TRANSMISSION AND DISPATCHING OPERATIONS MANUAL

11/30/04

Transmission & Dispatching Operations Manual

Version: 2.0

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Revision	Date	Changes
2.0	**12/15/04**	**12/01/03** Note 1: This Manual has been updated to reflect the SMD2 requirements and terminology. Note 2: The references to the Technical Bulletins do not imply that the TBs should be retired. Section 1 ▪ Major edits to reflect the new SCUC/RTC/RTD market structure Section 2.2.7 ▪ This section incorporates Technical Bulletin #111 Section 2.2.8 ▪ This section incorporates Technical Bulletin #100 Section 3.2.8 ▪ Technical Bulletin #61 refers to Section 3.2.8 of this Manual; however, this section does not need to refer to TB #61. Section 4.1.1 ▪ This section reflects Technical Bulletins #23, #40, #51, and #72 Section 4.1.3 ▪ This section reflects Technical Bulletin #66 Section 4.2.2 ▪ This section reflects Technical Bulletins #70, #83, #89, and #92 Section 4.2.3 This section reflects Technical Bulletins #58 and #61 Section 4.2.5 This section reflects Technical Bulletin #76 Section 4.2.6 This section reflects Technical Bulletin #96 Section 4.3.5 This section incorporates Technical Bulletin #45 Section 5.3.1 This section reflects Technical Bulletin #25 Section 5.4.2 This section reflects Technical Bulletin #33 Attachment A Same as previous Appendix A Attachment B Previous Appendix B-3 was removed from this Manual Attachment B.3 Moved from previous Appendix B-4 Attachment B.4 Moved from previous Appendix B-5 Attachment B.5 New Attachment section Attachment B.6 New Attachment section Attachment C Same as previous Appendix C Attachment D Same as previous Appendix D

		Attachment E New to consolidate LBMP concepts and equations. Also reflects Technical Bulletin #62. Attachment E.2 This Attachment section reflects Technical Bulletin #28 Attachment E.5 This Attachment section incorporates Technical Bulletin #108 Attachment E.7 This Attachment section reflects Technical Bulletin #48 Attachment F Same as previous Appendix E **10/02/2000** Sect. 1.1, Pg. 1, Paragraph 3 ▪ Delete “ISO” and replace with “NYISO” ▪ Delete “Attachment B” and replace with “Exhibit B-1" ▪ Insert “Reserve and Control Error” after “B-1" and “B-2" ▪ Delete “Appendices” and put “the Appendix” before “Exhibit B-1" ▪ Insert “Exhibit” before B-2 ▪ Delete “Attachment A” and replace with “the Appendix” #1, #2, paragraph after #2 ▪ Replace “ISO Secured Transmission System” with “NYISO Secured Transmission System” Sect. 1.1.2, Last Paragraph, after the last sentence: ▪ Add this text at the end: “The Local Reliability Rules of the New York Transmission Providers are listed in Appendix B-6 of the NYISO Transmission and Dispatching Operations Manual.” Sect. 1.1.3, Last paragraph, after the last sentence: ▪ Add this text at the end: “The Application of the Reliability Rules and the associated cost allocation are listed in Appendix B-7 of the NYISO Transmission and Dispatching Operations Manual.” Sect. 1.3.2, #6 ▪ Replace “Pool” with “Area” Sect. 2.2.1, Pg. 5, #2 f ▪ Delete “Energy” and replace with “Interchange” Sect. 2.2.2, Pg. 7 ▪ #2 c & d: Reverse order of info. Should be as follows: 2c. Activate reserves 2d. Adjust reactive sources and transformer taps 2e. Perform Generation shifts ▪ #2 f: Delete “Energy Transactions” and replace with “Interchange Schedules” ▪ #2: Insert this text as 2j: “May call for a reserve pickup to return to schedule if the NYISO Control Error exceeds -100 MW.” ▪ #2: Insert this text as 2k: “Take actions to maintain operating reserve, in accordance with the procedures described in Section 4.2 of this Manual.” ▪ #2: This text becomes 2 l: “Curtail non-essential Transmission Owner load.” ▪ #2l: Replace “Transmission Owner” with “Market Participant” ▪ #2: This text becomes 2m: “Order Generation to full operating capability.” Sect. 2.2.2 ▪ TO Actions, #1: Add “Shift Supervisor” after “NYISO” Sect. 3.2.9 ▪ 2nd Paragraph: Replace “Provider” with “Owner” Sect. 3.2.10, Pg. 19

