Attachment I

31.1 New York Comprehensive System Planning Process ("CSPP")

31.1.1 Definitions

Throughout Sections 31.1 through 31.6, the following capitalized terms shall have the meanings set forth in this subsection:

Affected TO: The Transmission Owner who receives written notification of a dispute related to a Local Transmission Planning Process pursuant to Section 31.2.1.3.1.

Bounded Region: A Load Zone or Zones within an area that is isolated from the rest of the NYCA as a result of constrained interface limits.

CARIS: The Congestion Assessment and Resource Integration Study for economic planning developed by the ISO in consultation with the Market Participants and other interested parties pursuant to Section 31.3 of this Attachment Y.

CRP: The Comprehensive Reliability Plan as approved by the ISO Board of Directors pursuant to this Attachment Y.

CSPP: The Comprehensive System Planning Process set forth in this Attachment Y, which covers reliability planning, economic planning, cost allocation and cost recovery, and interregional planning coordination.

Developer: A person or entity, including a Transmission Owner, sponsoring or proposing a project pursuant to this Attachment Y.

ESPWG: The Electric System Planning Work Group, or any successor work group or committee designated to fulfill the functions assigned to the ESPWG in this tariff.

Five Year Base Case: The model representing the New York State Power System over the first five years of the Study Period.

Gap Solution: A solution to a Reliability Need that is designed to be temporary and to strive to be compatible with permanent market-based proposals. A permanent regulated solution, if appropriate, may proceed in parallel with a Gap Solution.

LCR: An abbreviation for the term Locational Installed Capacity Requirement, as defined in the ISO Open Access Transmission Tariff.

Loss of Load Expectation ("LOLE"): A measure used to determine the amount of resources needed to minimize the possibility of an involuntary loss of firm electric load on the New York State Bulk Power Transmission Facilities.

LTP: The Local Transmission Owner Plan, developed by each Transmission Owner, which describes its respective plans that may be under consideration or finalized for its own Transmission District.

LTP Dispute Resolution Process ("DRP"): The process for resolution of disputes relating to a Transmission Owner's LTP set out in Section 31.2.1.3.

LTPP: The Local Planning Process conducted by each Transmission Owner for its own Transmission District.

Management Committee: The standing committee of the ISO of that name created pursuant to the ISO Agreement.

Net CONE: The value representing the cost of new entry, net of energy and ancillary services revenues, utilized by the ISO in establishing the ICAP Demand Curves pursuant to Section 5 of the ISO Market Services Tariff.

New York State Bulk Power Transmission Facilities ("BPTFs"): The facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to NPCC by the ISO pursuant to NPCC requirements.

NPCC: The Northeast Power Coordinating Council, or any successor organization.

NYCA Free Flow Test: A NYCA unconstrained internal transmission interface test, performed by the ISO to determine if a Reliability Need is the result of a statewide resource deficiency or a transmission limitation.

NYDPS: The New York State Department of Public Service, as defined in the New York Public Service Law.

NYISO Load and Capacity Data Report: As defined in Section 25 of the ISO OATT.

NYPSC: The New York Public Service Commission, as defined in the New York Public Service Law.

Operating Committee: The standing committee of the NYISO of that name created pursuant to the ISO Agreement.

Other Developers: Parties or entities sponsoring or proposing to sponsor regulated economic projects or regulated solutions to Reliability Needs who are not Transmission Owners.

Reliability Criteria: The electric power system planning and operating policies, standards, criteria, guidelines, procedures, and rules promulgated by the North American Electric Reliability Council ("NERC"), Northeast Power Coordinating Council ("NPCC"), and the New York State Reliability Council ("NYSRC"), as they may be amended from time to time.

Reliability Need: A condition identified by the ISO as a violation or potential violation of one or more Reliability Criteria .

Responsible Transmission Owner: The Transmission Owner or Transmission Owners designated by the ISO, pursuant to Section 31.2.4.1, to prepare a proposal for a regulated backstop solution to a Reliability Need or to proceed with a regulated solution to a Reliability Need. The Responsible Transmission Owner will normally be the Transmission Owner in whose Transmission District the ISO identifies a Reliability Need.

RNA: The Reliability Needs Assessment as approved by the ISO Board under this Attachment.

Study Period: The ten-year time period evaluated in the RNA.

Target Year: The calendar year in which a Reliability Need arises, as determined by the ISO pursuant to Section 31.2.

TPAS: The Transmission Planning Advisory Subcommittee, or any successor work group or committee designated to fulfill the functions assigned to TPAS pursuant to this Attachment.

Trigger Date: The date by which the ISO must request implementation of a regulated backstop solution pursuant to Section 31.2.5.7 in order to meet a Reliability Need.

All other capitalized terms shall have the meanings provided for them in the ISO's tariffs.

31.1.2 Reliability Planning Process

Sections 31.2.1 through 31.2.6 of this Attachment describe the process that the ISO, the Transmission Owners, and Market Participants and other interested parties shall follow for planning to meet the Reliability Needs of the BPTFs. The objectives of the process are to: (1) evaluate the Reliability Needs of the BPTFs pursuant to Reliability Criteria (2) identify, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the BPTFs; (3) provide a process whereby solutions to identified needs are proposed, evaluated on a comparable basis, and implemented in a timely manner to ensure the reliability of the system; (4) provide an opportunity first for the implementation of market-based solutions while ensuring the reliability of the BPTFs; and (5) coordinate the ISO's reliability assessments with neighboring Control Areas.

The ISO will provide, through the analysis of historical system congestion costs, information about historical congestion including the causes for that congestion so that Market Participants and other stakeholders can make appropriately informed decisions. See Appendix A.

31.1.3 Transmission Owner Planning Process

The Transmission Owners will continue to plan for their transmission systems, including the BPTFs and other NYS Transmission System facilities. The planning process of each Transmission Owner is referred to herein as the LTPP, and the plans resulting from the LTPP are referred to herein as LTPs, whether under consideration or finalized. Each Transmission Owner will be responsible for administering its LTPP and for making provisions for stakeholder input into its LTPP. The ISO's role in the LTPP is limited to the procedural activities described in this Attachment Y.

The finalized portions of the LTPs periodically prepared by the Transmission Owners will be used as inputs to the Reliability Planning Process described in this Attachment Y. Each Transmission Owner will prepare an LTP for its transmission system in accordance with the procedures described in Section 31.2.1.

31.1.4 Economic Planning Process

Sections 31.3.1 and 31.3.2 of this Attachment Y describe the process that the ISO, the Transmission Owners, and Market Participants shall follow for economic planning to identify and reduce current and future projected congestion on the BPTFs. The objectives of the economic planning process are to: (1) project congestion on the BPTFs over the ten-year planning period of this CSPP, (2) identify, through the development of appropriate scenarios, factors that might produce or increase congestion, (3) provide a process whereby projects to reduce congestion identified in the economic planning process are proposed and evaluated on a comparable basis in a timely manner, (4) provide an opportunity for the development of market-based solutions to reduce the congestion identified, and (5) coordinate the ISO's congestion assessments and economic planning process with neighboring Control Areas.

31.1.5 Participation In The ESPWG and TPAS

For purposes of any matter addressed by this Attachment Y, participation in the ESPWG and TPAS shall be open to any interested entity, irrespective of whether that entity has become a Party to the ISO Agreement.

31.1.31.1.6 NYISO Implementation and Administration

31.1.6.1 The ISO shall adopt procedures for the implementation and administration of the CSPP set forth in this Attachment Y, and shall revise those procedures as and when necessary. Such procedures will be incorporated in the ISO's manuals, including ISO's Comprehensive System Planning Process Manual. The ISO Procedures shall provide for the open and transparent coordination of the CSPP to allow Market Participants and all other interested parties to have a meaningful opportunity to participate in each stage of the CSPP through the meetings conducted in accordance with the ISO system of collaborative governance. Confidential Information and Critical Energy Infrastructure Information exchanged through the CSPP shall be subject to the protections for such information contained in the ISO's tariffs and procedures, including this Attachment Y and Attachment F of the NYISO OATT.

31.1.6.2 The ISO Procedures shall include a schedule for the collection and submission of data and the preparation of models to be used in the studies contemplated under this tariff. That schedule shall provide for a rolling two-year cycle of studies and reports. Each cycle commences with the LTPP providing input into the Reliability Planning Process. When the Reliability Planning Process is completed, it is then followed by the Economic Planning Process.

31.1.6.3 The ISO Procedures shall be designed to allow the coordination of the ISO's planning activities with those of NERC, NPCC, the NYSRC, neighboring Control Areas and other regional reliability organizations so as to develop consistency of the models, databases, and assumptions utilized in making reliability and economic determinations.

31.1.6.4 The ISO Procedures shall facilitate the timely identification and resolution of all substantive and procedural disputes that arise out of the CSPP. Any party participating in the CSPP and having a dispute arising out of the CSPP may seek to have its dispute resolved in accordance with ISO governance procedures during the course of the CSPP. If the party's dispute is not resolved in this manner as a part of the plan development process, the party may invoke formal dispute resolution procedures administered by the ISO that are the same as those available to Transmission Customers under Section 11 of the ISO Market Administration and Control Area Services Tariff. Disputes arising out of the LTPP shall be addressed by the LTP DRP set forth in Section 31.2.1.3 of this Attachment Y.

31.1.6.5 Except for those cases where the ISO OATT provides that an individual customer shall be responsible for the cost, or a specified share of the cost, of an individually requested study related to interconnection or to system expansion or to congestion and resource integration, the study costs incurred by the ISO as a result of its administration of the CSPP will be recovered from all customers through and in accordance with Rate Schedule 1 of the ISO OATT.

31.2 Reliability Planning Process

31.2.1 Local Transmission Owner Planning Process

31.2.1.1 Criteria, Assumptions and Data

Each Transmission Owner will post on its website the planning criteria and assumptions currently used in its LTPP as well as a list of any applicable software and/or analytical tools currently used in the LTPP. Customers, Market Participants and other interested parties may review and comment on the planning criteria and assumptions used by each Transmission Owner, as well as other data and models used by each Transmission Owner in its LTPP. The Transmission Owners will take into consideration any comments received. Any planning criteria or assumptions for a Transmission Owner's BPTFs will meet or exceed any applicable NERC, NPCC or NYSRC criteria. The LTPP shall include a description of the needs addressed by the LTPP as well as the assumptions, applicable planning criteria and methodology utilized. A link to each Transmission Owner's website will be posted on the ISO website.

31.2.1.2 Process Timeline

31.2.1.2.1 Each Transmission Owner, in accordance with a schedule set forth in the ISO Procedures, will post its current LTP on its website for review and comment by interested parties sufficiently in advance of the time for submission to the ISO for input to its RNA so as to allow adequate time for stakeholder review and comment. Each LTP will include:

- identification of the planning horizon covered by the LTP,
- data and models used,
- issues addressed,

- potential solutions under consideration, and,
- a description of the transmission facilities covered by the plan.

31.2.1.2.2 To the extent the current LTP utilizes data or inputs, related to the ISO's planning process, not already reported by the ISO in Form 715 and referenced on its website, any such data will be provided to the ISO at the time each Transmission Owner posts criteria and planning assumptions in accordance with Section 31..2.1.1 and will be posted by the ISO on its website subject to any confidentiality or Critical Energy Infrastructure Information restrictions or requirements.

31.2.1.2.3 Each planning cycle, the ISO shall hold one or more stakeholder meetings of the ESPWG and TPAS at which each Transmission Owner's current LTP will be discussed. Such meetings will be held either at the Transmission Owner's Transmission District, or at an ISO location. The ISO shall post notice of the meeting and shall disclose the agenda and any other material distributed prior to the meeting.

31.2.1.2.4 Interested parties may submit written comments to a Transmission Owner with respect to its current LTP within thirty days after the meeting. Each Transmission Owner shall list on its website, as part of its LTP, the person and/or location to which comments should be sent by interested parties. All comments will be posted on the ISO website. Each Transmission Owner will consider comments received in developing any modifications to its LTP. Any such modification will be explained in its current LTP posted on its website pursuant to Section 31.2.1.2.2 above and discussed at the next meeting held pursuant to Section 31.2.1.2.3 above.

31.2.1.2.5 Each planning cycle, each Transmission Owner will submit the finalized portions of its current LTP to the ISO as contemplated in Section 31.2.2.4.2 below for timely inclusion in the RNA.

31.2.1.3 LTP Dispute Resolution Process

31.2.1.3.1 Disputes Related to the LTPP; Objective; Notice

Disputes related to the LTPP are subject to the DRP. The objective of the DRP is to assist parties having disputes in communicating effectively and resolving disputes as expeditiously as possible. Within fifteen (15) calendar days of the presentation by a Transmission Owner of its LTP to the ESPWG and TPAS, a party with a dispute shall notify in writing the Affected TO, the ISO, the ESPWG and TPAS of its intention to utilize the DRP. The notice shall identify the specific issue in dispute and describe in sufficient detail the nature of the dispute.

31.2.1.3.2 Review by the ESPWG/TPAS

The issue raised by a party with a dispute shall be reviewed and discussed at a joint meeting of the ESPWG and the TPAS in an effort to resolve the dispute. The party with a dispute and the Affected TO shall have an opportunity to present information concerning the issue in dispute to the ESPWG and the TPAS.

31.2.1.3.3 Information Discussions

To the extent the ESPWG and the TPAS are unable to resolve the dispute, the dispute will be subject to good faith informal discussions between the party with a dispute and the Affected TO. Each of those parties will designate a senior representative authorized to enter into informal discussions and to resolve the dispute. The parties to the dispute shall make a good faith effort to resolve the dispute through informal discussions as promptly as practicable.

31.2.1.3.4 Alternative Dispute Resolution

In the event that the parties to the dispute are unable to resolve the dispute through informal discussions within sixty (60) days, or such other period as the parties may agree upon, the parties may, by mutual agreement, submit the dispute to mediation or any other form of alternative dispute resolution. The parties shall attempt in good faith to resolve the dispute in accordance with a mutually agreed upon schedule but in no event may the schedule extend beyond ninety (90) days from the date on which the parties agreed to submit the dispute to alternative dispute resolution.

31.2.1.3.5 Notice of Results of Dispute Resolution

The Affected TO shall notify the ISO and ESPWG and TPAS of the results of the DRP and update its LTP to the extent necessary. The ISO shall use in its planning process the LTP provided by the Affected TO.

31.2.1.3.6 Rights Under the Federal Power Act

Nothing in the DRP shall affect the rights of any party to file a complaint with the Commission under relevant provisions of the FPA.

31.2.1.3.7 Confidentiality

All information disclosed in the course of the DRP shall be subject to the same protections accorded to confidential information and CEII by the ISO under its confidentiality and CEII policies.

