sold in each Centralized TCC Auction Sub-Auction (or, to the extent that the revenue impact of transmission facility outages, returns-to-service, upratings, and deratings were settled pursuant to a different methodology, the net of such revenue impacts for Transmission Owner *q*), minus (iii) $\text{NetAuctionAllocations}_{t,n}$ as calculated pursuant to Formula N-27 and as adjusted for any charges or payments that are zeroed out for Transmission Owner *q* for Reconfiguration Auction *n*. For Centralized TCC Auctions conducted before May 1, 2010, the calculation of (ii) shall incorporate only Stage 1 six month rounds.

GFR& $\text{GFTCC}_{q,n}$	=	The one-month portion of the imputed value of Grandfathered TCCs and Grandfathered Rights, valued at one-sixth of the market clearing price in the last Centralized TCC Auction held for TCCs valid during the month corresponding to Reconfiguration Auction *n*, provided that the Transmission Owner is the selling party and the Existing Transmission Agreement related to each Grandfathered TCC and Grandfathered Right remains valid in the month corresponding to Reconfiguration Auction *n*. For Centralized TCC Auctions conducted before May 1, 2010, the calculation of the average market clearing price in rounds of the 6-month Sub-Auction shall incorporate Stage 1 six month rounds.
t	=	Transmission Owner *t*
T	=	The set of all Transmission Owners *q*.

Each Transmission Owner's share of Net Auction Revenues allocated pursuant to this Section 20.3.7 shall be incorporated into, or otherwise accounted for as part of, its TSC, NTAC, or other applicable rate mechanism under the ISO Tariffs used to assess charges for Transmission Service provided by the Transmission Owner pursuant to this Tariff, as the case may be.

31.1 New York Comprehensive System Planning Process ("CSPP")

31.1.1 Definitions

Throughout Sections 31.1 through 31.7, the following capitalized terms shall have the meanings set forth in this subsection:

Affected TO: The Transmission Owner who receives written notification of a dispute related to a Local Transmission Planning Process pursuant to Section 31.2.1.3.1.

Bounded Region: A Load Zone or Zones within an area that is isolated from the rest of the NYCA as a result of constrained interface limits.

CARIS: The Congestion Assessment and Resource Integration Study for economic planning developed by the ISO in consultation with the Market Participants and other interested parties pursuant to Section 31.3 of this Attachment Y.

CRP: The Comprehensive Reliability Plan as approved by the ISO Board of Directors pursuant to this Attachment Y.

CSPP: The Comprehensive System Planning Process set forth in this Attachment Y, and in the Interregional Planning Protocol, which covers reliability planning, economic planning, Public Policy Requirements planning, cost allocation and cost recovery, and the interregional planning process.

Developer: A person or entity, including a Transmission Owner, sponsoring or proposing a project pursuant to this Attachment Y.

Development Agreement: The agreement between the ISO and the Developer concerning the timely development and construction of: (i) a regulated transmission solution selected and/or triggered by the ISO to address a Reliability Need that the parties are required to enter into pursuant to Section 31.2.8.1.6 of this Attachment Y and is in the form set forth in Appendix C of this Attachment Y, or (ii) a Public Policy Transmission Project selected by the ISO to address a Public Policy Transmission Need that the parties are required to enter into pursuant to Section 31.4.12.2 of this Attachment Y and is in the form set forth in Appendix D of this Attachment Y.

ESPWG: The Electric System Planning Work Group, or any successor work group or committee designated to fulfill the functions assigned to the ESPWG in this tariff.

Gap Solution: A solution to a Reliability Need that is designed to be temporary and to strive to be compatible with permanent market-based proposals. A permanent regulated solution, if appropriate, may proceed in parallel with a Gap Solution.

Interregional Planning Protocol: The Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol, or any successor to that protocol.

Interregional Transmission Project: A transmission facility located in two or more transmission planning regions that is evaluated under the Interregional Planning Protocol and proposed to address an identified Reliability Need, congestion identified in the CARIS, or a transmission need driven by a Public Policy Requirement pursuant to Order No. 1000 and the provisions of this Attachment Y.

IPTF: The Interregional Planning Task Force, or any successor ISO stakeholder working group or committee, designated to fulfill the functions assigned to the IPTF in this tariff.

ISO/RTO Region: One or more of the three ISO or RTO regions known as PJM, ISO-New England, and NYISO, which are the "Parties" to the Interregional Planning Protocol.

ISO/TO Reliability Agreement: The Agreement Between the New York Independent System Operator, Inc. and the New York Transmission Owners on the Comprehensive Planning Process for Reliability Needs.

LCR: An abbreviation for the term Locational Minimum Installed Capacity Requirement, as defined in the ISO Open Access Transmission Tariff.

Loss of Load Expectation ("LOLE"): A measure used to determine the amount of resources needed to minimize the possibility of an involuntary loss of firm electric load on the New York State Bulk Power Transmission Facilities.

LTP: The Local Transmission Owner Plan, developed by each Transmission Owner, which describes its respective plans that may be under consideration or finalized for its own Transmission District.

LTP Dispute Resolution Process ("DRP"): The process for resolution of disputes relating to a Transmission Owner's LTP set out in Section 31.2.1.3.

LTPP: The Local Planning Process conducted by each Transmission Owner for its own Transmission District.

Management Committee: The standing committee of the ISO of that name created pursuant to the ISO Agreement.

Net CONE: The value representing the cost of new entry, net of energy and ancillary services revenues, utilized by the ISO in establishing the ICAP Demand Curves pursuant to Section 5 of the ISO Market Services Tariff.

New York State Bulk Power Transmission Facilities ("BPTFs"): The facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to NPCC by the ISO pursuant to NPCC requirements.

NPCC: The Northeast Power Coordinating Council, or any successor organization.

NYCA Free Flow Test: A NYCA unconstrained internal transmission interface test, performed by the ISO to determine if a Reliability Need is the result of a statewide resource deficiency or a transmission limitation.

NYDPS: The New York State Department of Public Service, as defined in the New York Public Service Law.

NYISO Load and Capacity Data Report: As defined in Section 25 of the ISO OATT.

NYPSC: The New York Public Service Commission, as defined in the New York Public Service Law.

Operating Agreement: An agreement between the NYISO and a non-incumbent owner of transmission facilities in the New York Control Area concerning the operation of the transmission facilities in the form of the agreement set forth in Appendix H (Section 31.11) of this Attachment Y.

Operating Committee: The standing committee of the NYISO of that name created pursuant to the ISO Agreement.

Order No. 1000: The Final Rule entitled Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, issued by the Commission on July 21, 2011, in Docket RM10-23-001, as modified on rehearing, or upon appeal. (See FERC Stats & Regs. ¶ 31,323 (2011) ("Order No. 1000"), on reh'g and clarification, 139 FERC ¶ 61,132 ("Order No. 1000-A"), on reh'g and clarification, 141 FERC ¶ 61,044 (2012) ("Order No. 1000-B").

Other Developer: A Developer, other than a Transmission Owner, sponsoring or proposing to sponsor a regulated economic project, a Public Policy Transmission Project, an Other Public Policy Project, or a regulated solution to a Reliability Need.

Other Public Policy Project: A non-transmission project or a portfolio of transmission and non-transmission projects proposed by a Developer to satisfy an identified Public Policy Transmission Need.

Public Policy Transmission Planning Process: The process by which the ISO solicits needs for transmission driven by Public Policy Requirements, evaluates all proposed Public Policy Transmission Projects and Other Public Policy Projects on a comparable basis, and selects the more efficient or cost effective Public Policy Transmission Project, if any, for eligibility for cost allocation under the ISO Tariffs.

Public Policy Transmission Need: A transmission need identified by the NYPSC that is driven by a Public Policy Requirement pursuant to Sections 31.4.2.1 through 31.4.2.3.

Public Policy Transmission Planning Report: The report approved by the ISO Board of Directors pursuant to this Attachment Y on the ISO's evaluation of all Public Policy Transmission Projects and Other Public Policy Projects proposed to satisfy an identified Public Policy Transmission Need pursuant to Section 31.4.6 and the ISO's selection of a proposed

Public Policy Transmission Project, if any, that is the more efficient or cost effective solution to the identified Public Policy Transmission Need pursuant to Section 31.4.8.

Public Policy Requirement: A federal or New York State statute or regulation, including a NYPSC order adopting a rule or regulation subject to and in accordance with the State Administrative Procedure Act, any successor statute, or any duly enacted law or regulation passed by a local governmental entity in New York State, that may relate to transmission planning on the BPTFs.

Public Policy Transmission Project: A transmission project or a portfolio of transmission projects proposed by Developer(s) to satisfy an identified Public Policy Transmission Need and for which the Developer(s) seek to be selected by the ISO for purposes of allocating and recovering the project's costs under the ISO OATT.

Reliability Criteria: The electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules promulgated by the North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), and the New York State Reliability Council ("NYSRC"), as they may be amended from time to time.

Reliability Need: A condition identified by the ISO as a violation or potential violation of one or more Reliability Criteria.

Responsible Transmission Owner: The Transmission Owner or Transmission Owners designated by the ISO, pursuant to Section 31.2.4.3, to prepare a proposal for a regulated backstop solution to a Reliability Need or to proceed with a regulated solution to a Reliability Need. The Responsible Transmission Owner will normally be the Transmission Owner in whose Transmission District the ISO identifies a Reliability Need and/or that owns a transmission facility on which a Reliability Need arises.

RNA: The Reliability Needs Assessment as approved by the ISO Board under this Attachment.

RNA Base Case: The model(s) representing the New York State Power System over the Study Period.

Site Control: Documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site or right of way for the purpose of constructing a proposed project; (2) an option to purchase or acquire a leasehold site or right of way for such purpose; or (3) an exclusivity or other business relationship between the Transmission Owner, or Other Developer, and the entity having the right to sell, lease, or grant the Transmission Owner, or Other Developer, the right to possess or occupy a site or right of way for such purpose.

Study Period: The ten-year time period evaluated in the RNA and the CRP.

Target Year: The calendar year in which a Reliability Need arises, as determined by the ISO pursuant to Section 31.2.

TPAS: The Transmission Planning Advisory Subcommittee, or any successor work group or committee designated to fulfill the functions assigned to TPAS pursuant to this Attachment.

Trigger Date: The date by which the ISO must request implementation of a regulated backstop solution or an alternative regulated solution pursuant to Section 31.2.8 in order to meet a Reliability Need.

Viability and Sufficiency Assessment: The results of the ISO's assessment of the viability and sufficiency of proposed solutions to a Reliability Need under Section 31.2.5 or a Public Policy Transmission Need under Section 31.4.6, as applicable.

All other capitalized terms shall have the meanings provided for them in the ISO's Tariffs.

31.1.2 Reliability Planning Process

Sections 31.2.1 through 31.2.13 of this Attachment Y describe the process that the ISO, the Transmission Owners, and Market Participants and other interested parties shall follow for planning to meet the Reliability Needs of the BPTFs. The objectives of the process are to: (1) evaluate the Reliability Needs of the BPTFs pursuant to Reliability Criteria (2) identify, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the BPTFs; (3) provide a process whereby solutions to identified needs are proposed, evaluated on a comparable basis, and implemented in a timely manner to ensure the reliability of the system; (4) provide a process by which the ISO will select the more efficient or cost effective regulated transmission solution to satisfy the Reliability Need for eligibility for cost allocation under the ISO Tariffs; (5) provide an opportunity first for the implementation of market-based solutions while ensuring the reliability of the BPTFs; and (6) coordinate the ISO's reliability assessments with neighboring Control Areas.

The ISO will provide, through the analysis of historical system congestion costs, information about historical congestion including the causes for that congestion so that Market Participants and other stakeholders can make appropriately informed decisions. See Appendix A.

31.1.3 Transmission Owner Planning Process

The Transmission Owners will continue to plan for their transmission systems, including the BPTFs and other NYS Transmission System facilities. The planning process of each Transmission Owner is referred to herein as the LTPP, and the plans resulting from the LTPP are referred to herein as LTPs, whether under consideration or finalized. Each Transmission Owner will be responsible for administering its LTPP and for making provisions for stakeholder input into its LTPP. The ISO's role in the LTPP is limited to the procedural activities described in this Attachment Y.

The finalized portions of the LTPs periodically prepared by the Transmission Owners will be used as inputs to the CSPP described in this Attachment Y. Each Transmission Owner will prepare an LTP for its transmission system in accordance with the procedures described in Section 31.2.1.

31.1.4 Economic Planning Process

Sections 31.3.1 and 31.3.2 of this Attachment Y describe the process that the ISO, the Transmission Owners, and Market Participants shall follow for economic planning to identify and reduce current and future projected congestion on the BPTFs. The objectives of the economic planning process are to: (1) project congestion on the BPTFs over the ten-year planning period of this CSPP, (2) identify, through the development of appropriate scenarios, factors that might produce or increase congestion, (3) provide a process whereby projects to reduce congestion identified in the economic planning process are proposed and evaluated on a comparable basis in a timely manner, (4) provide an opportunity for the development of market-based solutions to reduce the congestion identified, and (5) coordinate the ISO's congestion assessments and economic planning process with neighboring Control Areas.

31.1.5 Public Policy Transmission Planning Process

Section 31.4 of this Attachment Y describes the planning process that the ISO, and all interested parties, shall follow to consider Public Policy Requirements that drive the need for expansions or upgrades to BPTFs. The objectives of the Public Policy Transmission Planning Process are to: (1) allow Market Participants and other interested parties to propose transmission needs that they believe are being driven by Public Policy Requirements and for which transmission solutions should be evaluated, (2) provide a process by which the NYPSC will, with input from the ISO, Market Participants, and other interested parties, identify the transmission needs, if any, for which transmission solutions should be evaluated, (3) provide a process whereby Public Policy Transmission Projects and Other Public Policy Projects are proposed to satisfy each identified Public Policy Transmission Need and are evaluated by the ISO on a comparable basis, (4) provide a process by which the ISO will select the more efficient or cost effective regulated Public Policy Transmission Project, if any, to satisfy each identified Public Policy Transmission Need for eligibility for cost allocation under the ISO Tariffs; (5) provide a cost allocation methodology for regulated Public Policy Transmission Projects that have been selected by the ISO, and (6) coordinate the ISO's Public Policy Transmission Planning Process with neighboring Control Areas.

31.1.6 Interregional Planning Process

The ISO, the Transmission Owners, and Market Participants and other interested parties shall coordinate system planning activities with neighboring planning regions (*i.e.*, the ISO/RTO Regions and adjacent portions of Canada). The Interregional Planning Protocol includes a description of the committee structure, processes, and procedures through which system planning activities are openly and transparently coordinated by the ISO/RTO Regions. The objective of the interregional planning process is to contribute to the on-going reliability and the enhanced operational and economic performance of the ISO/RTO Regions through: (1) exchange of relevant data and information; (2) coordination of procedures to evaluate certain interconnection and transmission service requests; (3) periodic comprehensive interregional assessments; (4) identification and evaluation of potential Interregional Transmission Projects that can address regional needs in a manner that may be more efficient or cost-effective than separate regional solutions, in accordance with the requirements of Order No. 1000; (5) allocation of costs among the ISO/RTO Regions of Interregional Transmission Projects, identified in accordance with the Interregional Planning Protocol and approved by each region, pursuant to the cost allocation methodology set forth in Section 31.5.7 herein. The planning activities of the ISO/RTO Regions shall be conducted consistent with the planning criteria of each ISO/RTO Region's regional reliability organization(s) as well as the relevant local reliability entities. The ISO/RTO Regions shall periodically produce a Northeastern Coordinated System Plan that integrates the system plans of all of the ISO/RTO Regions.

