

4.8 Operating Arrangements

4.8.1 Operation Under The Network Operating Agreement:

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

4.8.2 Network Operating Agreement:

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part 4 of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the NYS Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the ISO, Transmission Owners and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the NYS Transmission System, interchange schedules, unit outputs for redispatch required under Section 4.6, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted Loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part 4 of this Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 C.F.R. § 39.1 and the

Northeast Power Coordinating Council (NPCC), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the ISO, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO and the NPCC requirements. The ISO shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services to the extent that such arrangements comply with the provisions for Self-Supply of Ancillary Services as described in Schedules 3 and 5. For Network Customers that are also taking service under the ISO Services Tariff, the Service Agreement under that Tariff will function as the Network Operating Agreement. All other Network Customers will negotiate a Network Operating Agreement with the ISO. A list of requirements for such Network Operating Agreement is included in Attachment G.

4.8.3 Network Operating Committee:

The ISO Operating Committee will serve as the Network Operating Committee and will coordinate operating criteria for the parties' respective responsibilities under the Network Operating Agreement. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

6.10.9.3 Cost Allocation

The eligible project development costs incurred by NEET New York for its project submitted in response to AC Transmission Public Policy Transmission Needs identified by the New York State Public Service Commission on December 17, 2015, in Case No. 12-T-0502 shall be allocated to Responsible LSEs in accordance with Section 31.8.2 of Appendix E of Attachment Y to the ISO OATT.

The costs of the Empire State Line Project selected in the Public Policy Transmission Report issued and approved by the ISO's Board of Directors on October 17, 2017 (and identified therein as "Project T014") eligible for recovery pursuant to Rate Schedule 10 of the ISO OATT shall be allocated to Responsible LSEs in accordance with Section 31.8.4 of Appendix E of Attachment Y to the ISO OATT.

9 Attachment C - Methodology to Assess Available Transfer Capability

The ISO shall calculate Available Transfer Capability ("ATC") according to the procedures set forth in this Attachment C which adopts the "Rated System Path Methodology" established by the North American Electric Reliability Corporation's Reliability Standard MOD-029-1a, or its successors. Additional information and detail shall be set forth in the ISO's ATC Implementation Document ("ATCID").

9.1 Overview

The ISO shall calculate and post ATC values for its Internal and External Interfaces and for Scheduled Lines. The ISO's Interfaces represent a defined set of transmission facilities that separate Locational Based Marginal Pricing (LBMP) Load Zones within the New York Control Area and that separate the New York Control Area from adjacent Control Areas. External Interfaces may be represented by one or more Proxy Generator Buses for scheduling and dispatching purposes. Each Proxy Generator Bus may be associated with distinct, posted ATC values. Scheduled Lines represent a transmission facility or set of transmission facilities that provide a separate scheduling path interconnecting the ISO to an adjacent Control Area. Each Scheduled Line is associated with a distinct Proxy Generator bus for which the ISO separately posts ATC.

Hourly ATCs for the current day and for the next six days, and daily and monthly ATCs shall be calculated for all External Interfaces and for Scheduled Lines. Specifically, for External Interfaces and for all Scheduled Lines, the ISO shall calculate: (i) hourly ATC values for at least the next forty eight hours; (ii) daily values for at least the next thirty one calendar days; and (iii) monthly values for at least the next twelve months (*i.e.*, months 2-13). For External Interfaces and for all Scheduled Lines, the ISO shall recalculate ATC at a minimum on the following

frequency, unless none of the calculated values identified in its ATC equation have changed: (i) for hourly values, once per hour (subject to the exception in MOD-001-1a which allows transmission service providers up to 175 hours per year during which calculations are not required); (ii) for daily values, once per day; and (iii) for monthly values, once per week. Hourly ATCs shall be calculated for all Internal Interfaces for the current day and for the next day. To the extent necessary for compliance with MOD-001-1a, the ISO: (i) accounts for the impacts of its internal congestion on its external interfaces as accurately as possible; and (ii) calculates internal flows in order to fulfill its obligation to calculate external flows. External ATC calculations shall be performed with models that depict system conditions consistent with the expected internal flows.

The ISO's calculation of ATC shall reflect its provision of transmission service under an LBMP system pursuant to the schedules produced by its Day-Ahead Market software (the "Security Constrained Unit Commitment" ("SCUC")) and Real-Time Market software (the "Real Time Commitment" ("RTC")) in the form of "Transmission Flow Utilization" information which is incorporated into the ISO's ATC equation as specified in sections 9.2 and 9.4, below.

The ISO continuously redispatches all resources subject to its control in order to meet Load and to accommodate requests for Firm Transmission Service through the use of SCUC, RTC, and its Real-Time Dispatch software. If the posted ATC value for an Interface is zero that is an indication that the Interface is congested. The ISO may, however, still be able to provide additional Firm Transmission Service over such Interfaces through redispatching and other schedule adjustments directed by the SCUC and RTC algorithms that will be incorporated into the Transmission Flow Utilization component of its ATC equation.

SCUC creates the ISO's Day-Ahead Market schedules and prices by performing a series

of commitment and dispatch runs. The SCUC algorithm simultaneously minimizes the ISO's total Bid Production Cost of: (i) supplying power or demand reductions to satisfy accepted purchasers' Bids to buy Energy from the Day-Ahead Market; (ii) providing sufficient Ancillary Services to support Energy purchased from the Day-Ahead Market consistent with the Regulation Service Demand Curve and Operating Reserve Demand Curve; (iii) committing sufficient Capacity to meet the ISO's Load forecast and provide associated Ancillary Services; and (iv) meeting Bilateral Transaction schedules submitted Day-Ahead excluding schedules of Bilateral Transactions with Trading Hubs as their POWs. The power flow information produced by the SCUC algorithm is incorporated into the ISO's ATC calculations as Transmission Flow Utilization_{Firm} data pursuant to sections 9.2 and 9.4, below.

RTC is a multi-period security constrained unit commitment and dispatch model that cooptimizes 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. RTC makes binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of resources that can respond in ten minutes) and thirty minutes (in the case of resources that can respond in thirty minutes) after the scheduled posting time of each RTC run, provides advisory commitment information for the remainder of the two and a half hour optimization period, and will produce binding schedules for External Transactions to begin at the start of each quarter hour. RTC co-optimizes to solve simultaneously for all Load, Operating Reserves and Regulation Service requirements and to minimize the total as bid production costs over its optimization timeframe. RTC considers SCUC's resource commitment for the day, load forecasts that RTC itself will produce each quarter hour, binding transmission constraints, and all Real-Time Bids and Bid parameters. The schedules produced by RTC are incorporated into the

ISO's ATC calculation as Transmission Flow Utilization_{Firm} data pursuant to sections 9.2 and 9.4 below.

At the conclusion of the SCUC and RTC processes, the ISO's software performs the calculation for determining ATC values for the current day and the next day in accordance with section 9.2. Hourly or quarter-hourly ATC values are then posted to the ISO's OASIS. In addition, the ISO's long-term ATC calculator software runs twice a day and calculates daily and monthly ATC values, and hourly values further ahead than the next day, for the ISO's External Interfaces and all Scheduled Lines, which are in turn posted to the ISO's OASIS.

When calculating ATC the ISO shall use assumptions no more limiting than those used in the planning of operations, for the corresponding time period studied, provided that such planning of operations has been performed for that time period. When different inputs are used in ATC calculations because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall be not be considered to be a difference in assumptions.

9.2 Methodology for Computing Firm ATC

The ISO calculates hourly Firm ATC based on the market schedules determined using its SCUC process for the Day-Ahead Market and its RTC processes for the Real-Time Market for the next day and current day time periods. These ATC values shall be posted for all Interfaces and Scheduled Lines in compliance with applicable North American Energy Standards Board requirements. The ISO also calculates and posts Firm ATC for External Interfaces for the additional hourly, as well as the daily and monthly periods specified in section 9.1, above. The ISO does not calculate Non-Firm ATC because NonFirm PointToPoint Transmission Service is not available in the markets that the NYISO administers.

When calculating Firm ATC (“ ATC_F ”) for all Interfaces for each of the time periods specified in section 9.1 above, the ISO shall use the algorithm established under Requirement 7 of MOD-029-1a. Specifically:

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

Where

ATC_F is the firm Available Transfer Capability for the Interface for that period.

TTC is the Total Transfer Capability of the Interface for that period.

ETC_F is the sum of existing firm commitments for the Interface during that period (including Firm Transmission Flow Utilization).

CBM is the Capacity Benefit Margin for the Interface during that period.

TRM is the Transmission Reliability Margin for the Interface during that period.

Postbacks_F are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_F are the adjustments to ATC_F as determined by the ISO and specified in its ATCID.

When calculating Non-Firm ATC (“ ATC_{NF} ”) for all Interfaces for each of the time periods specified in section 9.1 above, the ISO shall use the algorithm established under Requirement 8 of MOD-029-1a. Specifically:

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where

ATC_{NF} is the non-firm Available Transfer Capability for the Interface for that period.

TTC is the Total Transfer Capability of the Interface for that period.

ETC_F is the sum of existing firm commitments for the Interface during that period (including Firm Transmission Flow Utilization).

ETC_{NF} is the sum of existing non-firm commitments for the Interface during that period.

CBM_S is the Capacity Benefit Margin for the Interface that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the Interface that has not been released for sale (unreleased) as non-firm capacity by the ISO during that period.

Postbacks_{NF} are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices

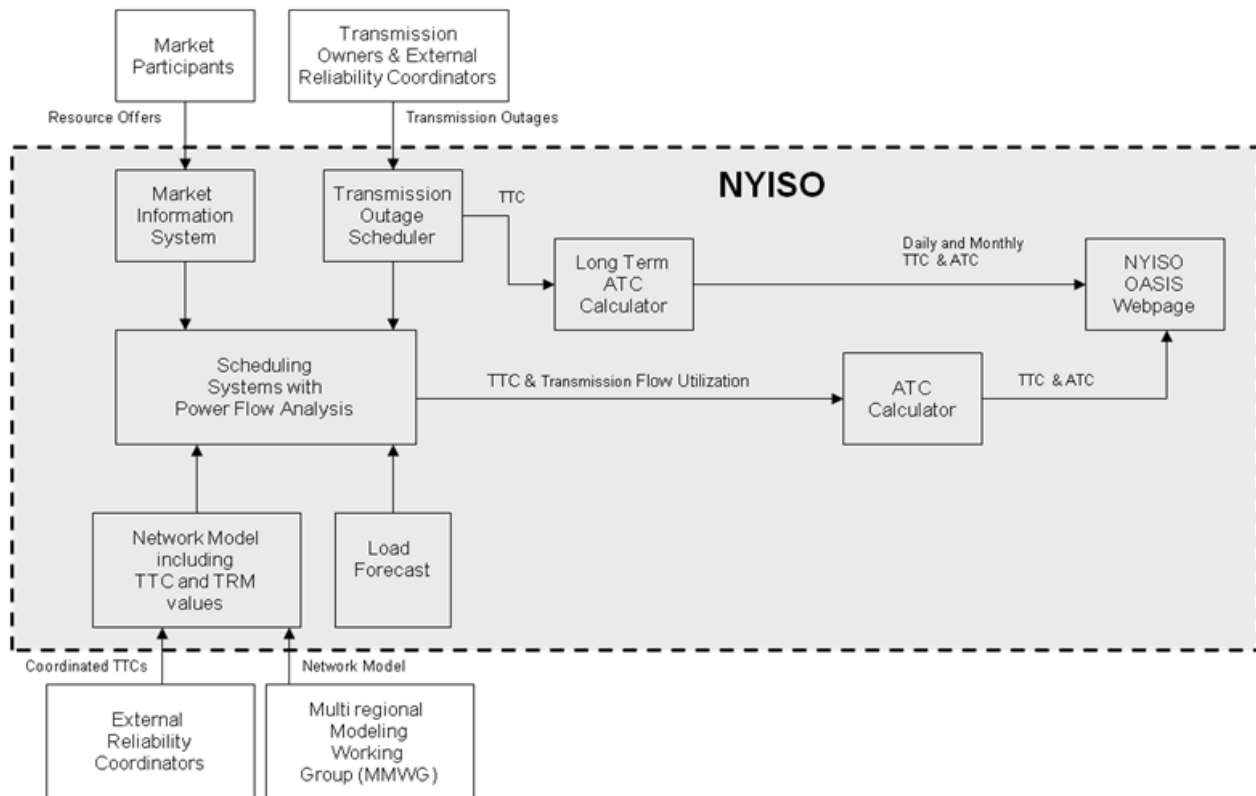
counterflows_{NF} are the adjustments to ATC_{NF} as determined by the ISO and specified in its ATCID.

The ISO's ATC calculation algorithms are posted at the "ATC Detailed Algorithms" link at:http://www.nyiso.com/public/webdocs/market_data/power_grid_info/ATCDetailedAlgorithm.pdf

9.3 Process Flow Diagram

The following diagram illustrates the process that the ISO follows when computing and posting ATC.

NYISO ATC Calculation Flow Diagram



9.4 Existing Transmission Commitments (“ETC”)

The ISO shall calculate ETC for firm Existing Transmission Commitments (ETCF) for a specified period for an Interface, using the formula established under Requirement 5 of MOD-029-1a. Specifically:

$$ETCF = NLF + NITSF + GFF + PTPF + RORF + OSF$$

Where:

NLF is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITSF is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GFF is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTPF is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

RORF is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OSF is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

The ISO shall calculate ETC for non-firm Existing Transmission Commitments (ETCNF) for a specified period for an Interface, using the formula established under Requirement 6 of MOD-029-1a. Specifically:

$$\text{ETCNF} = \text{NITSNF} + \text{GFNF} + \text{PTPNF} + \text{OSNF}$$

Where:

NITSNF is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GFNF is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTPNF is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OSNF is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

OS_F and OS_{NF} shall include a Transmission Flow Utilization value which shall be based on the market schedules determined using the SCUC and RTC market software for the current and next day time periods. The Day-Ahead Market and Real-Time Market schedules established by the market software are security constrained network powerflow solutions that are used to determine the Transmission Flow Utilization value for the ISO's Interfaces and Scheduled Lines.

Thus:

Transmission Flow Utilization_{Firm} for each Internal and External Interface is determined by the corresponding security constrained network powerflow solutions of SCUC or RTC, as applicable.

Transmission Flow Utilization_{Non-Firm} for each Internal and External Interface is the sum of Non-Firm Transactions scheduled.

Transmission Flow Utilization_{Firm} for Scheduled Lines is determined by the corresponding security constrained network powerflow solutions of SCUC or RTC, as applicable.

Transmission Flow Utilization_{Non-Firm} for Scheduled Lines is the sum of Non-Firm Transactions scheduled.

The Transmission Flow Utilization value for OS_F and OS_{NF} for time periods beyond the next day shall be zero because the ISO's Commission-approved market design does not permit transactions to be scheduled for such time periods.

9.5 Total Transfer Capability ("TTC")

The ISO shall develop TTC values for each Interface and Scheduled Line in conformance with all applicable requirements of MOD-001-1a and MOD-029-1a, or their successors.

External Interfaces may be represented by one or more Proxy Generator Buses for scheduling and dispatching purposes. Each Proxy Generator Bus associated with an External Interface may be associated with distinct, posted TTC values. Each Scheduled Line is associated with a distinct Proxy Bus for which the ISO separately posts a TTC value.

The TTC value for each Interface and Scheduled Line shall be the maximum amount of electric power that can be reliably transferred over the New York State Transmission System.