31.2.2 Reliability Needs Assessment

31.2.2.1 General

The ISO shall prepare and publish the RNA as described below. The RNA will identify Reliability Needs. The ISO shall also designate in the RNA the Responsible Transmission Owner with respect to each Reliability Need.

31.2.2.2 Interested Party Participation in the Development of the RNA

The ISO shall develop the RNA in consultation with Market Participants and all other interested parties. TPAS will have responsibility consistent with ISO Procedures for review of the ISO's reliability analyses. ESPWG will have responsibility consistent with ISO Procedures for providing commercial input and assumptions to be used in the development of reliability assessment scenarios provided under Section 31.2.2.5, and in the reporting and analysis of historic congestion costs. Coordination and communication will be established and maintained between these two groups and ISO staff to allow Market Participants and other interested parties to participate in a meaningful way during each stage of the CSPP. The ISO staff shall report any majority and minority views of these collaborative governance work groups when it submits the RNA to the Operating Committee for a vote, as provided below.

31.2.2.3 Preparation of the Reliability Needs Assessment

31.2.2.3.1 The ISO shall evaluate bulk power system needs in the RNA over the Study Period.

31.2.2.3.2 The starting point for the development of the Five Year Base Case will be the system as defined for the FERC Form No. 715 Base Case. The details of the development of the Five Year Base Case are contained in the ISO Procedures.

31.2.2.3.3 The ISO shall assess the Five Year Base Case to determine whether the BPTFs meet all Reliability Criteria for both resource and transmission adequacy in each year, and report the results of its evaluation in the RNA. Transmission analyses will include thermal, voltage, short circuit, and stability studies. Then, if any Reliability Criteria are not met in any year, the ISO shall perform additional analyses to determine whether additional resources and/or transmission capacity expansion are needed to meet those requirements, and to determine the Target Year of need for those additional resources and/or transmission. The study will not seek to identify specific additional facilities. Reliability Needs will be defined in terms of total deficiencies relative to Reliability Criteria and not necessarily in terms of specific facilities.

31.2.2.3.4 The ISO will also evaluate the BPTFs over the second five years of the Study Period to determine whether they meet all Reliability Criteria for both resource and transmission adequacy in each year and report the results of its evaluation in the RNA. A short circuit assessment will be performed for the tenth year of the Study Period. Reliability Needs will be defined in terms of total deficiencies relative to Reliability Criteria and not necessarily in terms of specific facilities. The ISO will determine the Target Year for each Reliability Need so identified.

31.2.2.3.5 The ISO shall develop the system representation to be used for its evaluations of the second five years of the Study Period using (1) the most recent NYISO Load and Capacity Data Report published by the ISO on its web site; (2) the most recent versions of ISO reliability analyses and assessments provided for or published by NERC, NPCC, NYSRC, and neighboring Control Areas; (3) information reported by neighboring Control Areas such as power flow data, forecasted load, significant new or modified generation and transmission facilities, and anticipated system conditions that the ISO determines may impact the BPTFs; and (4) data submitted pursuant to paragraph 31.2.2.4 below.

31.2.2.4 Planning Participant Data Input

31.2.2.4.1 At the ISO's request, Market Participants, Developers, and other parties shall provide, in accordance with the schedule set forth in the ISO Procedures, the data necessary for the development of the RNA. This input will include but not be limited to (1) existing and planned additions to the New York State Transmission System (to be provided by Transmission Owners and municipal electric utilities); (2) proposals for merchant transmission facilities (to be provided by merchant Developers); (3) generation additions and retirements (to be provided by generator owners and Developers); (4) demand response programs (to be provided by demand response providers); and (5) any long-term firm transmission requests made to the ISO.

31.2.2.4.2 The Transmission Owners shall submit their current LTPs referenced in Section 31.1.1.2 and Section 31.2.1 to the ISO. The ISO will review the Transmission Owners' LTPs, as they relate to BPTFs, to determine whether they will meet Reliability Needs, recommend an alternate means to resolve the needs from a regional perspective, where appropriate, or indicate that it is not in agreement with a Transmission Owner's proposed additions. The ISO shall report its determinations under this section in the RNA and in the CRP.

31.2.2.4.3 All input received from Market Participants, Developers, and other parties shall be considered in the development of the system representation for the Study Period in accordance with the ISO Procedures.

31.2.2.5 Reliability Scenario Development

The ISO, in consultation-with the ESPWG and TPAS, shall develop reliability scenarios addressing the first five years and the second five years of the Study Period. Variables for consideration in the development of these reliability scenarios include but are not limited to: load forecast uncertainty, fuel prices and availability, new resources, retirements, transmission network topology, and limitations imposed by proposed environmental or other legislation.

31.2.2.6 Evaluation of Alternate Reliability Scenarios

The ISO will conduct additional reliability analyses for the alternate reliability scenarios developed pursuant to paragraph 31.2.2.5. These evaluations will test the robustness of the needs assessment studies conducted under paragraphs 31.2.2.3. This evaluation will only identify conditions under which Reliability Criteria may not be met. It will not identify or propose additional Reliability Needs. In addition, the ISO will perform appropriate sensitivity studies to determine whether Reliability Needs previously identified can be mitigated through alternate system configurations or operational modes. The Reliability Needs may increase in some reliability scenarios and may decrease, or even be eliminated, in others. The ISO shall report the results of these evaluations in the RNA.

31.2.2.7 Reliability Needs Assessment Report Preparation

Once all the analyses described above have been completed, ISO staff will prepare a draft of the RNA including discussion of its assumptions, Reliability Criteria, and results of the analyses and, if necessary, designate the Responsible Transmission Owner.

31.2.3 RNA Review Process

31.2.3.1 Collaborative Governance Process

The draft RNA shall be submitted to both TPAS and the ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to replicate the results of the draft RNA. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of the TPAS and ESPWG review, the draft RNA reflecting the revisions resulting from the TPAS and ESPWG review, shall be forwarded to the Operating Committee for discussion and action. The ISO shall notify the Business Issues Committee of the date of the Operating Committee meeting at which the draft RNA is to be presented. Following the Operating Committee vote, the draft RNA will be transmitted to the Management Committee for discussion and action.

31.2.3.2 Board Action

Following the Management Committee vote, the draft RNA, with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft RNA will be provided to the Market Monitoring

Unit for its review and consideration of whether market rules changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. The Board may approve the RNA as submitted, or propose modifications on its own motion. If any changes are proposed by the Board, the revised RNA shall be returned to the Management Committee for comment. The Board shall not make a final determination on a revised RNA until it has reviewed the Management Committee comments. Upon approval by the Board, the ISO shall issue the final RNA to the marketplace by posting it on its web site.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of this Attachment are also addressed in Section 30.4.6.8.2 of the Market Monitoring Plan, Attachment O to the ISO OATT.

31.2.3.3 Needs Assessment Disputes

Notwithstanding any provision to the contrary in this Attachment, the ISO OATT, or the NYISO Services Tariff, in the event that a Market Participant raises a dispute solely within the NYPSC's jurisdiction relating to the final conclusions or recommendations of the RNA, a Market Participant may refer such dispute to the NYPSC for resolution. The NYPSC's final determination shall be binding, subject only to judicial review in the courts of the State of New York pursuant to Article 78 of the NYCPLR.

31.2.3.4 Public Information Sessions

In order to provide ample exposure for the marketplace to understand the identified Reliability Needs, the ISO will provide various opportunities for Market Participants and other potentially interested parties to discuss the final RNA. Such opportunities may include presentations at various ISO Market Participant committees, focused discussions with various industry sectors, and/or presentations in public venues.

31.2.4 Development of Solutions to Reliability Needs

31.2.4.1 Regulated Backstop Solutions

31.2.4.1.1 When a Reliability Need is identified in any RNA issued under this tariff, the ISO shall request and the Responsible Transmission Owner shall provide to the ISO, as soon as reasonably possible, a proposal for a regulated solution or combination of solutions that shall serve as a backstop to meet the Reliability Need if requested by the ISO due to the lack of sufficient viable market-based solutions to meet such Reliability Needs identified for the Study Period. Regulated backstop solutions may include generation, transmission, or demand side resources. Except as provided in Section 31.2.4.2.1, a proposed regulated backstop solution to address a Reliability Need that arises in the second five years of the Study Period will not require the same level of detail as a proposed solution for a Reliability Need arising in the first five years. Such proposals may include reasonable alternatives that would effectively address the Reliability Need; provided however, the Responsible Transmission Owner's obligation to propose and implement regulated backstop solutions under this tariff is limited to regulated transmission solutions. The Responsible Transmission Owner shall also estimate the lead time necessary for the implementation of its proposal. The ISO shall independently analyze the lead time required for implementation of the proposed potential regulated backstop solution. The ISO shall use the Responsible Transmission Owner estimate and its analysis to establish the Trigger Date for the Responsible Transmission Owner's regulated backstop solution. The ISO will also independently establish benchmark lead times for responses submitted pursuant to Sections 31.2.4.3 and 31.2.4.5.. Prior to providing its response to the RNA, each Responsible Transmission Owner will present for discussion at the ESPWG and TPAS any updates in its LTP that impact a Reliability Need identified in the RNA. Should more than one regulated backstop solution be proposed to address a Reliability Need, it will be the responsibility of the Responsible Transmission Owner to determine the regulated backstop solution that will proceed following a finding by the ISO under Section 31.2.6.4 of this Attachment Y. The determination by the Responsible Transmission Owner will be made prior to the approval of the CRP which precedes the Trigger Date for the regulated backstop solution with the longest lead time. Contemporaneous with the request to the Responsible Transmission Owner, the ISO shall solicit market-based and alternative regulated responses as set forth in Sections 31.2.4.3 and 31.2.4.5, which shall not be a formal RFP process.

31.2.4.2 Qualifications for Regulated Backstop Solutions

31.2.4.2.1 For Reliability Needs identified as occurring during the first five years of the Study Period, the submission of a regulated backstop solution shall include, at a minimum, the following details: (1) the lead time necessary to complete the project, (2) a description of the project, including planning and engineering specifications as appropriate, (3) evidence of a commercially viable technology, (4) a major milestone schedule, (5) a schedule for obtaining required siting permits and other certifications, (6) a demonstration of site control or a schedule for obtaining such control, (7) status of ISO interconnection studies and interconnection agreement, (8) status of equipment procurement, and (9) any other information requested by the ISO. These details also be provided for any regulated backstop solution proposed to address a Reliability Need identified during the second five years of the Study Period if the lead time for that regulated backstop solution has a Trigger Date within one planning cycle of the date that the Responsible Transmission Owner presents its proposed regulated backstop solution**.** If the regulated backstop solution does not meet the needs identified in the RNA, the ISO will provide sufficient information to the Responsible Transmission Owner to determine how the regulated backstop should be modified to meet the identified Reliability Needs. The Responsible Transmission Owner will make necessary changes to its proposed regulated backstop solution to address reliability deficiencies identified by the ISO, and submit a revised proposal to the ISO for review and approval.

31.2.4.2.2 Except as provided above, the submission of a proposed regulated backstop solution for a Reliability Need projected to occur during the second five years of the Study Period must include, at a minimum, the following: (1) an explanation of how the Responsible Transmission Owner considered, in the development of its proposal, one (or more) compensatory MW scenarios developed by the ISO as a guide to the development of proposed solutions that appear most likely to meet the statewide LOLE criterion of one day in ten years, (2) a description of the type of preliminary solution(s) or a variety of preliminary solution(s) (generation, demand-side, transmission, or any combination thereof) that could meet the need, (3) an estimate of the potential MW impact if either a generation or demand side solution is proposed, (4) for proposed transmission solutions, an identification of the zones where the potential solution may be located, as well as an identification indicating some general characteristics such as voltage level and approximate capacity, (5) for proposed transmission capacitor bank solutions, an identification of the MW amount of the voltage constrained interface that the Responsible Transmission Owner intends to restore up to the thermal limits of the interface, along with a commitment to size the capacitor bank solution to achieve this amount of restoration, (6) an estimated implementation time, or range of implementation times, to allow the ISO to establish a preliminary Trigger Date, and (7) any other information requested by the ISO. In addition to the foregoing, a Responsible Transmission Owner may propose at any time a specific solution to a Reliability Need projected to occur during the second five years of the Study Period. Because the potential needs indicated by each RNA for years six through ten are a preliminary assessment of future conditions based on assumptions that will evolve over time using analysis that can only be conducted by the ISO staff, the solutions proposed by the Responsible Transmission Owner may change in response to subsequent RNAs. The Responsible Transmission Owner must continue to collaborate with ISO staff to determine how the preliminary backstop solutions could meet the preliminary needs identified in years six through ten (6-10) of each RNA Study Period.

31.2.4.2.3 Market Participants and other interested parties may submit at any time optional suggestions for changes to ISO rules or procedures which could result in the identification of additional resources or market alternatives suitable for meeting Reliability Needs.

31.2.4.3 Market-Based Responses

At the same time that a proposal for a regulated backstop solution is requested from the Responsible Transmission Owner under Section 31.2.4.1, the ISO shall also request market-based responses from the market place. Subject to the execution of appropriately drawn confidentiality agreements and the Commission's standards of conduct, the ISO and the appropriate Transmission Owner or Transmission Owners shall provide any party who wishes to develop such a response access to the data that is necessary to develop its response. Such data shall only be used for the purposes of preparing a market-based response to a Reliability Need under this section. Such responses will be open on a comparable basis to all resources, including generation, demand response providers, and merchant transmission Developers.

31.2.4.4 Qualifications for a Valid Market-Based Response

The submission of a proposed market-based solution must include: (1) evidence of a commercially viable technology, (2) a major milestone schedule, (3) evidence of site control, or a plan for obtaining site control, (4) the status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place, (5) the status of any interconnection studies and an Interconnection Agreement, (6) the status of any required permits, (7) the status of equipment procurement, (8) evidence of financing, and (9) any other information requested by the ISO. Failure to provide any data requested by the ISO within a reasonable period of time (not to exceed 60 days from the date of the ISO request) will result in the rejection of the proposed market-based solution from further consideration. The ISO will perform continuing analyses of the viability of a proposed market-based solution as follows: (1) between three and five years before the Trigger Date for the regulated backstop solution, the ISO will use a screening analysis to verify the feasibility of the proposed market-based solution (this analysis will not require final permit approvals or final contract documents), (2) between one and two years before the Trigger Date for the regulated backstop solution, the ISO will perform a more extensive review of the proposed market-based solution, including such elements as status of interconnection studies, contract negotiations, permit applications, financing, and site control, and (3) less than one year before the Trigger Date for the regulated backstop solution, the ISO will perform a detailed review of the proposed market-based solution status and schedule. For the review conducted less than one year before the Trigger Date, the ISO will consider, among other things, whether the proposed market-based solution has obtained its final permits, any required interconnection studies have been completed, the status of an interconnection agreement, that financing is in place, and equipment is on order. If the ISO, following its analysis, determines that a proposed market-based solution is no longer viable to meet the Reliability Need, the proposed market-based solution will be removed from the list of potential market-based solutions.