31.1.7 Enrollment in the ISO's Transmission Planning Region

31.1.7.1 For purposes of any matter addressed by this Attachment Y, participation in the ESPWG, IPTF and TPAS shall be open to any interested entity, irrespective of whether that entity has become a Party to the ISO Agreement. Any entity may enroll in the ISO's transmission planning region in order to fully participate in the ISO's governance process by becoming a Party to the ISO Agreement, as set forth in Section 2.02 of the ISO Agreement.

31.1.7.2. An owner of transmission in New York State may become a Transmission Owner by executing the ISO/TO Agreement or an Operating Agreement as provided for in Section 31.1.7.3.

31.1.7.3 A transmission owner that is not a party to the ISO/TO Agreement or an Operating Agreement and will own transmission facilities in the New York Control Area over which Transmission Service will be provided under the ISO Tariffs must enter into an Operating Agreement prior to energizing its transmission facilities. The ISO will tender a draft Operating Agreement as soon as practicable following its selection of the transmission owner's transmission facilities under the CSPP in this Attachment Y. If the transmission owner's transmission facilities were not selected under the CSPP, the transmission owner shall request that the ISO tender the draft Operating Agreement as soon as practicable after receiving its Article VII certification or other applicable siting permits or authorizations under New York State law. The draft Operating Agreement will be completed by the ISO to the extent practicable for review and completion by the transmission owner. The draft shall be in the form of the ISO's Commission-approved Operating Agreement, which is located in Appendix H in Section 31.11 of this Attachment Y. The ISO and the transmission owner shall finalize and negotiate concerning any disputed provisions. Unless otherwise agreed by the ISO and the transmission owner, the transmission owner must execute the Operating Agreement within three (3) months of the ISO's tendering of the draft Operating Agreement; *provided, however*, if, during the negotiation period, the ISO or the transmission owner determines that negotiations are at an impasse, the ISO may file the Operating Agreement in unexecuted form with the Commission on its own or following the transmission owner's request in writing that the agreement be filed unexecuted.

31.1.7.4 If the Operating Agreement resulting from the negotiation between the ISO and the transmission owner does not conform with the Commission-approved standard form in Appendix H in Section 31.11 of this Attachment Y, the ISO shall file the agreement with the Commission for its acceptance within thirty (30) Business Days after the execution of the Operating Agreement by both parties. If the transmission owner requests that the Operating Agreement be filed unexecuted, the ISO shall file the agreement at the Commission within thirty (30) Business Days of receipt of the request from the transmission owner. The ISO will draft to the extent practicable the portions of the Operating Agreement and appendices that are in dispute and will provide an explanation to the Commission of any matters as to which the parties disagree. The transmission owner will provide in a separate filing any comments that it has on the unexecuted agreement, including any alternative positions it may have with respect to the disputed provisions.

31.1.7.5 Upon the ISO's and the transmission owner's execution of the Operating Agreement or the ISO's filing of an unexecuted Operating Agreement with the Commission, the ISO and the transmission owner shall perform their respective obligations in accordance with the terms of the Operating Agreement that are not in dispute, subject to modification by the Commission.

31.1.7.6 As of June 1, 2016, the Transmission Owners are: (1) Central Hudson Gas & Electric Corporation, (2) Consolidated Edison Company of New York, Inc., (3) New York State Electric & Gas Corporation, (4) Niagara Mohawk Power Corporation d/b/a National Grid, (5) Orange and Rockland Utilities, Inc., (6) Rochester Gas and Electric Corporation, (7) the Power Authority of the State of New York, (8) Long Island Lighting Company d/b/a LIPA, and (9) New York Transco, LLC.

31.1.8 NYISO Implementation and Administration

31.1.8.1 The ISO shall adopt procedures for the implementation and administration of the CSPP set forth in this Attachment Y and the Interregional Planning Protocol, and shall revise those procedures as and when necessary. Such procedures will be incorporated in the ISO's manuals. The ISO Procedures shall provide for the open and transparent coordination of the CSPP to allow Market Participants and all other interested parties to have a meaningful opportunity to participate in each stage of the CSPP through the meetings conducted in accordance with the ISO system of collaborative governance. Confidential Information and Critical Energy Infrastructure Information exchanged through the CSPP shall be subject to the protections for such information contained in the ISO's tariffs and procedures, including this Attachment Y and Attachment F of the NYISO OATT.

31.1.8.2 The ISO Procedures shall include a schedule for the collection and submission of data and the preparation of models to be used in the studies contemplated under this tariff. That schedule shall provide for a rolling two-year cycle of studies and reports conducted in each of the ISO planning processes (reliability, economic and public policy) as part of the Comprehensive System Planning Process. Each cycle commences with the LTPP providing input into the reliability planning process. The CARIS study under Section 31.3 of this Attachment Y will commence upon completion of the viability and sufficiency analysis performed pursuant to Section 31.2.5.7, as part of the CRP process. The Public Policy Transmission Planning Process will to the extent practicable run in parallel with the reliability planning process, provided that the NYPSC's issuance of a written statement pursuant to Section 31.4.2.1 will occur after the draft RNA study results are posted. If the CRP cannot be completed within a two-year cycle, the ISO will notify stakeholders and provide an estimated completion date and an explanation of the reasons the additional time is required. As further detailed in Sections 31.2, 31.3, 31.4, and 31.5, the interregional planning process shall be conducted in parallel with the reliability planning process, the economic planning process, and the Public Policy Transmission Planning Process to identify and evaluate Interregional Transmission Projects that may more efficiently or cost-effectively meet the needs of the region than a regional transmission project.

31.1.8.3 The ISO Procedures shall be designed to allow the coordination of the ISO's planning activities with those of the ISO/RTO Regions, NERC, NPCC, the NYSRC, and other regional reliability organizations so as to develop consistency of the models, databases, and assumptions utilized in making reliability and economic determinations.

31.1.8.4 The ISO Procedures shall facilitate the timely identification and resolution of all substantive and procedural disputes that arise out of the CSPP. Any party participating in the CSPP and having a dispute arising out of the CSPP may seek to have its dispute resolved in accordance with ISO governance procedures during the course of the CSPP. If the party's dispute is not resolved in this manner as a part of the plan development process, the party may invoke formal dispute resolution procedures administered by the ISO that are the same as those available to Transmission Customers under Section 11 of the ISO Market Administration and Control Area Services Tariff. Disputes arising out of the LTPP shall be addressed by the LTP DRP set forth in Section 31.2.1.3 of this Attachment Y.

31.1.8.5 Except for those cases where the ISO OATT provides that an individual customer shall be responsible for the cost, or a specified share of the cost, of an individually requested study related to interconnection or to system expansion or to congestion and resource integration, the study costs incurred by the ISO as a result of its administration of the CSPP will be recovered from all customers through and in accordance with Rate Schedule 1 of the ISO OATT.

31.1.8.6 The ISO shall make reasonable efforts to meet all deadlines provided in this Attachment Y; *provided, however,* that the ISO must meet all deadlines set forth in a development agreement entered into pursuant to this Attachment Y in accordance with the terms of that agreement. If the ISO cannot meet a deadline set forth in this Attachment Y and an extension of that deadline will not result in a reliability violation, the NYISO may extend the deadline, provided that it shall notify Market Participants and other interested parties, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable action.

31.1.8.7 The ISO may extend, at its discretion, the deadlines indicated below that are applicable to all parties participating in a given process for a reasonable period of time if the extension: (i) is applied equally to all parties that are required to meet the deadline, and (ii) will not result in a reliability violation. The deadlines eligible for extension are:

- Sixty (60) day deadline in Section 31.2.5.1 for interested Developers to propose solutions in response to the ISO's solicitation for solutions to a Reliability Need;
- Thirty (30) day deadline in Section 31.2.6.1 for Developers of viable and sufficient transmission solutions to submit project information in response to ISO request;
- Sixty (60) day deadline in Section 31.4.2 for stakeholders and interested parties to submit proposed transmission needs in response to ISO solicitation for proposed needs;
- Sixty (60) day deadline in Sections 31.4.3.1 and 31.4.4.3.1 for Developers to propose solutions to a Public Policy Transmission Need in response to ISO solicitation for solutions;
- Sixty (60) day deadline in Section 31.4.4.4 for Developers of Public Policy Transmission Projects to execute study agreement, provide study deposit, and provide application fee in response to ISO solicitation for solutions; and
- Deadlines in Sections 31.4.6.6 and 31.4.6.7 for Developers to inform NYISO following Viability and Sufficiency Assessment that their viable and sufficient Public Policy Transmission Projects will proceed to be evaluated by the ISO for purposes of selection.

31.5 Cost Allocation and Cost Recovery

31.5.1 The Scope of Attachment Y Cost Allocation

31.5.1.1 Regulated Responses

The cost allocation principles and methodologies in this Attachment Y cover only regulated transmission solutions to Reliability Needs, regulated transmission responses to congestion identified in the CARIS, and regulated Public Policy Transmission Projects whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer. The cost allocation principles and methodology for: (i) regulated transmission solutions to Reliability Needs are contained in Sections 31.5.3.1 and 31.5.3.2 of this Attachment Y, (ii) regulated transmission responses to congestion identified in the CARIS are contained in Sections 31.5.4.1 and 31.5.4.2 of this Attachment Y, and (iii) regulated Public Policy Transmission Projects are contained in Sections 31.5.5 and 31.5.6 of this Attachment Y.

31.5.1.2 Market-Based Responses

The cost allocation principles and methodologies in this Attachment Y do not apply to market-based solutions to Reliability Needs, to market-based responses to congestion identified in the CARIS, or to Other Public Policy Projects. The cost of a market-based project shall be the responsibility of the developer of that project.

31.5.1.3 Interconnection Cost Allocation

The cost allocation principles and methodologies in this Attachment Y do not apply to the interconnection costs of generation and merchant transmission projects. Interconnection costs are determined and allocated in accordance with Attachment P, Attachment S, Attachment X and Attachment Z of the ISO OATT.

31.5.1.4 Individual Transmission Service Requests

The cost allocation principles and methodologies in this Attachment Y do not apply to the cost of transmission expansion projects undertaken in connection with an individual request for Transmission Service. The cost of such a project is determined and allocated in accordance with Section 3.7 or Section 4.5 of the ISO OATT.

31.5.1.5 LTP Facilities

The cost allocation principles and methodologies in this Attachment Y do not apply to the cost of transmission projects included in LTPs or LTP updates. Each Transmission Owner will recover the cost of such transmission projects in accordance with its then existing rate recovery mechanisms.

31.5.1.6 Regulated Non-Transmission Projects

Costs related to regulated non-transmission projects will be recovered by Responsible Transmission Owners, Transmission Owners and Other Developers in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law. Nothing in this section shall affect the Commission's jurisdiction over the sale and transmission of electric energy subject to the jurisdiction of the Commission.

31.5.1.7 Eligibility for Cost Allocation and Cost Recovery

Any entity, whether a Responsible Transmission Owner, Other Developer, or Transmission Owner, shall be eligible for cost allocation and cost recovery as set forth in Section 31.5 of this Attachment Y and associated rate schedules, as applicable, for any transmission project proposed to satisfy an identified Reliability Need, regulated economic transmission project, or Public Policy Transmission Project that is determined by the ISO to be eligible under

Sections 31.2, 31.3, or 31.4, as applicable. Interregional Transmission Projects identified in accordance with the Interregional Planning Protocol, and that have been accepted in each region's planning process, shall be eligible for interregional cost allocation and cost recovery, as set forth in Section 31.5 of this Attachment Y and associated rate schedules. The ISO's share of the cost of an Interregional Transmission Project selected pursuant to this Attachment Y to meet a Reliability Need, congestion identified in the CARIS, or a Public Policy Transmission Need shall be eligible for cost allocation consistent with the cost allocation methodology applicable to the type of regional transmission project that would be replaced through the construction of such Interregional Transmission Project.

31.5.2 Cost Allocation Principles Required Under Order No. 1000

31.5.2.1 In compliance with Commission Order No. 1000, the ISO shall implement the specific cost allocation methodology in Section 31.5.3.2, 31.5.4.4, and 31.5.5.4 in accordance with the following Regional Cost Allocation Principles ("Order No. 1000 Regional Cost Allocation Principles"):

Regional Cost Allocation Principle 1: The ISO shall allocate the cost of transmission facilities to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, the ISO's CSPP will consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.

Regional Cost Allocation Principle 2: The ISO shall not involuntarily allocate any of the costs of transmission facilities to those that receive no benefit from transmission facilities.

Regional Cost Allocation Principle 3: In the event that the ISO adopts a benefit to cost threshold in its CSPP to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, such benefit to cost threshold will not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. If the ISO chooses to adopt such a threshold in its CSPP it will not include a ratio of benefits to costs that exceeds 1.25 unless the ISO justifies and the Commission approves a higher ratio.

Regional Cost Allocation Principle 4: The ISO's allocation method for the cost of a transmission facility selected pursuant to the process in the CSPP shall allocate costs solely within the ISO's transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. Costs for an Interregional Transmission Project must be assigned only to regions in which the facility is physically located. Costs cannot be assigned involuntarily to another region. The ISO shall not bear the costs of required upgrades in another region.

Regional Cost Allocation Principle 5: The ISO's cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility shall be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility, as consistent with confidentiality requirements set forth in this Attachment Y and the ISO Code of Conduct in Attachment F of the OATT.

Regional Cost Allocation Principle 6: The ISO's CSPP provides a different cost allocation method for different types of transmission facilities in the regional transmission plan and each cost allocation method is set out clearly and explained in detail in this Section 31.5.

31.5.2.2 In compliance with Commission Order No. 1000, the ISO shall implement the specific cost allocation methodology in Section 31.5.7 of this Attachment Y in accordance with the following Interregional Cost Allocation Principles:

Interregional Cost Allocation Principle 1: The ISO shall allocate the cost of new Interregional Transmission Projects to each region in which an Interregional Transmission Project is located in a manner that is at least roughly commensurate with estimated benefits of the Interregional Transmission Project in each of the regions. In determining the beneficiaries of Interregional Transmission Projects, the ISO will consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting Public Policy Requirements.

Interregional Cost Allocation Principle 2: The ISO shall not involuntarily allocate any of the costs of an Interregional Transmission Project to a region that receives no benefit from an Interregional Transmission Project that is located in that region, either at present or in a likely future scenario.

Interregional Cost Allocation Principle 3: In the event that the ISO adopts a benefit-cost threshold ratio to determine whether an Interregional Transmission

Project has sufficient net benefits to qualify for interregional cost allocation, this ratio shall not be so large as to exclude an Interregional Transmission Project with significant positive net benefits from cost allocation. If the ISO chooses to adopt such a threshold, they will not include a ratio of benefits to costs that exceeds 1.25 unless the Parties justify and the Commission approves a higher ratio.

Interregional Cost Allocation Principle 4: The ISO's allocation of costs for an Interregional Transmission Project shall be assigned only to regions in which the Interregional Transmission Project is located. The ISO shall not assign costs involuntarily to a region in which that Interregional Transmission Project is not located. The ISO shall, however, identify consequences for other regions, such as upgrades that may be required in a third region. The ISO's interregional cost allocation methodology includes provisions for allocating the costs of upgrades among the beneficiaries in the region in which the Interregional Transmission Project is located to the transmission providers in such region that agree to bear the costs associated with such upgrades.