The ISO shall use studies that it performs, joint studies conducted with neighboring Control Areas, and real-time system monitoring to determine the appropriate TTC values. The TTC values are periodically reviewed and may be updated as warranted to ensure that accurate values are posted. When calculating TTC the ISO shall use assumptions no more limiting than those used in the planning of operations, for the corresponding time period studied, provided that such planning of operations has been performed for that time period. When different inputs are used in TTC calculations because the calculations are performed at different times, such that the most recent information is used in any calculation, a difference in that input data shall be not be considered to be a difference in assumptions.

Databases used in the determination of the TTC values include Eastern Interconnection Reliability Assessment system representations, and the ISO's Day-Ahead Market and Real-Time Market system representations.

The normal maximum Interface and Scheduled Line TTC values correspond to TTC assessments that assume: (1) all significant Bulk Power System transmission facilities are in service, (2) Capability Period forecast peak-load conditions, (3) no significant generation outages with generation output levels consistent with typical operation for Capability Period forecast peak-load conditions, and (4) coordination with neighboring Control Area transfer capability assessments.

Interface or Scheduled Line TTC values may be modified in response to identified transmission facility or generation outage conditions. TTC values may also be modified to account for neighboring Control Area transfer capability assessments for identified transmission facility or generation outage conditions, assuming the ISO receives timely notification of such conditions, or to account for operating conditions affecting the New York State Transmission

System.

9.6 Transmission Reliability Margin (“TRM”)

TRM is the amount of transmission transfer capability necessary to ensure that the interconnected transmission network remains secure under a reasonable range of system conditions. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

The ISO shall maintain a TRM Implementation Document (“TRMID”) in compliance with the requirements of MOD-008-1, or its successors..

Databases used in the determination of the TRM values include the MultiRegional Modeling Working Group system representations and the ISO’s Day-Ahead Market and Real-Time Market system representations.

TRM equal to the sum of the following components shall be applied to calculations conducted up to eighteen months before the Dispatch Day to address unexpected system conditions including: (1) uncertainty in unscheduled loop or parallel flows ranging in value from zero (0) MW to five hundred (500) MW based on the greater of the average of the last three months of historical parallel flows observed for each External Interface or the average of the deviation in parallel flows observed over the last three months for each External Interface, (2) load forecast uncertainty (normally this value is set to zero (0) MW), (3) uncertainty in external system conditions (normally this value is set to zero (0) MW), and (4) External Interface transmission facility availability ranging in value from zero (0) MW to one thousand (1000) MW reflecting the uncertainty of transfer capability resulting from the most significant single transmission facility outage for each External Interface.

The TRM used for purposes of ATC calculations conducted for External Interfaces for

the Day-Ahead Market and the Real-Time Market shall be used to address unexpected system conditions equal to the sum of the following components: (1) uncertainty in unscheduled loop or parallel flows ranging in value from zero (0) to five hundred (500) MW based on the greater of the average of the last three months of historical parallel flows observed for each External Interface or the average of the deviation in parallel flows observed over the last three months for each External Interface, (2) load forecast uncertainty, normally of value zero (0) MW, and (3) uncertainty in external system conditions, normally of value zero (0) MW.

The TRM used for purposes of the ATC calculations conducted for Internal Interfaces for the Day-Ahead Market and the Real-Time Market shall normally be equal to the sum of the following components or a value of one hundred (100) MW, although the ISO may increase it above that level if necessary. TRM is applied to these ATC calculations to address unexpected system conditions including: (1) unscheduled loop or parallel flows normally of value zero (0) MW, (2) load forecast uncertainty normally of value zero (0) MW, (3) uncertainty in external and internal system conditions normally of value one hundred (100) MW, and (4) ISO Balancing Authority requirements normally of value zero (0) MW.

The TRM used for purposes of the ATC calculations conducted for Scheduled Lines for the Day-Ahead Market and the Real-Time Market shall normally be equal to the sum of the following components, which will ordinarily be expected to have a combined value of zero (0) MW, although the ISO may increase it above that level if necessary: (1) unscheduled loop or parallel flows ranging based on the average of the last three months of historical parallel flows observed for each associated External Proxy Generator Bus, normally of value zero (0) MW, (2) load forecast uncertainty, normally of value zero (0) MW, and (3) uncertainty in external system conditions, normally of value zero (0) MW.

TRM is used to decrement TTC from External and Internal Interfaces and from Scheduled Lines when calculating ATC. The ISO may, however, still be able to provide additional Firm Transmission Service over Internal Interfaces for Transmission Customers that are willing to pay congestion charges by redispatching the New York State Power System.

The specific values of TRM used on each Internal and External Interface and Scheduled Line are posted on the ISO's website. The TRM values are periodically reviewed by the ISO and may be updated as warranted. In compliance with Requirement 4 of MOD-008-1, or its successors, the ISO shall establish TRM values at least every thirteen months in accordance with its TRMID.

9.7 Capacity Benefit Margin

The ISO shall not set aside transmission capacity as CBM but shall maintain a CBM Implementation Document ("CBMID") in compliance with the requirements of MOD-004-1, or its successors, which shall include all of the information required by that Reliability Standard. In compliance with Requirements 5 and 6 of MOD-004-1, or its successors, the ISO shall establish CBM values at least every thirteen months in accordance with its CBMID.

9.8 Coordinated ATC Calculations

The ISO's seasonal operating studies are an input into its TTC calculations for External Interfaces that represent Control Area boundaries. The ISO coordinates those seasonal operating studies, and exchanges data necessary to support that coordination, with neighboring Control Areas.

The ISO also coordinates transmission outages and the TTCs associated with these system conditions, and exchanges related data, with neighboring Control Areas. The ISO's and neighboring Control Areas' practice is to provide relevant information to each other in sufficient

time for it to be incorporated into their own scheduling and ATC calculation processes. If a neighboring Control Area determines a more limiting TTC corresponding to a transmission outage, the ISO will use the other Control Area's TTC in its scheduling system (SCUC and RTC). These values are correspondingly used in the calculation of ATC consistent with the algorithms set forth in section 9.2 above.

10 Attachment D - Methodology for Completing a System Impact Study, Transmission Service Study, or Network Integration Transmission Service Study

An Eligible Customer may request a System Impact Study, Transmission Service Study, or Network Integration Transmission Service Study.

The purpose of the impact study will be to determine the effect the requested facilities will have on system operations, system Constraints, and whether system expansion will create the requested incremental Transfer Capability and associated TCCs.

The Commission's comparability standard will be applied in evaluating the impact of all requests. Specifically, the ISO will use the same due diligence in completing System Impact Studies, , Transmission Service Studies, and Network Integration Transmission Service Studies for any Eligible Customers that it uses when completing such studies for any Transmission Owner.

System Impact Studies will be evaluated, to the extent possible, as a part of the on-going planning process for expansions of the NYS Power System. Appropriate planning studies will be conducted periodically to assess the capability of the NYS Transmission System to deliver the planned Network Resources to the forecasted Network Loads of the existing LSEs and any prior committed Firm Transmission Service customers. The Loads and resources of Eligible Customers requesting new or additional service during the normal planning cycle will be incorporated into this aggregate planning process along with the Loads and resources of all other Firm Point-to-Point Transmission Customers and LSEs.

The ISO plans and evaluates the NYS Transmission System in strict compliance with the following:

- (1) NERC principles and guides;
- (2) Principles and standards for planning the bulk electric systems of the NPCC; and

- Transmission planning criteria, methods and procedures described in the FERC Form No. 715-Annual Transmission Planning and Evaluation Report for the NPCC Region; and
- (3) NYSRC Reliability Rules including Local Reliability Rules.

14.1 Transmission Service Charge (“TSC”)

14.1.1 Applicability of the Transmission Service Charge to Wholesale Customers

Each month, each wholesale Transmission Customer shall pay to the appropriate Transmission Owner the applicable Wholesale Transmission Service Charge (“Wholesale TSC”) calculated in accordance with Section 14.1.2.1 of this Attachment. The TSC shall apply to Transmission Service:

- 14.1.1.1 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”); provided, however, that the TSC shall not apply to Wheels Through 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;
- 14.1.1.2 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 Point (“Exports”); provided, however, that the TSC shall not apply to 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; or
- 14.1.1.3 to serve Load within the NYCA; except, the Wholesale TSC shall not apply to:
 - 14.1.1.3.1 a Transmission Owner’s use of its own system to provide bundled retail service to its Native Load Customers pursuant to a retail service tariff on file with

the PSC or, in the case of LIPA, has been approved by the Long Island Power Authority's Board of Trustees;

14.1.1.3.2 Transmission Service pursuant to an Existing Transmission Agreement whereby the otherwise applicable TSC does not apply pursuant to Attachment K; or

14.1.1.3.3 retail Transmission Service pursuant to any tariff or rate schedule of a Transmission Owner that explicitly provides for other transmission charges in lieu of the Wholesale TSC, subject to any applicable provisions of the Federal Power Act.

Each Transmission Owner subject to FERC and/or PSC jurisdiction may file with FERC a separate TSC applicable to retail access in accordance with its retail access program filed with the PSC. To the extent that LIPA's rates for service are established by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Section 1020-f(u) and 1020-s and are not subject to FERC jurisdiction, this requirement will not apply to LIPA.

14.1.2 Wholesale TSC Calculation

Sections 14.1.2-14.1.6 do not apply to the development of the NYPA TSC, which is described in Section 14.1.7.

14.1.2.1 Wholesale TSC Formula

Each Transmission Owner, except NYPA, shall calculate its TSC applicable to Transmission Service to serve Load within or exiting the NYCA at its Transmission District as follows:

$$\text{WHOLESALE TSC} = \{(\text{RR}\div 12) + (\text{CCC}\div 12) - \text{SR} - \text{ECR} - \text{CRR} - \text{WR} - \text{Reserved}\}/(\text{BU}\div 12).$$

Where:

- RR = The Annual Transmission Revenue Requirement, as stated in Table 1 of this Attachment. Gross Receipts Tax (“GRT”) treatment by each individual company is described in Section 14.1.7. Revenues from grandfathered agreements listed on Attachment H-1 are treated as a revenue credit in the RR;
- CCC = The annual Scheduling, System Control and Dispatch Costs of the individual Transmission Owner (*i.e.*, the transmission component of control center costs) as stated on Table 1 of this Attachment;
- SR = The Transmission Owner’s revenues associated with the sale of certain TCCs, as described in Section 14.1.2.1.1 of this Attachment;
- ECR = The Transmission Owner's share of Net Congestion Rents in a month, calculated pursuant to Attachment N of the OATT;
- CRR = The Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from ETA's, the expenses for which are included in the Transmission Owner's Revenue Requirement;
- WR = The Transmission Owner's revenues from external sales (Wheels Through and Export Transactions) not associated with Existing Transmission Agreements included in Attachment L, Tables 18.1, 18.2 and 18.3 and wheeling revenue, associated with OATT reservations extending beyond the start-up of the ISO. (*i.e.*, grandfathered OATT agreements), as described in Section 14.1.2.1.2 of this Attachment;

Reserved = The Transmission Owner's Congestion payments associated with, and value from the sale of ETCNL TCCs and RCRR TCCs, as described in Section 14.1.2.1.3 of this Attachment; and

BU = The Transmission Owner's Billing Units (annual MWh) for the Transmission District (see Table 1 of this Attachment). The Transmission Owner's BU has been adjusted upward to include subtransmission and distribution losses.

14.1.2.1.1 Elements of SR Component

$SR = SR_1 + SR_2 + SR_3 + SR_4.$

SR_1 will equal the revenues from the Direct Sale by the Transmission Owner of Original Residual TCCs, TCCs derived from Existing Transmission Capacity for Native Load, and Grandfathered TCCs associated with ETAs, the expenses for which are included in the Transmission Owner's Revenue Requirements where the Transmission Owner is the Primary Holder of said TCCs. SR_1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that the Transmission Owner will receive under each applicable TCC sold in a Direct Sale divided by the duration of that TCC (in months).

SR_2 will equal the Transmission Owner's revenues from the Centralized TCC Auctions and Reconfiguration Auctions allocated pursuant to Attachments N. SR_2 includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auctions and Reconfiguration Auctions; (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for those ETAs are included in the Transmission Owner's Revenue Requirements; and (c) TCCs derived from Existing Transmission Capacity for Native Load that are sold in the Centralized TCC Auction.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Owners sell through the Centralized TCC Auctions and the allocation of revenue for other TCCs sold through the Centralized TCC Auctions and Reconfiguration Auctions (per the Facility Flow-Based Methodology described in Attachment N).

SR₃ shall equal the Transmission Owner's share of revenues from the award and renewal of Historic Fixed Price TCCs (including extensions of Historic Fixed Price TCCs awarded pursuant to Section 19.2.1.4 of Attachment M of the OATT), as determined pursuant to Section 20.4 of Attachment N. The share of revenues allocated to a Transmission Owner pursuant to Section 20.4 of Attachment N shall be adjusted after each Centralized TCC Auction and divided equally across the months for which the Historic Fixed Price TCCs (including extensions of Historic Fixed Price TCCs awarded pursuant to Section 19.2.1.4 of Attachment M of the OATT) that were awarded or renewed prior to the relevant Centralized TCC Auction are valid.

Notwithstanding anything to the contrary herein, with respect to the Transmission Owner's share of any revenues for Historic Fixed Price TCCs that took effect on or before November 1, 2016, such revenues (or any portion thereof) shall be accounted for in SR₃ by dividing such revenues (or any portion thereof) equally across the six months of the first Capability Period following the effective date of this provision provided that the NYISO has informed the Transmission Owner of its respective share of such revenues (or any portion thereof) at least two weeks prior to the start of such Capability Period, otherwise such revenues (or any remaining portion thereof) shall be accounted for in SR₃ by dividing such revenues (or any remaining portion thereof) equally across the six months of the Capability Period that follows the first Capability Period following the effective date of this provision.

SR₄ shall equal the Transmission Owner's share of revenues from the initial award and renewal of Non-Historic Fixed Price TCCs, as determined pursuant to Section 20.5 of Attachment N. The share of revenues allocated to a Transmission Owner pursuant to Section 20.5 of Attachment N shall be adjusted after each Centralized TCC Auction and divided equally across the months for which the Non-Historic Fixed Price TCCs that were initially awarded or renewed as part of the relevant Centralized TCC Auction are valid. Notwithstanding anything to the contrary herein, with respect to the Transmission Owner's share of any revenues for Non-Historic Fixed Price TCCs that took effect on or before May 1, 2017, such revenues (or any portion thereof) shall be accounted for in SR₄ by dividing such revenues (or any portion thereof) equally across the six months of the first Capability Period that commences following the effective date of this provision provided that the NYISO has informed the Transmission Owner of its respective share of such revenues (or any portion thereof) at least two weeks prior to the start of such Capability Period, otherwise such revenues (or any remaining portion thereof) shall be accounted for in SR₄ by dividing such revenues (or any remaining portion thereof) equally across the six months of the Capability Period that follows the first Capability Period that commences following the effective date of this provision.

14.1.2.1.2 Elements of the WR Component

The WR component will equal the sum of: (1) TSC revenues received from new external transactions (Wheels Through and Export Transactions); (2) transmission revenues received under grandfathered OATT agreements and actual revenues under Schedule 1 to the grandfathered OATT agreements, but not under Schedules 2 through 6 to the grandfathered OATT agreements; and (3) any revenues related to pre-OATT grandfathered arrangements if the transmission owner increased its OATT revenue requirement to derive its RR component to

reflect the fact that revenues related to such transactions are at risk due to options available to the customers resulting from the current restructuring, and the customer retains its grandfathered arrangement.

In each subcomponent of the WR component above, the revenues will include the Gross Receipts Tax (“GRT”) when the Transmission Owner has included the GRT in the RR.