31.2.4.5 Alternative Regulated Responses

31.2.4.5.1 The ISO will request alternative regulated responses to Reliability Needs at the same time that it requests market- based responses and regulated backstop solutions. Such proposals may include reasonable alternatives that would effectively address the identified Reliability Need.

31.2.4.5.2 In response to the ISO’s request, Other Developers may develop alternative regulated proposals for generation, demand side alternatives, and/or other solutions to address a Reliability Need and submit such proposals to the ISO. Transmission Owners, at their option, may submit additional proposals for regulated solutions to the ISO. Transmission Owners and Other Developers may submit such proposals to the NYDPS for review at any time. Subject to the execution of appropriately drawn confidentiality agreements and the Commission's standards of conduct, the ISO and the appropriate Transmission Owner(s) shall provide Other Developers access to the data that is needed to develop their proposals. Such data shall be used only for purposes of preparing an alternative regulated proposal in response to a Reliability Need.

31.2.4.6 Qualifications for Alternative Regulated Solutions

The submission of a proposed alternative regulated solution must include: (1) evidence of a commercially viable technology, (2) a major milestone schedule, (3) evidence of site control, or a plan for obtaining site control, (4) the status of any contracts (other than an Interconnection Agreement) that are under negotiation or in place, (5) the status of any interconnection studies and an Interconnection Agreement, (6) the status of any required permits, (7) the status of equipment procurement, (8) evidence of financing, and (9) any other information requested by the ISO. Failure to provide any data requested by the ISO within a reasonable period of time (not to exceed 60 days from the date of the ISO request) will result in the rejection of the proposed alternative regulated solution from further consideration. A proponent of a proposed alternative regulated solution must notify the ISO immediately of any material change in status of a proposed alternative regulated solution. For purposes of this provision, a material change includes, but is not limited to, a change in the financial viability of the developer, a change in the siting status of the project, or a change in a major element of the project's development. If the ISO, at any time, learns of a material change in the status of a proposed alternative regulated solution, it may, at that time, make a determination as to the continued viability of the proposed alternative regulated solution. The ISO will perform continuing analyses of the viability of a proposed alternative regulated solution as follows: (1) between three and five years before the Trigger Date for the regulated backstop solution identified in the CRP as meeting the same Reliability Need, the ISO will use a screening analysis to verify the feasibility of the proposed alternative regulated solution (this analysis will not require final permit approvals or final contract documents), (2) between one and two years before the Trigger Date for the regulated backstop solution, the ISO will perform a more extensive review of the proposed alternative regulated solution, including such elements as status of interconnection studies, contract negotiations, permit applications, financing, and site control, and (3) less than one year before the Trigger Date for the regulated backstop solution, the ISO will perform a detailed review of the proposed alternative regulated solution status and schedule. For the review conducted less than one year before the Trigger Date, the ISO will consider, among other things, whether the proposed alternative regulated solution has obtained its final permits, any required interconnection studies have been completed, an interconnection agreement has been filed, financing is in place, and that equipment is on order. If the ISO, following its analysis, determines that a proposed alternative regulated solution is no longer viable to meet the Reliability Need, the proposed alternative regulated solution will be removed from the list of potential alternative regulated solutions.

31.2.4.7 Additional Solutions

Should the ISO determine that it has not received adequate regulated backstop or market-based solutions to satisfy the Reliability Need, the ISO may, in its discretion, solicit additional regulated backstop or market-based solutions. Other Developers may submit additional alternative regulated solutions for the ISO's consideration at that time.

31.2.5 ISO Evaluation of Proposed Solutions to Reliability Needs

31.2.5.1 Comparable Evaluation of All Proposed Solutions

When evaluating proposed solutions to Reliability Needs, all resource types shall be considered on a comparable basis as potential solutions to the Reliability Needs identified: generation, transmission, and demand response.

31.2.5.2 Evaluation of Regulated Backstop Solutions

The ISO shall evaluate a proposed regulated backstop solution submitted by a Responsible Transmission Owner pursuant to Section 31.2.4.1 to determine whether it will meet the identified Reliability Need in a timely manner, and will report the results of its evaluation in the CRP.

31.2.5.3 Evaluation of Market Based Proposals

The ISO shall review proposals for market-based solutions and determine whether they resolve a Reliability Need. If market-based solutions are found by the ISO to be sufficient to meet a Reliability Need in a timely manner, the ISO will so state in the CRP. The ISO will not select from among the market-based solutions if there is more than one proposal which will meet the same Reliability Need.

31.2.5.4 Evaluation of Alternative Regulated Responses

If the ISO determines that the submitted market-based solutions are sufficient to resolve the identified Reliability Needs, the ISO will perform a high-level review of any proposed alternative regulated solutions submitted in accordance with Section 31.2.4.5 above. If the ISO determines that the submitted market-based solutions do not resolve an identified Reliability Need, the ISO will perform a more detailed review of the proposed alternative regulated solutions. In either case, the ISO will report the results of its review in the CRP.

31.2.5.5 Resolution of Deficiencies

Following initial review of the proposals, as described above, ISO staff will identify any reliability deficiencies in each of the proposed solutions. The Responsible Transmission Owner, Transmission Owner or Other Developer will discuss any identified deficiencies with the ISO staff. Other Developers and Transmission Owners that propose alternative regulated solutions shall have the option to revise and resubmit their proposals to address any identified deficiency. With respect to regulated backstop solutions proposed by a Responsible Transmission Owner pursuant to Section 31.2.4.1, the Responsible Transmission Owner shall make necessary changes to its proposed backstop solution to address any reliability deficiencies identified by the ISO, and submit a revised proposal to the ISO for review. The ISO shall review all such revised proposals to determine that all of the identified deficiencies have been resolved.

31.2.5.6 Designation of Regulated Backstop Solution and Responsible Transmission Owner

If the ISO determines that a market-based solution will not be available in time to meet a Reliability Need, and finds that it is necessary to take action to ensure reliability, it will state in the CRP that implementation of a regulated solution is necessary. The ISO will also identify in the CRP (1) the regulated backstop solution that the ISO has determined will meet the Reliability Need in a timely manner, and (2) the Responsible Transmission Owner.

31.2.5.7 Determination of Necessity

31.2.5.7.1 If the ISO determines in the CRP, or at any time, that implementation of a regulated backstop solution reviewed in a previous RNA/CRP cycle is necessary, the ISO will request the Responsible Transmission Owner to submit its proposal for a regulated backstop solution to the appropriate governmental agency(ies) and/or authority(ies) to begin the necessary approval process. The Responsible Transmission Owner in response to the ISO request shall make such a submission. Other Developers and Transmission Owners proposing alternative regulated solutions pursuant to Section 31.2.4.5.2 that have completed any changes required by the ISO under Section 31.2.5.4, which the ISO has determined will resolve the identified Reliability Need, may submit these proposals to the appropriate governmental agency(ies) and/or authority(ies) for review. The appropriate governmental agency(ies) and/or authority(ies) with jurisdiction over the implementation or siting will determine whether the regulated backstop solution or an alternative regulated solution will be implemented to address the identified Reliability Need. If the appropriate governmental agency(ies) and/or authority(ies) makes a final determination that an alternative regulated solution is the preferred solution to a Reliability Need and that the regulated backstop solution should not be implemented, implementation of the alternative regulated solution will be the responsibility of the Transmission Owner or Other Developer that proposed the alternative regulated solution, and the Responsible Transmission

Owner will not be responsible for addressing the Reliability Need through the implementation of its regulated backstop solution. Should the alternative regulated solution not be implemented, the ISO may request a Gap Solution pursuant to Section 31.2.5.10 of this Attachment Y.

31.2.5.7.2 If the ISO determines that it is necessary for the Responsible Transmission Owner to proceed with a regulated backstop solution evaluated in the CRP in parallel with a market-based solution in order to ensure that a Reliability Need is met in a timely manner, the Responsible Transmission Owner shall proceed with due diligence to develop it in accordance with Good Utility Practice unless or until notified by the ISO that it has determined that the regulated backstop solution is no longer needed.

31.2.5.7.3 If, after consultation with the Responsible Transmission Owner, the ISO determines that the Responsible Transmission Owner has not submitted its proposed regulated backstop solution for necessary regulatory action within a reasonable period of time, or that the Responsible Transmission Owner has been unable to obtain the approvals or property rights necessary under applicable law to construct the project, the ISO shall submit a report to the Commission for its consideration and determination of whether any action is appropriate under federal law.

31.2.5.8 Process for Consideration of Regulated Backstop Solution and Alternative Regulated Solutions

Upon a determination by the ISO under Section 31.2.5.7 that a regulated solution should proceed, the Responsible Transmission Owner will make a presentation to the ESPWG that will provide a description of the regulated backstop solution. The presentation will include a non-binding preliminary cost estimate of that backstop solution; provided, however, that a Responsible Transmission Owner shall be entitled to full recovery of all reasonably incurred costs related to the regulated backstop solution. Any alternative regulated solution proponent seeking regulated cost recovery for its project will also make a presentation to the ESPWG at the time of the above finding by the ISO providing a description of the alternative regulated solution, including a non-binding preliminary cost estimate of the project. The ISO and stakeholders through this process will have the opportunity to review and discuss the scope of the projects and their associated non-binding preliminary cost estimates prior to implementation.

31.2.5.9 Regulated Backstop Solution to Proceed in Parallel with a Market-based Solution

If the ISO determines that it is necessary for the Responsible Transmission Owner to proceed with a regulated backstop solution to be conducted in parallel with a market-based solution in order to ensure that a Reliability Need is met in a timely manner, the CRP will so state.

31.2.5.10 Gap Solutions

31.2.5.10.1 If the ISO determines that neither market-based proposals nor regulated proposals can satisfy the Reliability Needs in a timely manner, the ISO will set forth its determination that a Gap Solution is necessary in the CRP. The ISO will also request the Responsible Transmission Owner to seek a Gap Solution**.** Gap Solutions may include generation, transmission, or demand side resources.

31.2.5.10.2 If there is an imminent threat to the reliability of the New York State Power System, the ISO Board, after consultation with the NYDPS, may request the appropriate Transmission Owner or Transmission Owners to propose a Gap Solution outside of the normal planning cycle.

31.2.5.10.3 Upon the ISO's determination of the need for a Gap Solution, pursuant to Sections 31.2.5.10.1 or 31.2.5.10.2 above, the Responsible Transmission Owner will propose such a solution as soon as reasonably possible, for consideration by the ISO and NYDPS.

31.2.5.10.4 Any party may submit an alternative Gap Solution proposal to the ISO and the NYDPS for their consideration. The ISO shall evaluate all Gap Solution proposals to determine whether they will meet the Reliability Need or imminent threat. The ISO will report the results of its evaluation to the party making the proposal as well as to the NYDPS and/or other appropriate governmental agency(ies) and/or authority(ies) for consideration in their review of the proposals. The appropriate governmental agency(ies) and/or authority(ies) with jurisdiction over the implementation or siting of Gap Solutions will determine whether the Gap Solution or an alternative Gap Solution will be implemented to address the identified Reliability Need.

31.2.5.10.5 Gap Solution proposals submitted under Sections 31.2.5.10.3 and 31.2.5.10.4 shall be designed to be temporary solutions and to strive to be compatible with permanent market-based proposals.

31.2.5.10.6 A permanent regulated solution, if appropriate, may proceed in parallel with a Gap Solution.

31.2.5.11 Confidentiality of Solutions

31.2.5.11.1 The term "Confidential Information" shall include all types of solutions to Reliability Needs that are submitted to the ISO as a response to Reliability Needs identified in any RNA issued by the ISO as part of the Reliability Planning Process if the Developer of that solution designates such reliability solutions as "Confidential Information."

31.2.5.11.2 For regulated backstop solutions and plans submitted by the Responsible Transmission Owner in response to the findings of the RNA, the ISO shall maintain the confidentiality of same until the ISO and the Responsible Transmission Owner have agreed that the Responsible Transmission Owner has submitted sufficient regulated backstop solutions and plans to meet the Reliability Needs identified in an RNA. Thereafter, the ISO shall disclose the regulated backstop solutions and plans to the Market Participants; however, any preliminary cost estimates that may have been provided to the ISO shall not be disclosed.

31.2.5.11.3 For an alternative regulated response, the ISO shall determine, after consulting with the Developer thereof, whether the response would meet part or all of the Reliability Needs identified in an RNA, and thereafter disclose the alternative regulated response to the Market Participants and other interested parties; however, any preliminary cost estimates that may have been provided to the ISO shall not be disclosed.

31.2.5.11.4 For a market-based response, the ISO shall maintain the confidentiality of same during the Reliability Planning Process and in the CRP, except for the following information which may be disclosed by the ISO: (i) the type of resource proposed (e.g., generation, transmission, demand side); (ii) the size of the resource expressed in megawatts of equivalent load that would be served by that resource; (iii) the subzone in which the resource would interconnect or otherwise be located; and (iv) the proposed in-service date of the resource.

31.2.5.11.5 In the event that the Developer of a market-based response has made a public announcement of its project or has submitted a proposal for interconnection with the ISO, the ISO shall disclose the identity of the market-based Developer and the specific project during the Reliability Planning Process and in the CRP.

31.2.6 Comprehensive Reliability Plan

Following the ISO's evaluation of the proposed market-based and regulated solutions to Reliability Needs, the ISO will prepare a draft CRP. The draft CRP shall set forth the ISO's findings and recommendations, including any determination that implementation of a regulated solution (which may be a Gap Solution) is necessary to ensure system reliability.

31.2.6.1 Collaborative Governance Process

The ISO staff shall submit the draft CRP to TPAS and ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to replicate the results of the draft CRP. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of the TPAS and ESPWG review, the draft CRP reflecting the revisions resulting from the TPAS and ESPWG review shall be forwarded to the Operating Committee for a discussion and action. The ISO shall notify the Business Issues Committee of the date of the Operating Committee meeting at which the draft

CRP is to be presented. Following the Operating Committee vote, the draft CRP will be transmitted to the Management Committee for a discussion and action.

31.2.6.2 Board Action

Following the Management Committee vote, the draft CRP, with working group, Operating Committee, and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CRP will also be provided to the Market Monitoring Unit for its review and consideration of whether market rule changes are necessary to address an identified failure, if any, in one of the ISO's competitive markets. The Board may approve the draft CRP as submitted or propose modifications on its own motion. If any changes are proposed by the Board, the revised CRP shall be returned to the Management Committee for comment. The Board shall not make a final determination on the draft CRP until it has reviewed the Management Committee comments. Upon final approval by the Board, the ISO shall issue the CRP to the marketplace by posting on its website. The ISO will provide the CRP to the appropriate regulatory agency(ies) for consideration in their review of the proposals.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Attachment Y to the ISO OATT are also addressed in Section 30.4.6.8.3 of the Market Monitoring Plan, Attachment O to the ISO OATT.