Interregional Cost Allocation Principle 5: The ISO's cost allocation methodology and data requirements for determining benefits and identifying beneficiaries for an Interregional Transmission Project shall be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed Interregional Transmission Project, as consistent with the confidentiality requirements set forth in this Attachment Y and the ISO Code of Conduct in Attachment F of the OATT.

Interregional Cost Allocation Principle 6: Though Order No. 1000 allows the ISO to provide a different cost allocation methodology for different types of interregional transmission facilities, such as facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements, the ISO has chosen to adopt one interregional cost allocation methodology for all Interregional Transmission Planning Projects. The interregional cost allocation methodology is set out clearly and explained in detail in Section 31.5.7 of this Attachment Y. The share of the cost related to any Interregional Transmission Project assigned to the ISO shall be allocated as described in Section 31.5.7.1.

31.5.3 Regulated Responses to Reliability Needs

31.5.3.1 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.3.2 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1. This methodology shall apply to cost allocation for a regulated transmission solution to an identified Reliability Need, including the ISO's share of the costs of an Interregional Transmission Project proposed as a regulated transmission solution to an identified Reliability Need allocated in accordance with Section 31.5.7 of this Attachment Y.

The specific cost allocation methodology in Section 31.5.3.2 incorporates the following elements:

31.5.3.1.1 The focus of the cost allocation methodology shall be on solutions to Reliability Needs.

31.5.3.1.2 Potential impacts unrelated to addressing the Reliability Needs shall not be considered for the purpose of cost allocation for regulated solutions.

31.5.3.1.3 Primary beneficiaries shall initially be those Load Zones identified as contributing to the reliability violation.

31.5.3.1.4 The cost allocation among primary beneficiaries shall be based upon their relative contribution to the need for the regulated solution.

31.5.3.1.5 The ISO will examine the development of specific cost allocation rules based on the nature of the reliability violation (*e.g.*, thermal overload, voltage, stability, resource adequacy and short circuit).

31.5.3.1.6 Cost allocation shall recognize the terms of prior agreements among the Transmission Owners, if applicable.

31.5.3.1.7 Consideration should be given to the use of a materiality threshold for cost allocation purposes.

31.5.3.1.8 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.5.3.1.9 Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

31.5.3.1.10 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.5.3.1.11 The methodology shall apply, to the extent possible, to Gap Solutions.

31.5.3.1.12 Cost allocation is independent of the actual triggered project(s), except when allocating cost responsibilities associated with meeting a Locational Minimum Installed Capacity Requirement ("LCR"), and is based on a separate process that results in NYCA meeting its LOLE requirement.

31.5.3.1.13 Cost allocation for a solution that meets the needs of a Target Year assumes that backstop solutions of prior years have been implemented.

31.5.3.1.14 Cost allocation will consider the most recent values for LCRs. LCRs must be met for the Target Year.

31.5.3.2 Cost Allocation Methodology

31.5.3.2.1 General Reliability Solution Cost Allocation Formula:

The cost allocation mechanism under this Section 31.5.3.2 sets forth the basis for allocating costs associated with a Responsible Transmission Owner's regulated backstop solution or an Other Developer's or Transmission Owner's alternative regulated transmission solution selected by the ISO as the more efficient or cost-effective transmission solution to an identified Reliability Need.

The formula is not applicable to that portion of a project beyond the size of the solution needed to provide the more efficient or cost effective solution appropriate to the Reliability Need identified in the RNA. Nor is the formula applicable to that portion of the cost of a regulated transmission reliability project that is, pursuant to Section 25.7.12 of Attachment S to the ISO OATT, paid for with funds previously committed by or collected from Developers for the installation of System Deliverability Upgrades required for the interconnection of generation or merchant transmission projects.

The same cost allocation formula is applied regardless of the project or sets of projects being triggered; however, the nature of the solution set may lead to some terms equaling zero, thereby dropping out of the equation. To ensure that appropriate allocation to the LCR and non-LCR zones occurs, the zonal allocation percentages are developed through a series of steps that first identify responsibility for LCR deficiencies, followed by responsibility for remaining need.

This cost allocation process can be applied to any solution or set of solutions that involve singel or multiple cost allocation steps. One formula can be applied to any solution set:

$$\text{Cost Allocation}_i = \left[\frac{\text{LCRdef}_i}{\text{Soln Size}} + \left(\frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_\text{i})}{\sum_{k=1}^{n} \text{Coincident Peak}_k * (1 + \text{IRM} - \text{LCR}_\text{k})} * \frac{\text{Soln STWdef}}{\text{Soln Size}} \right) + \left(\frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_\text{i})}{\sum_{l=1}^{m} \text{Coincident Peak}_l * (1 + \text{IRM} - \text{LCR}_\text{l})} * \frac{\text{Soln CIdef}}{\text{Soln Size}} \right) \right] *100\%$$

Where *i* is for each applicable zone, *n* represent the total zones in NYCA, *m* represents the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, LCRdef_i is the applicable zonal LCR deficiency, SolnSTWdef is the STWdef for each applicable project, SolnCIdef is the CIdef for each applicable project, and Soln_Size represents the total compensatory MW addressed by each applicable project.

Three step cost allocation methodology for regulated reliability solutions:

31.5.3.2.1.1 Step 1 - LCR Deficiency

31.5.3.2.1.1.1 Any deficiencies in meeting the LCRs for the Target Year will be referred to as the LCRdef. If the reliability criterion is met once the LCR deficiencies have been addressed, that is LOLE ≤ 0.1 for the Target Year is achieved, then the only costs allocated will be those related to the LCRdef MW. Cost responsibility for the LCRdef MW will be borne by each deficient locational zone(s), to the extent each is individually deficient.

For a single solution that addresses only an LCR deficiency in the applicable LCR zone, the equation would reduce to:

$$\text{Allocation}_i = \frac{\text{LCRdef}_i}{\text{Soln\_Size}} * 100\%$$

Where *i* is for each applicable LCR zone, LCRdef_i represents the applicable zonal LCR deficiency, and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.1.1.2 Prior to the LOLE calculation, voltage constrained interfaces will be recalculated to determine the resulting transfer limits when the LCRdef MW are added.

31.5.3.2.1.2 Step 2 - Statewide Resource Deficiency. If the reliability criterion is not met after the LCRdef has been addressed, that is an LOLE > 0.1, then a NYCA Free Flow Test will be conducted to determine if NYCA has sufficient resources to meet an LOLE of 0.1.

31.5.3.2.1.2.1 If NYCA is found to be resource limited, the ISO, using the transfer limits and resources determined in Step 1, will determine the optimal distribution of additional resources to achieve a reduction in the NYCA LOLE to 0.1.

31.5.3.2.1.2.2 Cost allocation for compensatory MW added for cost allocation purposes to achieve an LOLE of 0.1, defined as a Statewide MW deficiency (STWdef), will be prorated to all NYCA zones, based on the NYCA coincident peak load. The allocation to locational zones will take into account their locational requirements. For a single solution that addresses only a statewide deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_\text{i})}{\sum_{k=1}^{n} \text{Coincident Peak}_k * (1 + \text{IRM} - \text{LCR}_\text{k})} * \frac{\text{Soln STWdef}}{\text{Soln Size}} \right] *100\%$$

Where *i* is for each applicable zone, *n* is for the total zones in NYCA, IRM is the statewide reserve margin, and LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, Soln STWdef is the STWdef for the applicable project, and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.1.3 Step 3 - Constrained Interface Deficiency. If the NYCA is not resource limited as determined by the NYCA Free Flow Test, then the ISO will examine constrained transmission interfaces, using the Binding Interface Test.

31.5.3.2.1.3.1 The ISO will provide output results of the reliability simulation program utilized for the RNA that indicate the hours that each interface is at limit in each flow direction, as well as the hours that coincide with a loss of load event. These values will be used as an initial indicator to determine the binding interfaces that are impacting LOLE within the NYCA.

31.5.3.2.1.3.2 The ISO will review the output of the reliability simulation program utilized for the RNA along with other applicable information that may be available to make the determination of the binding interfaces.

31.5.3.2.1.3.3 Bounded Regions are assigned cost responsibility for the compensatory MW, defined as CIdef, needed to reach an LOLE of 0.1.

31.5.3.2.1.3.4 If one or more Bounded Regions are isolated as a result of binding interfaces identified through the Binding Interface Test, the ISO will determine the optimal distribution of compensatory MW to achieve a NYCA LOLE of 0.1. Compensatory MW will be added until the required NYCA LOLE is achieved.

31.5.3.2.1.3.5 The Bounded Regions will be identified by the ISO's Binding Interface Test, which identifies the bounded interface limits that can be relieved and have the greatest impact on NYCA LOLE. The Bounded Region that will have the greatest benefit to NYCA LOLE will be the area to be first allocated costs in this step. The ISO will determine if after the first addition of compensating MWs the Bounded Region with the greatest impact on LOLE has changed. During this iterative process, the Binding Interface Test will look across the state to identify the appropriate Bounded Region. Specifically, the Binding Interface Test will be applied starting from the interface that has the greatest benefit to LOLE (the greatest LOLE reduction per interface compensatory MW addition), and then extended to subsequent interfaces until a NYCA LOLE of 0.1 is achieved.

31.5.3.2.1.3.6 The CIdef MW are allocated to the applicable Bounded Region isolated as a result of the constrained interface limits, based on their NYCA coincident peaks. Allocation to locational zones will take into account their locational requirements. For a single solution that addresses only a binding interface deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Concident Peak}_i * (1 + \text{IRM} - \text{LCR}_\text{i})}{\sum_{l=1}^{m} \text{Coincident Peak}_l * (1 + \text{IRM} - \text{LCR}_\text{l})} * \frac{\text{SolnCIdef}}{\text{Soln Size}} \right] *100\%$$

Where *i* is for each applicable zone, *m* is for the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, SolnCIdef is the CIdef for the applicable project and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.1.4 If, after the completion of Steps 1 through 3, there is a thermal or voltage security issue that does not cause an LOLE violation, it will be deemed a local issue and related costs will not be allocated under this process. The ISO will address through its stakeholder process the development of a methodology to allow for the allocation of costs of transmission solutions to thermal or voltage security issues.

31.5.3.2.1.5 Costs related to the deliverability of a resource will be addressed under the ISO's deliverability procedures.

31.5.4 Regulated Economic Projects

31.5.4.1 The Scope of Section 31.5.4

As discussed in Section 31.5.1 of this Attachment Y, the cost allocation principles and methodologies of this Section 31.5.4 apply only to regulated economic transmission projects ("RETPs") proposed in response to congestion identified in the CARIS.

This Section 31.5.4 does not apply to generation or demand side management projects, nor does it apply to any market-based projects. This Section 31.5.4 does not apply to regulated backstop solutions triggered by the ISO pursuant to the CSPP, provided, however, the cost allocation principles and methodologies in this Section 31.5.4 will apply to regulated backstop solutions when the implementation of the regulated backstop solution is accelerated solely to reduce congestion in earlier years of the Study Period. The ISO will work with the ESPWG to develop procedures to deal with the acceleration of regulated backstop solutions for economic reasons.

Nothing in this Attachment Y mandates the implementation of any project in response to the congestion identified in the CARIS.

31.5.4.2 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.4.4 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1. The specific cost allocation methodology in Section 31.5.4.4 incorporates the following elements:

31.5.4.2.1 The focus of the cost allocation methodology shall be on responses to specific conditions identified in the CARIS.

31.5.4.2.2 Potential impacts unrelated to addressing the identified congestion shall not be considered for the purpose of cost allocation for RETPs.

31.5.4.2.3 Projects analyzed hereunder as proposed RETPs may proceed on a market basis with willing buyers and sellers at any time.

31.5.4.2.4 Cost allocation shall be based upon a beneficiaries pay approach. Cost allocation under the ISO tariff for a RETP shall be applicable only when a super majority of the beneficiaries of the project, as defined in Section 31.5.4.6 of this Attachment Y, vote to support the project.

31.5.4.2.5 Beneficiaries of a RETP shall be those entities economically benefiting from the proposed project. The cost allocation among beneficiaries shall be based upon their relative economic benefit.

31.5.4.2.6 Consideration shall be given to the proposed project's payback period.

31.5.4.2.7 The cost allocation methodology shall address the possibility of cost overruns.

31.5.4.2.8 Consideration shall be given to the use of a materiality threshold for cost allocation purposes.

31.5.4.2.9 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.5.4.2.10 Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

31.5.4.2.11 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.5.4.2.12 Benefits determination shall consider various perspectives, based upon the agreed-upon metrics for analyzing congestion.

31.5.4.2.13 Benefits determination shall account for future uncertainties as appropriate (e.g., load forecasts, fuel prices, environmental regulations).

31.5.4.2.14 Benefits determination shall consider non-quantifiable benefits as appropriate (*e.g.*, system operation, environmental effects, renewable integration).

31.5.4.3 Project Eligibility for Cost Allocation

The methodologies in this Section 31.5.4.3 will be used to determine the eligibility of a proposed RETP to have its cost allocated and recovered pursuant to the provisions of this Attachment Y.

31.5.4.3.1 The ISO will evaluate the benefits against the costs (as provided by the Developer) of each proposed RETP over a ten-year period commencing with the proposed commercial operation date for the project. The Developer of each project will pay the cost incurred by the ISO to conduct the ten-year benefit/cost analysis of its project. The ISO, in conjunction with the ESPWG, will develop methodologies for extending the most recently completed CARIS database as necessary to evaluate the benefits and costs of each proposed RETP.

31.5.4.3.2 The benefit metric for eligibility under the ISO's benefit/cost analysis will be expressed as the present value of the annual NYCA-wide production cost savings that would result from the implementation of the proposed project, measured for the first ten years from the proposed commercial operation date for the project.

31.5.4.3.3 The cost for the ISO's benefit/cost analysis will be supplied by the Developer of the project, and the cost metric for eligibility will be expressed as the present value of the first ten years of annual total revenue requirements for the project, reasonably allocated over the first ten years from the proposed commercial operation date for the project.

31.5.4.3.4 For informational purposes only, the ISO will also calculate the present value of the annual total revenue requirement for the project over a 30 year period commencing with the proposed commercial operation date of the project.

31.5.4.3.5 To be eligible for cost allocation and recovery under this Attachment Y, the benefit of the proposed project must exceed its cost measured over the first ten years from the proposed commercial operation date for the project, and the requirements of section 31.5.4.2 must be met. The total capital cost of the project must exceed $25 million. In addition, a super-majority of the beneficiaries must vote in favor of the project, as specified in Section 31.5.4.6 of this Attachment Y.

31.5.4.3.6 In addition to calculating the benefit metric as defined in Section 31.5.4.3.2, the ISO will calculate additional metrics to estimate the potential benefits of the proposed project, for information purposes only, in accordance with Section 31.3.1.3.5, for the applicable metric. These additional metrics shall include those that measure reductions in LBMP load costs, changes to generator payments, ICAP costs, Ancillary Service costs, emissions costs, and losses. TCC revenues will be determined in accordance with Section 31.5.4.4.2.3. The ISO will provide information on these additional metrics to the maximum extent practicable considering its overall resource commitments.