		▪ NYISO Actions #1: Change "K7" to "K6" ▪ NYISO Actions #3: Delete this: "Request Transmission Owners to implement appropriate emergency procedures, when a contingency occurs." and replace with this: "If a Warning of K6 or greater or an Alert of K7 or greater has been issued by SEC with significant GIC (Ground Induced Currents) activity observed by a neighboring Control Area or Transmission Owner initiate the following actions:" ▪ After NYISO Actions #3, insert: "Declare Alert State a. Notify Transmission Owners to reduce normal limits on inter-area and internal NYS Power System transmission lines and transformers to a maximum of 90% of the normal rating where appropriate. b. Request generators (via their TOs) to adjust machine excitation in order to maintain the ISO Secured Transmission System voltages within acceptable operating ranges to protect against voltage swings. c. Reduce SCD Stability Transfer Limits and SCD Central East Voltage Contingency Limits to 90% of the Stability Transfer Limit and Central East Voltage Contingency Limits where appropriate. d. Request Transmission Owners to implement appropriate emergency procedures, when a contingency occurs." ▪ In NYISO Actions, last item: Insert: "internal" after: "Reduce flows on inter-area and..." Sect. 4.2.6, Pg. 20 ▪ Delete "3) SCUC Re-Adjustment - Following Step #2 above, a subsequent SCUC run may re-adjust resources." Appendix A-3 ▪ Change the Bowline 345 Bus's Pre-Low from 338 to 345 ▪ Change the Buchanan 345 Bus's Pre-Low from 338 to 346 ▪ Change the Dunwoodie 345 Bus's Pre-Low from 338 to 346 ▪ Delete the Hurley Ave 345 Bus and all its information ▪ Change the Ladentown 345 Bus's Pre-Low from 338 to 346 ▪ Change the Oakdale 345 Bus's Pre-Low from 335 to 336 ▪ Change the Pannell Road 345 Bus's Pre-Low from "see pg. 2" to "see A-4" ▪ Change the Pleasant Valley 345 Bus's Pre-Low from 338 to 343 ▪ Change the Ramapo 345 Bus's Pre-Low from 338 to 346 ▪ After Ramapo 500, insert a new line: "Rock Tavern 345, 348, 362, 328, 362, CH" ▪ Change the Roseton 345 Bus's Pre-Low from 338 to 345 ▪ Change the Sprainbrook 345 Bus's Pre-Low from 338 to 346 ▪ Change the Station 80 345 Bus's Pre-Low from "see page 2" to "see A-4" ▪ Delete Note (2) "Pre-contingency low limits for various HQ to NYISO transfers are listed in Exhibit A-4." ▪ Delete all links to note 2 next to the following: Oakdale 345, Pannell Road 345, Ramapo 345, Station 80 345, Watercure 230. ▪ Delete Note (3) "Voltage below 327 kV at Ramapo may cause the loss of the Bowline Units." ▪ Delete all links to note 3 next to the following: Ramapo 345 Appendix B-6 ▪ Add the "Local Reliability Rules of the New York Transmission Providers" table Appendix B-7 ▪ Add the "Applications of Reliability Rules and Cost Allocation Responsibility" table **09/01/1999**

		Sect. 1, Pg. 15 ▪ Paragraph 3 - Delete “across zonal boundaries.” Sect. 1, Pg. 17 ▪ Delete “Direct” from “Direct Customers” in Exhibit 1.2 Sect. 2, Pg. 2 ▪ Delete 2.1.3 AC Thermal & Voltage Security Assessment Sect. 2, Pg. 3 2.1.3 ▪ Add “D. Sufficient Reserve in 10 minutes to return the system to a normal state following the most severe transmission contingency.” Sect. 2, Pg. 4 ▪ Delete Reserve Calculation NYISO Actions 1 through 7. Sect. 2, Pg. 5 2.2.1, 2f ▪ Change “Energy” to “Physical” Sect. 2, Pg. 7 2.2.2, 2f ▪ Change “Energy” to “Physical” Sect. 2, Pg. 12 2.2.9 ▪ last line delete from for - Manual and add “in the Emergency Operation Manual, Section 4.4" Sect. 3, Pg. 3 3.1.3 ▪ last line 1st paragraph add “See Exhibit 4.1" Last line 3rd paragraph add “See Exhibit 4.4" Sect. 3, Pg. 15 3.2. 8, ▪ Add #7: Attempt to purchase emergency energy from other CAs that will provide relief to the security violation. Sect. 4, Pg. 2 ▪ Replace last two lines with Sect. 4.1.2 from AI Sect. 4, Pg. 4 ▪ List Tables Sect. 4, Pg. 5 ▪ Delete “*’s”. In last line, row at bottom of Exhibit 4.1 Summary Table insert “Transmission Customer” before the words “load that is off-schedule...” Sect. 4, Pg. 10 ▪ Exhibit 4.6 Add last line “Marcy.........” Sect. 4, Pg. 12 ▪ Correct “Curtailment” in last column Sect. 4, Pg. 18 ▪ Add Header 4.2.5 Sect. 4, Pg. 20 ▪ Add Header 4.2.6 Sect. 4, Pg. 21 ▪ Add Header 4.2.7 Sect. 4, Pg. 22 ▪ Add Header 4.2.8 Sect. 4, Pg. 22 ▪ Remove “e.” Sect. 4, Pg. 23 ▪ Add Header 4.2.9 Sect. 4, Pg. 26 ▪ Add Header 4.2.10 Sect. 4, Pg. 27 ▪ Add Header 4.2.11 Sect. 4, (last item) ▪ Delete NYISO Actions – end