14.1.2.1.2.1 Treatment of Schedule 1 Associated with Grandfathered OATT Service

All customers under grandfathered OATT service agreements must continue to pay the Schedule 1 charge applicable under the individual OATT, absent a settlement to the contrary. The revenues received from Schedule 1 charges paid by grandfathered OATT customers will be treated as revenue credit in the WR component as part of the wheeling revenue associated with OATT reservations extending beyond the start-up of the ISO.

14.1.2.1.3 Elements of the Reserved Component

$$\text{Reserved} = \text{Reserved}_1 + \text{Reserved}_2 + \text{Reserved}_3 + \text{Reserved}_4$$

Reserved_1 will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner's ETCNL TCCs.

Reserved_2 will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner's RCRR TCCs.

Reserved_3 will equal the value that a Transmission Owner receives for the sale of its ETCNL TCCs in a month, with the value for each ETCNL TCC sold divided equally over the month(s) for which that sold ETCNL TCC is valid.

Reserved₄ will equal the value that a Transmission Owner receives for the sale of its RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the month(s) for which that sold RCRR TCC is valid.

The RR, SR and CRR will not include expenses for the Transmission Owner's purchase of TCCs or revenues from the sale of said TCCs or from the collection of Congestion Rents for said TCCs. The ECR, CRR, WR, and Reserved 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 (e.g., January actual data will be used in February to calculate the TSC effective in March). The TSC shall not apply to the scheduled quantities physically Curtailed by the ISO.

Each Member System is responsible for calculating: (1) the RR component of its TSC charge; (2) the CCC component of its TSC charge; (3) the SR₁ portion of the SR component of its TSC charge; and (4) the BU component of its TSC charge.

The NYISO is responsible for calculating or providing the information necessary to calculate: (1) the SR₂, SR₃ and SR₄ portions of the SR component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation; (2) the ECR component of each Member System's TSC charge based on information derived from ISO operation; (3) the CRR component of each Member System's TSC charge based on information derived from ISO operation; (4) the Reserved component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation; and (5) the WR component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation. Any calculations that the ISO is responsible for are subject to review and comment by all affected parties.

The RR term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when a Transmission Owner determines that a change to its RR is required under Section 205.

The CCC term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to the CCC is required.

SR: The revenue from the Direct Sale of TCCs will be determined monthly and will enter the TSC formula through the SR term with a two-month lag (e.g., January actual data will be used in February to calculate the SR term used in the TSC for March). The revenue that a Transmission Owner receives from a TCC sold in a Centralized Auction or Reconfiguration Auction will be divided equally among the month(s) for which the sold TCC is valid. The revenue from these TCCs will enter the TSC formula month-by-month through the SR term with a two-month lag (e.g., January actual data will be used in February to calculate the SR term used in the TSC for March). For Balance of Period Auctions, the ISO shall also provide each Transmission Owner information regarding their respective share of Net Auction Revenues for each month covered by each Balance-of-Period Auction. The ISO is responsible for providing the information necessary to calculate the SR₂, SR₃ and SR₄ portions of the SR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the information provided by the ISO.

The ECR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (e.g., January actual data will be used in February to calculate the ECR term used in the TSC for March). The ISO is responsible for calculating the ECR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation.

The CRR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (e.g., January actual data will be used in February to calculate the CRR term used in the TSC for March). Each Transmission Owner will identify for the ISO each ETA (“Identified ETA”), under which the Transmission Owner is a customer, the expenses for which are included in the Transmission Owner’s RR. The ISO shall calculate that Transmission Owner’s Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from the Transmission Owner’s Identified ETAs. If the inclusion of the costs under an Identified ETA in the Transmission Owner’s RR is subject to refund, then the CRR shall be subject to adjustment. If the costs under one or more of the Identified ETAs are removed from the RR and the Transmission Owner is required to recalculate its TSC with the adjusted RR, then in recalculating the TSC, the Transmission Owner shall reverse the portion of the CRR that was attributed to each such ETA. The Transmission Owner shall rebill the customers based on the recalculated TSC. To the extent the Transmission Owner owes a refund to the customer, it shall comply with any applicable refund obligations, including payment of interest to the extent due pursuant to 18 C.F.R. § 35.19a(a)(2)(iii), or its successor. If the reversal of the CRR results in a higher TSC than was charged, the customer shall pay in the time prescribed for payment of TSCs the Transmission Owner the difference between the TSC payments it made and the rebilled amounts, with interest thereon from the dates payments were made to the date that the rebilled amounts are due. Said interest will be calculated in the same manner as interest on over-payments as specified in 18 C.F.R. § 35.19a(a)(2)(iii), or its successor.

The Reserved will be calculated monthly and will enter the TSC formula with a two-month lag (e.g., January actual data will be used in February to calculate the ETCNL TCC term

used in the TSC for March). The ISO is responsible for providing the information necessary to calculate the Reserved Component of each Transmission Owner's TSC.

WR: The revenue that a Transmission Owner collects for new external sales will be calculated monthly and will enter the WR term in the TSC formula with a two-month lag (*i.e.*, January actual data will be used in February to calculate the WR term used in the TSC for March). The ISO is responsible for calculating new external sales subcomponent of the WR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation. The actual revenue that a Transmission Owner collects for grandfathered OATT service that extends beyond ISO start-up, and revenues related to pre-OATT grandfathered arrangements as provided for under numbers (2) and (3) of Original Sheet No. 214A, will also be calculated monthly and will enter the WR term in the TSC formula based upon the prior month's information. For the first month the credit will be equal to the actual revenues received under those grandfathered agreements to be included in the WR component.

The BU term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to its BU is required.

14.1.3 Filing and Posting of Wholesale TSCs

The Transmission Owners shall coordinate with the ISO to update certain components of the Wholesale TSC formula on a monthly basis or Capability Period basis. Each Transmission Owner may update its Wholesale TSC calculation to change its RR, CCC, or BU component value(s). Such updates, however, shall be subject to necessary FERC filings under the FPA. Each Transmission Owner will calculate its monthly Wholesale TSC and provide the ISO with the Wholesale TSC by no later than the fourteenth of each month, for posting on the OASIS to

become effective on the first of the next calendar month. The monthly Wholesale TSCs for each of the Transmission Districts shall be posted on the OASIS by the ISO no later than the fifteenth 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 of the next calendar month.

14.1.4 TSC Calculation Information

The Annual Transmission Revenue Requirements (“RR”); Scheduling, System Control and Dispatch Costs (“CCC”), Billing Units (“BU”) and Rates of the Transmission Owners, except NYPA, for the purpose of calculating the respective Transmission District-based Wholesale TSC are shown in Table 1 below.

**Table 1
Wholesale TSC Calculation Information**

Transmission Owner	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate \$/MWh ¹
Central Hudson Gas & Electric Corp.	\$15,326,852	\$1,309,980	4,723,659	\$3.5220
Consolidated Edison Co. of NY, Inc.	\$385,900,000	\$21,000,000	49,984,628	\$8.1405
LIPA ²	\$203,109,469	\$4,207,517	19,512,309	\$10.6249
New York State Electric & Gas Corporation ³	\$90,149,075	\$1,633,000	14,817,111	\$6.1943
Niagara Mohawk Power Corporation	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9
Orange and Rockland Utilities, Inc.	\$21,034,831	\$942,579	3,595,947	\$6.1117
Rochester Gas and Electric Corporation	\$24,242,747	\$583,577	6,967,556	\$3.5631
Rochester Gas and Electric Corporation	\$24,242,747	\$583,577	6,967,556	\$3.5631

¹The rate column represents the unit rate prior to crediting; the actual rate will be determined pursuant to the applicable TSC formula rate.

²LIPA and the Villages of Freeport, Greenport, and Rockville Centre (“Long Island Municipals”) agreed that the total discounted monthly Wholesale TSC rates to be billed to the Long Island Municipals during the period from November 1, 2021 through December 31, 2024 are as follows: (1) November 1, 2021 – December 31, 2022: \$6.00/MWh; (2) January 1, 2023 – December 31, 2023: \$7.00/MWh; and (3) January 1, 2024 – December 31, 2024: \$8.00/MWh. Starting January 1, 2025, LIPA’s then effective non-discounted Wholesale TSC rate, as described in Table 1 (including footnote 1 above), shall apply.

³NYSEG’s RR, BU and unit Rate prior to adjustment pursuant to Attachment H, are subject to retroactive modification pursuant to the provisions of the Settlement Agreement approved by the Commission in its March 26, 2004 order issued in Docket No. EL04-56-000. For any Transmission Customer that “opts out” of the Settlement Agreement as described in paragraph 1.E thereof, the applicable NYSEG “RR” shall be \$100,541,739; the “BU” shall be 13,741,901 MWh; and, the “Rate” prior to adjustment pursuant to Attachment H, shall be \$7.4235 effective as of March 1, 2004.

14.1.5 Treatment of Gross Receipts Tax

14.1.5.1 Central Hudson Gas & Electric Corporation

Central Hudson’s TSC shall be increased by dividing the following surcharge factors into the total of all applicable rates and charges to reflect the New York State GRT (0.94922 in the MTA regions and 0.95750 in the non-MTA regions), which is not specifically provided for in the transmission rate, to the extent such tax is imposed on Central Hudson as a result of the transmission service provided to such Customer. Central Hudson shall make an appropriate filing pursuant to Section 205 of the Federal Power Act to implement any change in the specified tax rate prior to altering the tax rate under this provision.

14.1.5.2 Consolidated Edison Company of New York, Inc.

The GRT is included in Con Edison’s TSC rate. Con Edison will not charge separately for GRT.

14.1.5.3 LIPA

The GRT is included in LIPA’s TSC rate. LIPA will not charge separately for GRT.

14.1.5.4 New York State Electric & Gas Corporation

The Transmission Customer shall pay an amount sufficient to reimburse NYSEG for any amounts payable by NYSEG as sales, excise, value-added, gross receipts or other applicable taxes with respect to the total amount payable to NYSEG pursuant to the Tariff. The total of all rates and charges will be divided by the appropriate tax factor listed below, depending upon the geographic location of the Transmission Customer's Point(s) of Delivery

Within the Metropolitan Commuter Transportation District: 0.984583

Not within the Metropolitan Commuter Transportation District: 0.986823

These tax factors incorporate the taxes imposed on the Transmission Provider's electric revenues pursuant to New York law and represents the Franchise Tax on Gross Earnings, the Gross Income Tax, and where applicable the Metropolitan Commuter Transportation District Surcharge.

This Provision shall be effective upon commencement of services under the ISO OATT.

14.1.5.5 Niagara Mohawk Power Corporation

For the settled Niagara Mohawk TSC rate, the GRT is included in the RR and there will be no separate GRT tax assessed; For the filed Niagara Mohawk TSC rate, GRT initially is included in the RR and there will be no separate GRT assessed; however, this issue with regard to GRT is subject to final Commission action in Docket No. OA96-194-000, including all stipulations executed in connection therewith.

14.1.5.6 Orange and Rockland Utilities, Inc.

The Transmission Customer's rate will be increased to reflect the gross receipts tax ("GRT") which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on Orange and Rockland as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and

186-a of the New York Tax Law. The current effective GRT rate for the Section 186-a tax is 3.25% from October 1, 1998 through October 31, 1999 and 2.5% on and after January 1, 2000.

The maximum locality rate allowable under state law for each locality is specified below.

However, if the actual locality rate is less than the maximum locality rate permitted under state law, O&R shall charge the actual tax rate levied by the locality. The currently effective GRT rate for the Section 186 tax is .75%.

Airmont	1.0%
Bloomington	1.0%
Chestnut Ridge	1.0%
Goshen	1.0%
Grandview on Hudson	1.0%
Greenwood Lake	1.0%
Harriman	1.0%
Haverstraw	1.0%
Highland Falls	1.0%
Hillburn	1.0%
Kaser	1.0%
Kiryas Joel	1.0%
Middletown	1.0%
Monroe	1.0%
Montebello	1.0%
New Hempstead	1.0%
New Square	1.0%
Nyack	1.0%
Otisville	1.0%
Piermont	1.0%
Pomona	1.0%
Port Jervis	1.0%
Sloatsburg	1.0%
South Nyack	1.0%
Spring Valley	1.0%
Suffern	1.0%
Unionville	1.0%
Upper Nyack	1.0%
Warwick	1.0%
Washingtonville	1.0%
Wesley Hills	1.0%
West Haverstraw	1.0%
Wurtsboro	1.0%

14.1.5.7 Rochester Gas & Electric Corporation

The Transmission Customer's rate will be increased to reflect the gross receipts tax which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on RG&E as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and 186-a of the New York Tax Law. The currently effective GRT rate for the Section 186-a tax is 3.5% and each locality rate is specified below. The currently effective GRT rate for the Section 186 tax is .75%.

City of Rochester	3.0%
Leroy	1.0%
Manchester	1.0%
Perry	1.0%
Shortsville	1.0%
Warsaw	1.0%
Hilton	1.0%
Pittsford	1.0%
Caledonia	1.0%
Wolcott	1.0%
Avon	1.0%
Leicester	1.0%
Nunda	1.0%
Genesco	1.0%
Mt. Morris	1.0%
Sodus Point	1.0%
Livonia	1.0%
Meridian	1.0%
City of Canandaigua	1.0%
Fairport	1.0%
Brockport	1.0%
Scottsville	1.0%
East Rochester	1.0%

14.1.6 TSC For Retail Access Customers ("RTSC")

Customers who apply for unbundled Transmission Service in accordance with the provisions of a Transmission Owner's retail access program filed with the PSC or, in the case of LIPA, approved by the Long Island Power Authority's Board of Trustees, will be responsible for paying a retail transmission service charge as detailed in Section 5 of this Tariff.

14.1.7 NYPA Transmission Service Charge

The NYPA TSC for service to its directly connected Loads (Reynolds Metals, GM-Massena, Town of Massena and the City of Plattsburgh) shall, at the Eligible Customer's option, be (a) \$1.30 per kilowatt-month or (b) no more than \$3.75 per MWh; not to exceed \$60.00 per MW Day applied to peak MWh scheduled any hour each day; not to exceed \$300.00 per MW-Week applied to the peak MWh scheduled any hour each week. The TSC applicable to service over the Vermont intertie and the Ontario-Hydro intertie shall be the same as (b); provided, however, that the NYPA TSC shall not apply to service over the Vermont intertie provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied. The TSC applicable to service over the Hydro-Quebec intertie shall be no more than \$4.62 per MWh; not to exceed \$73.85 per MW-Day applied to peak MWh scheduled each day; not to exceed \$369.23 per MW-Week applied to the peak MWh scheduled any hour each week. NYPA shall coordinate with the ISO to update its TSC. Such updates shall be subject to FERC filings.

14.1.8 Discounting

Each Transmission Owner may advise the ISO of discounts to its TSC applicable during a specified period to all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO shall post the discounts on the OASIS for the specified period.

Three principal requirements apply to discounts for Transmission Service as follows: (1) any offer of a discount made by a Transmission Owner must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by a Transmission Owner's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount that the Transmission Owner agrees to

and advises the ISO of, the same discounted Transmission Service rate will be offered to all Transmission Customers for the same period for all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO will post the discounts on the OASIS for the specified period.