31.5.4.3.7 In addition to the benefit/cost analysis performed by the ISO under this Section 31.5.4.3, the ISO will work with the ESPWG to consider the development and implementation of scenario analyses, for information only, that shed additional light on the benefit/cost analysis of a proposed project. These additional scenario analyses may cover fuel and load forecast uncertainty, emissions data and the cost of allowances, pending environmental or other regulations, and alternate resource and energy efficiency scenarios. Consideration of these additional scenarios will take into account the resource commitments of the ISO.

31.5.4.4 Cost Allocation for Eligible Projects

As noted in Section 31.5.4.2 of this Attachment Y, the cost of a RETP will be allocated to those entities that would economically benefit from implementation of the proposed project. This methodology shall apply to cost allocation for a RETP, including the ISO’s share of the costs of an Interregional Transmission Project proposed as a RETP allocated in accordance with Section 31.5.7 of this Attachment Y.

31.5.4.4.1 The ISO will identify the beneficiaries of the proposed project over a ten-year time period commencing with the proposed commercial operation date for the project. The ISO, in conjunction with the ESPWG, will develop methodologies for extending the most recently completed CARIS database as necessary for this purpose.

31.5.4.4.2 The ISO will identify beneficiaries of a proposed project as follows:

31.5.4.4.2.1 The ISO will measure the present value of the annual zonal LBMP load savings for all Load Zones which would have a load savings, net of reductions in TCC revenues, and net of reductions from bilateral contracts (based on available information provided by Load Serving Entities to the ISO as set forth in subsection 31.5.4.4.2.5 below) as a result of the implementation of the proposed project. For purposes of this calculation, the present value of the load savings will be equal to the sum of the present value of the Load Zone's load savings for each year over the ten-year period commencing with the project's commercial operation date. The load savings for a Load Zone will be equal to the difference between the zonal LBMP load cost without the project and the LBMP load cost with the project, net of reductions in TCC revenues and net of reductions from bilateral contracts.

31.5.4.4.2.2 The beneficiaries will be those Load Zones that experience net benefits measured over the first ten years from the proposed commercial operation date for the project. If the sum of the zonal benefits for those Load Zones with load savings is greater than the revenue requirements for the project (both load savings and revenue requirements measured in present value over the first ten years from the commercial operation date of the project), the ISO will proceed with the development of the zonal cost allocation information to inform the beneficiary voting process.

31.5.4.4.2.3 Reductions in TCC revenues will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, not including the congestion rents that accrue to any Incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: (1) the total impact of that project on the Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); (2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and (3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item (1) above. These forecasts shall be performed using the procedure described in Appendix B to this Attachment Y.

31.5.4.4.2.4 Estimated TCC revenues from any Incremental TCCs created by a proposed RETP over the ten-year period commencing with the project's commercial operation date will be added to the Net Load Savings used for the cost allocation and beneficiary determination.

31.5.4.4.2.5 The ISO will solicit bilateral contract information from all Load Serving Entities, which will provide the ISO with bilateral energy contract data for modeling contracts that do not receive benefits, in whole or in part, from LBMP reductions, and for which the time period covered by the contract is within the ten-year period beginning with the commercial operation date of the project. Bilateral contract payment information that is not provided to the ISO will not be included in the calculation of the present value of the annual zonal LBMP savings in section 31.5.4.4.2.1 above.

31.5.4.4.2.5.1 All bilateral contract information submitted to the ISO must identify the source of the contract information, including citations to any public documents including but not limited to annual reports or regulatory filings

31.5.4.4.2.5.2 All non-public bilateral contract information will be protected in accordance with the ISO's Code of Conduct, as set forth in Section 12.4 of Attachment F of the ISO OATT, and Section 6 of the ISO Services Tariff.

31.5.4.4.2.5.3 All bilateral contract information and information on LSE-owned generation submitted to the ISO must include the following information:

(1) Contract quantities on an annual basis:

(a) For non-generator specific contracts, the Energy (in MWh) contracted to serve each Zone for each year.

(b) For generator specific contracts or LSE-owned generation, the name of the generator(s) and the MW or percentage output contracted or self-owned for use by Load in each Zone for each year.

(2) For all Load Serving Entities serving Load in more than one Load Zone, the quantity (in MWh or percentage) of bilateral contract Energy to be applied to each Zone, by year over the term of the contract.

(3) Start and end dates of the contract.

(4) Terms in sufficient detail to determine that either pricing is not indexed to LBMP, or, if pricing is indexed to LBMP, the manner in which prices are connected to LBMP.

(5) Identify any changes in the pricing methodology on an annual basis over the term of the contract.

31.5.4.4.2.5.4 Bilateral contract and LSE-owned generation information will be used to calculate the adjusted LBMP savings for each Load Zone as follows:

$AdjLBMPS_{y,z}$, the adjusted LBMP savings for each Load Zone z in each year y, shall be calculated using the following equation:

$$AdjLBMPS_{y,z} = \max\left[0, TL_{\mathrm{y,z}} - \sum_{b \in B_{y,z}} \left(BCL_{\mathrm{b,y,z}} * \left(1 - Ind_{\mathrm{b,y,z}}\right)\right) - SG_{\mathrm{y,z}}\right] * \left(LBMP1_{\mathrm{y,z}} - LBMP2_{\mathrm{y,z}}\right)$$

Where:

$TL_{y,z}$ is the total annual amount of Energy forecasted to be consumed by Load in year y in Load Zone z;

$B_{y,z}$ is the set of blocks of Energy to serve Load in Load Zone z in year y that are sold under bilateral contracts for which information has been provided to the ISO that meets the requirements set forth elsewhere in this Section 31.5.4.4.2.5

$BCL_{b,y,z}$ is the total annual amount of Energy sold into Load Zone z in year y under bilateral contract block b;

$Ind_{b,y,z}$ is the ratio of (1) the increase in the amount paid by the purchaser of Energy, under bilateral contract block *b*, as a result of an increase in the LBMP in Load Zone *z* in year *y* to (2) the increase in the amount that a purchaser of that amount of Energy would pay if the purchaser paid the LBMP for that Load Zone in that year for all of that Energy (this ratio shall be zero for any bilateral contract block of Energy that is sold at a fixed price or for which the cost of Energy purchased under that contract otherwise insensitive to the LBMP in Load Zone *z* in year *y*);

$SG_{y,z}$ is the total annual amount of Energy in Load Zone *z* that is forecasted to be served by LSE-owned generation in that Zone in year *y*;

LBMP1y,z is the forecasted *annual load-weighted average LBMP* for Load Zone *z* in year *y*, calculated under the assumption that the project is not in place; and

$LBMP2_{y,z}$ is the forecasted annual load-weighted average LBMP for Load Zone *z* in year *y*, calculated under the assumption that the project is in place.

31.5.4.4.2.6 NZS_z, the Net Zonal Savings for each Load Zone *z* resulting from a given project, shall be calculated using the following equation:

$$NZS_z = \max\left[0, \sum_{y=PS}^{PS+9}\left(\left(AdjLBMPS_{\mathrm{y,z}} - TCCRevImpact_{\mathrm{y,z}}\right) * DF_{\mathrm{y}}\right)\right]$$

Where:

PS is the year in which the project is expected to enter commercial operation;

$AdjLBMPS_{y,z}$ is as calculated in Section 31.5.4.4.2.5;

$\mathrm{TCCRevImpact}_{y,z}$ is the forecasted impact of TCC revenues allocated to Load Zone *z* in year *y*, calculated using the procedure described in Appendix B in Section 31.7 of this Attachment Y; and

DF_y is the discount factor applied to cash flows in year y to determine the present value of that cash flow in year *PS*.

31.5.4.4.3 Load Zones not benefiting from a proposed RETP will not be allocated any of the costs of the project under this Attachment Y. There will be no "make whole" payments to non-beneficiaries.

31.5.4.4.4 Costs of a project will be allocated to beneficiaries as follows:

31.5.4.4.4.1 The ISO will allocate the cost of the RETP based on the zonal share of total savings to the Load Zones determined pursuant to Section 31.5.4.4.2 to be beneficiaries of the proposed project. Total savings will be equal to the sum of load savings for each Load Zone that experiences net benefits pursuant to Section 31.5.4.4.2. A Load Zone's cost allocation will be equal to the present value of the following calculation:

$$\text{Zonal Cost Allocation} = \text{Project Cost} * \left(\frac{\text{(Zonal Benefits)}}{\text{Total Zonal Benefits for zone with positive net benefits}}\right)$$

31.5.4.4.4.2 Zonal cost allocation calculations for a RETP will be performed prior to the commencement of the ten-year period that begins with the project's commercial operation date, and will not be adjusted during that ten-year period.

31.5.4.4.4.3 Within zones, costs will be allocated to LSEs based on MWhs calculated for each LSE for each zone using data from the most recent available 12 month period. Allocations to an LSE will be calculated in accordance with the following formula:

$$\text{LSE Intrazonal Cost Allocation} = \text{Zonal Cost Allocation} * \left(\frac{\text{LSE Zonal MWh}}{\text{Total Zonal MWh}}\right)$$

31.5.4.4.5 Project costs allocated under this Section 31.5.4.4 will be determined as follows:

31.5.4.4.5.1 The project cost allocated under this Section 31.5.4.4 will be based on the total project revenue requirement, as supplied by the Developer of the project, for the first ten years of project operation. The total project revenue requirement will be determined in accordance with the formula rate on file at the Commission. If there is no formula rate on file at the Commission, then the Developer shall provide to the ISO the project-specific parameters to be used to calculate the total project revenue requirement.

31.5.4.4.5.2 Once the benefit/cost analysis is completed the amortization period and the other parameters used to determine the costs that will be recovered for the project should not be changed, unless so ordered by the Commission or a court of applicable jurisdiction, for cost recovery purposes to maintain the continued validity of the benefit/cost analysis.

31.5.4.4.5.3 The ISO, in conjunction with the ESPWG, will develop procedures to allocate the risk of project cost increases that occur after the ISO completes its benefit/cost analysis under this Attachment Y. These procedures may include consideration of an additional review and vote prior to the start of construction and whether the developer should bear all or part of the cost of any overruns**.**

31.5.4.4.6 The Commission must approve the cost of a proposed RETP for that cost to be recovered through the ISO OATT. The developer's filing with the Commission must be consistent with the project proposal evaluated by the ISO under this Attachment Y in order to be cost allocated to beneficiaries.

31.5.4.5 Collaborative Governance Process and Board Action

31.5.4.5.1 The ISO shall submit the results of its project benefit/cost analysis and beneficiary determination to the ESPWG and TPAS, and to the identified beneficiaries of the proposed RETP for comment. The ISO shall make available to any interested party sufficient information to replicate the results of the benefit/cost analysis and beneficiary determination. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of the review by the ESPWG and TPAS of the project benefit/cost analysis, the ISO's analysis reflecting any revisions resulting from the TPAS and ESPWG review shall be forwarded to the Business Issues Committee and Management Committee for discussion and action.

31.5.4.5.2 Following the Management Committee vote, the ISO's project benefit/cost analysis and beneficiary determination will be forwarded, with the input of the Business Issues Committee and Management Committee, to the ISO Board for review and action. In addition, the ISO's determination of the beneficiaries' voting shares will be forwarded to the ISO Board for review and action. The Board may approve the analysis and beneficiary determinations as submitted or propose modifications on its own motion. If any changes to the benefit/cost analysis or the beneficiary determinations are proposed by the Board, the revised analysis and beneficiary determinations shall be returned to the Management Committee for comment. If the Board proposes any changes to the ISO's voting share determinations, the Board shall so inform the LSE or LSEs impacted by the proposed change and shall allow such an LSE or LSEs an opportunity to comment on the proposed change. The Board shall not make a final determination on the project benefit/cost analysis and beneficiary determination until it has reviewed the Management Committee comments. Upon final approval of the Board, project benefit/cost analysis and beneficiary determinations shall be posted by the ISO on its website and shall form the basis of the beneficiary voting described in Section 31.5.4.6 of this Attachment Y.

31.5.4.6 Voting by Project Beneficiaries

31.5.4.6.1 Only LSEs serving Load located in a beneficiary zone determined in accordance with the procedures in Section 31.5.4.4 of this Attachment Y shall be eligible to vote on a proposed project. The ISO will, in conjunction with the ESPWG, develop procedures to determine the specific list of voting entities for each proposed project. Prior to a vote being conducted, the Developer of the RETP must have a completed System Impact Study or System Reliability Impact Study, as applicable.

31.5.4.6.2 The voting share of each LSE shall be weighted in accordance with its share of the total project benefits, as allocated by Section 31.5.4.4 of this Attachment Y.

31.5.4.6.3 The costs of a RETP shall be allocated under this Attachment Y if eighty percent (80%) or more of the actual votes cast on a weighted basis are cast in favor of implementing the project.

31.5.4.6.4 If the proposed RETP meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project.

31.5.4.6.5 The ISO will tally the results of the vote in accordance with procedures set forth in the ISO Procedures, and report the results to stakeholders. Beneficiaries voting against approval of a project must submit to the ISO their rationale for their vote within 30 days of the date that the vote is taken. Beneficiaries must provide a detailed explanation of the substantive reasons underlying the decision, including, where appropriate: (1) which additional benefit metrics, either identified in the tariff or otherwise, were used; (2) the actual quantification of such benefit metrics or factors; (3) a quantification and explanation of the net benefit or net cost of the project to the beneficiary; and (4) data supporting the metrics and other factors used. Such explanation may also include uncertainties, and/or alternative scenarios and other qualitative factors considered, including state public policy goals. The ISO will report this information to the Commission in an informational filing to be made within 60 days of the vote. The informational filing will include: (1) a list of the identified beneficiaries; (2) the results of the benefit/cost analysis; and (3) where a project is not approved, whether the developer has provided any formal indication to the ISO as to the future development of the project.

31.5.5 Regulated Transmission Solutions to Public Policy Transmission Needs

31.5.5.1 The Scope of Section 31.5.5

As discussed in Section 31.5.1 of this Attachment Y, the cost allocation principles and methodologies of this Section 31.5.5 apply only to regulated Public Policy Transmission Projects. This Section 31.5.5 does not apply to Other Public Policy Projects, including generation or demand side management projects, or any market-based projects. This Section 31.5.5 does not apply to regulated reliability solutions implemented pursuant to the reliability planning process, nor does it apply to RETPs proposed in response to congestion identified in the CARIS.

A regulated solution shall only utilize the cost allocation methodology set forth in Section 31.5.3 where it is: (1) a Responsible Transmission Owner's regulated backstop solution, (2) an alternative regulated transmission solution selected by the ISO as the more efficient or cost effective regulated transmission solution to satisfy a Reliability Need, or (3) seeking cost recovery where it has been halted or cancelled pursuant to the provisions of Section 31.2.8.2. A regulated economic transmission solution proposed in response to congestion identified in the CARIS, and approved pursuant to Section 31.5.4.6, shall only be eligible to utilize the cost allocation principles and methodologies set forth in Section 31.5.4.

31.5.5.2 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.5.4 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1. The specific cost allocation methodology in Section 31.5.5.4 incorporates the following elements:

31.5.5.2.1 The focus of the cost allocation methodology shall be on regulated Public Policy Transmission Projects.

31.5.5.2.2 Projects analyzed hereunder as Public Policy Transmission Projects may proceed on a market basis with willing buyers and sellers at any time.

31.5.5.2.3 Cost allocation shall be based on a beneficiaries pay approach.

31.5.5.2.4 Project benefits will be identified in accordance with Section 31.5.5.4.

31.5.5.2.5 Identification of beneficiaries for cost allocation and cost allocation among those beneficiaries shall be according to the methodology specified in Section 31.5.5.4.