		Sect. 5, Pg. 3 ▪ Add Header 5.1.1 Sect. 5, Pg. 5 ▪ Add Header 5.1.2 - 5.1.3 Sect. 5, Pg. 9 ▪ Add Header 5.2.1 - 5.2.2 Sect. 5, Pg. 10 ▪ Add Header 5.2.3 - 5.2.4 Sect. 5, Pg. 14 ▪ Add Header 5.2.5 - 5.2.6 - 5.2.7 Sect. 5, Pg. 15 ▪ Add Header 5.2.8 - 5.2.9 Sect. 5, Pg. 16 ▪ Correct Header 5.2.10 Sect. 5, Pg. 18 ▪ Correct Header 5.2.11 Sect. 5, Pg. 20 ▪ Correct Header 5.2.12 Sect. 5, Pg. 21 ▪ Correct Header 5.2.13
1.0	**9/01/99**	Initial Release

~~1. OVERVIEW~~

~~This section describes the operating policies and states of the power system.~~

1. Introduction

This *NYISO Transmission & Dispatching Operations Manual* is one of a series of manuals within the Operations Manuals. ~~This manual~~This Manual focuses on describing each of the Transmission & Dispatching Operations that the NYISO facilitates and/or controls.

The NYISO Transmission & Dispatching Operations Manual consists of five sections as follows:

- Section 1: ~~Overview~~Introduction
- Section 2: Overview
- Section ~~2~~3: Operations Monitoring
- Section ~~3~~4: Transmission Operations
- Section ~~4~~5: Scheduling Operations
- Section ~~5~~6: Dispatching Operations

References

The references to other documents that provide background or additional detail directly related to the *NYISO Transmission & Dispatching Operations Manual* are:

- NYISO Emergency Operations Manual
- NYISO Accounting & Billing Manual
- NYISO Day-Ahead Scheduling Manual
- NYISO Ancillary Services Manual
- New York ISO Tariffs
- NYSRC Agreement
- NYSRC - Reliability Rules Manual
- Market Participant User's Guide

2. Overview

This section presents an overview of the following:

~~a.~~Operating Policy

- NYISO versus Transmission Owner Responsibilities and Authorities
- Normal and Warning Operating States
- Market Operations Time Line
- Operations Functions
- Communications

2.1. Operating Policy

Under the terms of the NYISO Agreement, the NYISO/~~TP~~Transmission Owner Agreement, and the NYSRC Agreement, the NYISO has the authority to direct the operation of the NYS Power System to maintain system reliability in accordance with good utility practice and the Reliability Rules. The goal is to anticipate potential problems, apply preventative measures, and to quickly respond to actual problems when they occur.

In order to meet its obligations under the Reliability Rules with respect to maintaining the security of the ~~Bulk~~ NYS Power System, the NYISO shall maintain a list of transmission facilities included within the NYS Transmission System, defined as the NYISO Secured Transmission system~~, that it will be~~. The NYISO is responsible ~~to secure through:~~ for:

1. ~~the~~ The coordination of the operation of those facilities under its Operational Control with the responsible Transmission Owners,
2. ~~the~~ The commitment and/or dispatch of supply and demand resources connected to the NYS Transmission system, and/or
3. ~~the~~ The control and/or coordination of ~~system elements~~ facilities used to provide ancillary services.