TABLE 2
Applicable Wholesale TSC for Exports from
New York State, by Transmission Circuit

Ckt.Id	From/To	kV	From Co./To Ext.	Wholesale TSC Paid
5018	Ramapo / Branchburg	500	O&R/PJM	Con Ed/O&R
398	Pleasant Valley/ Long Mtn	345	CHG&E / NE	Con Ed
B3402	Farragut / Hudson	345	Con Ed / PJM	Con Ed
C3403	Farragut / Hudson	345	Con Ed / PJM	Con Ed
A2253	Goethals / Linden	230	Con Ed / PJM	Con Ed
FE	Smithfield / Falls Village	69	CHG&E/NE	CHG&E
1385	Northport / Norwalk 1	138	LIPA / NE	LIPA
393	Alps / Berkshire	345	NMPC / NE	NMPC
69	So. Ripley / Erie East	230	NMPC / PJM	NMPC
E205W	Rotterdam / Bear Swamp	230	NMPC / NE	NMPC
BP76	Packard / Beck	230	NMPC / OH	NMPC
171	Falconer / Warren	115	NMPC / PJM	NMPC
6	Hoosick / Bennington	115	NMPC /NE	NMPC
7	Whitehall / Blissville	115	NMPC / NE	NMPC
1	Dennison / Rosemont	115	NMPC / HQ	NMPC
2	Dennison / Rosemont	115	NMPC / HQ	NMPC
37-HS	Stolle Road / Homer City	345	NYSEG / PJM	NYSEG
30-HW	Watercure / Homer City	345	NYSEG / PJM	NYSEG
70-EH	Hillside / East Towanda	230	NYSEG / PJM	NYSEG
952	Goudey / Laurel Lake	115	NYSEG / PJM	NYSEG
956	No. Waverly / East Sayre	115	NYSEG / PJM	NYSEG
J	So. Mahwah / Waldwick	345	O&R / PJM	Con Ed/O&R
K	So. Mahwah / Walkwick	345	O&R / PJM	Con Ed/O&R
7040	Massena / Chateaugay	765	NYPA / HQ NYPA	NYPA
PA302	Niagara / Beck A	345	NYPA / OH	NYPA
PA301	Niagara / Beck B	345	NYPA / OH	NYPA
L34P	Moses / St. Lawrence	230	NYPA / OH	NYPA

L33P	Moses / St. Lawrence	230	NYPA / OH	NYPA
PA27	Niagara / Beck	230	NYPA / OH	NYPA
PV-20	Plattsburgh / Grand Isle	115	NYPA / NE	NYPA

¹ All scheduling over the Northport - Norwalk Intertie is conducted by LIPA pursuant to Section 5.7 of this Tariff.

TABLE 3
Applicable Wholesale TSC for Municipal Utilities,
Electric Cooperatives and Loads

Except for those municipal utilities and electric cooperatives that continue to take transmission service under an Existing Transmission Agreement, the following Loads shall be obligated to pay the noted Transmission District - based TSC as applicable in accordance with Section 2.7 of this Tariff.

Load	TSC Paid	Load	TSC Paid	Load	TSC Paid
		Greene	NYSEG	Sherrill	NMPC
		Green Island	NMPC	Silver Springs	NYSEG
		Greenport	LIPA	Skaneateles	NMPC
		Groton	NYSEG	Solvay	NMPC
		Hamilton	NYSEG	Spencerport	RG&E
		Holley	NMPC	Springville	NMPC
		Ilion	NMPC	Steuben	NYSEG
Akron	NMPC	Lake Placid	NMPC	Theresa	NMPC
Andover	NMPC	Little Valley	NMPC	Tupper Lake	NMPC
Angelica	RG&E	Marathon	NYSEG	Watkins Glen	NYSEG
Arcade	NMPC	Mayville	NMPC	Wellsville	NMPC
Bath	NYSEG	Mohawk	NMPC	Westfield	NMPC
Bergen	NMPC	Oneida -Madison	NMPC/ NYSEG	Massena	NYPA
Boonville	NMPC	Otsego	NYSEG	Freeport	LIPA
Brolton	NMPC	Penn Yan	NYSEG	Jamestown	NMPC
Castile	NYSEG	Philadelphia	NMPC	Rockville Ctr.	LIPA
Churchville	NMPC	Plattsburgh	NYPA	Alcoa	(1)
Delaware	NYSEG	Richmondville	NMPC	Reynolds	NYPA
Endicott	NYSEG	Rouses Point	NYSEG	Gen. Motors (Massena, NY)	NYPA
Fairport	NMPC	Salamanca	NMPC	Cornwall	NMPC
Frankfort	NMPC	Sherburne	NYSEG		

Notes: (1) - Load is treated as an entity external to the NYCA.

14.1.9 Niagara Mohawk Power Corporation Wholesale TSC Formula Components RR, CCC and BU and Sources of Data Inputs

Niagara Mohawk Power Corporation (“NMPC”) will calculate and update each of its RR, CCC, and BU components annually using the formulas for each component contained in Attachment 1 and in accordance with the update procedures set forth in Section 14.1.9.4. With the exception of forecasted information, the cost data used in the Formula Rate will be cost data from NMPC’s annual FERC Form 1, NMPC’s Annual Report to the New York State Public Service Commission, or NMPC’s official books of record.

14.1.9.1 Definitions

Capitalized terms used in this calculation will have the following definitions:

Allocation Factors

14.1.9.1.1 Electric Wages and Salaries Allocation Factor shall be fixed at 0.835.

14.1.9.1.2 Gross Transmission Plant Allocation Factor shall equal the total investment in Transmission Plant in Service, Transmission Related Electric General Plant, Transmission Related Common Plant and Transmission Related Intangible Plant divided by Gross Electric Plant.

14.1.9.1.3 Transmission Wages and Salaries Allocation Factor shall be fixed at 0.13.

14.1.9.1.4 Gross Electric Plant Allocation Factor shall equal Gross Electric Plant divided by the sum of Total Gas Plant, Total Electric Plant, and total Common Plant.

Ratebase and Expense Items

14.1.9.1.5 Administrative and General Expense shall equal expenses as recorded in FERC Account Nos. 920-935. FERC Account No. 926 shall be adjusted by

reversing the adjustment to the deferred pension costs booked per the NYPSC Statement of Policy for Accounting and Ratemaking Treatment for Pension and Post-Retirement Benefits Other than Pensions. In addition, Administrative and General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions (“PBOP”) expenses included in FERC Account No. 926, and shall add back the FERC accepted Post Employment Benefit Other than Pensions of \$88,644,000 annually or \$7,387,000 per month or any other amount subsequently approved by FERC under Section 205 or 206 of the Federal Power Act.

14.1.9.1.6 Amortization of Investment Tax Credits shall equal credits as recorded in FERC Account No. 420, per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.7 Amortization of Debt Discount Expense shall equal expenses as recorded in FERC Account No. 428.

14.1.9.1.8 Amortization of Loss on Reacquired Debt shall equal expenses as recorded in FERC Account No. 428.1.

14.1.9.1.9 Amortization of Premium on Debt –Credit shall equal the expenses as recorded in FERC Account 429.

14.1.9.1.10 Amortization of Gain on Reacquired Debt--Credit shall equal the expenses as recorded in FERC Account No. 429.1.

14.1.9.1.11 Common Plant shall equal the balance of plant recorded in FERC Account Nos. 389-399. Common Plant shall be defined as the plant common to NMPC’s gas and electric functions per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.12 Common Plant Depreciation Expense shall equal the common plant depreciation expenses as recorded in FERC Account No. 403, 404 and 405 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.13 Common Plant Depreciation Reserve shall equal the common plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.14 Depreciation Expense for Transmission Plant in Service shall equal depreciation expenses as recorded in FERC Account No. 403, 404 and 405 calculated using the depreciation rates set forth in the following table:

Depreciation Rates

FERC Account/NMPC Internal Account No. Annual Rate

Transmission Plant

350	Land –Rights of Way and Easements	1.32
352	Structures and Improvements	2.42
353	Station Equipment	2.53
353.55	Station Equipment – EMS	4.20
354	Towers and Fixtures	1.80
355	Poles and Fixtures	2.23
356	Overhead Conductors and Devices	1.69
357	Underground Conduit	1.24
358	Underground Conductors and Devices	1.59
359	Roads and Trails	1.33

Electric General Plant

390	Structures and improvements	2.51
391.01	Office furniture, equipment	4.55

391.20	Office furniture equipment (Data Processing Equipment)	20.00
392.22	Transportation Equipment	3.33
394	Tools, shop, garage equipment	4.55
395	Laboratory equipment	4.55
396	Power operated equipment	4.55
397.01	Communication equipment – Radio	4.55
397.02	Communication equipment – Telephone	12.50
397.50 &.60	Communication equipment – Network	4.55
398.01	Power and Supervisory Control	4.55

Common General Plant

390	Structures and improvements	2.57
391.10	Office furniture and equipment	4.55
391.21	Data Processing Equipment	20.00
392.21	Transportation Equipment – Aircraft	7.50
393	Stores equipment	4.55
394	Tools, shop and garage equipment	4.55
395	Laboratory equipment	4.55
396	Power operated equipment	4.55
397.10	Communication equipment – Radio	4.55
397.20	Communication equipment – Telephone	12.50
397.30	Communication equipment – Network	4.55
398	Miscellaneous equipment	4.55
398.10	Power and Supervisory Control	4.55

Electric Distribution Plant – Large Meters

370.30	Large Meters Installation – Bare Costs	5.05
370.35	Large Meters – Installation Costs	5.05

Intangible Plant

302	Franchises and Consents	2.38
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303 Miscellaneous Intangible Assets 14.29

- 14.1.9.1.15 Distribution Plant shall equal the plant balance as recorded in FERC Account Nos. 360 – 374.
- 14.1.9.1.16 Equity AFUDC Component of Depreciation Expense shall equal the activity recorded in FERC Account No. 419.1.
- 14.1.9.1.17 Electric Environmental Remediation Expense shall be the environmental remediation expense as recorded in FERC Account 930.2.
- 14.1.9.1.18 Electric General Plant shall equal the plant balance recorded in FERC Account Nos. 389-399. Electric General Plant shall be defined as the general plant associated with NMPC's electric function.
- 14.1.9.1.19 Electric General Plant Depreciation Expense shall equal general plant depreciation expenses as recorded in FERC Account No. 403, 404 and 405 associated with Electric General Plant.
- 14.1.9.1.20 Electric General Plant Depreciation Reserve shall equal the general plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Electric General Plant.
- 14.1.9.1.21 Electric Property Insurance shall equal property insurance recorded in FERC Account No. 924.
- 14.1.9.1.22 Electric Research and Development Expense shall equal research and development expenses as recorded in FERC Account No. 930.2.
- 14.1.9.1.23 Gain on Reacquired Debt shall equal the balance as recorded in FERC Account No. 257.

- 14.1.9.1.24 Gross Electric Plant shall equal Total Electric Plant plus an allocation of Common Plant determined by multiplying Common Plant by the Electric Wages and Salaries Allocation Factor.
- 14.1.9.1.25 Gross Plant (Gas & Electric) shall equal Total Gas Plant plus Total Electric Plant plus Total Common Plant.
- 14.1.9.1.26 Gross Transmission Investment shall equal the total of Transmission Plant in Service, Transmission Related Electric General Plant, Transmission Related Common Plant and Transmission Related Intangible Plant.
- 14.1.9.1.27 Intangible Electric Plant shall equal the balance of plant recorded in FERC Account Nos. 301-303. Intangible Electric Plant shall be defined as the intangible plant associated with NMPC's electric functions.
- 14.1.9.1.28 Intangible Electric Plant Depreciation Expense shall equal the intangible electric plant depreciation expenses as recorded in FERC Account No. 403, 404 and 405 associated with Intangible Electric Plant.
- 14.1.9.1.29 Intangible Electric Plant Depreciation Reserve shall equal the intangible plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Intangible Electric Plant.
- 14.1.9.1.30 Loss on Recquired Debt shall equal the loss on reacquired debt as recorded in FERC Account No. 189.
- 14.1.9.1.31 Materials and Supplies shall equal materials and supplies balance as recorded in FERC Account No. 154 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

- 14.1.9.1.32 Payroll Taxes shall equal the electric payroll tax expenses related to FICA and federal and state unemployment as recorded in FERC Account 408.1.
- 14.1.9.1.33 Plant Held for Future Use shall equal the balance as recorded in FERC Account No. 105 for transmission uses within 5 years.
- 14.1.9.1.34 Prepayments shall equal prepayment balance as recorded in FERC Account No. 165 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas) less prepaid state and Federal income taxes.
- 14.1.9.1.35 Real Estate Tax Expenses shall equal electric real estate tax expense as recorded in FERC Account 408.1.
- 14.1.9.1.36 Regulatory Assets and Liabilities shall equal state and federal regulatory asset balances in FERC Account Nos. 182.3 and 254, assets and liabilities solely related to FAS109, and excess AFUDC.
- 14.1.9.1.37 Total Accumulated Deferred Income Taxes shall equal the sum of deferred tax balances recorded in FERC Account Nos. 281 - 283 plus accumulated deferred investment tax credits as reflected in FERC Account No. 255, minus the deferred tax balance in FERC Account No. 190. Total Accumulated Deferred Income Taxes shall exclude the specifically identified generation-related stranded cost deferred taxes.
- 14.1.9.1.38 Total Electric Plant shall equal the sum of Transmission Plant, Distribution Plant, Electric General Plant and Intangible Electric Plant.
- 14.1.9.1.39 Total Gas Plant shall equal the plant balance recorded in 18 C.F.R. Part 201, FERC Account Nos. 301-399. Total Gas Plant shall exclude Common Plant.

- 14.1.9.1.40 Transmission Depreciation Reserve shall equal electric transmission plant related depreciation reserve balance as recorded in FERC Account No. 108, plus Transmission Related General Plant Accumulated Depreciation, Transmission Related Amortization of Other Utility Plant, and Common Plant Accumulated Depreciation associated with Gross Electric Plant.
- 14.1.9.1.41 Transmission Operation and Maintenance Expense shall equal the sum of electric expenses as recorded in FERC Account Nos. 560 and 562-574 which shall include Transmission Support Payments, but shall exclude expenses incurred pursuant to agreements entered into with generators or other similar resources for the purpose of supporting transmission reliability that do not qualify as Transmission Support Payments.
- 14.1.9.1.42 Transmission Plant shall equal the gross plant balance as recorded in FERC Account Nos. 350-359.
- 14.1.9.1.43 Transmission Related Bad Debt Expense shall equal Bad Debt Expense as reported in FERC Account 904 related to NMPC's wholesale transmission billing.
- 14.1.9.1.44 Unamortized Discount on Long-Term Debt shall equal the balance in FERC Account No. 226.
- 14.1.9.1.45 Wholesale Metering Investment shall equal the gross plant investment associated with any Revenue or Remote Terminal Unit ("RTU") meters and associated equipment connected to an internal or external tie at voltages equal to or greater than 23 kV. The gross plant investment shall be determined by multiplying the number of such existing wholesale meters recorded in FERC Account No. 370.3 and in blanket metering accounts by the average cost of the

meters plus the average costs of installation. To the extent future gross plant investment for Wholesale Metering can be specifically identified, actual gross meter costs will be used.

Forecast and True-up Related Terms

14.1.9.1.46 Forecast Period shall mean the calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available, as of the beginning of the Update Year.

14.1.9.1.47 Forecasted Transmission Plant Additions (“FTPA”) shall mean the sum of:

14.1.9.1.47.1 NMPC’s actual Transmission Plant additions during the first quarter (January 1 through March 31) of the Forecast Period; and

14.1.9.1.47.2 NMPC’s forecasted transmission investment for the Forecast Period less the amount (i), divided by 2.

14.1.9.1.48 Interest on refunds, surcharges, or adjustments, as applicable, shall mean interest calculated in accordance with the methodology specified in the Commission’s regulations at 18 C.F.R. § 35.19a (a) (2) (iii) (or as such provision may be renumbered in the future).