31.5.5.3 Project Eligibility for Cost Allocation

The Developer of a Public Policy Transmission Project will be eligible for cost allocation in accordance with the process set forth in Section 31.5.5.4 when its project is selected by the ISO as the more efficient or cost effective regulated Public Policy Transmission Project; *provided, however*, that if the appropriate federal, state, or local agency(ies) rejects the selected project's necessary authorizations, or such authorizations are withdrawn, the costs the Developer is eligible to recover under Section 31.4.12.1 shall be allocated in accordance with Section 31.5.5.4.3, except as otherwise determined by the Commission. The Developer of the selected regulated transmission solution may recover its costs in accordance with Section 31.5.6.

31.5.5.4 Cost Allocation for Eligible Projects

As noted in Section 31.5.5.2 of this Attachment Y, the identification of beneficiaries for cost allocation and the cost allocation of a selected Public Policy Transmission Project will be conducted in accordance with the process described in this Section 31.5.5.4. This Section will also apply to the allocation within New York of the ISO's share of the costs of an Interregional Transmission Project proposed as a solution to a Public Policy Transmission Need allocated in accordance with Section 31.5.7 of this Attachment Y. The establishment of a cost allocation methodology and rates for a proposed solution that is undertaken by LIPA or NYPA as an Unregulated Transmitting Utility to a Public Policy Transmission Need as determined in Sections 31.4.2.1 through 31.4.2.3, as applicable, or an Interregional Transmission Project shall occur pursuant to Section 31.5.5.4.4 through 31.5.5.4.6, as applicable. Nothing herein shall deprive a Transmission Owner or Other Developer of any rights it may have under Section 205 of the Federal Power Act to submit filings proposing any other cost allocation methodology to the Commission or create any Section 205 filing rights for any Transmission Owner, Other Developer, the ISO, or any other entity. The ISO shall apply the cost methodology accepted by the Commission.

31.5.5.4.1 If the Public Policy Requirement that results in the identification by the NYPSC of a Public Policy Transmission Need prescribes the use of a particular cost allocation and recovery methodology, then the ISO shall file that methodology with the Commission within 60 days of the issuance by the NYPSC of its identification of a Public Policy Transmission Need. Nothing herein shall deprive a Transmission Owner or Other Developer of any rights it may have under Section 205 of the Federal Power Act to submit filings proposing any other cost allocation methodology to the Commission or create any Section 205 filing rights for any Transmission Owner, Other Developer, the ISO, or any other entity. If the Developer files a different proposed cost allocation methodology under Section 205 of the Federal Power Act, it shall have the burden of demonstrating that its proposed methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles taking into account the methodology specified in the Public Policy Requirement.

31.5.5.4.2 Subject to the provisions of Section 31.5.5.4.1, the Developer may submit to the NYPSC for its consideration – no later than 30 days after the ISO's selection of the regulated Public Policy Transmission Project – a proposed cost allocation methodology, which may include a cost allocation based on load ratio share, adjusted to reflect, as applicable, the Public Policy Requirement or Public Policy Transmission Need, the party(ies) responsible for complying with the Public Policy Requirement, and the party(ies) who benefit from the transmission facility.

31.5.5.4.2.1 The NYPSC shall have 150 days to review the Developer's proposed cost allocation methodology and to inform the Developer regarding whether it supports the methodology.

31.5.5.4.2.2. If the NYPSC supports the proposed cost allocation methodology, the Developer shall file that cost allocation methodology with the Commission for its acceptance under Section 205 of the Federal Power Act within 30 days of the NYPSC informing the Developer of its support. The Developer shall have the burden of demonstrating that the proposed cost allocation methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles.

31.5.5.4.2.3 If the NYPSC does not support the proposed cost allocation methodology, then the Developer shall take reasonable steps to respond to the NYPSC's concerns and to develop a mutually agreeable cost allocation methodology over a period of no more than 60 days after the NYPSC informing the Developer that it does not support the methodology.

31.5.5.4.2.4 If a mutually acceptable cost allocation methodology is developed during the timeframe set forth in Section 31.5.5.4.2.3, the Developer shall file it with the Commission for acceptance under Section 205 of the Federal Power Act no later than 30 days after the conclusion of the 60 day discussion period with the NYPSC. The Developer shall have the burden of demonstrating that the proposed cost allocation methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles.

31.5.5.4.2.5 If no mutually agreeable cost allocation methodology is developed, the Developer shall file its preferred cost allocation methodology with the Commission for acceptance under Section 205 of the Federal Power Act no later than 30 days after the conclusion of the 60 day discussion period with the NYPSC. The Developer shall have the burden of demonstrating that its proposed methodology is compliant with the Order No. 1000 Regional Cost Allocation Principles in consideration of the position of the NYPSC. The filing shall include the methodology supported by NYPSC for the Commission's consideration. If the Developer elects to use the load ratio share cost allocation methodology referenced below in Section 31.5.5.4.3, the Developer shall notify the Commission of its intent to utilize the load ratio share methodology and shall include in its notice the NYPSC supported methodology for the Commission's consideration.

31.5.5.4.3. Unless the Commission has accepted an alternative cost allocation methodology pursuant to this Section, the ISO shall allocate the costs of the Public Policy Transmission Project to all Load Serving Entities in the NYCA using the default cost allocation methodology, based upon a load ratio share methodology.

31.5.5.4.4 The NYISO will make any Section 205 filings related to this Section on behalf of NYPA to the extent requested to do so by NYPA. NYPA shall bear the burden of demonstrating that such a filing is compliant with the Order No. 1000 Regional Cost Allocation Principles. NYPA shall also be solely responsible for making any jurisdictional reservations or arguments related to their status as non-Commission-jurisdictional utilities that are not subject to various provisions of the Federal Power Act.

31.5.5.4.5 The cost allocation methodology and any rates for cost recovery for a proposed solution to a Public Policy Transmission Need undertaken by LIPA, as an Unregulated Transmitting Utility (for purposes of this section a "LIPA project"), shall be established and recovered as follows:

31.5.5.4.5.1 *For costs solely to LIPA customers.* The cost allocation methodology and rates to be established for a LIPA project, for which cost recovery will only occur from LIPA customers, will be established pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Prior to the adoption of any cost allocation mechanism or rates for such a LIPA project, and pursuant to Section 1020-f(u), the Long Island Power Authority's Board of Trustees shall request that the NYDPS provide a recommendation with respect to the cost allocation methodology and rate that LIPA has proposed and the Board of Trustees shall consider such recommendation in accordance with the requirements of Section 1020-f(u). Upon approval of the cost allocation mechanism and/or rates by the Long Island Power Authority's Board of Trustees, LIPA shall provide to the ISO, for purposes of inclusion within the ISO OATT and filing with FERC on an informational basis only, a description of the cost allocation mechanism and the rate that LIPA will charge and collect within the Long Island Transmission District.

31.5.5.4.5.2 *For Costs for a LIPA Project That May be Allocated to Other Transmission Districts.* A LIPA project that meets a Public Policy Transmission Need as determined by the NYPSC pursuant to Section 31.4.2.3(iii) may be allocated to market participants outside of the Long Island Transmission District. The cost allocation methodology and rate for such a LIPA project shall be established in accordance with the following procedures. LIPA's proposed cost allocation methodology and/or rate shall be reviewed and approved by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Prior to the adoption of any cost allocation mechanism or rates for such project and pursuant to Section 1020-f(u), the Long Island Power Authority's Board of Trustees shall request that the NYDPS provide a recommendation with respect to the cost allocation methodology and rate that LIPA has proposed and the Board of Trustees shall consider such recommendation in accordance with the requirements of Section 1020-f(u). LIPA shall inform the ISO of the cost allocation methodology and rate that has been approved by the Long Island Power Authority's Board of Trustees for filing with the Commission.

Upon approval by the Long Island Power Authority's Board of Trustees, LIPA shall submit and request that the ISO file the LIPA cost allocation methodology for approval with the Commission. Any cost allocation methodology for a LIPA project that allocates costs to market participants outside of the Long Island Transmission District shall be reviewed as to whether there is comparability in the derivation of the cost allocation for market participants such that LIPA has demonstrated that the proposed cost allocation is compliant with the Order No. 1000 cost allocation principles, there are benefits provided by the project to market participants outside of the Long Island Transmission District, and that the proposed allocation is roughly commensurate to the identified benefits.

Article 5, Title 1-A of the New York Public Authorities Law, Sections 1020-f(u) and 1020-s, requires that LIPA's rates be established at the lowest level consistent with sound fiscal and operating practices of the Long Island Power Authority and which provide for safe and adequate service. Upon approval of a LIPA rate by the Long Island Power Authority's Board of Trustees pursuant to Section 1020-f(u), LIPA shall submit, and request that the ISO file, the LIPA rate with the Commission for review under the same comparability standard as applied to the review of changes in LIPA's TSC under Attachment H of this tariff.

In the event that the cost allocation methodology or rate approved by the Long Island Power Authority's Board of Trustees did not adopt the NYDPS recommendation, the NYDPS recommendation shall be included in the filing for the Commission's consideration.

31.5.5.4.5.3 *Support for Filing*. LIPA shall intervene in support of the filing(s) made pursuant to Section 31.5.5.4.5 at the Commission and shall take the responsibility to demonstrate that: (i) the cost allocation methodology and/or rate approved by the Long Island Power Authority's Board of Trustees meets the applicable standard of comparability, and (ii) the Commission should accept such methodology or rate for filing. LIPA shall also be responsible for responding to, and seeking to resolve, concerns about the contents of the filing that might be raised in such proceeding.

31.5.5.4.5.4 *Billing of LIPA Charges Outside of the Long Island Transmission District*. For Transmission Districts other than the Long Island Transmission District, the ISO shall bill for LIPA, as a separate charge, the costs incurred by LIPA for a solution to a Public Policy Transmission Need allocated using the cost allocation methodology and rates established pursuant to Section 31.5.5.4.5.2 and accepted for filing by the Commission and shall remit the revenues collected to LIPA each Billing Period in accordance with the ISO's billing and settlement procedures.

31.5.5.4.6 The inclusion in the ISO OATT or in a filing with the Commission of the cost allocation and charges for recovery of costs incurred by NYPA or LIPA related to a solution to a transmission need driven by a Public Policy Requirement or Interregional Transmission Project as provided for in Sections 31.5.5.4.4 and 31.5.5.4.5 shall not be deemed to modify the treatment of such rates as non-jurisdictional pursuant to Section 201(f) of the FPA.

31.5.6 Cost Recovery for Regulated Projects

Responsible Transmission Owners, Transmission Owners and Other Developers will be entitled, if eligible for cost recovery under Section 31.2 of this Attachment Y, to full recovery of all reasonably incurred costs, including a reasonable return on investment and any applicable incentives, related to the development, construction, operation and maintenance of regulated solutions, including Gap Solutions, proposed or undertaken pursuant to the provisions of this Attachment Y to meet a Reliability Need. Transmission Owners and Other Developers will be entitled to recovery of costs associated with the implementation of a regulated economic transmission project ("RETP") in accordance with the provisions of Section 31.5.6 of this Attachment Y. Developers will be entitled to recover the costs, to the extent permitted under Sections 31.4 and 31.5.6.5 of this Attachment Y, associated with the implementation of a regulated Public Policy Transmission Project in accordance with the requirements in Section 31.5.6.5 of this Attachment Y.

31.5.6.1 The Responsible Transmission Owner, Transmission Owner or Other Developer will receive cost recovery for a regulated solution it undertakes to meet a Reliability Need pursuant to Section 31.2 of this Attachment Y that is subsequently halted in accordance with the criteria established pursuant to Section 31.2.8.2 of this Attachment Y. Such costs will include reasonably incurred costs through the time of cancellation, including any forward commitments made.

31.5.6.2 The Responsible Transmission Owner, Transmission Owner or Other Developer will recover its costs described in this Section 31.5 incurred with respect to the implementation of a regulated transmission solution to Reliability Needs, in accordance with the provisions of Rate Schedule 10 of this ISO OATT, or as determined by the Commission. Provided further that cost recovery for regulated transmission projects undertaken by a Transmission Owner pursuant to this Attachment Y shall be in accordance with the provisions of the NYISO/TO Reliability Agreement or an Operating Agreement.

31.5.6.3 Costs related to non-transmission regulated solutions to Reliability Needs will be recovered by Responsible Transmission Owners, Transmission Owners and Other Developers in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law. A Responsible Transmission Owner, a Transmission Owner, or Other Developer may propose and undertake a regulated non-transmission solution, provided that the appropriate state agency(ies) has established cost recovery procedures comparable to those provided in this tariff for regulated transmission solutions to ensure the full and prompt recovery of all reasonably-incurred costs related to such non-transmission solutions. Nothing in this section shall affect the Commission's jurisdiction over the sale and transmission of electric energy subject to the jurisdiction of the Commission.

31.5.6.4 For a regulated economic transmission project that is approved pursuant to Section 31.5.4.6 of this Attachment Y, the Transmission Owner or Other Developer shall have the right to make a filing with the Commission, under Section 205 of the Federal Power Act, for approval of its costs associated with implementation of the project. The filing of the Transmission Owner or Other Developer must be consistent with its project proposal made to and evaluated by the ISO under Section 31.5.4 of this Attachment Y. Costs will be recovered when the project is completed pursuant to a rate schedule filed with and accepted by the

Commission in accordance with the cost recovery requirements set forth in this Section, or as otherwise determined by the Commission. Upon request by NYPA, the ISO will make a filing on behalf of NYPA.

31.5.6.5 For a regulated Public Policy Transmission Project, the Developer shall have the right to make a filing with the Commission under Section 205 of the Federal Power Act, for approval of its costs eligible for recovery under Section 31.4 and this Section 31.5.6.5.

31.5.6.5.1 The Developer of a Public Policy Transmission Project selected by the ISO as the more efficient or cost-effective Public Policy Transmission Project will be entitled to full recovery of all reasonably incurred costs, including a reasonable return on investment and any applicable incentives, related to the development, construction, operation, and maintenance of the selected Public Policy Transmission Project. Such cost recovery will include reasonable costs incurred by the Developer to provide a more detailed study or cost estimate for such project at the request of the NYPSC, and to prepare the application required to comply with New York Public Service Law Article VII, or any successor statute or any other applicable permits, and to seek other necessary authorizations. The filing of the Developer must be consistent with its project proposal submitted to, evaluated by and selected by the ISO under Section 31.4 of this Attachment Y. The period for cost recovery, if any cost recovery is approved, will be determined by the Commission and will begin if and when the project is completed, or as otherwise determined by the Commission.

31.5.6.5.2 If the appropriate federal, state or local agency(ies) either rejects a necessary authorization, or approves and later withdraws authorization, for the selected Public Policy Transmission Project, the Developer may recover all of the necessary and reasonable costs incurred and commitments made up to the final federal, state or local regulatory decision, including reasonable and necessary expenses incurred to implement an orderly termination of the project, to the extent permitted by the Commission in accordance with its regulations on abandoned plant recovery. The period for cost recovery will be determined by the Commission and will begin as determined by the Commission.