~~Facilities included in the ISO Secured System~~ Transmission facilities that are ~~identified in Attachment B, Appendices B-1 and B-2~~ under NYISO operational control are listed in Attachment A.1 of ~~this manual~~this Manual.

Transmission facilities that require NYISO notification are listed in Attachment A.2 of ~~this manual~~this Manual.

Bus Voltage Limits for buses included as part of the NYISO Secured Transmission System are listed in Attachment A~~, Exhibit A-3.~~ .3 of ~~this manual~~this Manual.

2.1.1. Operating States

The following five operating states are defined for the NYS Power System:

~~—~~1. Normal

~~—~~2. Warning

~~—~~3. Alert

~~—~~4. Major Emergency

~~—~~5. Restoration

The NYISO Shift Supervisor shall determine the state of the NYISO Secured Transmission System~~:~~ by comparing system conditions against certain monitoring criteria. The NYISO Shift Supervisor shall also monitor weather conditions and forecasts. ~~Exhibit A-1 of~~ Attachment ~~A~~ B.1 summarizes the system conditions defining each state and the monitored criteria.

1. When the NYISO Shift Supervisor determines ~~that the~~the state of the NYISO Secured Transmission System is Normal or Warning, the NYISO shall operate the NYS Power System according to the procedures described in ~~this manual~~this Manual.
2. When the NYISO Shift Supervisor determines ~~that the~~the state of the NYISO Secured Transmission System is Alert, Major Emergency, or Restoration, the NYISO shall operate the NYS Power ~~system~~System according to procedures in the NYISO ~~Manual for~~ Emergency Operations~~.~~ Manual.

2.1.2. NYISO Objective

It is the objective of the NYISO to operate the NYISO Secured Transmission System within the Normal State. Conditions may cause the NYISO Secured Transmission System to depart from ~~this~~the Normal State, however. Such conditions include, but are not limited to, the following:

1. ~~capacity~~Capacity deficiencies ~~• energy~~

~~6.~~2.Energy deficiencies

~~7.~~3.~~loss~~Loss of generation or transmission facilities

~~8.~~4.~~high~~High voltage

~~9.~~5.~~low~~Low voltage

~~10.~~6. ~~environmental~~Environmental episodes

~~11.~~7. ~~transmission~~ Transmission overloads

~~12.~~8. ~~abnormal~~Abnormal power system frequency

When the NYISO Secured Transmission System enters a condition other than the Normal State, the NYISO shall act to return the NYISO Secured Transmission System to the Normal State. When the criteria for the Normal State cannot be achieved, the NYISO shall satisfy as many of the Normal State criteria as possible and shall minimize the consequences of any single contingency. Should a disturbance occur, its extent and duration shall be minimized.

When multiple violations occur within the same state, actual violations shall be corrected before predicted violations. Where multiple violations of differing state criteria occur, the most serious violation shall be solved first.

2.1.3. Emergency Conditions

The NYISO Schedule Coordinator, the NYISO Shift Supervisor, or both shall forecast the likelihood of the occurrence of states other than the Normal State as far in advance as possible. If it is predicted that Load Relief, either by Voltage Reduction or Load Shedding, may be necessary during a future period, the NYISO Shift Supervisor shall notify all Transmission Owners.

Refer to the *NYISO* ~~Manual for~~ *Emergency Operations Manual* for a detailed description of the procedures to be followed under these conditions.

Transmission Owners shall develop the necessary communication policies with Transmission Customers. The specific operating methods used by each Transmission Owner are not necessarily identical. The NYISO Shift Supervisor shall coordinate such methods in order to achieve uniform results.

~~i.~~2.1.4. General Reliability Rules

The NYSRC has the responsibility to develop, establish, maintain, assure compliance with, and, from time-to-time, update the Reliability Rules, which must be complied with by the NYISO and all entities engaging in electric power transactions on the NYS Power System. The NYSRC uses the reliability standards, regulations, criteria, procedures, and rules established or imposed by:

1. NERC
2. NPCC
3. FERC
4. PSC
5. NRC
6. Any other government agency with jurisdiction over the reliability of the NYS Power System

~~anyAny other government agency with jurisdiction over the reliability of the NYS Power System~~.

The NYSRC will initially adopt those existing rules, policies, and procedures of the NYISO that relate to or affect the reliability of the NYS Power System. The NYSRC will adopt or create from time-to-time such additional Reliability Rules that it deems necessary to meet the unique reliability needs of New York State.