14.1.9.1.49 Actual Transmission Revenue Requirement shall mean the current Historical Transmission Revenue Requirement (as defined in Attachment 1).

14.1.9.1.50 Actual Scheduling, System Control and Dispatch cost shall mean the most recently established CCC (as defined in Attachment 1).

14.1.9.1.51 Actual Billing Units shall mean the most recently established BU (as defined in Attachment 1).

- 14.1.9.1.52 Prior Year Transmission Revenue Requirement shall equal RR less Annual True-Up (“ATU”), as defined in Attachment 1, for the most recently ended calendar year as of the beginning of the Update Year.
- 14.1.9.1.53 Prior Year Scheduling, System Control and Dispatch shall equal the CCC, as defined in Attachment 1, for the prior calendar year.
- 14.1.9.1.54 Prior Year Billing Units shall equal the BU, as defined in Attachment 1, for the prior calendar year.
- 14.1.9.1.55 Prior Year Unit Rate shall equal the sum of RR, as defined in Attachment 1, for the most recently ended Prior Year Revenue Requirement and the Prior Year Scheduling, System Control and Dispatch divided by the Prior Year Billing Units.
- 14.1.9.1.56 Annual Update shall mean the calculation of the RR, CCC, and BU components with Data Inputs for an Update Year in accordance with Section 14.1.9.4.
- 14.1.9.1.57 Data Input shall mean any data required for the calculation of RR, CCC and BU, in accordance with the Formula Rate.
- 14.1.9.1.58 Formal Challenge shall mean a challenge presented in accordance with Section 14.1.9.4.3.2.
- 14.1.9.1.59 Informational Filing shall mean the filing that NMPC makes in accordance with Section 14.1.9.4 to establish the Annual Update for an Update Year.
- 14.1.9.1.60 Interested Party shall mean a person that is (i) a party to FERC Docket No. ER08-552, (ii) the New York State Public Service Commission; (iii) a transmission customer under this Tariff that pays charges based on the Formula

Rate during the calendar year prior to the submission of the Informational Filing; or (iv) a state regulatory authority having jurisdiction over the retail electric rates of such a transmission customer, provided that such regulatory authority or such customer notifies NMPC of that fact no later than 30 days prior to the Publication Date. An Interested Person includes employees of or consultants to such person.

14.1.9.1.61 Material Accounting Change shall mean an accounting policy or practice, including, but not limited to, a policy or practice affecting the allocation of costs or revenues, employed by NMPC during an Update Year that differs from the corresponding policy or practice in effect during any of the three previous calendar years which change affects any Data Input for the Update Year by \$1.0 million or more, as compared to the previous calendar year.

14.1.9.1.62 Preliminary Challenge shall mean a challenge presented by an Interested Party in accordance with Section 14.1.9.4.2.1.

14.1.9.1.63 Publication Date shall be the date of an Informational Filing for an Update Year.

14.1.9.1.64 Review Period shall be the period ending one-hundred and fifty (150) days after the Publication Date, unless extended in accordance with Section 14.1.9.4.2.1.

14.1.9.1.65 Formula Rate shall be the formulas set forth in Attachment 1.

14.1.9.1.66 Update Year shall be the period from July 1 of a given calendar year through June 30 of the subsequent calendar year for a particular Annual Update.

14.1.9.1.67 Transmission Support Payments shall be expenses accepted by FERC for inclusion in the Historical Transmission Revenue Requirement pursuant to

agreements entered into with generators or other similar resources for the purpose of supporting transmission reliability that have been submitted to FERC for review. Pursuant to the settlement agreement accepted by FERC in Docket No. ER14-543, Transmission Support Payments shall include the costs incurred by Niagara Mohawk pursuant to the reliability support services agreements entered into between Niagara Mohawk and Dunkirk Power, LLC on July 12, 2012 and March 4, 2013, including the costs of extending the March 4, 2013 agreement through the end of 2015, less a sum total of \$35 million.

All references to FERC accounts in the above definitions are references to 18 C.F.R. Part 101, unless specifically noted otherwise. In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

14.1.9.2 Calculation of RR

The RR component shall equal the (a) Historical Transmission Revenue Requirement, plus (b) the Forecasted Transmission Revenue Requirement which shall exclude the impact of any Transmission Support Payments, plus (c) the Annual True-Up, determined in accordance with the Formula Rate.

14.1.9.3 Fixed Formula Inputs

Formula Rate inputs for (i) the authorized return on common equity (“ROE”), (ii) any cap on the common equity component of the capital structure, (iii) amount and amortization period of extraordinary property losses, (iv) depreciation and/or amortization rates, (v) PBOP expenses, and (vi) the electric wages and salaries allocation factor and transmission wages and salaries allocation factor shall be stated values until changed by the FERC pursuant to Section 205 or

Section 206 of the Federal Power Act. An application under Section 205 or 206 or a proceeding initiated by FERC sua sponte under Section 206 to modify any of these stated values under the Formula Rate other than the ROE, the cap on the common equity component of the capital structure or the allocation factors in (vi) shall not be deemed to open for review other components of the Formula Rate.

14.1.9.4 Annual Update Process

14.1.9.4.1 Annual Updates

14.1.9.4.1.1 On or before June 14th of each year, NMPC shall recalculate its RR, CCC, and BU components, applying the Data Inputs called for in the Formula Rate to produce the Annual Update for the upcoming Update Year, and:

14.1.9.4.1.1.1 shall post such Annual Update and a “workable” excel file containing that year’s Annual Update on the NYISO’s Internet website;

14.1.9.4.1.1.2 shall file such Annual Update with the FERC as the Informational Filing. The submission of such Informational Filing with FERC shall not require any action by the agency; and

14.1.9.4.1.1.3 shall serve the Annual Update electronically on all Interested Parties.

14.1.9.4.1.2 If the date for making the Informational Filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall coincide with the NYISO posting requirement for July rates.

14.1.9.4.1.3 The Annual Update for the Update Year:

14.1.9.4.1.3.1 shall use the Data Inputs specified in NMPC’s Formula Rate, and therefore, to the extent specified in NMPC’s Formula Rate, be based upon

NMPC's FERC Form No. 1 data for the most recent calendar year; to the extent specified in NMPC's Formula Rate, be based upon the books and records of NMPC consistent with FERC accounting policies, and, to the extent specified in NMPC's Formula Rate, be based on projections for the upcoming calendar year;

14.1.9.4.1.3.2 shall provide supporting documentation for Data Inputs in the form of the data provided in Attachment C to the Offer of Settlement dated April 6, 2009, in Docket No. ER08-552; and, with respect to Billing Units, shall include monthly documents in PDF format with redacted names and revised reference numbers for each entity to protect confidentiality, showing the Billing Units for each month of the most recently completed calendar billing year (the six-month updated BUs), including NMPC's Transmission Owner Load ("TOL"), consisting of metered loads for the December through November timeframe showing the calendar billing year BUs reported to the NYISO by NMPC. The total MWh of generation (including load modifiers) and net interchange for each NMPC transmission zone will be displayed. National Grid will also provide a document as a "workable" Excel file summarizing the TOL for disputed station service, High Load Factor Fitzpatrick and any other entity excluded from the Billing Units calculation in Attachment 1, Schedule 6.12, of the Formula Rate. The summary will be labeled to show the reason for exclusion, consistent with the definition of Billing Units and will reconcile to the totals shown on Attachment 1, Schedule 6.12.

14.1.9.4.1.3.3 shall provide notice of and describe all Material Accounting Changes, which description shall include an explanation of the purpose for and

the circumstances giving rise to the Material Accounting Change, including references to any relevant orders, policies or notices of the Securities and Exchange Commission, the FERC or a retail regulator, which explanation may incorporate by reference any applicable disclosure statements filed with any such agency;

14.1.9.4.1.3.4 shall provide notice of the date and location of the meeting to be held in accordance with Section 14.1.9.4.2.2;

14.1.9.4.1.3.5 shall be subject to challenge and review only in accordance with the procedures set forth in this Section 14.1.9.4, provided that such procedures shall not preclude investigation of the Annual Update by FERC, including through hearing procedures;

14.1.9.4.1.3.6 shall not seek to modify NMPC's Formula Rate and shall not be subject to challenge by an Interested Party seeking to modify NMPC's Formula Rate (i.e., all such modifications to the Formula Rate will require, as applicable, a Federal Power Act Section 205 or Section 206 proceeding), provided that an Interested Party may propose for consideration a change to the Formula Rate, as provided in Section 14.1.9.4.3.5;

14.1.9.4.1.3.7 shall include a list of the email addresses of Interested Parties upon which the Annual Update was served; and

14.1.9.4.1.3.8 shall provide a description of, and workpapers for, any correction of an error discovered by NMPC that affects the calculation of any charges under the Formula Rate during a prior year within the period applicable under Section 14.1.9.4.4.

14.1.9.4.1.4 The fixed Formula Rate inputs set forth in Section 14.1.9.3 shall not be subject to adjustment in an Annual Update.

14.1.9.4.2 Annual Review Procedures

Each Annual Update shall be subject to the following review procedures:

14.1.9.4.2.1 Any Interested Party shall have up to one hundred fifty (150) days after the Publication Date (unless such period is extended with the written consent of NMPC) to review the calculations and to notify NMPC in writing of any specific challenges to the accuracy of any Data Input in the Annual Update or the conformance of any such Data Input with the requirements of the Formula Rate (“Preliminary Challenge”); provided, however, that each Interested Party shall make a good faith effort to submit Preliminary Challenges at the earliest practicable date so that they may be resolved as soon as possible, and provide NMPC with a non-binding list of potential Preliminary Challenges it may present, based on its review of the Annual Update and on responses to information requests provided to that point, within ninety (90) days of the Publication Date. Any Preliminary Challenge shall be posted on the NYISO’s internet website and served by electronic service on all Interested Parties by the next business day following the date it is provided to NMPC.

14.1.9.4.2.2 Within thirty (30) days of the Publication Date, NMPC shall hold a meeting open to all Interested Parties, at which meeting: (a) NMPC shall present and explain the Annual Update; (b) NMPC shall respond to questions from Interested Parties, to the extent such questions can be answered immediately; and

(c) Interested Parties shall identify any areas of potential Preliminary Challenges, to the extent they have identified them at the time of the meeting.

14.1.9.4.2.3 Interested Parties shall have up to one hundred thirty (130) days after each annual Publication Date (unless such period is extended with the written consent of NMPC) to serve reasonable information requests on NMPC; provided, however, that the Interested Parties shall make a good faith effort to submit consolidated sets of information requests that limit the number and overlap of questions to the extent practicable. Such information requests may be directed to matters relevant to the accuracy of the Data Inputs included in the Annual Update and the conformance of those Data Inputs with the requirements of the corresponding provisions of the Formula Rate, including: (a) the reasons for any change in a Data Input from the corresponding Data Input in an earlier Annual Update; (b) the reasons for any change in a Data Input based on actual costs from the corresponding Data Input based on a cost projection in an earlier Annual Update; (c) any reports or other materials provided to fulfill the requirements of a state or federal regulatory agency that explain the basis for projected or actual costs reflected in a Data Input; and (d) the impact of any Material Accounting Change identified in the Annual Update on the charges produced by the Formula Rate.

14.1.9.4.2.4 NMPC shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) business days of receipt of such requests. NMPC may give reasonable priority to responding to requests that satisfy the practicable coordination and consolidation provision of

Section 14.1.9.4.2.3, above. NMPC's responses to information requests shall not be entitled to protection as privileged settlement communications; provided, however, that: (a) any communications between NMPC and any Interested Party in connection with efforts to negotiate a resolution of a Preliminary Challenge or Formal Challenge shall be entitled to such protection; (b) if NMPC's response to an information request contains proprietary or trade secret information or critical energy infrastructure information, NMPC and the Interested Party or Parties receiving such information shall enter into a confidentiality agreement materially similar to the model protective order used by the FERC to protect the confidentiality of such information; and (c) nothing herein shall require NMPC to provide information that is protected by the attorney-client privilege, the attorney work product doctrine, or any other legally recognized privilege.

14.1.9.4.3 Resolution of Challenges

14.1.9.4.3.1 NMPC and the Interested Parties shall negotiate in good faith throughout the Review Period to attempt to resolve any Preliminary Challenges.

14.1.9.4.3.2 If NMPC and any Interested Party or Parties have not resolved any Preliminary Challenge to the Annual Update within the Review Period, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of NMPC to continue efforts to resolve a Preliminary Challenge) to present the subject matter of the Preliminary Challenge to the FERC as a Formal Challenge, which shall be served on NMPC and all other Interested Parties by electronic service on the date of such filing and posted on the NYISO's internet website, however, there shall be no need to make a Formal

Challenge or to await conclusion of the time periods in Section 14.1.9.4.2 if the FERC already has initiated a proceeding to investigate the Annual Update. By no later than five (5) business days after the end of the Review Period, NMPC shall apprise Interested Parties of the resolution of all Preliminary Challenges that have been resolved and of the impact of the resolution of all such Preliminary Challenges on the Annual Update. Within an additional fifteen (15) business days, NMPC shall submit a supplement to its Informational Filing to the FERC, with electronic service upon the Interested Parties, reflecting the impact of all successfully resolved Preliminary Challenges.

14.1.9.4.3.3 Any response by NMPC to a Formal Challenge must be submitted to the FERC within twenty-one (21) days of the date of the filing of the Formal Challenge, and shall be posted on the NYISO's Internet website and served on all Interested Parties by electronic service on the date of such filing.

14.1.9.4.3.4 In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, NMPC shall bear the burden of proving that the Data Inputs in that year's Annual Update are correct and conform to the terms of the Formula Rate and refunds or adjustments may be made, in either case with interest, to charges collected under the Formula Rate if the FERC concludes that the Data Inputs are incorrect or do not conform to the terms of the Formula Rate. In all other respects, any such proceeding shall be governed by the rules and requirements applicable to proceedings under Section 206 of the Federal Power Act.

14.1.9.4.3.5 An Interested Party may propose that resolution of a Preliminary Challenge or Formal Challenge concerning a Material Accounting Change necessitates changes to the Formula Rate to ensure that the resulting charges, including the effect of the Material Accounting Change, are just and reasonable. If NMPC agrees to such a proposed change to the Formula Rate to resolve a Preliminary Challenge, NMPC shall file the change to the Formula Rate with the FERC for approval pursuant to Section 205 of the Federal Power Act. If NMPC does not agree to such a proposed change, the Interested Party may file the proposed change with the FERC for approval pursuant to Section 206 of the Federal Power Act concurrent with its submission of a Formal Challenge; provided that if FERC approves the proposed change, the change to the Formula Rate shall take effect as of the beginning of the Update Year during which the Section 206 filing is made, and refunds or surcharges shall be made, in either case with interest, to charges under the Formula Rate after the beginning of such Update Year to reflect the proposed change.

14.1.9.4.3.6 Nothing herein shall be deemed to limit in any way the right of NMPC to file unilaterally, pursuant to Section 205 of the Federal Power Act and the regulations thereunder, changes to NMPC's Formula Rate (including changes in connection with any incentive mechanism) or any of its Data Inputs (including, but not limited to, any fixed Data Inputs) or the right of any other party to file for such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. All parties reserve all rights to challenge, or take any position in response to, any such filing by any other party.