31.5.6.5.3 Upon request by NYPA, the ISO will make a filing on behalf of NYPA under this Section 31.5.6.5.

31.5.6.6 To the extent that Incremental TCCs are created as a result of a regulated economic transmission project that has been approved for cost recovery under the NYISO Tariff, those Incremental TCCs that can be sold will be auctioned or otherwise sold by the ISO. The ISO shall determine the amount of Incremental TCCs that may be awarded to an expansion in accordance with the provisions of Section 19.2.2 of Attachment M of the ISO OATT. The ISO will use these revenues to offset the revenue requirements for the project. The Incremental TCCs shall continue to be sold for the depreciable life of the project, and the revenues offset will commence upon the first payment of revenues related to a sale of Incremental TCCs on or after the charge for a specific RETP is implemented.

31.5.7 Cost Allocation for Eligible Interregional Transmission Projects

31.5.7.1 Costs of Approved Interregional Transmission Projects

The cost allocation methodology reflected in this Section 31.5.7.1 shall be referred to as the "Northeastern Interregional Cost Allocation Methodology" (or "NICAM"), and shall not be modified without the mutual consent of the Section 205 rights holders in each region.

The costs of Interregional Transmission Projects, as defined in the Interregional Planning Protocol, evaluated under the Interregional Planning Protocol and selected by ISO-NE, PJM and the ISO in their regional transmission plans for purposes of cost allocation under their respective tariffs shall, when applicable, be allocated to the ISO-NE region, PJM region and the ISO region in accordance with the cost allocation principles of FERC Order No. 1000, as follows:

(a) To be eligible for interregional cost allocation, an Interregional Transmission Project must be selected in the regional transmission plan for purposes of cost allocation in each of the transmission planning regions in which the transmission project is proposed to be located, pursuant to agreements and tariffs on file at FERC for each region. With respect to Interregional Transmission Projects and other transmission projects involving the ISO and PJM, the cost allocation of such projects shall be in accordance with the Joint Operating Agreement ("JOA") among and between the ISO and PJM. With respect to Interregional Transmission Projects and other transmission projects involving the ISO and ISO-NE, the cost allocation for such projects shall be in accordance with this Section 31.5.7 of Attachment Y of the NYISO Open Access Transmission Tariff and with the respective tariffs of ISO-NE.

(b) The share of the costs of an Interregional Transmission Project allocated to a region will be determined by the ratio of the present value of the estimated costs of such region's displaced regional transmission project to the total of the present values of the estimated costs of the displaced regional transmission projects in all regions that have selected the Interregional Transmission Project in their regional transmission plans.

(i) The present values of the estimated costs of each region’s displaced regional transmission project shall be based on a common base date that will be the beginning of the calendar month of the cost allocation analysis for the subject Interregional Transmission Project (the “Base Date”).

(ii) In order to perform the analysis in this Section 31.5.7.1(b), the estimated cost of the displaced regional transmission projects shall specify the year’s dollars in which those estimates are provided.

(iii) The present value analysis for all displaced regional transmission projects shall use a common discount rate. The regions having displaced projects will mutually agree, in consultation with their respective transmission owners, and for purposes of the ISO, its other stakeholders, on the discount rate to be used for the present value analysis.

(iv) For the purpose of this allocation, cost estimates shall use comparable cost estimating procedures. In the Interregional Planning Stakeholder Advisory Committee review process, the regions having displaced projects will review and determine, in consultation with their respective transmission owners, and for purposes of the NYISO, its other stakeholders, that reasonably comparable estimating procedures have been used prior to applying this cost allocation.

(c) No cost shall be allocated to a region that has not selected the Interregional Transmission Project in its regional transmission plan.

(d) When a portion of an Interregional Transmission Project evaluated under the Interregional Planning Protocol is included by a region (Region 1) in its regional transmission plan but there is no regional need or displaced regional transmission project in Region 1, and the neighboring region (Region 2) has a regional need or displaced regional project for the Interregional Transmission Project and selects the Interregional Transmission Project in its regional transmission plan, all of the costs of the Interregional Transmission Project shall be allocated to Region 2 in accordance with the NICAM and none of the costs shall be allocated to Region 1. However, Region 1 may voluntarily agree, with the mutual consent of the Section 205 rights holders in the other affected region(s) (including the Long Island Power Authority and the New York Power Authority in the NYISO region) to use an alternative cost allocation method filed with and accepted by the Commission.

(e) The portion of the costs allocated to a region pursuant to the NICAM shall be further allocated to that region's transmission customers pursuant to the applicable provisions of the region's FERC-filed documents and agreements, for the ISO in accordance with Section 31.5.1.7 of Attachment Y of the ISO OATT.

(f) The following example illustrates the cost allocation for such an Interregional Transmission Project:

- A cost allocation analysis of the costs of Interregional Transmission Project Z is to be performed during a given month establishing the beginning of that month as the Base Date.
- Region A has identified a reliability need in its region and has selected a transmission project (Project X) as the preferred solution in its regional plan. The estimated cost of

Project X is: Cost (X), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is: N(X).

- Region B has identified a reliability need in its region and has selected a transmission project (Project Y) as the preferred solution in its Regional Plan. The estimated cost of Project Y is: Cost (Y), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (Y) is: N(Y).
- Regions A and B, through the interregional planning process have determined that an Interregional Transmission Project (Project Z) will address the reliability needs in both regions more efficiently and cost-effectively than the separate regional projects. The estimated cost of Project Z is: Cost (Z). Regions A and B have each determined that Interregional Transmission Project Z is the preferred solution to their reliability needs and have adopted that Interregional Transmission Project in their respective regional plans in lieu of Projects X and Y respectively. If Regions A and B have agreed to bear the costs of upgrades in other affected transmission planning regions, these costs will be considered part of Cost (Z).
- The discount rate used for all displaced regional transmission projects is: D
- Based on the foregoing assumptions, the following formulas will be used:
    - Present Value of Cost (X) = PV Cost (X) = Cost (X) / $(1+D)^{N(X)}$
    - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / $(1+D)^{N(Y)}$
    - Cost Allocation to Region A = Cost (Z) x PV Cost (X)/[PV Cost (X) + PV Cost (Y)]

- Cost Allocation to Region B = Cost (Z) x PV Cost (Y)/[PV Cost (X) + PV Cost (Y)]

- Applying those formulas, if:

  Cost (X) = $60 Million and N(X) = 8.25 years

  Cost (Y) = $40 Million and N(Y) = 4.50 years

  Cost (Z) = $80 Million

  D = 7.5% per year

  Then:

  PV Cost (X) = $60/(1+0.075)^{8.25}$ = 33.039 Million

  PV Cost (Y) = $40/(1+0.075)^{4.50}$ = 28.888 Million

  Cost Allocation to Region A = $80 x 33.039/(33.039 + 28.888) = $42,681 Million

  Cost Allocation to Region B = $80 x 28.888/(33.039+28.888) = $37.319 Million

31.5.7.2 Other Cost Allocation Arrangements

(a) Except as provided in Section 31.5.7.2(b), the NICAM is the exclusive means by which any costs of an Interregional Transmission Project may be allocated between or among PJM, the ISO, and ISO-NE.

(b) Nothing in the FERC-filed documents of ISO-NE, the ISO or PJM shall preclude agreement by entities with cost allocation rights under Section 205 of the Federal Power Act for their respective regions (including the Long Island Power Authority and the New York Power Authority in the ISO region) to enter into separate agreements to allocate the cost-of Interregional Transmission Projects proposed to be located in their regions as an alternative to the NICAM, or other transmission projects identified pursuant to assessments and studies conducted pursuant to Section 6 of the Interregional Planning Protocol. Such other cost-allocation methodologies must be approved in each region pursuant to the Commission-approved rules in each region, filed with and accepted by the Commission, and shall apply only to the region's share of the costs of an Interregional Transmission Project or other transmission projects pursuant to Section 6 of the Interregional Planning Protocol, as applicable.

31.5.7.3 Filing Rights

Nothing in this Section 31.5.7 will convey, expand, limit or otherwise alter any rights of ISO-NE, the ISO, PJM, each region's transmission owners, market participants, or other entities to submit filings under Section 205 of the Federal Power Act regarding interregional cost allocation or any other matter.

Where applicable, the regions have been authorized by entities that have cost allocation rights for their respective regions to implement the provisions of this Section 31.5.7.

31.5.7.4. Merchant Transmission and Individual Transmission Owner Projects

Nothing in this Section 31.5.7 shall preclude the development of Interregional Transmission Projects that are funded solely by merchant transmission developers or by individual transmission owners.

31.5.7.5 Consequences to Other Regions from Regional or Interregional Transmission Projects

Except as provided herein in Sections 31.5.7.1 and 31.5.7.2, or where cost responsibility is expressly assumed by ISO-NE, the ISO or PJM in other documents, agreements or tariffs on file with FERC, neither the ISO-NE region, the ISO region nor the PJM region shall be responsible for compensating another region or each other for required upgrades or for any other consequences in another planning region associated with regional or interregional transmission facilities, including but not limited to, transmission projects identified pursuant to Section 6 of the Interregional Planning Protocol and Interregional Transmission Projects identified pursuant to Section 7 of the Interregional Planning Protocol.

31.6 Other Provisions

31.6.1 The Commission's Role in Dispute Resolution

Disputes directly relating to the ISO's compliance with its tariffs that are not resolved in the internal ISO collaborative governance appeals process or ISO dispute resolution process, and all disputes relating to matters that fall within the exclusive jurisdiction of the Commission, shall be reviewed at the Commission pursuant to the Federal Power Act if such review is sought by any party to the dispute. The NYPSC or any party to a dispute regarding matters over which both the NYPSC and the Commission have jurisdiction and responsibility for action may submit a request to the Commission for a joint or concurrent hearing to resolve the dispute.

31.6.2 Non-Jurisdictional Entities

LIPA's and NYPA's participation in the CSPP shall in no way be considered to be a waiver of their non-jurisdictional status pursuant to Section 201(f) of the Federal Power Act, including with respect to the Commission's exercise of the Federal Power Act's general ratemaking authority.

31.6.3 Tax Exempt Financing Provisions

Con Edison, NYPA and LIPA shall not be required to construct, or cause to construct, a transmission facility identified through the ISO reliability planning process if such construction would result in the loss of tax-exempt status of any tax-exempt bond issued by Con Edison, NYPA or LIPA, or impair their ability to secure future tax-exempt financing.

31.6.4 Rights of Transmission Owners

Nothing in this Attachment Y affects the right of a Transmission Owner to: (1) build, own, and recover outside of the ISO's Tariffs the costs for upgrades to the facilities it owns, regardless of whether the upgrade has been selected in the regional transmission plan for purposes of cost allocation; (2) retain, modify, or transfer rights-of-way subject to relevant law or regulation granting such rights-of-way; or (3) develop a local transmission solution that is not eligible for regional cost allocation to meet its reliability needs or service obligations in its Transmission District or footprint, as applicable. For purposes of Section 31.6.4, the term "upgrade" shall refer to an improvement to, addition to, or replacement of a part of an existing transmission facility and shall not refer to an entirely new transmission facility.

31.6.5 Notice of Reliability Requirements

The Developer of a project selected pursuant to the provisions in this Attachment Y is hereby notified that it must comply with all applicable reliability criteria, policies, standards, rules, regulations, and other requirements of NERC, NPCC, NYSRC, Transmission Owners, and any other applicable reliability entities or their successors, to the extent required by, and in accordance with, their procedures.

31.11 Appendix H – Form of Operating Agreement

FORM OF OPERATING AGREEMENT

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OPERATING AGREEMENT

THIS OPERATING AGREEMENT (“Agreement”) is made and entered into this ___ day of _______ 20__, by and between ______________, a non-incumbent transmission owner organized and existing as a [corporate description] under the laws of the State/Commonwealth of ___________ (“NTO”), and the New York Independent System Operator, Inc., a not-for-profit corporation organized and existing under the laws of the State of New York (“ISO”). The NTO and the ISO each may be referred to as a “Party” or collectively referred to as the “Parties.”

WITNESSETH:

WHEREAS, the ISO is an independent system operator that is responsible under its Open Access Transmission Tariff (“ISO OATT”) and its Market Administration and Control Area Services Tariff (“ISO Services Tariff”) as they may be amended from time to time (collectively, “ISO Tariffs”), and the ISO Related Agreements, filed with and accepted by the Federal Energy Regulatory Commission (“Commission”), for providing non-discriminatory, open access transmission service, maintaining reliability, performing system planning, and administering competitive wholesale markets for energy, capacity, and ancillary services in New York State;

WHEREAS, the NTO is the owner of certain transmission facilities specified herein that are integrated with the NYS Transmission System and the NTO has fiduciary responsibilities to its investors to assure, among other things, the receipt of adequate revenues to maintain its transmission facilities, a reasonable rate of return on its transmission facilities, and to provide for recovery of the capital invested in its transmission facilities;

WHEREAS, the NTO has executed, along with this Agreement, the Independent System Operator Agreement ("ISO Agreement") and has executed a Service Agreement(s) as a Transmission Owner for purposes of the ISO Tariffs;

WHEREAS, the ISO will exercise ISO Operational Control over certain of the NTO's transmission facilities classified as "NTO Transmission Facilities Under ISO Operational Control";

WHEREAS, the NTO and ISO have agreed to enter into this Agreement for the purpose of the NTO authorizing the ISO to exercise, and the ISO assuming, ISO Operational Control over the NTO Transmission Facilities Under ISO Operational Control in accordance with the requirements set forth in this Agreement, the ISO Tariffs, and the ISO Related Agreements, as applicable;

WHEREAS, the NTO will continue to own and be responsible for the physical operation, modification and maintenance of its NTO Transmission Facilities Under ISO Operational Control; and

WHEREAS, the ISO OATT will provide for the payment by Transmission Customers for Transmission Service at rates designed to enable the NTO to recover its revenue requirement to the extent allowed, accepted, or approved by FERC;

WHEREAS, the ISO has a comprehensive planning process for reliability needs ("Reliability Planning Process") and each Transmission Owner, including the NTO, will participate in this planning process as described in the ISO OATT;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements set forth herein, the Parties do hereby agree with each other, for themselves and their successors and assigns, as follows:

ARTICLE 1.0: DEFINITIONS

1.01 Capitalized Terms

Capitalized terms that are not otherwise defined herein shall have the meaning set forth in the definitions contained in Article 1 of the ISO Agreement, as it existed on the date this Agreement is signed by the Parties. Those definitions contained in Article 1 of the ISO Agreement are hereby incorporated by reference in their entirety into this Agreement; *provided, however*, that an NTO shall be a Transmission Owner for purposes of the ISO Tariffs and this Agreement notwithstanding the definition of Transmission Owner contained in the ISO Agreement related to the ownership of 100 circuit miles of transmission in New York State and becoming a signatory to the ISO/TO Agreement. Modifications to such definitions in the ISO Agreement shall apply to this Agreement only if the Parties to this Agreement agree in writing pursuant to Section 6.14 below.

ARTICLE 2.0: RESPONSIBILITIES OF THE NTO

2.01 Transmission Facilities

The NTO owns certain transmission facilities over which the ISO will have day-to-day operational control to maintain these facilities in a reliable state, as defined by the Reliability Rules and all other applicable reliability rules, standards and criteria, and in accordance with the ISO Tariffs, ISO Related Agreements and ISO Procedures ("ISO Operational Control"). These NTO facilities shall be classified as "NTO Transmission Facilities Under ISO Operational Control," and are listed in Appendix A-1 of this Agreement. The NTO also will be responsible for providing notification to the ISO with respect to actions related to certain other transmission facilities. These facilities shall be classified as "NTO Transmission Facilities Requiring ISO Notification," and are listed in Appendix A-2 of this Agreement. Transmission facilities may be added to, or deleted from, the lists of facilities provided in Appendices A-1 and A-2 herein by mutual written agreement of the ISO and the NTO owning and controlling such facilities. Currently listed facilities will be posted on the ISO's OASIS.