The NYISO or a member of the NYSRC may petition the NYSRC Executive Committee to seek specific and limited exceptions to NERC and NPCC criteria, provided the intent of the criteria is not compromised. The NYSRC will adopt all new mandatory compliance rules of NERC and NPCC, unless existing Reliability Rules are more stringent.

~~i.~~2.1.5. Local Reliability Rules ~~[NYSRC Agreement - 3.02]~~

The NYSRC will adopt as a Reliability Rule each Local Reliability Rule in existence at the time the NYSRC Agreement becomes effective. Such existing Local Reliability Rules cannot be modified or eliminated by the NYSRC without the consent of the Transmission Owner who implemented such Local Reliability Rule. A Transmission Owner may promulgate a new Local Reliability Rule if that Transmission Owner determines that a new Local Reliability Rule is necessary to protect the reliable delivery of electricity over its transmission and/or distribution facilities.

The Board of Directors of the NYISO or the NYSRC may request that the PSC review a Local Reliability Rule. In the event the NYISO Board or the NYSRC seeks to modify or eliminate any Local Reliability Rule, and the Transmission Owner promulgating that rule does not agree to modify or eliminate that rule, that Local Reliability Rule can be modified or eliminated pursuant to an order by the PSC or FERC.

The ~~Board~~commitment and/or dispatch of ~~Directors of the NYISO or the NYSRC~~supply and/or demand resources in a localized area may ~~request that~~be required to maintain the reliability of certain areas of the ~~PSC review a Local Reliability Rule. In~~NYS Power system in accordance with the ~~event the NYISO Board or the NYSRC seeks to modify or eliminate any~~ Local Reliability Rule~~, and the~~s of a Transmission ~~Provider promulgating~~Owner. Local Reliability Rules generally exceed the basic criteria set forth in the Reliability Rules and/or are required by regulatory order. Any incremental uplift costs incurred to meet Local Reliability Rules implemented by the NYISO shall be recovered by the NYISO through the application of an uplift charge. Uplift charges administered by the NYISO associated with selected Local Reliability Rules that ~~rule does not agree to modify or eliminate that rule, that Local Reliability Rule can be modified or eliminated only pursuant to an order by the PSC or FERC.~~impact the NYISO Secured Transmission System may be borne by all customers while others will be assigned to the local customers receiving the reliability benefits from the Local Reliability Rules. The Local Reliability Rules of the New York Transmission Owners are listed in Attachment B.5 of ~~this manual~~this Manual.

~~ii.~~2.1.6. Applications of Reliability Rules

Operation of the NYS Power System by the NYISO will be subject to two critical changes from past operation under the NYPP:

1. ~~many~~Many of the generating units previously owned and operated by the Transmission Owners have been or will be divested, and
2. ~~the~~ The responsibility for unit commitment, previously performed by each Transmission Owner, will reside with the NYISO.

The NYISO will be responsible to enforce the Reliability Rules for the NYISO Secured Transmission System. Certain applications of the Reliability Rules, previously implemented by the Transmission Owners, will continue to require close coordination between the Transmission Owners and the NYISO in order to insure the reliability of the NYS Power System. The Transmission Owners will need to:

1. ~~implement~~Implement the Reliability Rules for those portions of the NYS Transmission System not included in the NYISO Secured Transmission System, and
2. ~~coordinate~~ Coordinate with the NYISO the implementation of certain Applications to the Reliability Rules where the NYISO lacks the necessary analysis and/or monitoring capabilities.

In general, any incremental uplift costs incurred to meet Applications of the Reliability Rules shall be recovered by the NYISO through a statewide uplift if the Application secures a facility within the NYISO Secured Transmission System. Also, Applications of the Reliability Rules may include facilities that are not included in the NYISO Secured Transmission System, but are implemented by the NYISO at the Transmission Owner's request. Incremental costs associated with such Applications shall generally be borne by the Locality. The Application of the Reliability Rules and the associated cost allocation are listed in Attachment B.6 of ~~this manual~~this Manual.

~~b.~~2.2. NYISO ~~vs.~~ and TO Responsibilities and Authorities

The following defines the responsibilities and authorities assigned to the NYISO and associated Transmission Owners.

~~i.~~2.2.1. Background Definitions

New York State Transmission System~~: The entire~~ (NYSTS)

The New York State electric transmission ~~system,~~system ~~which~~ includes: (1) the Transmission Facilities Under NYISO Operational Control; (2) the Transmission Facilities Requiring NYISO Notification; and (3) all remaining transmission facilities within the NYCA.