14.1.9.4.4 Changes to Data Inputs

14.1.9.4.4.1 Any changes to the Data Inputs for an Annual Update, including but not limited to revisions resulting from any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall take effect as of the beginning of the Update Year and the impact of such changes shall be incorporated into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19(a)) in the Annual Update for the next effective Update Year. This mechanism shall apply in lieu of mid-Update Year adjustments and any refunds or surcharges, except that, if an error in a Data Input is discovered and agreed upon within the Review Period, the impact of such change shall be incorporated prospectively into the charges produced by the Formula Rate during the remainder of the year preceding the next effective Update Year, in which case the impact reflected in subsequent charges shall be reduced accordingly.

14.1.9.4.4.2 The impact of an error affecting a Data Input on charges collected during the Formula Rate during the five (5) years prior to the Update Year in which the error 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. § 35.19(a)) in the Annual Update for the next effective Update Year. Charges collected before the five-year period shall not be subject to correction.

14.2 Attachment 1 to Attachment H (Niagara Mohawk Power Corporation) and NYPA Transmission Adjustment Charge

14.2.1 Attachment 1 to Attachment H: Schedules (Niagara Mohawk Power Corporation)

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Niagara Mohawk Power Corporation

Attachment 1

Calculation of RR Pursuant to Attachment H, Section 14.1.9.2

	Year
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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.

1	<u>Historical Transmission Revenue Requirement (Historical TRR)</u>			
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		<u>Reference</u>		
9		<u>Section:</u>	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)		<u>#DIV/0!</u>	
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 -			
25	Line 22)		#DIV/0!	

Niagara Mohawk Power Corporation
Forecasted Transmission Revenue Requirement
Attachment H, Section 14.1.9.2

Attachment 1
Schedule 2

	Year
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Shading denotes an input

Line No.

1 14.1.9.2 **FORECASTED TRANSMISSION REVENUE REQUIREMENTS**
 (b)

2 Forecasted TRR shall equal (1) the Forecasted Transmission Plant Additions (FTPA) multiplied by the Adjusted Annual (AFTRRF), plus (2) Forecasted ADIT Adjustment (FADITA), plus (3) the Mid-Year Trend Adjustment (MYTA), less (4) Transmission Support Payments (TSP), plus (5) the Tax Rate Adjustment (TRA), less (6) Other Billing Adjustments (OBA) as shown in the following formula:

$$\text{Forecasted TRR} = (\text{FTPA} * \text{AFTRRF}) + \text{FADITA} + \text{MYTA} - \text{TSP} + \text{TRA} - \text{OBA}$$

	<u>Period</u>	<u>Reference</u>	<u>Source</u>
--	---------------	------------------	---------------

10	(1) FORECASTED TRANSMISSION PLANT ADDITIONS (FTPA)	\$0	
11	Adjusted Annual Transmission Revenue Requirement Factor (AFTRRF)	#DIV/0!	Workpaper 8, Section I, Line 16 Line 78
12	Sub-Total (Lines 10*11)	#DIV/0!	
13			
14	(2) FORECASTED ADIT ADJUSTMENT (FADITA)		
15	The Forecasted ADIT Adjustment (FADITA) shall equal the Forecasted ADIT (FADIT)		
16	multiplied by the Cost of Capital Rate, where:		
17			
18	Forecasted ADIT(FADIT) shall equal the projected change in Accumulated Deferred Income Taxes from the most recently concluded calendar year related to accelerated depreciation and associated with Transmission Plant for the		
19	Forecasted Period calculated in accordance with Treasury regulation Section 1.167(1)-1(h)(6).		
20			
21			
22	Forecasted ADIT (FADIT)	#DIV/0!	Schedule 13, Line 24
23	Cost of Capital Rate	#DIV/0!	Schedule 8, Line 62
24	Forecasted ADIT Adjustment (FADITA)	#DIV/0!	Line 22 * Line 23
25			
26	(3) MID YEAR TREND ADJUSTMENT (MYTA)		
27	The Mid-Year Trend Adjustment shall be the difference, whether positive or negative, between		
28	(i) the Historical TRR Component (E) excluding Transmission Support Payments, based on actual data for the first three months of the		

29	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.		
30			
31	Plus Mid-Year Trend Adjustment (MYTA)	\$0	Workpaper 9, line 32, variance column
32			
33	(4) TRANSMISSION SUPPORT PAYMENTS (TSP)		
34	Less Impact of Transmission Support Payments on Historical Transmission Revenue Requirement	\$0	Workpaper 9A
35	Less: Other Billing Adjustments - Dunkirk Settlement ER14-543-000	\$0	Schedule 10
36			
37	(5) TAX RATE ADJUSTMENT (TRA)		
38	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		
39	and/or the State Income Tax Rate that takes effect during the first five months of the Forecast Period.		
40			
41	Tax Rate Adjustment (TRA)	\$0	
42			
43	(6) OTHER BILLING ADJUSTMENTS (OBA)		
44	Other Billing Adjustments shall equal any amounts related to the HTRR calculation that are		
45	required to be adjusted in the current year's FTRR to remove the impact on the Update Year		
46			
47	Other Billing Adjustments (OBA)	\$0	Schedule 10, Line 1
48			
49	Forecasted Transmission Revenue Requirement (Line 12 + Line 24 + Line 31 – Line 34 – Line 35 + Line 41-Line 47)	#DIV/0!	
50			
51	14.1.9.2(c) <u>ANNUAL FORECAST TRANSMISSION REVENUE REQUIREMENT FACTOR</u>		
52			
53	Adjusted Annual Forecast Transmission Revenue Requirement Factor (AFTRRF) shall equal the difference between the Annual Forecast		
54	Transmission Revenue Requirement Factor (FTRRF) and the quotient of (1) Cost of Capital Rate multiplied by the Transmission Related		
55	Accumulated Deferred Taxes less Accumulated Deferred Inv. Tax Cr (255) for the most recently concluded calendar year,		
56	and (ii) the year-end Transmission Plant in Service determined in accordance with Section 14.1.9.2 (a), component (A)1(a).		
57			
58	The Annual Forecast Transmission Revenue Requirement Factor (Annual FTRRF) shall equal the sum of Historical TRR components (A) through (C),		
59	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).		
60			
61	Derivation of Annual Forecast Transmission Revenue Requirement		

Factor (FTRRF)				
62	Investment Return and Income Taxes	(A)	#DIV/0!	Schedule 1, Line 10
63	Depreciation Expense	(B)	#DIV/0!	Schedule 1, Line 11
64	Property Tax Expense	(C)	#DIV/0!	Schedule 1, Line 12
65	Total Expenses (Lines 62 thru 64)		#DIV/0!	
66	Transmission Plant	(a)	#DIV/0!	Schedule 6, Page 1, Line 12
67	Annual Forecast Transmission Revenue Requirement Factor (Lines 65/ Line 66)		#DIV/0!	
68				
69	Adjustment to FTRRF to reflect removal of ADIT that is subject to normalization			
70	Transmission Related ADIT Balance at year-end		#DIV/0!	Schedule 7, Line 6, Column L
71	Less: Accumulated Deferred Inv. Tax Cr (255)		#DIV/0!	Schedule 7, Line 5, Column L
72	Net Transmission ADIT Balance at year-end		#DIV/0!	Line 70 - Line 71
73	Cost of Capital Rate		#DIV/0!	Schedule 8, Line 62
74	Total Return and Income Taxes Associated with ADIT Balance at year-end		#DIV/0!	Line 72 * Line 73
75				
76	Annual Forecast Transmission Revenue Requirement Factor (FTRRF)		#DIV/0!	Line 67
77	Less: Incremental Annual Forecast Transmission Revenue Requirement Factor Adjustment for ADIT		#DIV/0!	Line 74 / Line 66
78	Adjusted Annual Forecast Transmission Revenue Requirement Factor (AFTRRF)		#DIV/0!	Line 76 - Line 77

Niagara Mohawk Power Corporation

**Attachment 1
Schedule 3**

Annual True-up (ATU)

Attachment H Section 14.1.9.2 (c)

Line No.		Year	Source:
1			
2	14.1.9.2(d)		
3	The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year		
4	Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs		
5	and Prior Year Scheduling, System Control and Dispatch costs, plus (3) the difference between the Prior Year Billing Units and the Actual Year		
6	Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.		
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, Column 9
27			
28	Annual True-up RR Component	#DIV/0!	(Line 24 + Line 26)
29			

30 Interest Calculation per 18 CFR § 35.19a

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Quarters	Annual Interest Rate (a)	Accrued Prin & Int. @ Beg Of Period	Monthly (Over)/Under Recovery	Days in Period (b)	Period Days	Multiplier	Accrued Prin & Int. @ End Of Period	Accrued Int. @ End Of Period
36	3rd QTR		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		#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		#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!	28	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		#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>

(b) For leap years use 29 days in the month of February

**Attachment 1
Schedule 4**

Niagara Mohawk Power Corporation

Wholesale TSC Calculation Information

Line No.		(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 49							
(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, Line 21 - 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 Operator (NYISO) system control and load dispatch expenses already recovered under Schedule 1 of the NYISO Tariff.							
(f)	Schedule 12, line 17 - 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

Year

Shading denotes an input

Line
 No.

Line No.	Description	Amount	Source	Definition
1	14.1.9.1.1. <u>Electric Wages and Salaries Factor</u>	83.5000%		Fixed per settlement Docket ER08-552
2				
3	14.1.9.1.3. <u>Transmission Wages and Salaries Allocation Factor</u>	13.0000%		Fixed per settlement Docket ER08-552
4				
5				
6				
7				
8	14.1.9.1.2. <u>Gross Transmission Plant Allocation Factor</u>			
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
12	Plus: Transmission Related Intangible Plant	\$0	Schedule 6, Page 2, Line 15, Col 5	Related Intangible Plant
13	Gross Transmission Investment	#DIV/0!	Sum of Lines 9 - 13	divided by Gross Electric Plant.
14				
15	Total Electric Plant		FF1 207.104g	
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	<u>#DIV/0!</u>	Line 13 / Line 17	
20				
21	14.1.9.1.4. <u>Gross Electric Plant Allocation Factor</u>			
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	<u><u>#DIV/0!</u></u>	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) Transmission Investment Base

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

Description	Reference	Year	Reference
	<i>Section:</i>		
Transmission Plant in Service	(a)	#DIV/0!	Schedule 6, page 2, line 3, column 5
General Plant	(b)	\$0	Schedule 6, page 2, line 5, column 5
Common Plant	(c)	\$0	Schedule 6, page 2, line 10, column 5
Intangible Plant	(d)	\$0	Schedule 6, page 2, line 15, column 5
Plant Held For Future Use	(e)	\$0	Schedule 6, page 2, line 19, column 5
Total Plant (Sum of Line 12 - Line 16)		#DIV/0!	
Accumulated Depreciation	(f)	#DIV/0!	Schedule 6, page 2, line 29, column 5
Accumulated Deferred Income Taxes	(g)	#DIV/0!	Schedule 7, line 6, column 5
Other Regulatory Assets	(h)	#DIV/0!	Schedule 7, line 11, column 5
Net Investment (Sum of Line 17 -Line 21)		#DIV/0!	
Prepayments	(i)	#DIV/0!	Schedule 7, line 15, column 5
Materials & Supplies	(j)	#DIV/0!	Schedule 7, line 21, column 5
Cash Working Capital	(k)	\$0	Schedule 7, line 28, column 5
Total Investment Base (Sum of Line 22 - Line 26)		#DIV/0!	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)

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

Year

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)	<u>Definition</u>
1	<u>Transmission Plant</u>				#DIV/0!	FF1 207.58g 14.1.9.2(a)A.1.(a)	Transmission Plant in Service shall equal the balance of total investment in Transmission Plant plus Wholesale Metering Investment.
2	Wholesale Meter Plant				#DIV/0!	Workpaper 1	
3	Total Transmission Plant in Service (Line 1+ Line 2)				#DIV/0!		
4							
5	<u>General Plant</u>	100.00%	\$0	13.00%	(c) \$0	FF1 207.99g 14.1.9.2(a)A.1.(b)	Transmission Related Electric General Plant shall equal the balance of investment in Electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.
6							
7							
8							
9							
10	<u>Common Plant</u>	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 Plant multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Wages and Salaries Allocation Factor.
11							
12							
13							
14							
15	<u>Intangible Plant</u>	100.00%	-	13.00%	(c) \$0	FF1 205.5g 14.1.9.2(a)A.1.(d)	Transmission Related Intangible Plant shall equal Intangible Electric Plant multiplied by the
16							

17										Transmission Wages and Salaries Allocation Factor.
18										
19	<u>Transmission Plant Held for Future Use</u>	\$0				\$0		Workpaper 10	14.1.9.2(a)A.1.(e)	Transmission Related Plant Held for Future Use shall equal the balance in Plant Held for Future Use associated with property planned to be used for transmission service within five years.
20										
21										
22										
23	<u>Transmission Accumulated Depreciation</u>									
24	Transmission Accum. Depreciation					\$0		FF1 219.25b	14.1.9.2(a)A.1.(f)	Transmission Related Depreciation Reserve shall equal the balance of: (i) Transmission Depreciation Reserve, plus (ii) the product of Electric General Plant Depreciation Reserve multiplied by the Transmission Wages and Salaries Allocation Factor, plus (iii) the product of Common Plant Depreciation Reserve multiplied by the Electric Wages and Salaries Allocation Factor and further multiplied by the Transmission Wages and Salaries Allocation Factor plus (iv) the product of Intangible Electric Plant Depreciation Reserve multiplied by the Transmission Wages and Salaries Allocation Factor plus (v) depreciation reserve associated with the Wholesale Metering Investment.
25	General Plant Accum. Depreciation		100.00%	\$0	13.00% (c)	\$0		FF1 219.28b		
26	Common Plant Accum Depreciation		83.50% (a)	\$0	13.00% (c)	\$0		FF1 356.1	end of year balance	
27	Amortization of Other Utility Plant		100.00%	\$0	13.00% (c)	\$0		FF1 200.21c		
28	Wholesale Meters	#DIV/0!				#DIV/0!		Workpaper 1		
29	Total Depreciation (Sum of Line 24 - Line 28)					#DIV/0!				
30										
31										
32										
33										
34										
35										
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

**Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 2 of 2)**

**Attachment 1
Schedule 7**

Attachment H Section 14.1.9.2 (a) A. 1.