31.2.6.3 Reliability Disputes

Notwithstanding any provision to the contrary in this Attachment, the ISO OATT, or the NYISO Services Tariff, in the event that a Market Participant or other interested party raises a dispute solely within the NYPSC's jurisdiction concerning ISO's final determination in the CRP that a proposed solution will or will not meet a Reliability Need, a Market Participant or other interested party seeking further review shall refer such dispute to the NYPSC for resolution, as provided for in the ISO Procedures. The NYPSC's final determination of such disputes shall be binding, subject only to judicial review in the courts of the State of New York pursuant to Article 78 of the New York Civil Practice Law and Rules.

31.2.7 Monitoring of Reliability Project Status

31.2.7.1 The ISO will monitor and report on the status of market-based solutions to ensure their continued viability to meet Reliability Needs on a timely basis in the CRP. The ISO's criteria to assess the continued viability of such projects are included in the ISO Procedures.

31.2.7.2 The ISO will monitor and report on the status of regulated solutions to ensure their continued viability to meet Reliability Needs on a timely basis in the CRP. The ISO's criteria to assess the continued viability of such projects are included in the ISO Procedures.

31.2.7.3 The ISO will apply the criteria in this Section 31.2.7.3 for halting a regulated backstop solution that is already underway because the ISO has determined that a viable market-based solution will meet the same Reliability Need. These criteria shall also include a cut-off point as provided in Section 31.2.7.3.2 following which a regulated backstop solution may not be halted regardless of the status of a market-based solution.

31.2.7.3.1 The ISO shall review proposals for market-based solutions, pursuant to Section 31.2.5.3 of this Attachment Y. If, based on the availability of market-based solution(s) to meet the identified Reliability Need, the ISO determines that the regulated backstop solution is no longer needed and should be halted, it will immediately notify the Responsible Transmission Owner and will so state in the

CRP. If a regulated backstop solution is halted by the ISO, all of the costs incurred and commitments made by the Responsible Transmission Owner up to that point, including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable by the Responsible Transmission Owner under the cost recovery mechanism in Rate Schedule 10 of this tariff regardless of the nature of the solution.

31.2.7.3.2 Once the Responsible Transmission Owner submits its application for state regulatory approval of the regulated backstop solution, pursuant to Section 31.2.5.7 of this Attachment Y, or, if state regulatory approval is not required, once the Responsible Transmission Owner submits its application for any necessary regulatory approval, the entry of a market-based solution will not result in the halting by the ISO of the regulated backstop solution. The ISO, however, will continue to monitor proposed market-based solutions to determine their ability to meet the identified Reliability Need, and will provide the results of its review to the Responsible Transmission Owner, Market Participants and the appropriate state regulatory agency(ies).

31.2.7.3.3 If a material modification to the regulated backstop solution is proposed by any federal, state or local agency, the Responsible Transmission Owner will request the ISO to conduct a supplemental reliability review. If the NYISO identifies any reliability deficiency in the modified solution, the ISO will so advise the Responsible Transmission Owner and the appropriate federal, state or local regulatory agency(ies).

31.2.7.3.4 If the appropriate federal, state or local agency(ies) does not approve a necessary authorization for the regulated backstop solution, all of the necessary and reasonable costs incurred and commitments made up to the final federal, state or local regulatory decision, including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable by the Responsible Transmission Owner under the ISO cost recovery mechanism in Rate Schedule 10 of this tariff regardless of the nature of the solution.

31.2.7.3.5 The ISO is not required to review market-based solutions to determine whether they will meet the identified Reliability Need in a timely manner after the regulated backstop solution has received federal and state regulatory approval, unless a federal or state regulatory agency requests the ISO to conduct such a review. The ISO will report the results of its review to the federal or state regulatory agency, with copies to the Responsible Transmission Owner.

31.2.7.3.6 If a necessary federal, state or local authorization for a regulated backstop solution is withdrawn, all expenditures and commitments made up to that point including reasonable and necessary expenses incurred to implement an orderly termination of the project, will be recoverable under the ISO cost recovery mechanism in Rate Schedule 10 of this tariff by the Responsible Transmission Owner regardless of the nature of the solution. When an alternative regulated solution proposed by a Transmission Owner or Other Developer has been determined by the NYPSC or other State authorities to be the preferred solution to a Reliability Need and the Transmission Owner or Other Developer makes all best efforts to obtain necessary federal, state or local authorization, but these authorizations are not granted or are withdrawn, then all reasonably incurred expenditures and necessary expenses incurred to implement an orderly termination of the project will be recoverable under the ISO cost recovery mechanism in Rate Schedule 10 of this tariff by the Transmission Owner or Other Developer, provided that such expenditures and commitments were before the NYPSC or other State authorities when it made its determination that the alternative regulated solution is the preferred solution.

31.2.7.4 The ISO will apply the criteria in this Section 31.2.7.4 for determining the cutoff date for a determination that a market-based solution will not be available to meet a Reliability Need on a timely basis.

31.2.7.4.1 In the first instance, the ISO shall employ its procedures for monitoring the viability of a market-based solution to determine when it may no longer be viable. Under the conditions where a market-based solution is proceeding after the Trigger Date for the relevant regulated backstop solution, it becomes even more critical for the ISO to conduct a continued analysis of the viability of such market-based solutions.

31.2.7.4.2 The Developer of such a market-based solution shall submit updated information to the ISO twice during each Reliability Planning Process cycle, first during the input phase of the RNA, and again during the solutions phase during the period allowed for the solicitation for market-based and regulated backstop solutions. If no solutions are requested in a particular year, then the second update will be provided during the ISO's analysis of whether existing solutions continue to meet identified Reliability Needs. The updated information of the project status shall include: status of final permits, status of major equipment, current status of construction schedule, estimated in-service date, any potential impediments to completion by the Target Year, and any other information requested by the ISO.

31.2.7.4.3 The Developer shall immediately report to the ISO when it has any indication of a material change in the project status or that the project in-service date may slip beyond the Target Year. A material change shall include, but not be limited to, a change in the financial viability of the Developer, a change in siting status, or a change in a major element of the project development.

31.2.7.4.4 Based upon the above information, the ISO will perform an independent review of the development status of the market-based solution to determine whether it remains viable to meet the identified Reliability Need in a timely manner. If the ISO, at any time, learns of a material change in the project status of a market-based solution, it may, at that time, make a determination as to the continued viability of such project.

31.2.7.4.5 The ISO, prior to making a determination about the viability of a specific proposed solution, will communicate its intended determination to the project Developer along with the basis for its intended determination. The ISO shall provide the Developer a reasonable period (not more than 2 weeks) to respond to the ISO's intended determination, including an opportunity to provide additional information to the ISO to support the continued viability of the proposed solution.

31.2.7.4.6 If the ISO determines that a market-based solution that is needed to meet an identified Reliability Need is no longer viable, it will request that the

Responsible Transmission Owner proceed with the regulated backstop solution, or to seek other measures including, but not limited to, a Gap Solution, to ensure the reliability of the system.

31.2.7.4.7 If the ISO determines that the market-based solution is still viable, but that its in-service date is likely to slip beyond the Target Year, the ISO will request the Responsible Transmission Owner to prepare a Gap Solution in accordance with the provisions of this Attachment Y.

31.3 Economic Planning Process

31.3.1 Congestion Assessment and Resource Integration Study for Economic Planning

31.3.1.1 General

The ISO shall prepare and publish the CARIS as described below. Each CARIS shall (1) develop a ten-year projection of congestion and shall identify, rank, and group the most congested elements on the New York bulk power system based on historic and projected congestion; and (2) include three studies, selected pursuant to Section 31.3.1.2.2, of the potential impacts of generic solutions to mitigate the identified congestion. The CARIS will align with the Reliability Planning Process.

31.3.1.2 Interested Party Participation in the Development of the CARIS

31.3.1.2.1 The ISO shall develop the CARIS in consultation with Market Participants and all other interested parties. The TPAS will have responsibilities consistent with ISO Procedures for review of the ISO's technical analyses. ESPWG will have responsibilities consistent with ISO Procedures for providing commercial input and assumptions to be used in the development of the congestion assessment and the congestion assessment scenarios provided for under Section 31.3.1.5, and in the reporting and analysis of congestion costs. Coordination and communication will be established and maintained between these two groups and ISO staff to allow Market Participants and other interested parties to participate in a meaningful way during each stage of the economic planning process. The ISO staff shall report any majority and minority views of these collaborative governance work groups when it submits the CARIS to the Business Issues Committee for a vote, as provided below.

31.3.1.2.2 The ISO, in conjunction with ESPWG, will develop criteria for the selection and grouping of the three congestion and resource integration studies that comprise each CARIS, as well as for setting the associated timelines for completion of the selected studies. Study selection criteria may include congestion estimates, and shall include a process to prioritize the three studies that comprise each CARIS. Criteria shall also include a process to set the cut off date for inputs into and completion of each CARIS study cycle.

31.3.1.2.3 The ISO, in conjunction with ESPWG, will develop a process by which interested parties can request and fund other congestion and resource integration studies, in addition to those included in each CARIS. These individual congestion and resource integration studies are in addition to those studies that a customer can request related to firm point-to-point transmission service pursuant to Section 3.7 of the ISO OATT, or studies that a customer can request related to Network Integration Transmission Service pursuant to Section 4.5 of the ISO OATT, or studies related to interconnection requests under Attachment X or Attachment Z of the ISO OATT.

31.3.1.2.4 The ISO shall post all requests for congestion and resource integration studies on its website.

31.3.1.3 Preparation of the CARIS

31.3.1.3.1 The Study Period for the CARIS shall be the same ten-year Study Period covered by the most recently approved CRP.

31.3.1.3.2 The CARIS will assume a reliable system throughout the Study Period, based first upon the solutions identified in the most recently completed and approved CRP. The baseline system for the CARIS shall first incorporate sufficient viable market-based solutions to meet the identified Reliability Needs as well as any regulated backstop solutions triggered by an ISO request pursuant to Section 31.2.5.7. The ISO, in conjunction with the ESPWG, will develop methodologies to scale back market-based solutions to the minimum needed to meet the identified Reliability Needs, if more have been proposed than are necessary to meet the identified Reliability Needs. Regulated backstop solutions that have been proposed but not triggered pursuant to Section 31.2.5.7 shall also be used if there are insufficient market-based solutions for the ten-year Study Period. Multiple market-based solutions, as well as regulated solutions to Reliability Needs, may be included in the scenario assessments described in Section 31.3.1.5.

31.3.1.3.3 In conducting the CARIS, the ISO shall combine the component studies selected and assess system congestion and resource integration over the Study Period, measuring congestion by the metrics discussed in Appendix A to this Attachment Y. The ISO, in conjunction with the ESPWG, will develop the specific production costing model to be used in the CARIS. All resource types shall be considered on a comparable basis as potential solutions to the congestion identified: generation, transmission, demand response, and energy efficiency. The CARIS may include consideration of the economic impacts of advancing a regulated back stop solution contained in the CRP.

31.3.1.3.4 In conducting the CARIS, the ISO shall conduct benefit/cost analysis of each potential solution to the congestion identified, applying benefit/cost metrics that are described in this Section 31.3.1.3. The principal benefit metric for the CARIS analysis will be expressed as the present value of the NYCA-wide production cost reduction that would result from each potential solution. The present value of the NYCA-wide production cost reduction will be determined in accordance with the following formula:

Present Value in year 1 = Sum of the Present Values from each of the 10 years of the Study Period.

The discount rate to be used for the present value analysis shall be the current after-tax weighted average cost of capital for the Transmission Owners.

31.3.1.3.5 Additional benefit metrics shall include estimates of reductions in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs, and TCC payments. The ISO will work with the ESPWG to determine the most useful metrics for each CARIS cycle, given overall ISO resource requirements. The additional metrics will estimate the benefits of the potential generic solutions in mitigating the congestion identified for information purposes only. All the quantities, except ICAP, will be the result of the forward looking production cost simulation. The additional benefit metrics will be determined by measuring the difference between the CARIS base case system value and a system value when the potential generic solution is added. All three resource types will be considered as potential generic solutions to the congestion identified, such as generation, transmission, and/or demand response. The value of the additional metrics will be expressed in present value by using the following formula:

Present Value in year 1 = Sum of the Present Values from each of the 10 years of the Study Period.

The discount rate to be used for the present value analysis shall be the current after-tax weighted average cost of capital for the Transmission Owners. The definitions of the LBMP load cost metric, generator payments metric, reduction in losses metric, Ancillary Services costs metric, and TCC payment metric are set forth below.

31.3.1.3.5.1 LBMP load costs measure the change in total load payments and unhedged load payments. Total load payments will include the LBMP payments (energy, congestion and losses) paid by electricity demand (forecasted load, exports, and wheeling). Exports will be consistent with the input assumptions for each neighboring control area. Unhedged load payments will represent total load payments minus the TCC payments.

31.3.1.3.5.2 Reductions in losses measure the change in marginal losses payments. Losses payments will be based upon the loss component of the zonal LBMP load payments.

31.3.1.3.5.3 Generator payments measure the change in generation payments. Generation payments will include the LBMP payments (energy, congestion, losses), and Ancillary Services payments made to electricity suppliers. Ancillary Services costs will include payments for Regulation Services and Operating Reserves, including 10 Minute Synchronous, 10 Minute Non-synchronous and 30 Minute Non-synchronous. Generator payments will be the sum of the LBMP payments and Ancillary Services payments to generators and imports. Imports will be consistent with the input assumptions for each neighboring Control Area.

31.3.1.3.5.4 The TCC payment metric set forth below will be used for purposes of the study phase of the CARIS process, and will not be used for regulated economic transmission project cost allocation under Section 31.4.3.4. The TCC payment metric will measure the change in total congestion rents collected in the day-ahead market. These congestion rents shall be calculated as the product of the Congestion Component of the Day-Ahead LBMP in each Load Zone or Proxy Generator Bus and the withdrawals scheduled in each hour at that Load Zone or Proxy Generator Bus, minus the product of the Congestion Component of the Day-Ahead LBMP at each Generator Bus or Proxy Generator Bus and the injections scheduled in each hour at that Generator bus or Proxy Generator Bus, summed over all locations and hours.

31.3.1.3.5.5 The emission metric will measure the change in CO_2, NOx, and SO_2, emissions in tons on a zonal basis as well as the change in emission cost by emission type. Emission costs will be reflected in the development of the production cost curve.