2.02 Transmission System Operation

The NTO shall be responsible for ensuring that all actions related to the operation, maintenance and modification of its facilities that are designated as NTO Transmission Facilities Under ISO Operational Control and NTO Transmission Facilities Requiring ISO Notification are performed in accordance with the terms of this Agreement, all Reliability Rules and all other applicable reliability rules, standards and criteria, all operating instructions, ISO Tariffs, ISO Procedures, and any transmission interconnection agreement(s) for its facilities.

2.03 Local Area Transmission System Facilities

Transmission system facilities not designated as NTO Transmission Facilities Under ISO Operational Control or as NTO Transmission Facilities Requiring ISO Notification shall be collectively known as "Local Area Transmission System Facilities" and are listed in Appendix A-3 of this Agreement. Transmission facilities may be added to, or deleted from, the list of facilities provided in Appendix A-3 herein by mutual written agreement of the ISO and the NTO owning and controlling such facilities. The NTO shall have sole responsibility for the operation of its Local Area Transmission System Facilities, provided, however, that such operation shall comply with all Reliability Rules and ISO Tariffs as applicable, and all other applicable reliability rules, standards and criteria, and shall not compromise the reliable and secure operation of the NYS Transmission System. The NTO shall promptly comply to the extent practicable with a request from the ISO, or from the Transmission Owner(s) to which its facilities are interconnected ("Interconnecting Transmission Owner(s)" or "ITO(s)"), to take action with respect to coordination of the operation of its Local Area Transmission System Facilities.

2.04 Safe Operations

Notwithstanding any other provision of this Agreement, an NTO may take, or cause to be taken, such action with respect to the operation of its facilities as it deems necessary to maintain Safe Operations. To ensure Safe Operations, the local operating rules of the ITO(s) shall govern the connection and disconnection of generation with NTO transmission facilities. Safe Operations include the application and enforcement of rules, procedures and protocols that are intended to ensure the safety of personnel operating or performing work or tests on transmission facilities.

2.05 Local Control Center, Metering and Telemetry

The NTO shall operate, pursuant to ISO Tariffs, ISO Procedures, Reliability Rules and all other applicable reliability rules, standards and criteria on a twenty-four (24) hour basis, a suitable local control center(s) with all equipment and facilities reasonably required for the ISO to exercise ISO Operational Control over NTO Transmission Facilities Under ISO Operational Control, and for the NTO to fulfill its responsibilities under this Agreement. Operation of the NYS Power System is a cooperative effort coordinated by the ISO control center in conjunction with local control centers and will require the exchange of all reasonably necessary information. The NTO shall provide the ISO with Supervisory Control and Data Acquisition ("SCADA") information on facilities listed in Appendices A-1 and A-2 herein as well as on generation and merchant transmission resources interconnected to the NTO's transmission facilities pursuant to the ISO OATT.

The NTO shall provide metering data for its transmission facilities to the ISO, unless other parties are authorized by the appropriate regulatory authority to provide metering data. The NTO shall collect and submit to the ISO billing quality metering data and any other information for its transmission facilities required by the ISO for billing purposes. The NTO shall provide to the ISO the telemetry and other operating data from generation and merchant transmission resources interconnected to its transmission facilities that the ISO requires for the operation of the NYS Power System. The NTO will establish and maintain a strict code of conduct to prevent such information from reaching any unauthorized person or entity.

2.06 Security Constrained Unit Commitment Adjustments

The NTO shall coordinate with its ITO(s) as applicable regarding any request for commitment of additional Generators. If, following coordination among the NTO and its ITO(s), an additional resource(s) needs to be committed to ensure local area reliability, the NTO, or the ITO(s) at the NTO's request, may request commitment of additional Generators (including specific output level(s)). The ISO will use Supplemental Resource Evaluation ("SRE"), pursuant to ISO Tariffs and ISO Procedures, to fulfill a request from the NTO or ITO(s), as appropriate, for additional units.

2.07 Design, Maintenance and Rating Capabilities

The NTO shall comply with the provisions of this Agreement, all Reliability Rules and all other applicable reliability rules, standards and criteria, ISO Procedures, the local reliability rules and planning criteria of its ITO(s), and Good Utility Practice with respect to the design, maintenance and rating the capabilities of NYS Transmission System facilities.

2.08 Maintenance Scheduling

The NTO shall schedule maintenance of its facilities designated as NTO Transmission Facilities Under ISO Operational Control and schedule any outages (other than forced transmission outages) of said transmission system facilities in accordance with outage schedules approved by the ISO. The NTO shall comply with maintenance schedules coordinated by the ISO, pursuant to this Agreement, for NTO Transmission Facilities Under ISO Operational Control. The NTO shall be responsible for providing notification of maintenance schedules to the ISO and ITO(s) for NTO Transmission Facilities Requiring ISO Notification, and for providing notification of maintenance schedules to its ITO(s) for Local Area Transmission Facilities.

2.09 NERC Registration

The NTO shall register or enter into agreement with a NERC registered entity for all required NERC functions applicable to the NTO, that may include, without limitation, those functions designated by NERC to be: “Transmission Owner” and “Transmission Planner” and “Transmission Operator.” Notwithstanding the foregoing, the ISO shall register for the “Transmission Operator” function for all NTO Transmission Facilities under ISO Operational Control identified in Appendix A-1 of this Agreement.

2.10 Investigations and Restoration

The NTO shall promptly conduct investigations of equipment malfunctions and failures and forced transmission outages in a manner consistent with applicable FERC, PSC, NRC, NERC, NPCC and NYSRC rules, principles, guidelines, standards and requirements, ISO Procedures and Good Utility Practice. The NTO shall supply the results of such investigations to the NYSRC, the ISO, its ITO(s), and the other affected Transmission Owners. Following a total or partial system interruption, restoration shall be coordinated between the ISO control center and local control centers. The local control centers shall have the authority, in coordination with the ISO, to restore the system and to re-establish service if doing so would minimize the period of service interruption. The NTO shall determine the level of resources to be applied to restore facilities to service following a failure, malfunction, or forced transmission outage.

2.11 Information and Support

The NTO shall obtain from the ISO, and the ISO shall provide to the NTO, the necessary information and support services to comply with their obligations under this Article.

2.12 Performance of Obligation by Third Parties

The NTO may arrange for one or more third parties to perform its responsibilities under this Agreement; *provided, however,* that the NTO shall require each such third party to agree in writing to comply with all applicable terms and conditions of this Agreement; *provided, further,* that in all cases the NTO shall be responsible for the acts and omissions of each such third party to the same extent as if such acts and omissions were made by the NTO or its employees, and such use of a third party shall not relieve the NTO of its responsibilities under this Agreement.

2.13 Comprehensive Planning Process for Reliability Needs

a. Notwithstanding any provision, including Section 3.08(e) contained in this Agreement, the NTO acknowledges its obligations described in the ISO’s

Reliability Planning Process set forth in Attachment Y of the ISO OATT, that arise when the ISO designates the NTO as a "Responsible Transmission Owner," pursuant to Section 31.2.4.3 of the ISO OATT, to address a reliability need(s) related to the transmission facilities that the NTO owns and that are subject to this Agreement.

b. The NTO's obligations described in Section 2.13(a) above shall be subject to the full recovery in wholesale rates on a current basis by the NTO, in accordance with the rate mechanism set forth in Section 6.10 of the ISO OATT (Rate Schedule 10), of all reasonably incurred costs, including a reasonable return on investment and any applicable regulatory incentives, related to the preparation of a proposal for, and the development, construction, operation, and maintenance of, regulated transmission projects undertaken, or caused to be undertaken, by the NTO to meet a reliability need identified in the ISO's Reliability Planning Process as a result of being designated as the Responsible Transmission Owner, including those regulated transmission projects that were subsequently determined by the ISO not to be necessary to meet a reliability need or that cannot be completed because of the failure to obtain necessary federal, state, or local authorizations or for any other circumstance beyond the NTO's reasonable control;

c. The NTO's obligations described in Section 2.13(a) above shall be further conditioned on:

1. The recovery of transmission-related costs in rates, as provided for in Section 2.13(b) above, will include, but not limited to, all reasonable costs related to (i) obtaining or attempting to obtain all federal, state and local

authorizations necessary for completion of the project included in the Comprehensive Reliability Plan and (ii) acquiring or attempting to acquire all necessary real property rights for such project;

2. The receipt by the NTO of all federal, state, and local authorizations necessary for completion of the regulated transmission project and acquisition by the NTO of all necessary property rights; and

3. The right of the NTO to request any incentives available under regulatory policies related to investments in transmission projects as part of any filing under rates as provided for in Section 2.13(b) above.

d. Nothing contained in Section 2.13 of this Agreement shall limit the right of the NTO to protest, comment on, or engage in litigation before FERC, the New York Public Service Commission, or any court with respect to proposed changes to the Reliability Planning Process.

ARTICLE 3.0: RESPONSIBILITIES OF THE ISO

3.01 Operation and Coordination

The ISO shall direct the operation of, coordinate the maintenance scheduling of, and coordinate the planning of certain facilities of the NYS Power System, including coordination with the control center(s) maintained by or on behalf of the NTO, in accordance with the Reliability Rules and all other applicable reliability rules, standards and criteria, as follows:

a. Administering Control Area operations of the NYS Power System;

b. Performing balancing of Generation and Load while ensuring the safe, reliable and efficient operation of the NYS Power System;

c. Exercising ISO Operational Control over certain facilities of the NYS Power System under normal operating conditions and system Emergencies to maintain system reliability;

d. Coordinating the NYS Power System equipment outages and maintenance and maintaining the safety and short term reliability of the NYS Power System; and

e. Conducting the Reliability Planning Process in accordance with Attachment Y of the ISO OATT.

3.02 Tariff Administration and Performance of Responsibilities Under ISO Related Agreements

The ISO shall (a) administer the ISO OATT, the ISO Services Tariff and the ISO Agreement in accordance with their provisions as they may be amended from time to time, and (b) shall comply with the provisions of this Agreement, the ISO/TO Agreement, the NYSRC Agreement and the ISO/NYSRC Agreement.

3.03 Granting of Authority

The ISO responsibilities set forth in Article 3 of this Agreement, are granted by the NTO to the ISO only so long as each of the conditions set forth below is met and continues to be met throughout the term of this Agreement:

a. The ISO fully implements all Reliability Rules and all other applicable reliability rules, standards and criteria including, without limitation, using all reasonable efforts to require all Market Participants to maintain applicable levels of Installed Capacity and Operating Capacity, consistent with the ISO OATT, the ISO Services Tariff, all Reliability Rules and all other applicable reliability rules, standards and criteria;

b. The ISO has a FERC-accepted transmission tariff(s) and rate schedules which provide(s) for full recovery of the transmission revenue requirement of the NTO to the extent allowed, accepted or approved by FERC;

c. The ISO does not act in violation of lawful PSC or FERC Orders;

d. The ISO does not have a financial interest in any commercial transaction involving the use of the NYS Power System or any other electrical system except to the limited extent required for the ISO to be the single counterparty to market transactions in accordance with the credit requirements for organized wholesale electric markets set forth in Commission Order Nos. 741 and 741-A as codified in 18 C.F.R. § 35.47 (2011) or successor provisions;

e. The ISO distributes revenues from the collection of transmission charges to the NTO in a timely manner; and

f. The ISO enforces and complies with the creditworthiness and collection standards of the ISO Procedures, the ISO OATT and the ISO Services Tariff.

3.04 Collection and Billing

The ISO shall facilitate and/or perform the billing and collection of revenues related to services provided by the ISO pursuant to the terms of the ISO OATT and the ISO Services Tariff.

3.05 Proposed Material Modifications to the NYS Power System

Pursuant to the requirements of applicable provisions of the ISO OATT, ISO Related Agreements and ISO Procedures, the ISO shall evaluate the impact of any proposed material modification to the NYS Power System. Any proposed material modification to the NTO's facilities must satisfy the requirements of applicable provisions of the ISO OATT, ISO Related Agreements, ISO Procedures, and this Agreement. In the event of a dispute regarding the impact of the proposed modification, the ISO or the NTO may refer the issue for resolution pursuant to procedures set forth in Article 11 of the ISO Services Tariff, as such procedures may be amended from time to time.

3.06 OASIS

The ISO shall maintain the OASIS for the New York Control Area.

3.07 NERC Registration

If and to the extent any of the NTO's facilities are NERC jurisdictional facilities, the ISO will register for certain NERC functions applicable to those NTO facilities. Such functions may include, without limitation, those functions designated by NERC to be "Reliability Coordinator" and "Balancing Authority" and "Planning Coordinator." The ISO shall register for the "Transmission Operator" function for all NTO Transmission Facilities under ISO Operational Control identified in Appendix A-1 of this Agreement.

3.08 NTO's Reserved Rights

Notwithstanding any other provision of this Agreement with the exception of Section 2.13 above, the NTO shall retain all of the rights set forth in this Section; provided, however, that such rights shall be exercised in a manner consistent with the NTO's rights and obligations under the Federal Power Act and the Commission's rules and regulations thereunder. This Section is not intended to reduce or limit any other rights of the NTO as a signatory to this Agreement or any of the ISO Related Agreements or under an ISO Tariff.

a. The NTO shall have the right to make a filing with the Commission pursuant to Section 205 of the Federal Power Act to recover, in accordance with the requirements of Attachment Y to the ISO OATT and/or applicable rate schedule of the ISO OATT, all of its reasonably incurred costs, including a reasonable return on investment related to the development, construction, operation and maintenance of its transmission facilities and any applicable regulatory incentives.

b. Nothing in this Agreement shall restrict any rights, to the extent such rights exist: (i) of the NTO that is a party to a merger, acquisition or other restructuring transaction to make filings under Section 205 of the Federal Power Act with respect to the reallocation or redistribution of revenues among Transmission Owners or the assignment of its rights or obligations, to the extent the Federal Power Act requires such filings; or (ii) of the NTO to terminate its participation in the ISO pursuant to Section 3.02 of the ISO Agreement or Article 6 of this Agreement, notwithstanding any effect its withdrawal from the ISO may have on the distribution of transmission revenues among other Transmission Owners.

c. The NTO retains all rights that it otherwise has incident to its ownership of its assets, including, without limitation, its transmission facilities including, without limitation, the right to build, acquire, sell, merge, dispose of, retire, use as security, or otherwise transfer or convey all or any part of its assets, including, without limitation, the right to amend or terminate the NTO's relationship with the ISO in connection with the creation of an alternative arrangement for the ownership and/or operation of its transmission facilities on an unbundled basis (e.g., a transmission company), subject to necessary regulatory approvals and to any approvals required under applicable provisions of this Agreement.

d. The obligation of the NTO to expand or modify its transmission facilities in accordance with the ISO OATT shall be subject to the NTO's right to recover, pursuant to appropriate financial arrangements contained in Commission-accepted tariffs or agreements, all reasonably incurred costs, plus a reasonable return on investment, associated with constructing and owning or financing such expansions or modifications to its facilities.

e. Except as provided in Section 2.13 above, the responsibilities granted to the ISO under this Agreement shall not expand or diminish the responsibilities of the NTO to modify or expand its transmission system, nor confer upon the ISO the authority to direct the NTO to modify or expand its transmission system.

f. The NTO shall have the right to construct (or cause to be constructed), invest in, and own any regulated transmission facilities that the ISO determines are required to meet a reliability need identified by the Reliability Planning Process, so long as the appropriate regulatory agency(ies) has granted its approval. The costs associated with any such transmission facilities shall be covered in rates as provided for in Section 2.13(b) above and the ISO OATT.

g. The NTO shall have the right to adopt and implement procedures it deems necessary to protect its electric facilities from physical damage or to prevent injury or damage to persons or property.

h. The NTO retains the right to take whatever actions it deems necessary to fulfill its obligations under local, state or federal law.

i. Nothing in this Agreement shall be construed as limiting in any way the rights of the NTO to make any filing with the PSC.

j. Notwithstanding anything to the contrary in this Agreement, no amendment to any provision of this Section may be adopted without the agreement of the NTO.