Shading denotes an input

Line No.	(1) Total	(2) Allocation Factor	Year			(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)	Definition
			(3) = (1)*(2) Electric Allocated	(4) Allocation Factor	(d)			
1	<u>Transmission Accumulated Deferred Taxes</u>							
2		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	\$0	100.00%	\$0	#DIV/0!	(d)	#DIV/0!	Workpaper 2, Line 5	shall equal the electric balance of Total Accumulated Deferred
4		100.00%	\$0	#DIV/0!	(d)	#DIV/0!	FF1 234.8c	Income Taxes (FERC Accounts 190, 55,281, 282, and 283 net of
5		100.00%	\$0	#DIV/0!	(d)	#DIV/0!	FF1 267.8h	stranded costs), multiplied by the Gross Transmission Plant
6			\$0	#DIV/0!	(d)	#DIV/0!		Allocation Factor.
7								
8	<u>Other Regulatory Assets</u>							
9		100.00%	\$0	#DIV/0!	(d)	#DIV/0!	FF1 232 lines 2,20,25,31	14.1.9.2(a)A.1.(h) Transmission Related Regulatory Assets shall be Regulatory
10		100.00%	\$0	#DIV/0!	(d)	#DIV/0!	FF1 278lines 1& 29(f)	Assets net of Regulatory Liabilities multiplied by the Gross
11	\$0		\$0	#DIV/0!	(d)	#DIV/0!		Transmission Plant Allocation Factor.
12								
13	<u>Transmission Prepayments</u>							
14							FF1 111.57c FF1 263 lines 2 &7 (h)	14.1.9.2(a)A.1.(i) Transmission Related Prepayments shall be the product of
15	\$0	#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!		Prepayments excluding Federal and State taxes multiplied by
16								the Gross Electric Plant Allocation Factor and further
17								multiplied by the Gross Transmission Plant Allocation Factor.
18	<u>Transmission Material and Supplies</u>							
19						\$0	FF1 227.8c	14.1.9.2(a)A.1.(j) Transmission Related Materials and Supplies shall equal: (i)
20		#DIV/0! (b)	#DIV/0!	#DIV/0!	(d)	#DIV/0!	FF1 227.5c	the balance of Materials and Supplies assigned to
								Transmission plus (ii) the product of Material and Supplies

21	Total (Line 19 + Line 20)	<u><u>#DIV/0!</u></u>		assigned to Construction multiplied by the Gross Electric Plant Allocation Factor and further multiplied by Gross Transmission Plant Allocation Factor.
22				
23				
24				
25	<u>Cash Working Capital</u>		14.1.9.2(a)A.1.(k)	Transmission Related Cash Working Capital shall be an allowance equal to the product of: (i) 12.5% (45 days/ 360 days = 12.5%) multiplied by (ii) Transmission Operation and Maintenance Expense.
26	Operation & Maintenance Expense	\$0	Schedule 9, Line 23	
27		0.1250	x 45 / 360	
28	Total (Line 26 * Line 27)	<u><u>\$0</u></u>		
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
Annual Revenue Requirements of Transmission Facilities
Cost of Capital Rate

Attachment 1
Schedule 8

Shading denotes an input

Year

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
 13

		CAPITALIZATION	Source:	CAPITALIZATION RATIOS	COST OF CAPITAL	Source:	WEIGHTED COST OF CAPITAL	EQUITY PORTION
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!
21	Total Investment Return	\$0		#DIV/0!			#DIV/0!	#DIV/0!

26 Federal Income
 14.1.9.2.2.(b) Tax shall equal = ($\frac{A + [B / C] \times \text{Federal Income Tax Rate}}{1 - \text{Federal Income Tax Rate}}$)

27
 28 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)
 29 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
 31 28.

32 = $\frac{\#DIV/0! + (\$0)}{1 - 0} \times \#DIV/0!$
 33
 34
 35 = #DIV/0!

36
 37
 38 State Income
 14.1.9.2.2.(c) Tax shall equal = $\frac{A + [B / C] + \frac{\text{Federal Income Tax Rate}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}}{1 - \text{Federal Income Tax Rate}}$

39
 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
 42 component of Depreciation Expense for Transmission Plant in
 43 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.

44
 45
 46 = $\frac{\#DIV/0! + \$0}{1 - 0} + \#DIV/0! \times \#DIV/0!$
 47
 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

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

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Expenses

Attachment 1
Schedule 9

Attachment H Section 14.1.9.2

Year

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
<u>Depreciation Expense</u>							
1					\$0	FF1 336.7f	14.1.9.2.B. Transmission Related Depreciation Expense shall equal the sum of: (i) Depreciation Expense for Transmission Plant in Service, plus (ii) the product of Electric General Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Allocation Factor plus (iii) Common Plant Depreciation Expense multiplied by the Electric Wages and Salaries Allocation Factor, further multiplied by the Transmission Wages and Salaries Allocation Factor plus (iv) Intangible Electric Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Factor plus (v) depreciation expense associated with the Wholesale Metering Investment.
2		100.0000%	\$0	13.0000% (c)	\$0	FF1 336.10f	
3		83.5000% (a)	\$0	13.0000% (c)	\$0	FF1 356.1	
4		100.0000%	\$0	13.0000% (c)	\$0	FF1 336.1f	
5					#DIV/0!	Workpaper 1	
6					#DIV/0!		
7							
8							
9							
10							
11							
12		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 electric Real Estate Tax Expenses multiplied by the Gross Transmission Plant Allocation Factor.
13							
14							
15							
16		#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							
<u>Transmission Operation and Maintenance</u>							
21					\$0	FF1 321.112b	14.1.9.2.E. Transmission Operation and Maintenance Expense shall equal the sum of electric expenses as recorded in FERC Account Nos. 560, 562-574.
22					\$0	FF1 321.84-92b	
23					\$0		
24							
<u>Transmission Administrative and General</u>							
25							14.1.9.2.F. Transmission Related Administrative and General Expenses shall equal the product of electric Administrative and General Expenses, excluding the sum of Electric Property Insurance, Electric
26						FF1 323.197b	
27						FF1 323.185b	

28	less Pensions and Benefits (#926)					FF1 323.187b	Research and Development Expense and Electric Environmental Remediation Expense,
29	less: Research and Development Expenses (#930)	\$0				Workpaper 12	and 50% of the NYPSC Regulatory Expense multiplied by the Transmission Wages and Salaries Allocation Factor,
30	Less: 50% of NY PSC Regulatory Expense					50% of Workpaper 15	
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 Transmission Plant Allocation Factor, plus transmission-specific Electric
33	Subtotal (Line 26-27-28-29-30-31-32)	\$0	100.0000%	\$0	13.0000% (c)	\$0	
34	PLUS Property Insurance alloc. using Plant Allocation	\$0	100.0000%	\$0	#DIV/0! (d)	#DIV/0!	Line 27
35	PLUS Pensions and Benefits	\$88,644,000	100.0000%	\$88,644,000	13.0000% (c)	\$11,523,720	Workpaper 3
36	PLUS Transmission-related research and development	\$0				\$0	Workpaper 12
37	PLUS Transmission-related Environmental Expense	\$0				\$0	Workpaper 11
38	Total A&G (Line 33+34+35+36+37)	\$88,644,000		\$88,644,000		#DIV/0!	
39							and General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926, and shall add back in the amounts shown on Workpaper 3, page 1, 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 263.9i	
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

Year

Attachment H Section
 14.1.9.2 (a)

Shading denotes an input

Line No.	Description	(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. () indicates a refund or a reduction to the revenue requirement on Schedule 1.
2				
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
32
33
34
35
36

Formula Rate during the five (5) years prior to the Update Year in which the error 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.

Line No.	<u>Scheduling and Dispatch Expenses</u>			<u>Year</u>	<u>Source</u>
1	<u>Scheduling and Dispatch Expenses</u>				
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 of Lines 3 - 11
14					
15	Less Account 561 directly recovered under Schedule 1 of the NYISO 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.			<u>SOURCE</u>
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 of Lines 1-6
8	LESS: All non-retail transactions		
9	Watertown		FF1 page 329.10.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 of Lines 9 - 11
13	PLUS: TSC Load		
14	NYMPA Muni's, Misc. Villages, Jamestown (X1)		FF1 page 329.17.j
15	NYPA Niagara Muni's (X2)		FF1 page 329.1.j
16	Total additions	0.000	Sum of Lines 14 -15
17	Total Billing Units	0.000	Line 7 - Line 12 + Line 16

Niagara Mohawk Power Corporation
Forecasted Accumulated Deferred Income Taxes (FADIT)

Attachment 1
Schedule 13
Page 1 of 1

Shading denotes an input

Line No.	Description	Amount	
1	Transmission Related ADIT Balance at year-end		Schedule 7, Line 6, Column L
2	Less: Accumulated Deferred Inv. Tax Cr (255)		Schedule 7, Line 5, Column L
3	Net Transmission ADIT Balance at year-end (a)		Line 1 - Line 2
4			
5	Forecasted Transmission Related ADIT balance		Internal Records
6			
7	Change in ADIT		Line 5 - Line 3
8			
9	Monthly Change in ADIT		Line 7 / 12 Months
10			

	(A) Month	(B) Remaining Days	(C) = (B) / Line 17 (B) IRS Proration %	(D) = Line 9 * (C) Prorated ADIT
11				
12	Month 1		100.00%	-
13	Month 2		100.00%	-
14	Month 3		100.00%	-
15	Month 4		100.00%	-
16	Month 5		100.00%	-
17	Month 6		100.00%	-
18	Month 7		#DIV/0! %	-
19	Month 8		#DIV/0! %	-
20	Month 9		#DIV/0! %	-
21	Month 10		#DIV/0! %	-
22	Month 11		#DIV/0! %	-
23	Month 12		#DIV/0! %	-
24	Total Prorated ADIT Change (Sum of 12 through 23)			\$ -

to Schedule 2, Line 22

(a) The balance in Line 1, Total Transmission ADIT Balance at year-end, shall equal such ADIT that is subject to the normalization rules prescribed by the IRS and the net of the amounts recorded in FERC Account Nos. 281-283 and 190.

-

15 Attachment I - Index of Network Integration Transmission Service Customers

Appendix 1
TRANSMISSION INTERCONNECTION APPLICATION

1. The undersigned Transmission Developer submits this request to interconnect its proposed transmission project with the New York State Transmission System pursuant to Section [*] of the NYISO OATT.

2. This Transmission Interconnection Application is submitted by:

Name of Transmission Developer: _____

By (signature): _____

Name (type or print): _____

Title: _____

Date: _____

3. Name of project: _____

4. Description of proposed project:

a. Description of proposed Point(s) of Interconnection (*i.e.*, name of existing substation or line to which the project proposes to interconnect):

b. General description of the equipment configuration and kV level:

c. Attach a conceptual breaker one-line diagram (*i.e.*, breaker-level details for proposed elements along with high-level depiction of proposed interconnection with existing system)

- d. Technical data/parameters: [to be provided as attachment to initial study agreement]
- e. In-Service Date (Month and Year): _____
- f. Name, title, company address, telephone number, and e-mail address of the Transmission Developer's contact person:

24 Attachment R - Cost Allocation and Measurement and Verification Methodologies for Demand Reductions Arising Under the Incentivized Day-Ahead Economic Load Curtailment Program

Under the Incentivized Day-Ahead Economic Load Curtailment Program – also referred to in the ISO Tariffs and ISO Procedures as the Day-Ahead Demand Response Program – (“Program” or “DADRP”), costs incurred by the ISO in covering Demand Reduction Providers’ Curtailment Initiation Costs and making Demand Reduction Incentive Payments for scheduled and verified Demand Reductions are to be recovered under Schedule 1. Measurement and verification of actual Demand Reductions scheduled under the Program shall be conducted in accordance with subsections 24.2, 24.3, and 24.4.

24.1 Cost Allocation Methodology for Payments to Demand Reduction Providers under the Program Recovered Pursuant to Schedule 1

The “Schedule 1 Program Costs” for scheduled and verified Demand Reductions shall be allocated to Transmission Customers, pursuant to the methodology set forth below, on the basis of their Load Ratio Shares and in proportion to the probability, given historical transmission congestion patterns, that a particular Demand Reduction will benefit them by reducing Energy costs in their Load Zones or “Composite Load Zones” (see below).

More specifically, Schedule 1 Program Costs shall be allocated to Transmission Customers each Billing Period as follows:

- a) Schedule 1 Program Costs shall initially be attributed to the Load Zone where the Generator Bus that was used to bid the Demand Reduction associated with them is located.
- b) In determining whether and how Transmission Customers located in particular Load Zones, or Composite Load Zones, have benefited from the Demand

Reduction, and how much they shall be required to pay a share of the associated Schedule 1 Program Costs, the ISO shall account for the effects of congestion at the most frequently constrained NYCA interfaces. When none of these interfaces are constrained Transmission Customers in all Load Zones shall be deemed to have benefited from the Demand Reduction and shall pay a share of the associated Schedule 1 Program Costs. When one or more of the most frequently constrained NYCA interfaces is constrained, then Transmission Customers located in a Load Zone, or Composite Load Zone, that is upstream of the constrained interface, shall be deemed to have benefited from an upstream Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. Similarly, when one or more of the interfaces is congested, Transmission Customers located in a Load Zone, or Composite Load Zone, that is downstream of a constrained interface, shall be deemed to have benefited from a downstream Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. By contrast, Transmission Customers that are “separated” from a Demand Reduction by a constrained interface shall be deemed not to have benefited from it and shall not be required to pay a share of the associated Schedule 1 Program Costs.

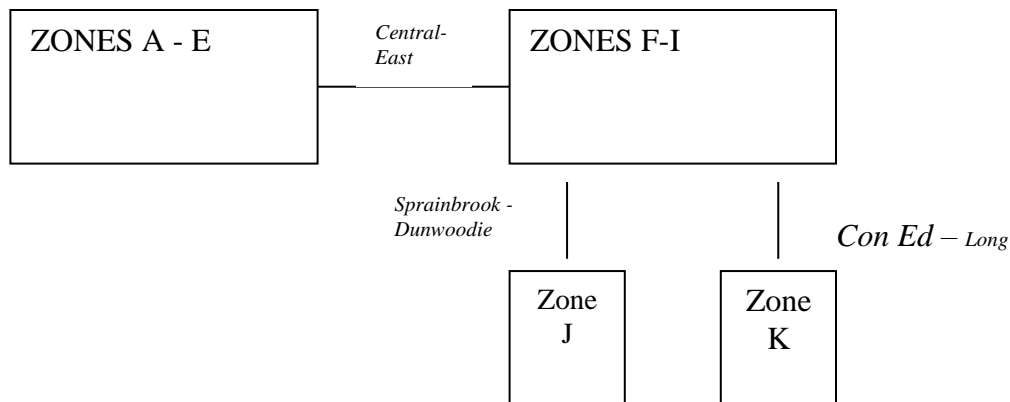
- c) The ISO shall determine the extent of congestion at the most frequently constrained interfaces using a series of equations that calculate the static probability that: (i) no constraints existed in the transmission system serving the Load Zone or Composite Load Zone; (ii) the Composite Load Zone was upstream of a constraint and curtailment pursuant to the Program occurred upstream, and

(iii) the Composite Load Zone was downstream of a constraint and curtailment pursuant to the Program occurred downstream.

Costs shall be allocated to each Transmission Customer that is deemed to have benefited from the scheduled and verified Demand Reduction on a Load Ratio Share basis, using Real-Time metered hourly Load data.

- d) The three most frequently constrained interfaces are currently the “Central-East” interface, which divides western from eastern New York State, the Sprainbrook-Dunwoodie interface, which divides New York City and Long Island from the rest of New York State, and the Consolidated Edison Company (“ConEd”) - Long Island interface (including the Y49/Y50 lines), which divides New York City from Long Island. Given these limiting interfaces, four Composite Load Zones currently exist, *i.e.*, West of Central-East (Load Zones A, B, C, D, E), East Upstate Excluding New York City and Long Island (Load Zones F, G, H, I), New York City (Load Zone J), and Long Island (Load Zone K). The geographic configuration of these Composite Load Zones is depicted in the illustration below.