31.3.1.3.5.6 The calculation of the ICAP cost metric will be determined as set forth below. The ICAP cost metric will be highly dependent on the rules and procedures guiding the calculation of the IRM, LCR, and the ICAP Demand Curves, both for the next capability period and future capability periods. In each CARIS cycle, the ISO will review, with the ESPWG and, as appropriate, other ISO committees, the results of the ICAP cost metric.

31.3.1.3.5.6.1 The ICAP metric, in the form of a megawatt impact, will be computed for both generic and actual economic project proposals based on a methodology that: (1) determines the base system LOLE for the applicable horizon year; (2) adds the proposed project; and (3) calculates the LOLE for the system with the addition of the proposed project. If the system LOLE is lower than that of the base system, the ISO will reduce generation in all NYCA zones proportionally (*i.e.*, based on proportion of zonal capacity to total NYCA capacity) until the base system LOLE is achieved. That amount of reduced generation is the NYCA megawatt impact.

31.3.1.3.5.6.2 The ISO will calculate both of the following ICAP cost metrics described in subsections (1) and (2) below by first determining the megawatt impact described above in Section 31.3.1.3.5.6.1 and then:

(1) For Rest of State, the ISO will measure the cost impact of a proposed generic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in Rest of State under the assumption that the proposed generic project is not in place, with that forecast based on the latest available ICAP Demand Curve for the NYCA and the amount of Installed Capacity available in the NYCA, as shown in the NYISO Load and Capacity Data Report developed for that year; and (ii) multiplying that forecasted cost per megawatt-year for Rest of State in that year by the sum of the megawatt impact for all Load Zones contained within Rest of State, as calculated in accordance with subsection (A) of this Section 31.3.1.3.5.4.

For each Locality, the ISO will measure the cost impact of a proposed generic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in that Locality under the assumption that the proposed generic project is not in place, with that forecast based on the latest available ICAP Demand Curve for that Locality and the amount of Installed Capacity available in that Locality as shown in the relevant NYISO Load and Capacity Data Report developed for that year, and (ii) multiplying that forecasted cost per megawatt-year for that Locality in each year by the sum of the megawatt impact for all Load Zones contained within that Locality, as calculated in accordance with subsection (A) of this Section 31.3.1.3.5.4.

This ICAP cost metric will then be presented for each applicable planning year as a stream of present value benefits for each Locality and for Rest of State. The applicable planning years start with the proposed commercial operation date of the proposed generic project and end ten years after the proposed commercial operation date of the proposed generic project.

(2) For Rest of State, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in Rest of State under the assumption that the proposed generic project is in place, with that forecast based on the latest available ICAP Demand Curve for the NYCA and the amount of Installed Capacity available in the NYCA; (ii) subtracting that forecasted cost per megawatt-year from the forecasted cost per megawatt-year of Installed Capacity in Rest of State calculated in subsection (1) under the assumption that the proposed generic project is not in

place; and (iii) multiplying that difference by fifty percent (50%) of the assumed amount of Installed Capacity available in Rest of State as calculated from the relevant NYISO Load and Capacity Data Report developed for the CARIS process.

For each Locality, the ISO will measure the cost impact of a proposed generic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in that Locality under the assumption that the proposed generic project is in place, with that forecast based on the latest available ICAP Demand Curve for that Locality and the amount of Installed Capacity available in that Locality as shown in the relevant NYISO Load and Capacity Data Report developed for that year; (ii) subtracting the greater of that forecasted cost per megawatt-year with the proposed generic project in place or the forecasted Rest of State Installed Capacity cost per megawatt-year with the proposed generic project in place from the forecasted cost of Installed Capacity in that Locality calculated in subsection (1) under the assumption that the proposed generic project is not in place; and (iii) multiplying that difference by fifty percent (50%) of assumed amount of Installed Capacity available in that Locality, as taken from the relevant Load and Capacity tables developed for the CARIS process.

This ICAP cost metric will then be represented for each applicable planning year as a stream of present value benefits for each Locality and for Rest of State. The applicable planning years start with the proposed commercial operation date of the proposed generic project and end with the earlier of: (i) the year when the system, with the proposed generic project in place, reaches an LOLE of 0.1, or (ii) ten years after the proposed commercial operation date of the proposed generic project.

(3) The forecast of Installed Capacity costs per megawatt-year are developed by: first, escalating the Net Cost of New Entry ("CONE") for the NYCA or a Locality from the most recently completed ICAP Demand Curves for each year of the planning period; second, determining the future proxy Locational Minimum Installed Capacity Requirement or Minimum Installed Capacity Requirement for the NYCA as the actual amount of Installed Capacity in the Locality or the NYCA for the year that NYCA reaches 0.1 LOLE; third, reducing the cost per megawatt-year in each year from the escalated Net CONE to reflect the excess Installed Capacity from the NYISO Load and Capacity Data Report above the future proxy Minimum Installed Capacity Requirement with the adjustment calculated from the excess and the slope of the ICAP Demand Curve.

The forecasts of Installed Capacity costs for Localities or Rest of State performed in subsections (1) and (2) above shall, in addition to the assumptions listed above, be based upon: (i) the forecasted Net CONE for the Locality (the NYCA in the case of the Rest of State forecast); (ii) the amount of Installed Capacity required to meet the future proxy Locational Minimum Installed Capacity Requirement (the Minimum Installed Capacity Requirement for the NYCA in the case of the Rest of State forecast); (iii) the slope of the relevant ICAP Demand Curve, and (iv) the smallest quantity where the cost of Installed Capacity on that ICAP Demand Curve reaches zero.

31.3.1.4 Planning Participant Data Input

At the ISO's request, Market Participants, Developers, and other parties shall provide, in accordance with the schedule set forth in the ISO Procedures, the data necessary for the development of the CARIS. This input will include but not be limited to existing and planned additions and modifications to the New York State Transmission System (to be provided by Transmission Owners and municipal electric utilities); proposals for merchant transmission facilities (to be provided by merchant Developers); generation additions and retirements (to be provided by generator owners and Developers); demand response programs (to be provided by demand response providers); and any long-term firm transmission requests made to the ISO. The relevant Transmission Owners will assist the ISO in developing the potential solution cost estimates to be used by the ISO to conduct benefit/cost analysis of each of the potential solutions.

31.3.1.5 Congestion and Resource Integration Scenario Development

The ISO, in consultation with the ESPWG, shall develop congestion and resource integration scenarios addressing the Study Period. Variables for consideration in the development of these congestion and resource integration scenarios include but are not limited to: load forecast uncertainty, fuel price uncertainty, new resources, retirements, emission data, the cost of allowances and potential requirements imposed by proposed environmental and energy efficiency mandates, as well as overall ISO resource requirements. The ISO shall report the results of these scenario analyses in the CARIS.

31.3.1.6 CARIS Report Preparation

Once all the analyses described above have been completed, ISO staff will prepare a draft of the CARIS including a discussion of its assumptions, inputs, methodology, and the results of its analyses.

31.3.2 CARIS Review Process and Actual Project Proposals

31.3.2.1 Collaborative Governance Process

The draft CARIS shall be submitted to both TPAS and the ESPWG for review and comment. The ISO shall make available to any interested party sufficient information to replicate the results of the draft CARIS. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of that review, the draft CARIS reflecting the revisions resulting from the TPAS and ESPWG review shall be forwarded to the Business Issues Committee and the Management Committee for discussion and action.

31.3.2.2 Board Action

Following the Management Committee vote, the draft CARIS, with Business Issues Committee and Management Committee input, will be forwarded to the ISO Board for review and action. Concurrently, the draft CARIS will be provided to the Market Monitoring Unit for its review and consideration. The Board may approve the CARIS as submitted, or propose modifications on its own motion. If any changes are proposed by the Board, the revised CARIS shall be returned to the Management Committee for comment. The Board shall not make a final determination on a revised CARIS until it has reviewed the Management Committee comments.

Upon approval by the Board, the ISO shall issue the CARIS to the marketplace by posting it on its website.

The responsibilities of the Market Monitoring Unit that are addressed in the above section of Attachment Y to the ISO OATT are also addressed in Section 30.4.6.8.4 of the Market Monitoring Plan, Attachment O to the ISO OATT.

31.3.2.3 Public Information Sessions

In order to provide ample exposure for the market place to understand the content of the CARIS, the ISO will provide various opportunities for Market Participants and other potentially interested parties to discuss final CARIS. Such opportunities may include presentations at various ISO Market Participant committees, focused discussions with various industry sectors, and /or presentations in public venues.

31.3.2.4 Actual Project Proposals

As discussed in Section 31.3.1 of this Attachment Y, the CARIS analyzes system congestion over the Study Period and, for informational purposes, provides benefit/cost analysis and other analysis of potential generic solutions to the congestion identified. If, in response to the CARIS, a Developer proposes an actual project to address specific congestion identified in the CARIS, then the ISO will process that project proposal in accordance with the relevant provisions of Sections 31.4.1, 31.4.3 and 31.4.4 of this Attachment Y.

31.4 Cost Allocation and Cost Recovery

31.4.1 The Scope of Attachment Y Cost Allocation

31.4.1.1 Regulated Responses

The cost allocation principles and methodologies in this Attachment Y cover only regulated transmission solutions to Reliability Needs and regulated transmission responses to congestion identified in the CARIS, whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer. The cost allocation principles and methodology covering regulated transmission solutions to Reliability Needs are contained in Sections 31.4.2.1 and 31.4.2.2 of this Attachment Y. The separate cost allocation principles and methodology covering regulated transmission responses to congestion identified in the CARIS are contained in Sections 31.4.3.1 and 31.4.3.2 of this Attachment Y.

31.4.1.2 Market-Based Responses

The cost allocation principles and methodologies in this Attachment Y do not apply to market-based solutions to Reliability Needs or to market-based responses to congestion identified in the CARIS. The cost of a market-based project shall be the responsibility of the developer of that project.

31.4.1.3 Interconnection Cost Allocation

The cost allocation principles and methodologies in this Attachment Y do not apply to the interconnection costs of generation and merchant transmission projects. Interconnection costs are determined and allocated in accordance with Attachment S, Attachment X and Attachment Z of the ISO OATT.

31.4.1.4 Individual Transmission Service Requests

The cost allocation principles and methodologies in this Attachment Y do not apply to the cost of transmission expansion projects undertaken in connection with an individual request for Transmission Service. The cost of such a project is determined and allocated in accordance with Section 3.7 or Section 4.5 of the ISO OATT.

31.4.1.5 LTP Facilities

The cost allocation principles and methodologies in this Attachment Y do not apply to the cost of transmission projects included in LTPs or LTP updates. Each Transmission Owner will recover the cost of such transmission projects in accordance with its then existing rate recovery mechanisms.

31.4.1.6 Regulated Non-Transmission Solutions to Reliability Needs

Costs related to regulated non-transmission reliability projects will be recovered by Responsible Transmission Owners, Transmission Owners and Other Developers in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law. Nothing in this section shall affect the Commission's jurisdiction over the sale and transmission of electric energy subject to the jurisdiction of the Commission.

31.4.2 Regulated Responses to Reliability Needs

31.4.2.1 Cost Allocation Principles

Cost allocation for regulated transmission solutions to Reliability Needs shall be determined by the ISO based upon the principle that beneficiaries should bear the cost responsibility. The specific cost allocation methodology, to be developed by the ISO in consultation with the ESPWG, will incorporate the following elements:

31.4.2.1.1 The focus of the cost allocation methodology shall be on solutions to Reliability Needs.

31.4.2.1.2 Potential impacts unrelated to addressing the Reliability Needs shall not be considered for the purpose of cost allocation for regulated solutions.

31.4.2.1.3 Primary beneficiaries shall initially be those Load Zones identified as contributing to the reliability violation.

31.4.2.1.4 The cost allocation among primary beneficiaries shall be based upon their relative contribution to the need for the regulated solution.

31.4.2.1.5 The ISO will examine the development of specific cost allocation rules based on the nature of the reliability violation (e.g., thermal overload, voltage, stability, resource adequacy and short circuit).

31.4.2.1.6 Cost allocation shall recognize the terms of prior agreements among the Transmission Owners, if applicable.

31.4.2.1.7 Consideration should be given to the use of a materiality threshold for cost allocation purposes.

31.4.2.1.8 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.4.2.1.9 Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

31.4.2.1.10 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.4.2.1.11 The methodology shall apply, to the extent possible, to Gap Solutions.

31.4.2.1.12 Cost allocation is independent of the actual triggered project(s), except when allocating cost responsibilities associated with meeting a minimum Locational Installed Capacity Requirement ("LCR"), and is based on a separate process that results in NYCA meeting its LOLE requirement.

31.4.2.1.13 Cost allocation for a solution that meets the needs of a Target Year assumes that backstop solutions of prior years have been implemented.

31.4.2.1.14 Cost allocation will consider the most recent values for LCRs. LCRs must be met for the Target Year.

31.4.2.2 Cost Allocation Methodology

31.4.2.2.1 General Reliability Solution Cost Allocation Formula:

The cost allocation mechanism under Rate Schedule 10 of this tariff for regulated transmission solutions to Reliability Needs, whether proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer, would be used as a basis for allocating costs associated with projects determined to be necessary pursuant to Section 31.2.5.7. The formula is not applicable to that portion of a project oversized beyond the smallest technically feasible solution that meets the Reliability Need identified in the RNA. Nor is the formula applicable to that portion of the cost of a regulated transmission reliability project that is, pursuant to Section 25.7.12 of Attachment S to the ISO OATT, paid for with funds previously committed by or collected from Developers for the installation of System Deliverability Upgrades required for the interconnection of generation or merchant transmission projects. The same cost allocation formula is applied regardless of the project or sets of projects being triggered; however, the nature of the solution set may lead to some terms equaling zero, thereby dropping out of the equation. To ensure that appropriate allocation to the LCR and non-LCR zones occurs, the zonal allocation percentages are developed through a series of steps that first identify responsibility for LCR deficiencies, followed by responsibility for remaining need. This cost allocation process can be applied to any solution or set of solutions that involve single or multiple cost allocation steps. One formula can be applied to any solution set:

$$\text{Cost Allocation}_i = \left[\frac{\text{LCRdef}_i}{\text{Soln\_Size}} + \left[\frac{\text{Coincident Peak}_i \text{ x } (1 + \text{IRM} - \text{LCR}_i)}{\sum_{k=1}^{N} \text{Coincident Peak}_k \text{ x } (1 + \text{IRM-LCR}_k)} \text{ x } \frac{\text{Soln STWdef}}{\text{Soln\_Size}} \right] \right.$$

$$= \quad + \left[\frac{\text{Coincident Peak}_i \text{ x } (1 + \text{IRM} - \text{LCR}_i)}{\sum_{l=1}^{M} \text{Coincident Peak}_l \text{ x } (1 + \text{IRM} - \text{LCR}_l)} \text{ x } \frac{\text{SolnCIdef}}{\text{Soln\_Size}} \right] \quad \text{x } 100\%$$

Where i is for each applicable zone, n represent the total zones in NYCA, m represents the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, LCRdef_i is the applicable zonal LCR deficiency, SolnSTWdef is the STWdef for each applicable project, SolnCIdef is the CIdef for each applicable project, and Soln_Size represents the total compensatory MW addressed by each applicable project.