3.09 Retention of Non-Transferred Obligations

Any and all other rights and responsibilities of the NTO related to the ownership or operation of its transmission assets or to its rights to withdraw its assets from ISO control, that have not been specifically transferred to the ISO under this Agreement or otherwise addressed under this Agreement, will remain with the NTO.

ARTICLE 4.0: ASSIGNMENT

4.01 Assignments by the NTO or the ISO.

This Agreement may be assigned by either Party including, without limitation, to any entity(ies) in connection with a merger, consolidation, reorganization or change in the organizational structure of the assigning Party, provided that the surviving entity(ies) agree, in writing, to be bound by the terms of this Agreement.

ARTICLE 5.0: LIMITATION OF LIABILITY AND INDEMNIFICATION

5.01 Limitations of Liability

Except as otherwise provided under the ISO OATT, neither Party shall be liable (whether based on contract, indemnification, warranty, tort, strict liability or otherwise) to the other Party, any Market Participant, any third party or other party for any damages whatsoever, including without limitation, special, indirect, incidental, consequential, punitive, exemplary or direct damages resulting from any act or omission under this Agreement, except to the extent the Party is found liable for gross negligence or intentional misconduct, in which case the Party shall not be liable for any special, indirect, incidental, consequential, punitive or exemplary damages. Nothing in this Section will excuse an NTO from an obligation to pay for services provided to the NTO by the ISO or to pay any deficiency payments, penalties, or sanctions imposed by the ISO under the ISO OATT or the ISO Services Tariff.

5.02 Additional Limitations of Liability

Except as otherwise provided under the ISO OATT, neither the NTO nor the ISO shall be liable for any indirect, consequential, exemplary, special, incidental or punitive damages including, without limitation, lost revenues or profits, the cost of replacement power or the cost of capital, even if such damages are foreseeable or the damaged party has been advised of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

5.03 Indemnification

Each Party shall at all times indemnify, save harmless and defend the other Party, including their directors, officers, employees, trustees, and agents, or each of them, from and against all claims, demands, losses, liabilities, judgments, damages (including, without limitation, any consequential, incidental, direct, special, indirect, exemplary or punitive damages and economic costs), and related costs and expenses (including, without limitation, reasonable attorney and expert fees, and disbursements incurred by the Party in any actions or proceedings between the Party and a Market Participant, or any other third party) arising out of or related to the ISO's or the NTO's acts or omissions related in any way to the NTO's ownership or operation of its transmission facilities when such acts or omissions are either (1) pursuant to or consistent with ISO Procedures or direction; or (2) in any way related to the NTO's or the ISO's performance under the ISO OATT, the ISO Services Tariff, the ISO Agreement, the ISO/NYSRC Agreement, NYSRC Agreement, or this Agreement; *provided*, *however*, that the NTO shall not have any indemnification obligation under this Section 5.02 with respect to any loss to the extent the loss results from the gross negligence or intentional misconduct of the ISO; *provided, further*, that the ISO shall not have any indemnification obligation under this Section 5.02 with respect to any loss except to the extent the loss results from the gross negligence or intentional misconduct of the ISO.

5.04 Force Majeure

Each Party shall not be considered to be in default or breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, arising out of or from any act, omission, or circumstance occasioned by or in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials, act of the public enemy, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes beyond such Party's reasonable control, including any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities, or by the making of repairs necessitated by an emergency circumstance not limited to those listed above upon the property or equipment of the ISO or any party to the ISO Agreement. Nothing contained in this Article shall relieve any entity of the obligations to make payments when due hereunder or pursuant to a Service Agreement. Any party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except the settlement of any labor disturbance shall be in the sole judgment of the affected party.

5.05 Claims by Employees and Insurance

Each Party shall be solely responsible for and shall bear all of the costs of claims by its own employees, contractors, or agents arising under and covered by, any workers' compensation law. Each Party shall furnish, at its sole expense, such insurance coverage and such evidence thereof, or evidence of self-insurance, as is reasonably necessary to meet its obligations under this Agreement.

5.06 Survival

The provisions of this Article, “Limitations of Liability and Indemnification” shall survive the termination or expiration of this Agreement or the ISO Tariffs.

ARTICLE 6.0: OTHER PROVISIONS

6.01 Term and Termination for Cause

This Agreement shall become effective upon the execution of this Agreement by the NTO and the ISO and on the later of: (i) the date on which FERC, the PSC and any other regulatory agency having jurisdiction accepts this agreement without condition or material modification and grants all approvals needed to place the NTO's facilities in service, including, without limitation, any approvals required under Section 70 of the Public Service Law and Section 203 of the FPA; or (ii) on such later date specified by FERC. Without waiving or limiting any of its other rights under this Article, if the NTO determines that any of the conditions set forth in Section 3.03 hereof is not being met or ceases to be in full force and effect the NTO may terminate this Agreement, withdraw from the ISO Agreement and the ISO Tariffs, and withdraw its assets from the ISO's control and administration on ninety (90) days prior written notice to the ISO and FERC, subject to the NTO obtaining all regulatory approvals for such termination and withdrawal, and having on file with FERC its own open access transmission tariff. Such notice shall identify the condition or conditions set forth in Section 3.03 that have not been met or no longer are in full force and effect; provided, however, that prior to the filing of such notice, the ISO shall be advised of the specific condition or conditions that are no longer in full force and effect, and the ISO shall have the opportunity to restore the effectiveness of the condition or conditions identified within a thirty (30) day period. If the effectiveness of the condition or conditions is not restored within thirty (30) days, the NTO may file a notice of termination with the ISO and FERC; provided, however, that if the ISO demonstrates that it has made a good faith effort but has been unable to restore the effectiveness of the condition or conditions within the thirty (30) day period, the ISO shall be provided an additional thirty (30) day period to restore the effectiveness of the condition or conditions and the NTO may not file the notice of termination until the expiration of the second thirty (30) day period. The NTO's termination of this Agreement under this Section shall be effective ninety (90) days after the filing of the notice of termination unless FERC finds that such termination of the NTO is contrary to the public interest, as that standard has been judicially construed under the Mobile-Sierra doctrine. However, the NTO may withdraw the notice or extend the termination date. Nothing in this section shall be construed as a voluntary undertaking by the NTO to remain a Party to this Agreement after the expiration of its notice of termination.

6.02 Termination by Election

The NTO may terminate this Agreement, withdraw from the ISO Agreement and the ISO Tariffs, and withdraw its assets from the ISO control and administration upon ninety (90) days written notice to the ISO Board and FERC, subject to the NTO obtaining all regulatory approvals for such termination and withdrawal, and having on file with FERC its own open access transmission tariff. Such termination and withdrawal shall be effective unless FERC finds that such termination and withdrawal is contrary to the public interest, as that standard has been judicially construed under the Mobile-Sierra doctrine. Any modification to this Article shall provide the NTO with the right to terminate this Agreement pursuant to the unmodified provisions of this Article, within ninety (90) days of the effective date of such modification, subject to the NTO obtaining all regulatory approvals for such termination, and having on file with FERC its own open access transmission tariff.

6.03 Obligations after Termination

a. Following termination of this Agreement, a Party shall remain liable for all obligations arising hereunder prior to the effective date of termination, including all obligations accrued prior to the effective date, imposed on the Party by this Agreement or the ISO Tariffs or other ISO Related Agreements.

b. Termination of this Agreement shall not relieve the NTO of any continuing obligation it may have under the ISO Tariffs and ISO Related Agreements, unless the NTO also withdraws from the ISO Tariffs or ISO Related Agreements.

c. Termination of this Agreement and withdrawal from the ISO Tariffs and ISO Related Agreements shall not relieve the NTO of its responsibility for the operation, maintenance, and modification of its transmission facilities in accordance with its own open access transmission tariff, all Reliability Rules and all other applicable reliability rules, standards and criteria, and all other requirements applicable to transmission facilities in the NYCA.

6.04 Winding Up

Any provision of this Agreement that expressly or by implication comes into or remains in force following the termination of this Agreement shall survive such termination. The surviving provisions shall include, but shall not be limited to: (i) those provisions necessary to permit the orderly conclusion, or continuation pursuant to another agreement, of transactions entered into prior to the termination of this Agreement, (ii) those provisions necessary to conduct final billing, collection, and accounting with respect to all matters arising hereunder, and (iii) the indemnification and limitation of liability provisions as applicable to periods prior to such termination. The ISO and the terminating NTO shall have an obligation to make a good faith effort to agree upon a mutually satisfactory termination plan. Such plan shall have among its objectives an orderly termination. The plan shall address, to the extent necessary, the allocation of any costs directly related to the termination by the NTO.

6.05 Confidentiality

A. Party Access. Each Party shall supply information to the other Party as required by this Agreement. Information shall be treated as Confidential Information under this Agreement if (i) it has been clearly marked or otherwise designated as “Confidential information” by the Party supplying the information, or (ii) it is information designated as Confidential Information by applicable provisions of the ISO Tariffs; *provided, however,* Confidential Information does not include information: (i) in the public domain or that has been previously publicly disclosed without violation of this Agreement, (ii) required by law to be publicly submitted or disclosed (with notice to the other Party), or (iii) necessary to be divulged in an action to enforce this Agreement.

Notwithstanding anything in this Section to the contrary, the NTO shall not have a right hereunder to receive or review any documents, data or other information of another Market Participant or the ISO, including documents, data or other information provided to the ISO, to the extent such documents, data or information have been designated as confidential pursuant to the procedures specified in the ISO Tariffs or to the extent that they have been designated as confidential by such other Market Participant; *provided, however,* that the NTO may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Market Participant’s confidential data or information.

B. Required Disclosure. The ISO shall treat any Confidential Information it receives from the NTO in accordance with applicable provisions of the ISO Tariffs. If the NTO receives Confidential Information from the ISO, it shall hold such information in confidence, employing at least the same standard of care to protect the Confidential Information obtained from the ISO as it employs to protect its own Confidential Information. Each Party shall not disclose the other Party’s Confidential Information to any third party or to the public without prior written authorization of the Party providing the information; *provided, however,* if the ISO is required by applicable law, or in the course of administrative or judicial proceedings, or subpoena, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section, the ISO will do so in accordance with applicable provisions of the ISO Tariffs. And if the NTO is required by applicable law, or in the course of administrative or judicial proceedings, or subpoena, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section, the NTO may make disclosure of such information; *provided, however*, that as soon as the NTO learns of the disclosure requirement and prior to making such disclosure, the NTO shall notify the ISO of the requirement and the terms thereof and the ISO may, at its sole discretion and cost, assert any challenge to or defense against the disclosure requirement and the NTO shall cooperate with the ISO to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. Each Party shall cooperate with the Other Party to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

6.06 Governing Law; Jurisdiction

The interpretation and performance of this Agreement shall be in accordance with and shall be controlled by the laws of the State of New York as though this Agreement is made and performed entirely in New York. With respect to any claim or controversy arising from this Agreement or performance hereunder within the subject matter jurisdiction of the Federal or State courts of the State of New York, the Parties consent to the exclusive jurisdiction and venue of said courts.

6.07 Headings

The section headings herein are for convenience and reference only and in no way define or limit the scope of this Agreement or in any way affect its provisions. Whenever the terms hereto, hereunder, herein or hereof are used in this Agreement, they shall be construed as referring to this entire Agreement, rather than to any individual section, subsection or sentence.

6.08 Mutual Agreement

Nothing in this Agreement is intended to limit the Parties' ability to mutually agree upon taking a course of action different than that provided for herein; provided that doing so will not adversely affect any other Parties' rights under this Agreement.

6.09 Contract Supremacy

In the case of a conflict between the express terms of this Agreement and the terms of the ISO Agreement, the express terms of this Agreement shall prevail.

6.10 Additional Remedies

The Parties agree that remedies at law will be inadequate to protect their respective interests and that irreparable damage would occur in the event that any of the provisions of this Agreement were not performed by the responsible Party in accordance with their specific terms or were otherwise breached. Accordingly, it is agreed that each Party shall be entitled to an injunction or injunctions to prevent breaches of this Agreement or an ISO Tariff by the other Party, and specific performance to enforce specifically the terms and provisions thereof in any court of the United States or any state having jurisdiction, this being in addition to any other remedy to which each Party is entitled at law or in equity.

6.11 No Third Party Rights

Nothing in this Agreement, express or implied, is intended to confer on any person, other than the Parties hereto, any rights or remedies under or by reason of this Agreement.

6.12 Not Partners

Nothing contained in this Agreement shall be construed to make the Parties partners or joint venturers or to render either Party liable for the debts or obligations of the other Party.

6.13 Waiver

Any waiver at any time of the rights of either Party as to any default or failure to require strict adherence to any of the terms herein, on the part of the other Party to this Agreement or as to any other matters arising hereunder shall not be deemed a waiver as to any default or other matter subsequently occurring.

6.14 Modification

This Agreement is subject to change under Section 205 of the Federal Power Act, as that section may be amended or superseded, upon the mutual written agreement of the Parties. Absent mutual agreement of the Parties, it is the intent of this Section 6.14 that, to the maximum extent permitted by law, the terms and conditions set forth in Sections 2.01, 2.13, 3.03, 3.08, 3.09, 4.01, 5.01, 5.02, 5.03, 5.04, 5.05, 5.06, 6.01, 6.02, 6.09 and 6.14 of this Agreement shall not be subject to change, regardless of whether such change is sought (a) by the Commission acting sua sponte on behalf of either Party or third party, (b) by a Party, (c) by a third party, or (d) in any other manner; subject only to an express finding by the Commission that such change is required under the public interest standard under the Mobile-Sierra doctrine. Any other provision of this Agreement may be changed pursuant to a filing with FERC under Section 206 of the Federal Power Act and a finding by the Commission that such change is just and reasonable.

6.15 Counterparts

This Agreement may be executed in counterparts, neither one of which needs to be executed by both Parties, and this Agreement shall be binding upon both Parties with the same force and effect as if both Parties had signed the same document, and each such signed counterpart shall constitute an original of this Agreement.

IN WITNESS WHEREOF, each of the Parties hereto has caused this Agreement to be executed in its corporate name by its proper officers as of the date first written above.

New York Independent System Operator, Inc.

By: ________________________

Title:_______________________

Date:_______________________

[Insert name of NTO]

By:________________________

Title:_______________________

Date:_______________________

APPENDIX A-1

LISTING OF NTO TRANSMISSION FACILITIES
UNDER ISO OPERATIONAL CONTROL

APPENDIX A-2

LISTING OF NTO TRANSMISSION FACILITIES REQUIRING ISO NOTIFICATION

APPENDIX A-3

LISTING OF NTO LOCAL AREA TRANSMISSION SYSTEM FACILITIES