Relationship Between Frequently Constrained Interfaces and Composite Load Zones



Based on these factors, Schedule 1 Program Costs shall be allocated to Transmission Customers

as follows:

For Transmission Customer m in Load Zones A-E:

$a_1 * (cost_A + \dots + cost_K) * load_m / (load_A + \dots + load_K) +$	'no constraints
$a_2 * (cost_A + \dots + cost_E) * load_m / (load_A + \dots + load_E) +$	'Central East const
$a_3 * (cost_A + \dots + cost_I + cost_K) * load_m / (load_A + \dots + load_I + load_K) +$	'NYC constraint
$a_4 * (cost_A + \dots + cost_J) * load_m / (load_A + \dots + load_J) +$	'LI constraint
$a_5 * (cost_A + \dots + cost_E) * load_m / (load_A + \dots + load_E) +$	'Cent East + NYC
$a_6 * (cost_A + \dots + cost_E) * load_m / (load_A + \dots + load_E) +$	'Cent East + LI
$a_7 * (cost_A + \dots + cost_I) * load_m / (load_A + \dots + load_I) +$	'NYC + LI
$a_8 * (cost_A + \dots + cost_E) * load_m / (load_A + \dots + load_E)$	'Cent East + NYC + LI

For Transmission Customer m in Load Zones F-I:

$a_1 * (cost_A + \dots + cost_K) * load_m / (load_A + \dots + load_K) +$	'no constraints
$a_2 * (cost_F + \dots + cost_K) * load_m / (load_F + \dots + load_K) +$	'Central East const
$a_3 * (cost_A + \dots + cost_I + cost_K) * load_m / (load_A + \dots + load_I + load_K) +$	'NYC constraint
$a_4 * (cost_A + \dots + cost_J) * load_m / (load_A + \dots + load_J) +$	'LI constraint
$a_5 * (cost_F + \dots + cost_I + cost_K) * load_m / (load_F + \dots + load_I + load_K) +$	'Cent East + NYC
$a_6 * (cost_F + \dots + cost_J) * load_m / (load_F + \dots + load_J) +$	'Cent East + LI
$a_7 * (cost_A + \dots + cost_I) * load_m / (load_A + \dots + load_I) +$	'NYC + LI
$a_8 * (cost_F + \dots + cost_I) * load_m / (load_F + \dots + load_I)$	'Cent East + NYC + LI

For Transmission Customer m in Load Zone J:

$a_1 * (cost_A + \dots + cost_K) * load_m / (load_A + \dots + load_K) +$	'no constraints
$a_2 * (cost_F + \dots + cost_K) * load_m / (load_F + \dots + load_K) +$	'Central East const
$a_3 * cost_J * load_m / load_J +$	'NYC constraint
$a_4 * (cost_A + \dots + cost_J) * load_m / (load_A + \dots + load_J) +$	'LI constraint
$a_5 * cost_J * load_m / load_J +$	'Cent East + NYC
$a_6 * (cost_F + \dots + cost_J) * load_m / (load_F + \dots + load_J) +$	'Cent East + LI
$a_7 * cost_J * load_m / load_J +$	'NYC + LI
$a_8 * cost_J * load_m / load_J$	'Cent East + NYC + LI

For Transmission Customer m in Load Zone K:

$a_1 * (cost_A + \dots + cost_K) * load_m / (load_A + \dots + load_K) +$	'no constraints
$a_2 * (cost_F + \dots + cost_K) * load_m / (load_F + \dots + load_K) +$	'Central East const
$a_3 * (cost_A + \dots + cost_I + cost_K) * load_m / (load_A + \dots + load_I + load_K) +$	'NYC constraint
$a_4 * cost_K * load_m / load_K +$	'LI constraint
$a_5 * (cost_F + \dots + cost_I + cost_K) * load_m / (load_F + \dots + load_I + load_K) +$	'Cent East + NYC
$a_6 * cost_K * load_m / load_K +$	'Cent East + LI
$a_7 * cost_K * load_m / load_K +$	'NYC + LI
$a_8 * cost_K * load_m / load_K$	'Cent East + LI + NYC

In all cases, the variables are:

$a_1 =$ fraction of time when no constraints exist

- a_2 = fraction of time when Central East interface alone is constraining
 - a_3 = fraction of time when Sprainbrook-Dunwoodie interface alone is constraining
 - a_4 = fraction of time when Con Ed-Long Island (including the Y49/Y50 lines) interfaces are constraining, but Central East and Sprainbrook-Dunwoodie interfaces are not constraining
 - a_5 = fraction of time when Central East and Sprainbrook-Dunwoodie interfaces are constraining
 - a_6 = fraction of time when Central East, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining
 - a_7 = fraction of time when Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining
 - a_8 = fraction of time when Central East, Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining
-
- $cost_{A...K}$ = revenue deficiencies due to DADRP Demand Reductions in Load Zones A...K, calculated on a hourly basis
 - $load_m$ = real-time Load for Transmission Customer m, calculated on an hourly basis
 - $load_{A...K}$ = real-time Loads for all Transmission Customers in Load Zones A...K, calculated on an hourly basis

24.2 Measurement of Actual Demand Reduction Scheduled in the Program

The measured amount of Demand Reduction supplied by a Demand Reduction Provider under the Program shall be the difference between the Demand Reduction Provider's baseline load for each scheduled hour, which shall be calculated in accordance with section 24.2.1 and ISO Procedures, and the actual metered hourly load for each scheduled hour.

24.2.1 Methodology for the Calculating the Economic Customer Baseline Load for a Resource Scheduled to Reduce Load Under the Program

The ISO shall employ two different calculation methodologies of the Economic Customer Baseline Load ("ECBL") for scheduled Demand Reductions, depending on whether the Demand Reduction is scheduled on a weekend or a weekday.

24.2.1.1 Definitions

Adjusted Weekday ECBL: For each hour of the scheduled Demand Reduction, the Adjusted Weekday ECBL shall be equal to the ECBL multiplied by the ECBL In-Day Adjustment Factor calculated for the scheduled Demand Reduction period.

ECBL In-Day Adjustment Factor: The ECBL In-Day Adjustment shall be an adjustment factor that is applied to the ECBL for each hour of the scheduled Demand Reduction period.

- a) Calculate the ECBL In-Day Adjustment by dividing the average of the metered load for the two hours of the ECBL In-Day Adjustment Period on the day of the scheduled Demand Reduction by the average of the ECBL for the same two hours.
- b) The ECBL In-Day Adjustment Factor shall be limited to a minimum of 0.8 and a maximum of 1.2.

ECBL In-Day Adjustment Period: The ECBL Adjustment Period is the time prior to the scheduled Demand Reduction period that is used to determine the ECBL In-Day Adjustment. The hours to be used in the ECBL Adjustment Period shall be the two consecutive hours that occur four hours prior to the first hour of the scheduled Demand Reduction period, provided that the hours are part of the same calendar day.

To determine the two hours of the ECBL In-Day Adjustment Period:

- a) The fourth hour before the first hour of the scheduled Demand Reduction period shall be the first hour of the ECBL In-Day Adjustment Period, except when the fourth hour before first hour of the scheduled Demand Reduction period occurs on the previous day.

- b) The third hour before the first hour of the scheduled Demand Reduction period shall be the second hour of the ECBL In-Day Adjustment Period, except when the third hour before the first hour of the scheduled Demand Reduction period occurs on the previous day.
- c) When the third and/or fourth hour of the ECBL In-Day Adjustment Period occurs on the previous day, the ISO shall use as a substitute the hour beginning midnight on the day of the scheduled Demand Reduction. Both hours of the ECBL In-Day Adjustment Period may equal the hour beginning midnight on the day of the scheduled Demand Reduction.

ECBL Weekday Window: The ECBL Weekday Window is the time period reviewed in determining the ECBL for any hour of scheduled Demand Reduction that takes place on a weekday. It shall consist of the hours from the previous ten weekdays that correspond to each hourly interval of the scheduled Demand Reduction period. Treatment of NERC holidays that occur on weekdays shall be equivalent to all hours scheduled on the NERC holiday.

ECBL Weekend Window: The ECBL Weekend Window is the time period reviewed in determining the ECBL for any hour of scheduled Demand Reduction that takes place on a weekend. It shall consist of the hours from the previous three weekend days of the same type (Saturday or Sunday) that correspond to each hourly-interval of the scheduled Demand Reduction period. Treatment of NERC holidays that occur on weekend days shall be equivalent to all hours scheduled on the NERC holiday.

Weekday Proxy: The Weekday Proxy is a value that is substituted for the metered load for any hour in any ECBL Weekday Window in which a Demand Reduction was scheduled. It shall be

determined by (1) establishing a new ECBL Weekday Window for that hour consisting of the corresponding hours in the ten weekdays preceding the day the Demand Reduction occurred, and (2) repeating the steps described at section 24.2.1.2 b, c, d, and e.

Weekend Proxy: The Weekend Proxy is a value that is substituted for the metered load for any hour in any ECBL Weekend Window in which a Demand Reduction was scheduled. It shall be determined by (1) establishing a new ECBL Weekend Window for that hour consisting of the corresponding hours in the three weekends preceding the day the Demand Reduction occurred, and (2) repeating the steps described at section 24.2.1.2 b, c, d, and e.

24.2.1.2 Methodology for the Calculating the Economic Customer Baseline Load for Demand Reductions Scheduled on a Weekday

To determine the ECBL for an hour of scheduled Demand Reduction (a “Target Hour”) that occurs on a weekday:

- a) Select the hours that comprise the ECBL Weekday Window for that Target Hour.
- b) Select the metered load value for each hour in the ECBL Weekday Window where no scheduled Demand Reduction occurred pursuant to this Program.
- c) For each hour of the ECBL Weekday Window where a scheduled Demand Reduction occurred, select the Weekday Proxy for that hour and day in place of the actual metered load for that hour.
- d) Rank in descending order the metered load and Weekday Proxy values determined in steps b and c.
- e) Calculate the average of the fifth and sixth ranked values. The value as so calculated shall be the ECBL for the Target Hour.

- f) Apply the ECBL In-Day Adjustment Factor to the ECBL to determine the Adjusted Weekday ECBL for the Target Hour.

24.2.1.3 Methodology for the Calculating the Economic Customer Baseline Load for a Resource's Demand Reduction Scheduled Under the Program on a Weekend

To determine the ECBL for a Target Hour that occurs on a weekend:

- a) Select the hours that comprise the ECBL Weekend Window for the Target Hour.
- b) Select the metered load value for each hour in the ECBL Weekend Window where no scheduled Demand Reduction occurred pursuant to this Program.
- c) For each hour of the ECBL Weekend Window where a Scheduled Demand Reduction occurred, select the ECBL Weekend Proxy for that hour and day in place of the actual metered load for the hour.
- d) Rank in descending order the metered load and ECBL Weekend Proxy values determined in steps b and c.
- e) Calculate the average of the metered load and ECBL Proxy values. The value so calculated is the ECBL for the Target Hour.
- f) Apply the ECBL In-Day Adjustment Factor to the ECBL to calculate the Adjusted Weekend ECBL for the Target Hour.

24.3 Verification of Actual Demand Reduction Scheduled in the Program

Demand Reduction calculated using the Economic Customer Baseline Load methodology is subject to verification by the ISO. Demand Reduction Providers shall report the data at the time and in the format required by the ISO pursuant to Section 24.4. If a Demand Reduction Provider fails to report the required data to the ISO in accordance with Section 24.4, the Demand Reduction Provider will be subject to penalties associated with a failure to supply the scheduled

Demand Reductions and may lose its eligibility to participate in the Program. All Demand Reduction data are subject to audit by the ISO. If the ISO determines that it has made an erroneous payment to a Demand Reduction Provider, it shall have the right to recover it either by reducing other payments to that Demand Reduction Provider or by any other lawful means.

24.4 Data Reporting Requirements for Demand Reduction Providers

The Demand Reduction Provider must submit to the ISO the information specified in this Section 24.4 for each Demand Side Resource that it has enrolled either as an individual DADRP resource or with other Demand Side Resources as part of a single, aggregated DADRP resource.

The Demand Reduction Provider must submit this information for the purpose of enrolling, registering, making settlements, and verifying the participation of each Demand Side Resource in the ISO's Energy market. To enroll and participate in the DADRP, a Demand Side Resource must have NYPSC-approved, revenue-quality, hourly-interval meters sufficient to calculate its net Load. If the Demand Side Resource has a Local Generator at its site, it must also have an hourly-interval meter that measures the total output of the Local Generator within a 2% accuracy threshold, regardless of whether at initial enrollment the Local Generator is intended to be used to provide Demand Reduction in the DADRP.

24.4.1 Data Reporting Requirements for Enrollment of Demand Side Resources Participating as DADRP Resources

The Demand Reduction Provider shall provide to the ISO the following information for each Demand Side Resource that is seeking to enroll, either individually or collectively with other Demand Side Resources, as a DADRP resource participating in the ISO's Energy market, which shall include providing information regarding each of the Demand Side Resource's interval meters required under Section 24.4:

- a. As-left meter test criteria, as prescribed in the New York Department of Public Service 16 NYCRR Part 92 Operating Procedure;
- b. Documentation to validate installation of interval meter equipment;
- c. Interval metering installation individual, company, and professional engineering license information;
- d. Make and model of installed interval metering device(s);
- e. Accuracy of installed interval metering device(s);
- f. Interval meter Current Transformer (CT) and Potential Transformer (PT) type designation, if applicable;
- g. CT Ratio, if applicable;
- h. Use of pulse data recorder as an interval metering device, if applicable;
- i. Pulse data recorder multiplier, if applicable;
- j. Any other type of meter multiplier used in the translation of data collected by the device for measuring demand, kWh, and/or MWh, if applicable;
- k. Its service address;
- l. Its Load Serving Entity;
- m. Its Transmission Owner;
- n. Its meter authority/Meter Data Service Provider;
- o. Demand Side Resource's maximum Winter and Summer reduction MW;
- p. Business classification of the Demand Side Resource (based on ISO-defined categories or national standards for business classification); and
- q. A description of any Local Generator at its site, including the Local Generator's system, its primary fuel type, the year in which it was built, the year of any

retrofit, its nameplate capacity, and its horsepower, if applicable.

24.4.2 Data Reporting Requirements for Verification of Energy Reductions of DADRP Resources Scheduled in the ISO's Energy Market

The meter authority or Meter Data Service Provider of the Demand Reduction Provider shall provide the ISO with the following required data from each interval meter required under Section 24.4 for each Demand Side Resource that is registered, either individually or collectively with other Demand Side Resources, as a DADRP resource, to verify the scheduled Load reduction of a DADRP resource in the ISO's Energy market:

- a) Totalized net hourly Load reduction data of the DADRP resource (*i.e.*, the net hourly Load reduction data totalized across all Demand Side Resources that are registered, either individually or collectively with other Demand Side Resources, as a DADRP resource) for the period of the scheduled Load reduction of the DADRP resource in the format required for reporting to the ISO's Settlement Data Exchange application;
- b) Hourly-interval metered Load data for each of the individual Demand Side Resources that is registered as part of a single DADRP resource, for all hours of the day on the days of the scheduled Load reduction of the DADRP resource; and
- c) Hourly-interval metered Load data for each of the individual Demand Side Resources that is registered as part of a single DADRP resource, for all hours of each of the thirty days preceding the day in which the DADRP resource is scheduled.

The meter authority or Meter Data Service Provider of the Demand Reduction Provider shall comply with the following when reporting Demand Reduction metering data to the ISO:

- a) Section 7.4.1 of the ISO Services Tariff;

- b) Section 13 of the ISO Services Tariff; and
- c) The ISO's Meter Data Management Protocols as provided on the ISO's website.

24.4.3 Additional Data Required Upon Request

To verify the participation of each Demand Side Resource that is enrolled, either individually or collectively with other Demand Side Resources, as a DADRP resource in the ISO's Energy market, Demand Reduction Providers and/or their meter authority/Meter Data Service Provider shall provide the ISO upon the ISO's request such additional information that may be required, including, but not limited, to the following:

- a) Any data reporting requirements of Attachments H and O to the ISO Services Tariff;
- b) Any data reporting requirements of Section 3.4 of the ISO Services Tariff;
- c) Historical Load documentation;
- d) Load data history for Pre- and Post-Validation, Edit and Estimation (VEE);
- e) Up to three months of historical Load data when enrolling a Demand Side Resource to participate in the ISO's Energy market;
- f) New and existing metering documentation, including, but not limited to:
 - 1. Calibration records;
 - 2. Time check;
 - 3. Sum check;
 - 4. High/Low check; and
 - 5. Zero value check.