Three step cost allocation methodology for regulated reliability solutions:

31.4.2.2.1.1 Step 1 - LCR Deficiency

31.4.2.2.1.1.1 Any deficiencies in meeting the LCRs for the Target Year will be referred to as the LCRdef. If the reliability criterion is met once the LCR deficiencies have been addressed, that is LOLE ≤ 0.1 for the Target Year is achieved, then the only costs allocated will be those related to the LCRdef MW. Cost responsibility for the LCRdef MW will be borne by each deficient locational zone(s), to the extent each is individually deficient.

For a single solution that addresses only an LCR deficiency in the applicable LCR zone, the equation would reduce to:

$$\text{Allocation}_i = \frac{\text{LCRdef}_i}{\text{Soln\_ Size}} \times 100\%$$

Where *i* is for each applicable LCR zone, LCRdef_i represents the applicable zonal LCR deficiency, and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.4.2.2.1.1.2 Prior to the LOLE calculation, voltage constrained interfaces will be recalculated to determine the resulting transfer limits when the LCRdef MW are added.

31.4.2.2.1.2 Step 2 - Statewide Resource Deficiency. If the reliability criterion is not met after the LCRdef has been addressed, that is an LOLE > 0.1, then a NYCA Free Flow Test will be conducted to determine if NYCA has sufficient resources to meet an LOLE of 0.1.

31.4.2.2.1.2.1 If NYCA is found to be resource limited, the ISO, using the transfer limits and resources determined in Step 1, will determine the optimal distribution of additional resources to achieve a reduction in the NYCA LOLE to 0.1.

31.4.2.2.1.2.2 Cost allocation for compensatory MW added for cost allocation purposes to achieve an LOLE of 0.1, defined as a Statewide MW deficiency (STWdef), will be prorated to all NYCA zones, based on the NYCA coincident peak load. The allocation to locational zones will take into account their locational requirements. For a single solution that addresses only a statewide deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i \text{ x } \left(1+\text{IRM-}LCR_i\right)}{\sum_{k=1}^{n} \text{Coincident Peak}_k \text{ x } \left(1+\text{IRM-}LCR_k\right)} \text{ x } \frac{\text{SolnSTWdef}}{\text{Soln\_Size}} \right] \text{ x } 100\%$$

Where *i* is for each applicable zone, n is for the total zones in NYCA, IRM is the statewide reserve margin, and LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, Soln STWdef is the STWdef for the applicable project, and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.4.2.2.1.3 Step 3 - Constrained Interface Deficiency. If the NYCA is not resource limited as determined by the NYCA Free Flow Test, then the ISO will examine constrained transmission interfaces, using the Binding Interface Test.

31.4.2.2.1.3.1 The ISO will provide output results of the reliability simulation program utilized for the RNA that indicate the hours that each interface is at limit in each flow direction, as well as the hours that coincide with a loss of load event. These values will be used as an initial indicator to determine the binding interfaces that are impacting LOLE within the NYCA.

31.4.2.2.1.3.2 The ISO will review the output of the reliability simulation program utilized for the RNA along with other applicable information that may be available to make the determination of the binding interfaces.

31.4.2.2.1.3.3 Bounded Regions are assigned cost responsibility for the compensatory MW, defined as CIdef, needed to reach an LOLE of 0.1.

31.4.2.2.1.3.4 If one or more Bounded Regions are isolated as a result of binding interfaces identified through the Binding Interface Test, the ISO will determine the optimal distribution of compensatory MW to achieve a NYCA LOLE of 0.1. Compensatory MW will be added until the required NYCA LOLE is achieved.

31.4.2.2.1.3.5 The Bounded Regions will be identified by the ISO's Binding Interface Test, which identifies the bounded interface limits that can be relieved and have the greatest impact on NYCA LOLE. The Bounded Region that will have the greatest benefit to NYCA LOLE will be the area to be first allocated costs in this step. The ISO will determine if after the first addition of compensating MWs the Bounded Region with the greatest impact on LOLE has changed. During this iterative process, the Binding Interface Test will look across the state to identify the appropriate Bounded Region. Specifically, the Binding Interface Test will be applied starting from the interface that has the greatest benefit to LOLE (the greatest LOLE reduction per interface compensatory MW addition), and then extended to subsequent interfaces until a NYCA LOLE of 0.1 is achieved.

31.4.2.2.1.3.6 The CIdef MW are allocated to the applicable Bounded Region isolated as a result of the constrained interface limits, based on their NYCA coincident peaks. Allocation to locational zones will take into account their locational requirements.

For a single solution that addresses only a binding interface deficiency, the equation would reduce to:

$$\text{Allocation}_i = \left[\frac{\text{Coincident Peak}_i \times \left(1+\text{IRM-}LCR_i\right)}{\sum_{l=1}^{m} \text{Coincident Peak}_k \times \left(1+\text{IRM-}LCR_l\right)} \times \frac{SolnCIdef}{\text{Soln\_Size}} \right] \times 100\%$$

Where *i* is for each applicable zone, m is for the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, SolnCIdef is the CIdef for the applicable project and Soln_Size represents the total compensatory MW addressed by the applicable project.

31.4.2.2.1.4 If, after the completion of Steps 1 through 3, there is a thermal or voltage security issue that does not cause an LOLE violation, it will be deemed a local issue and related costs will not be allocated under this process.

31.4.2.2.1.5 Costs related to the deliverability of a resource will be addressed under the ISO's deliverability procedures.

31.4.2.2.1.6 This cost allocation methodology would be used for any projects required to meet Reliability Needs identified in the RNA that are triggered prior to January 1, 2016 Costs associated with any projects triggered on or after January 1, 2016 will be allocated according to a methodology, which, after proper consideration within the ISO stakeholder process, will be filed by the ISO for the Commission's approval prior to January 1, 2016, in accordance with the ISO governance process. The filing may provide for a continuation of the forgoing methodology or a revised methodology.

31.4.3 Regulated Economic Projects

31.4.3.1 The Scope of Section 31.4.3

As discussed in Section 31.4.1 of this Attachment Y, the cost allocation principles and methodologies of this Section 31.4.3 apply only to regulated economic transmission projects ("RETPs) proposed in response to congestion identified in the CARIS. This Section 31.4.3 does not apply to generation or demand side management projects, nor does it apply to any market-based projects. This Section 31.4.3 does not apply to regulated backstop solutions triggered by the ISO pursuant to the CSPP, provided, however, the cost allocation principles and methodologies in this Section 31.4.3 will apply to regulated backstop solutions when the implementation of the regulated backstop solution is accelerated solely to reduce congestion in earlier years of the Study Period. The ISO will work with the ESPWG to develop procedures to deal with the acceleration of regulated backstop solutions for economic reasons.

Nothing in this Attachment Y mandates the implementation of any project in response to the congestion identified in the CARIS.

31.4.3.2 Cost Allocation Principles

Cost allocation for RETPs shall be determined by the ISO based upon the principle that beneficiaries should bear the cost responsibility. The specific cost allocation methodology in Section 31.4.3.4 incorporates the following elements:

31.4.3.2.1 The focus of the cost allocation methodology shall be on responses to specific conditions identified in the CARIS.

31.4.3.2.2 Potential impacts unrelated to addressing the identified congestion shall not be considered for the purpose of cost allocation for RETPs.

31.4.3.2.3 Projects analyzed hereunder as proposed RETPs may proceed on a market basis with willing buyers and sellers at any time.

31.4.3.2.4 Cost allocation shall be based upon a beneficiaries pay approach. Cost allocation under the ISO tariff for a RETP shall be applicable only when a super majority of the beneficiaries of the project, as defined in Section 31.4.3.6 of this Attachment Y, vote to support the project.

31.4.3.2.5 Beneficiaries of a RETP shall be those entities economically benefiting from the proposed project. The cost allocation among beneficiaries shall be based upon their relative economic benefit.

31.4.3.2.6 Consideration shall be given to the proposed project's payback period.

31.4.3.2.7 The cost allocation methodology shall address the possibility of cost overruns.

31.4.3.2.8 Consideration shall be given to the use of a materiality threshold for cost allocation purposes.

31.4.3.2.9 The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.

31.4.3.2.10 Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.

31.4.3.2.11 The methodology shall provide cost recovery certainty to investors to the extent possible.

31.4.3.2.12 Benefits determination shall consider various perspectives, based upon the agreed-upon metrics for analyzing congestion.

31.4.3.2.13 Benefits determination shall account for future uncertainties as appropriate (e.g., load forecasts, fuel prices, environmental regulations).

31.4.3.2.14 Benefits determination shall consider non-quantifiable benefits as appropriate (*e.g.,* system operation, environmental effects, renewable integration).

31.4.3.3 Project Eligibility for Cost Allocation

The methodologies in this Section 31.4.3.3 will be used to determine the eligibility of a proposed RETP to have its cost allocated and recovered pursuant to the provisions of this Attachment Y.

31.4.3.3.1 The ISO will evaluate the benefits against the costs (as provided by the Developer) of each proposed RETP over a ten-year period commencing with the proposed commercial operation date for the project. The Developer of each project will pay the cost incurred by the ISO to conduct the ten-year benefit/cost analysis of its project. The ISO, in conjunction with the ESPWG, will develop methodologies for extending the most recently completed CARIS database as necessary to evaluate the benefits and costs of each proposed RETP.

31.4.3.3.2 The benefit metric for eligibility under the ISO's benefit/cost analysis will be expressed as the present value of the annual NYCA-wide production cost savings that would result from the implementation of the proposed project, measured for the first ten years from the proposed commercial operation date for the project.

31.4.3.3.3 The cost for the ISO's benefit/cost analysis will be supplied by the Developer of the project, and the cost metric for eligibility will be expressed as the present value of the first ten years of annual total revenue requirements for the project, reasonably allocated over the first ten years from the proposed commercial operation date for the project.

31.4.3.3.4 For informational purposes only, the ISO will also calculate the present value of the annual total revenue requirement for the project over a 30 year period commencing with the proposed commercial operation date of the project.

31.4.3.3.5 To be eligible for cost allocation and recovery under this Attachment Y, the benefit of the proposed project must exceed its cost measured over the first ten years from the proposed commercial operation date for the project, and the requirements of section 31.4.3.2 must be met. The total capital cost of the project must exceed $25 million. In addition, a super-majority of the beneficiaries must vote in favor of the project, as specified in Section 31.4.3.6 of this Attachment Y.

31.4.3.3.6 In addition to calculating the benefit metric as defined in Section 31.4.3.3.2, the ISO will calculate additional metrics to estimate the potential benefits of the proposed project, for information purposes only, in accordance with Section 31.3.1.3.5, for the applicable metric. These additional metrics shall include those that measure reductions in LBMP load costs, changes to generator payments, ICAP costs, Ancillary Service costs, emissions costs, and losses. TCC revenues will be determined in accordance with Section 31.4.3.4.2.3. The ISO will provide information on these additional metrics to the maximum extent practicable considering its overall resource commitments.

31.4.3.3.7 In addition to the benefit/cost analysis performed by the ISO under this Section 31.4.3.3, the ISO will work with the ESPWG to consider the development and implementation of scenario analyses, for information only, that shed additional light on the benefit/cost analysis of a proposed project. These additional scenario analyses may cover fuel and load forecast uncertainty, emissions data and the cost of allowances, pending environmental or other regulations, and alternate resource and energy efficiency scenarios. Consideration of these additional scenarios will take into account the resource commitments of the ISO.

31.4.3.4 Cost Allocation for Eligible Projects

As noted in Section 31.4.3.2 of this Attachment Y, the cost of a RETP will be allocated to those entities that would economically benefit from implementation of the proposed project.

31.4.3.4.1 The ISO will identify the beneficiaries of the proposed project over a ten-year time period commencing with the proposed commercial operation date for the project. The ISO, in conjunction with the ESPWG, will develop methodologies for extending the most recently completed CARIS database as necessary for this purpose.

31.4.3.4.2 The ISO will identify beneficiaries of a proposed project as follows:

31.4.3.4.2.1 The ISO will measure the present value of the annual zonal LBMP load savings for all Load Zones which would have a load savings, net of reductions in TCC revenues, and net of reductions from bilateral contracts (based on available information provided by Load Serving Entities to the ISO as set forth in subsection 31.4.3.4.2.5 below) as a result of the implementation of the proposed project. For purposes of this calculation, the present value of the load savings will be equal to the sum of the present value of the Load Zone's load savings for each year over the ten-year period commencing with the project's commercial operation date. The load savings for a Load Zone will be equal to the difference between the zonal LBMP load cost without the project and the LBMP load cost with the project, net of reductions in TCC revenues and net of reductions from bilateral contracts.

31.4.3.4.2.2 The beneficiaries will be those Load Zones that experience net benefits measured over the first ten years from the proposed commercial operation date for the project. If the sum of the zonal benefits for those Load Zones with load savings is greater than the revenue requirements for the project (both load savings and revenue requirements measured in present value over the first ten years from the commercial operation date of the project), the ISO will proceed with the development of the zonal cost allocation information to inform the beneficiary voting process.

31.4.3.4.2.3 Reductions in TCC revenues will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, not including the congestion rents that accrue to any Incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: (1) the total impact of that project on the

Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); (2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and (3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item (1) above. These forecasts shall be performed using the procedure described in Appendix B to this Attachment Y.

31.4.3.4.2.4 Estimated TCC revenues from any Incremental TCCs created by a proposed RETP over the ten-year period commencing with the project's commercial operation date will be added to the Net Load Savings used for the cost allocation and beneficiary determination.

31.4.3.4.2.5 The ISO will solicit bilateral contract information from all Load Serving Entities, which will provide the ISO with bilateral energy contract data for modeling contracts that do not receive benefits, in whole or in part, from LBMP reductions, and for which the time period covered by the contract is within the ten-year period beginning with the commercial operation date of the project. Bilateral contract payment information that is not provided to the ISO will not be included in the calculation of the present value of the annual zonal LBMP savings in section 31.4.3.4.2.1 above.

31.4.3.4.2.5.1 All bilateral contract information submitted to the ISO must identify the source of the contract information, including citations to any public documents including but not limited to annual reports or regulatory filings

31.4.3.4.2.5.2 All non-public bilateral contract information will be protected in accordance with the ISO's Code of Conduct, as set forth in Section 12.4 of Attachment F of the ISO OATT, and Article 6 of the ISO Services Tariff.

31.4.3.4.2.5.3 All bilateral contract information and information on LSE-owned generation submitted to the ISO must include the following information:

(1) Contract quantities on an annual basis:

(a) For non-generator specific contracts, the Energy (in MWh) contracted to serve each Zone for each year.

(b) For generator specific contracts or LSE-owned generation, the name of the generator(s) and the MW or percentage output contracted or self-owned for use by Load in each Zone for each year.

(2) For all Load Serving Entities serving Load in more than one Load Zone, the quantity (in MWh or percentage) of bilateral contract Energy to be applied to each Zone, by year over the term of the contract.

(3) Start and end dates of the contract.

(4) Terms in sufficient detail to determine that either pricing is not indexed to LBMP, or, if pricing is indexed to LBMP, the manner in which prices are connected to LBMP.

(5) Identify any changes in the pricing methodology on an annual basis over the term of the contract.

31.4.3.4.2.5.4 Bilateral contract and LSE-owned generation information will be used to calculate the adjusted LBMP savings for each Load Zone as follows:

AdjLBMPS$_{y,z}$, the adjusted LBMP savings for each Load Zone *z* in each year *y*, shall be calculated using the following equation:

$$AdjLBMPS_{y,z} = \max\left[0, TL_{y,z} - \sum_{b \in B_{y,z}} \left(BCL_{b,y,z} \cdot \left(1 - Ind_{b,y,z}\right)\right) - SG_{y,z}\right] \cdot \left(LBMP1_{y,z} - LBMP2_{y,z}\right),$$

Where:

$TL_{y,z}$ is the total annual amount of Energy forecasted to be consumed by Load in year *y* in Load Zone *z*;

$B_{y,z}$ is the set of blocks of Energy to serve Load in Load Zone *z* in year *y* that are sold under bilateral contracts for which information has been provided to the ISO that meets the requirements set forth elsewhere in this Section 31.4.3.4.2.5

$BCL_{b,y,z}$ is the total annual amount of Energy sold into Load Zone *z* in year *y* under bilateral contract block *b*;

$Ind_{b,y,z}$ is the ratio of (1) the increase in the amount paid by the purchaser of Energy, under bilateral contract block *b*, as a result of an increase in the LBMP in Load Zone *z* in year *y* to (2) the increase in the amount that a purchaser of that amount of Energy would pay if the purchaser paid the LBMP for that Load Zone in that year for all of that Energy (this ratio shall be zero for any bilateral contract block of Energy that is sold at a fixed price or for which the cost of Energy purchased under that contract otherwise insensitive to the LBMP in Load Zone *z* in year *y*);

$SG_{y,z}$ is the total annual amount of Energy in Load Zone *z* that is forecasted to be served by LSE-owned generation in that Zone in year *y*;

LBMP1y,z is the forecasted *annual load-weighted average LBMP* for Load Zone *z* in year *y*, calculated under the assumption that the project is not in place; and

$LBMP2_{y,z}$ is the forecasted annual load-weighted average LBMP for Load Zone z in year y, calculated under the assumption that the project is in place.

31.4.3.4.2.6. NZS_z, the Net Zonal Savings for each Load Zone z resulting from a given project, shall be calculated using the following equation:

$$NZS_z = \max\left[0, \sum_{y=PS}^{PS+9}\left(\left(AdjLBMPS_{y,z} - TCCRevImpact_{y,z}\right)\cdot DF_y\right)\right],$$

Where:

PS is the year in which the project is expected to enter commercial operation;

$AdjLBMPS_{y,z}$ is as calculated in Section 31.4.3.4.2.5;

$TCCRevImpact_{y,z}$ is the forecasted impact of TCC revenues allocated to Load Zone z in year y, calculated using the procedure described in Appendix B in Section 31.6 of this Attachment Y; and

DF_y is the discount factor applied to cash flows in year y to determine the present value of that cash flow in year PS.

31.4.3.4.3 Load Zones not benefiting from a proposed RETP will not be allocated any of the costs of the project under this Attachment Y. There will be no "make whole" payments to non-beneficiaries.

31.4.3.4.4 Costs of a project will be allocated to beneficiaries as follows:

31.4.3.4.4.1 , The ISO will allocate the cost of the RETP based on the zonal share of total savings to the Load Zones determined pursuant to Section 31.4.3.4.2 to be beneficiaries of the proposed project. Total savings will be equal to the sum of load savings for each Load Zone that experiences net benefits pursuant to Section 31.4.3.4.2. A Load Zone's cost allocation will be equal to the present value of the following calculation:

$$\text{Zonal Cost Allocation} = \text{Project Cost} \times \left(\frac{(\text{Zonal Benefits})}{\text{Total Zonal Benefits for zones with positive net benefits}} \right)$$

31.4.3.4.4.2 Zonal cost allocation calculations for a RETP will be performed prior to the commencement of the ten-year period that begins with the project's commercial operation date, and will not be adjusted during that ten-year period.

31.4.3.4.4.3 Within zones, costs will be allocated to LSEs based on MWhs calculated for each LSE for each zone using data from the most recent available 12 month period. Allocations to an LSE will be calculated in accordance with the following formula:

$$\text{LSE Intrazonal Cost Allocation} = \text{Zonal Cost Allocation} \times \left(\frac{\text{LSE Zonal MWh}}{\text{Total Zonal MWh}} \right)$$

31.4.3.4.5 Project costs allocated under this Section 31.4.3.4 will be determined as follows:

31.4.3.4.5.1 The project cost allocated under this Section 31.4.3.4 will be based on the total project revenue requirement, as supplied by the Developer of the project, for the first ten years of project operation. The total project revenue requirement will be determined in accordance with the formula rate on file at the Commission. If there is no formula rate on file at the Commission, then the Developer shall provide to the ISO the project-specific parameters to be used to calculate the total project revenue requirement.

31.4.3.4.5.2 Once the benefit/cost analysis is completed the amortization period and the other parameters used to determine the costs that will be recovered for the project should not be changed, unless so ordered by the Commission or a court of applicable jurisdiction, for cost recovery purposes to maintain the continued validity of the benefit/cost analysis.

31.4.3.4.5.3 The ISO, in conjunction with the ESPWG, will develop procedures to allocate the risk of project cost increases that occur after the ISO completes its benefit/cost analysis under this Attachment Y. These procedures may include consideration of an additional review and vote prior to the start of construction and whether the developer should bear all or part of the cost of any overruns**.**

31.4.3.4.6 The Commission must approve the cost of a proposed RETP for that cost to be recovered through the ISO OATT. The developer's filing with the Commission must be consistent with the project proposal evaluated by the ISO under this Attachment Y in order to be cost allocated to beneficiaries.

31.4.3.5 Collaborative Governance Process and Board Action

31.4.3.5.1 The ISO shall submit the results of its project benefit/cost analysis and beneficiary determination to the ESPWG and TPAS, and to the identified beneficiaries of the proposed RETP for comment. The ISO shall make available to any interested party sufficient information to replicate the results of the benefit/cost analysis and beneficiary determination. The information made available will be electronically masked and made available pursuant to a process that the ISO reasonably determines is necessary to prevent the disclosure of any Confidential Information or Critical Energy Infrastructure Information contained in the information made available. Following completion of the review by the ESPWG and TPAS of the project benefit/cost analysis, the ISO's analysis reflecting any revisions resulting from the TPAS and ESPWG review shall be forwarded to the Business Issues Committee and Management Committee for discussion and action.

31.4.3.5.2 Following the Management Committee vote, the ISO's project benefit/cost analysis and beneficiary determination will be forwarded, with the input of the Business Issues Committee and Management Committee, to the ISO Board for review and action. In addition, the ISO's determination of the beneficiaries' voting shares will be forwarded to the ISO Board for review and action. The Board may approve the analysis and beneficiary determinations as submitted or propose modifications on its own motion. If any changes to the benefit/cost analysis or the beneficiary determinations are proposed by the Board, the revised analysis and beneficiary determinations shall be returned to the Management Committee for comment. If the Board proposes any changes to the ISO's voting share determinations, the Board shall so inform the LSE or LSEs impacted by the proposed change and shall allow such an LSE or LSEs an opportunity to comment on the proposed change. The Board shall not make a final determination on the project benefit/cost analysis and beneficiary determination until it has reviewed the Management Committee comments. Upon final approval of the Board, project benefit/cost analysis and beneficiary determinations shall be posted by the ISO on its website and shall form the basis of the beneficiary voting described in Section 31.4.3.6 of this Attachment Y.

31.4.3.6 Voting by Project Beneficiaries

31.4.3.6.1 Only LSEs serving Load located in a beneficiary zone determined in accordance with the procedures in Section 31.4.3.4 of this Attachment Y shall be eligible to vote on a proposed project. The ISO will, in conjunction with the ESPWG, develop procedures to determine the specific list of voting entities for each proposed project.

31.4.3.6.2 The voting share of each LSE shall be weighted in accordance with its share of the total project benefits, as allocated by Section 31.4.3.4 of this Attachment Y.

31.4.3.6.3 The costs of a RETP shall be allocated under this Attachment Y if eighty percent (80%) or more of the actual votes cast on a weighted basis are cast in favor of implementing the project.

31.4.3.6.4 If the proposed RETP meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project.

31.4.3.6.5 The ISO will tally the results of the vote in accordance with procedures set forth in the ISO Procedures, and report the results to stakeholders. Beneficiaries voting against approval of a project must submit to the ISO their rationale for their vote within 30 days of the date that the vote is taken. Beneficiaries must provide a detailed explanation of the substantive reasons underlying the decision, including, where appropriate: (1) which additional benefit metrics, either identified in the tariff or otherwise, were used; (2) the actual quantification of such benefit metrics or factors; (3) a quantification and explanation of the net benefit or net cost of the project to the beneficiary; and (4) data supporting the metrics and other factors used. Such explanation may also include uncertainties, and/or alternative scenarios and other qualitative factors considered, including state public policy goals. The ISO will report this information to the Commission in an informational filing to be made within 60 days of the vote. The informational filing will include: (1) a list of the identified beneficiaries; (2) the results of the benefit/cost analysis; and (3) where a project is not approved, whether the developer has provided any formal indication to the ISO as to the future development of the project.

31.4.4 Cost Recovery for Regulated Projects

Responsible Transmission Owners, Transmission Owners and Other Developers will be entitled to full recovery of all reasonably incurred costs, including a reasonable return on investment and any applicable incentives, related to the development, construction, operation and maintenance of regulated solutions, including Gap Solutions, proposed or undertaken pursuant to the provisions of this Attachment Y to meet a Reliability Need. Transmission Owners and Other Developers will be entitled to recovery of costs associated with the implementation of a regulated economic transmission project ("RETP") in accordance with the provisions of Section 31.4.4.4 of this Attachment Y.

31.4.4.1 The Responsible Transmission Owner, Transmission Owner or Other Developer will receive cost recovery for a regulated solution it undertakes to meet a Reliability Need pursuant to Section 31.2. of this Attachment Y that is subsequently halted in accordance with the criteria established pursuant to Section 31.2.7 of this Attachment Y. Such costs will include reasonably incurred costs through the time of cancellation, including any forward commitments made.

31.4.4.2 The Responsible Transmission Owner, Transmission Owner or Other Developer will recover its costs described in this Section 31.4. incurred with respect to the implementation of a regulated transmission solution to Reliability Needs in accordance with the provisions of Rate Schedule 10 of this ISO OATT. Provided further that cost recovery for regulated transmission projects undertaken by a Transmission Owner pursuant to this Attachment Y shall be in accordance with the provisions of the NYISO/TO Reliability Agreement.

31.4.4.3 Costs related to non-transmission regulated solutions to Reliability Needs will be recovered by Responsible Transmission Owners, Transmission Owners and Other Developers in accordance with the provisions of New York Public Service Law, New York Public Authorities Law, or other applicable state law. A Responsible Transmission Owner, a Transmission Owner, or Other Developer may propose and undertake a regulated non-transmission solution, provided that the appropriate state agency(ies) has established cost recovery procedures comparable to those provided in this tariff for regulated transmission solutions to ensure the full and prompt recovery of all reasonably-incurred costs related to such non-transmission solutions. Nothing in this section shall affect the Commission's jurisdiction over the sale and transmission of electric energy subject to the jurisdiction of the Commission.

31.4.4.4 For a regulated economic transmission project that is approved pursuant to Section 31.4.6.3 of this Attachment Y, the Transmission Owner or Other Developer shall have the right to make a filing with the Commission, under Section 205 of the Federal Power Act, for approval of its costs associated with implementation of the project. The filing of the Transmission Owner or Other Developer must be consistent with its project proposal made to and evaluated by the ISO under Section 31.4.3 of this Attachment Y. The period for cost recovery, if any is approved, will be determined by the Commission and will begin if and when the project begins commercial operation. Upon request by NYPA, the ISO will make a filing on behalf of NYPA.

31.4.4.5 To the extent that Incremental TCCs are created as a result of a regulated economic transmission project that has been approved for cost recovery under the NYISO Tariff, those Incremental TCCs that can be sold will be auctioned or otherwise sold by the ISO. The ISO shall determine the amount of Incremental TCCs that may be awarded to an expansion in accordance with the provisions of Section 19.2.2 of Attachment M of the ISO OATT. The ISO will use these revenues to offset the revenue requirements for the project. The Incremental TCCs shall continue to be sold for the depreciable life of the project, and the revenues offset will commence upon the first payment of revenues related to a sale of Incremental TCCs on or after the charge for a specific RETP is implemented.

31.5 Other Provisions

31.5.1 The Commission's Role in Dispute Resolution

Disputes directly relating to the ISO's compliance with its tariffs that are not resolved in the internal ISO collaborative governance appeals process or ISO dispute resolution process, and all disputes relating to matters that fall within the exclusive jurisdiction of the Commission, shall be reviewed at the Commission pursuant to the Federal Power Act if such review is sought by any party to the dispute. The NYPSC or any party to a dispute regarding matters over which both the NYPSC and the Commission have jurisdiction and responsibility for action may submit a request to the Commission for a joint or concurrent hearing to resolve the dispute.

31.5.2 Non-Jurisdictional Entities

LIPA's and NYPA's participation in the CSPP shall in no way be considered to be a waiver of their non-jurisdictional status pursuant to Section 201(f) of the Federal Power Act, including with respect to the the Commission's exercise of the Federal Power Act's general ratemaking authority.

31.5.3 Tax Exempt Financing Provisions

Con Edison, NYPA and LIPA shall not be required to construct, or cause to construct, a transmission facility identified through the ISO Reliability Planning Process if such construction would result in the loss of tax-exempt status of any tax-exempt bond issued by Con Edison, NYPA or LIPA, or impair their ability to secure future tax-exempt financing.

31.5.4 Interregional Planning Coordination

31.5.4.1 The Northeastern ISO/RTO Planning Coordination Protocol

The ISO will coordinate the transmission system planning activities for the NYCA described in this Attachment Y through the Northeastern ISO/RTO Planning Coordination Protocol. This protocol describes the committee structure, processes and procedures through which system planning activities are openly and transparently coordinated by the ISOs and RTOs of the northeastern United States and eastern Canada. The activities covered by the protocol are to be conducted in coordination with the Regional Reliability Councils of the northeastern United States and eastern Canada. The primary purpose of the protocol is to contribute, through transparent, coordinated planning based on consistent assumptions and data, to the on-going reliability and the enhanced operational and economic performance of the parties to the protocol. To accomplish this, the parties will coordinate the evaluation of tariff-provided services, such as generation interconnection, to recognize the impacts that result across the different systems. The parties will also produce, on a periodic basis, a Northeastern Coordinated System Plan that integrates the system plans of the parties and includes upgrade projects jointly identified by the parties to enhance the coordinated performance of their systems.

31.6 Appendices

APPENDIX A - REPORTING OF HISTORIC AND PROJECTED CONGESTION

1.0 General

As part of its CSPP, the ISO will prepare summaries and detailed analysis of historic and projected congestion across the NYS Transmission System. This will include analysis to identify the significant causes of historic congestion in an effort to help Market Participants and other interested parties distinguish persistent and addressable congestion from congestion that results from one time events or transient adjustments in operating procedures that may or may not recur. This information will assist Market Participants and other stakeholders to make appropriately informed decisions.

2.0 Definition of Cost of Congestion

The ISO will report the cost of congestion as the change in bid production costs that results from transmission congestion. The following elements of congestion-related costs also will be reported: (i) impact on load payments; (ii) impact on generator payments; and (iii) hedged and unhedged congestion payments.

The determination of the change in bid production costs and the other elements of congestion will be based upon the difference in costs between the actual constrained system prices computed in the ISO's Day-Ahead Market and a simulation of an unconstrained system. The simulation shall be developed by the use of the PROBE model approved by the ISO Operating Committee on January 22, 2004 or by such other software as may provide the required congestion information.

3.0 Analysis

Each RNA will include the ISO's summaries and detailed analysis of the prior year's congestion across the NYS Transmission System. The ISO's analysis will identify the significant causes of the historic congestion.

Each study of projected congestion for economic planning will include the results of the ISO's analysis conducted in accordance with Section 31.3.1 of this Attachment Y. The ISO's analysis will identify the significant causes of the projected congestion.

4.0 Detailed Cause Analysis for Unusual Events

The ISO will perform an analysis to identify unusual events causing significant congestion levels. Such analysis will include the following elements: (i) identification of major transmission or generation outages; and (ii) quantification of the market impact of relieving historic constraints.

Some of the information necessary to this analysis may constitute critical energy infrastructure information and will need to be handled with appropriate confidentiality limitations to protect national security interests.

5.0 Summary Reports

The ISO will prepare various reports of historic and projected congestion costs. Historic congestion reports will be based upon the actual congestion data from the ISO Day-Ahead Market, and will include summaries, aggregated by month and calendar year, such as: (i) NYCA; (ii) by zone; (iii) by contingency in rank order; (iv) by constraint in rank order; (v) total dollars; and (vi) number of hours. Results of projected congestion studies conducted pursuant to Section 31.3.1 of this Attachment Y will include summaries of selected additional metrics and scenarios.

These reports will be based upon the foregoing definitions of congestion.

APPENDIX B - PROCEDURE FOR FORECASTING THE NET REDUCTIONS IN TCC REVENUES THAT WOULD RESULT FROM A PROPOSED PROJECT

For the purpose of determining the allocation of costs associated with a proposed project as described in Section 31.4.3.4.of this Attachment Y, the ISO shall use the procedure described herein to forecast the net reductions in TCC revenues allocated to Load in each Load Zone as a result of a proposed project.

Definitions

The following definitions will apply to this appendix:

Pre-CARIS Centralized TCC Auction: The last Centralized TCC Auction that had been completed as of the date the input assumptions were determined for the CARIS in which the Project was identified as a candidate for development under the provisions of this Attachment Y.

Project: The proposed transmission project for which the evaluation of the net benefits forecasted for Load in each Load Zone, as described in Section 31.4.3.4.2 of this Attachment Y, is being performed.

TCC Revenue Factor: A factor that is intended to reflect the expected ratio of (1) revenue realized in the TCC auction from the sale of a TCC to (2) the Congestion Rents that a purchaser of that TCC would expect to realize. The value to be used for the TCC Revenue Factor shall be stated in the ISO Procedures.

Steps 1 Through 6 of the Procedure

For each Project, the ISO will perform Steps 1 through 6 of this procedure twice for each of the ten (10) years following the proposed commercial operation date of the Project: once under the assumption that the Project is in place in each of those years, and once under the assumption that the Project is not in place in each of those years.

Forecasting the Value of Grandfathered TCCs and TCC Auction Revenue

Step 1. The ISO shall forecast Congestion Rents collected on the New York electricity system in each year, which shall be equal to:

(a) the product of:

(i) the forecasted Congestion Component of the Day-Ahead LBMP for each hour at each Load Zone or Proxy Generator Bus and

(ii) forecasted withdrawals scheduled in that hour in that Load Zone or Proxy Generator Bus, summed over all locations and over all hours in that year, minus:

(b) the product of:

(i) the forecasted Congestion Component of the Day-Ahead LBMP for each hour at each Generator bus or Proxy Generator Bus and

(ii) forecasted injections scheduled in that hour at that Generator bus or Proxy Generator Bus,

summed over all locations and over all hours in that year.

Step 2. The ISO shall forecast:

(a) payments in each year associated with any Incremental TCCs that the ISO projects would be awarded in conjunction with that Project (which will be zero for the calculation that is performed under the assumption that the Project is not in place);

(b) payments in each year associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation; and

(c) payments that would be made to holders of Grandfathered Rights and imputed payments that would be made to the Primary Holders of Grandfathered TCCs that would be in effect in each year, under the following assumptions:

(i) all Grandfathered Rights and Grandfathered TCCs expire at their stated expiration dates;

(ii) imputed payments to holders of Grandfathered Rights are equal to the payments that would be made to the Primary Holder of a TCC with the same Point of Injection and Point of Withdrawal as that Grandfathered Right; and

(iii) in cases where a Grandfathered TCC is listed in Table 1 of Attachment M of the ISO OATT, the number of those TCCs held by their Primary Holders shall be set to the number of such TCCs remaining at the conclusion of the ETCNL reduction procedure conducted before the Pre-CARIS Centralized TCC Auction.

Step 3. The ISO shall forecast TCC auction revenues for each year by subtracting:

(a) the forecasted payments calculated for that year in Steps 2(a), 2(b) and 2(c) of this procedure

from:

(b) the forecasted Congestion Rents calculated for that year in Step 1 of this procedure, and multiplying the difference by the TCC Revenue Factor.

Forecasting the Allocation of TCC Auction Revenues Among the Transmission Owners

Step 4. The ISO shall forecast the following:

(a) payments in each year to the Primary Holders of Original Residual TCCs and

(b) payments in each year to the Primary Holders of TCCs that correspond to the amount of ETCNL remaining at the conclusion of the ETCNL reduction procedure conducted before the Pre-CARIS Centralized TCC Auction,

and multiply each by the TCC Revenue Factor to determine the forecasted payments to the Primary Holders of Original Residual TCCs and the Transmission Owners that have been allocated ETCNL.

Step 5. The ISO shall forecast residual auction revenues for each year by subtracting:

(a) the sum of the forecasted payments for each year to the Primary Holders of Original Residual TCCs and the Transmission Owners that have been allocated ETCNL, calculated in Step 4 of this procedure

from:

(b) forecasted TCC auction revenues for that year calculated in Step 3 of this procedure.

Step 6. The ISO shall forecast each Transmission Owner’s share of residual auction revenue for each year by multiplying:

(a) the forecast of residual auction revenue calculated in Step 5 of this procedure and

(b) the ratio of:

(i) the amount of residual auction revenue allocated to that Transmission Owner in the Pre-CARIS Centralized TCC Auction to

(ii) the total amount of residual auction revenue allocated in the Pre-CARIS Centralized TCC Auction.

Steps 7 Through 10 of the Procedure

The ISO will perform Steps 7 through 10 of this procedure once for each of the ten (10) years following the proposed commercial operation date of the Project, using the results of the preceding calculations performed both under the assumption that the Project is in place in each of those years, and under the assumption that the Project is not in place in each of those years.

Forecasting the Impact of the Project on TSC Offsets and the NTAC Offset

Step 7. The ISO shall calculate the forecasted net impact of the Project on the TSC offset for each megawatt-hour of electricity consumed by Load in each Transmission District (other than the NYPA Transmission District) in each year by:

(a) summing the following, each forecasted for that Transmission District for that year under the assumption that the Project is in place:

(i) forecasted Congestion Rents associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, as calculated in Step 2(b) of this procedure, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation, if those Congestion Rents would affect the TSC for that Transmission District;

(ii) forecasted Congestion Rents associated with any Grandfathered TCCs and forecasted imputed Congestion Rents associated with any Grandfathered Rights held by the Transmission Owner serving that Transmission District that would be paid to that Transmission Owner for that year, as calculated in Step 2(c) of this procedure, if those Congestion Rents would affect the TSC for that Transmission District;

(iii) the payments that are forecasted to be made for that year to the Primary Holders of Original Residual TCCs and ETCNL that have been allocated to the Transmission Owner serving that Transmission District, as calculated in Step 4 of this procedure; and

(iv) that Transmission District's forecasted share of residual auction revenues for that year, as calculated in Step 6 of this procedure for the Transmission Owner serving that Transmission District;

(b) subtracting the sum of items (i) through (iv) above, each forecasted for that Transmission District for that year under the assumption that the Project is not in place; and

(c) dividing this difference by the amount of Load forecasted to be served in that Transmission District in that year, stated in terms of megawatt-hours, net of any Load served by municipally owned utilities that is not subject to the TSC.

Step 8. The ISO shall calculate the forecasted net impact of the Project on the NTAC offset for each megawatt-hour of electricity consumed by Load in each year by:

(a) summing the following, each forecasted for that year under the assumption that the Project is in place:

(i) forecasted Congestion Rents associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, as calculated in Step 2(b) of this procedure, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation, if those Congestion Rents would affect the NTAC;

(ii) forecasted Congestion Rents associated with any Grandfathered TCCs and forecasted imputed Congestion Rents associated with any Grandfathered Rights held by NYPA that would be paid to NYPA for that year, as calculated in Step 2(c) of this procedure, if those Congestion Rents would affect the NTAC;

(iii) the payments that are forecasted to be made for that year to NYPA in association with Original Residual TCCs allocated to NYPA, as calculated in Step 4 of this procedure; and

(iv) NYPA's forecasted share of residual auction revenues for that year, as calculated in Step 6 of this procedure;

(b) subtracting the sum of items (i) through (iv) above, each forecasted for that year under the assumption that the Project is not in place; and

(c) dividing this difference by the amount of Load expected to be served in the NYCA in that year, stated in terms of megawatt-hours, net of any Load served by municipally owned utilities that is not subject to the NTAC.

Forecasting the Net Impact of the Project on TCC Revenues Allocated to Load in Each Zone

Step 9. The ISO shall calculate the forecasted net impact of the Project in each year in each Load Zone on payments made in conjunction with TCCs and Grandfathered Rights that benefit Load but which do not affect TSCs or the NTAC, which shall be the sum of:

(a) Forecasted Congestion Rents paid or imputed to municipally owned utilities serving Load in that Load Zone that own Grandfathered Rights or Grandfathered TCCs that were not included in the calculation of the TSC offset in Step 7(a)(ii) of this procedure or the NTAC offset in Step 8(a)(ii) of this procedure, which the ISO shall calculate by:

(i) summing forecasted Congestion Rents that any such municipally owned utilities serving Load in that Load Zone would be paid for that year in association with any such Grandfathered TCCs and any forecasted imputed Congestion Rents that such a municipally owned utility would be paid for that year in association with any such Grandfathered Rights, as calculated in Step 2(c) of this procedure under the assumption that the Project is in place; and

(ii) subtracting forecasted Congestion Rents that any such municipally owned utilities would be paid for that year in association with any such Grandfathered TCCs, and any forecasted imputed Congestion Rents that such a municipally owned utility would be paid for that year in association with any such Grandfathered Rights, as calculated in Step 2(c) of this procedure under the assumption that the Project is not in place.

(b) Forecasted Congestion Rents collected from Incremental TCCs awarded in conjunction with projects that were previously funded through this procedure, if those Congestion Rents are used to reduce the amount that Load in that Load Zone must pay to fund such projects, which the ISO shall calculate by:

(i) summing forecasted Congestion Rents that would be collected for that year in association with any such Incremental TCCs, as calculated in Step 2(b) of this procedure under the assumption that the Project is in place; and

(ii) subtracting forecasted Congestion Rents that would be collected for that year in association with any such Incremental TCCs, as calculated in Step 2(b) of this procedure under the assumption that the Project is not in place.

Step 10. The ISO shall calculate the forecasted net reductions in TCC revenues allocated to Load in each Load Zone as a result of a proposed Project by summing the following:

(a) the product of:

(i) the forecasted net impact of the Project on the TSC offset for each megawatt-hour of electricity consumed by Load, as calculated for each Transmission District (other than the NYPA Transmission District) in Step 7 of this procedure; and

(ii) the number of megawatt-hours of energy that are forecasted to be consumed by Load in that year, in the portion of that Transmission District that is in that Load Zone, for Load that is subject to the TSC;

summed over all Transmission Districts;

(b) the product of:

(i) the forecasted net impact of the Project on the NTAC offset for each megawatt-hour of electricity consumed by Load, as calculated in Step 8 of this procedure; and

(ii) the number of megawatt-hours of energy that are forecasted to be consumed by Load in that year in that Load Zone, for Load that is subject to the NTAC; and

(c) the forecasted net impact of the Project on payments and imputed payments made in conjunction with TCCs and Grandfathered Rights that benefit Load but which do not affect TSCs or the NTAC, as calculated in Step 9 of this procedure.

Additional Notes Concerning the Procedure

For the purposes of Steps 2(c) and 4(b) of this procedure, the ISO will utilize the currently effective version of Attachment L of the ISO OATT to identify Existing Transmission Agreements and Existing Transmission Capacity for Native Load.

Each Transmission Owner, other than NYPA, will inform the ISO of any Grandfathered Rights and Grandfathered TCCs it holds whose Congestion Rents should be taken into account in Step 7 of this procedure because those Congestion Rents affect its TSC.

NYPA will inform the ISO of any Grandfathered Rights and Grandfathered TCCs it holds whose Congestion Rents should be taken into account in Step 8 of this procedure because those Congestion Rents affect the NTAC.