~~Appendix~~Attachment A~~-~~.1 Facilities = Transmission Facilities Under NYISO Operational Control

~~Appendix~~Attachment A~~-~~.2 Facilities = Transmission Facilities Requiring NYISO Notification

Local Area Transmission System Facilities = Transmission Facilities including sub-transmission not ~~on Appendix~~included in Attachment A~~-~~.1 or A~~-~~.2

Thus, ~~New York State Transmission System =~~

NYSTS = A~~-~~.1 Facilities + A~~-~~.2 Facilities + Local Area Transmission System Facilities

New York State Power System~~:~~ (NYSPS)

All facilities of the ~~NYS New York State Transmission System,~~New York State Transmission System and all those Generators located within New York or outside New York, some of which may be from time-to-time subject to operational control by the ~~ISO.~~ NYISO.

~~4.~~

Thus, ~~New York State Power System =~~

NYSPS = NYSTS + Int/Ext Gens Subject to NYISO Op Control

Reliability Rules~~:~~

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

NYISO Secured Transmission System~~:~~

Certain transmission facilities in the NYS Transmission System which the NYISO will be responsible to secure through: (1) the coordination of the operation of those facilities under its Operational Control with the responsible Transmission Owners, (2) the commitment and/or dispatch of supply and demand resources connected to the NYS Transmission System, and/or (3) the control and/or coordination of system elements used to provide ancillary services.

All the facilities in the NYISO Secured Transmission System are identified in ~~Appendices~~Attachments A~~-~~.1 and A~~-~~.2. Bus Voltage Limits for buses included as part of the NYISO Secured Transmission System are listed in ~~Appendix~~Attachment A~~–~~.3.

Therefore:

~~4.~~1.~~1.1.2~~ A Transmission Facility may be under NYISO Operational Control but not part of the NYISO Secured Transmission System.

~~5.~~2.~~1.1.3~~ A Transmission Facility may be subject to NYISO Notification (i.e., not under NYISO Operational Control), and yet be part of the NYISO Secured Transmission System.

~~6.~~3.~~1.1.4~~ NYISO Secured Transmission System Facilities designated on the NYISO Operational Control and/or NYISO Notification Lists will be secured by the NYISO only in terms of flows on those facilities. NYISO ~~Secured~~Secured Transmission System Facilities designated on the Bus Voltage Limit list will be secured by the NYISO in terms of voltages at those buses.

~~7.~~4.~~1.1.5~~ Maintenance of the Normal State by the NYISO, and declaration of the Alert, Warning, Major Emergency, and Restorative States by the NYISO will pertain to the NYISO Secured Transmission System only.

~~7.~~

~~i.~~2.2.2. General Relationships ~~Between~~between NYISO and ~~TOs~~ Transmission Owners

Operation of the NYS Power System will be a cooperative effort coordinated by the NYISO control center in conjunction with each Transmission Owner's control center, and will require instantaneous exchange of all scheduling information.

In general, the NYISO, much like the previous NYPP, will have operational control over key transmission facilities and will be notified of any change in status for other facilities.

The NYISO will be responsible to enforce the Reliability Rules for the NYISO Secured Transmission System. Certain applications of the Reliability Rules, previously implemented by the Transmission Owners, will continue to require close coordination between the Transmission Owners and the NYISO in order to insure the reliability of the NYS Power System.

~~ii.~~2.2.3. NYISO Responsibilities and Authorities

The primary responsibilities and authorities of the NYISO are:

1. Assume responsibility for Control Area operations of the NYS Power System~~.~~.
2. Perform balancing of generation and load while ensuring the safe, reliable, and efficient operation of the NYS Power System.
3. Mitigate the impact of Constraints on the NYS Transmission System, including nondiscriminatory redispatch and Curtailments.
4. Maintain the NYISO Secured Transmission System in Normal State; based upon reliability criteria, declare Warning, Alert, Major Emergency, and Restorative States for the NYISO Secured Transmission System.
5. Exercise Operational Control over certain facilities of the NYS Power System under normal operating conditions and system Emergencies to maintain system reliability. For the NYISO Secured Transmission System, maintain appropriate flows and voltage levels during normal operations and can order adjustments to be made under emergency conditions.
6. In the event of, or in order to prevent, a Major Emergency State, Eligible Customers shall comply with all directions from the NYISO concerning the avoidance, management, and alleviation of the Major Emergency and shall comply with all procedures concerning Major Emergencies set out in the NYISO Procedures and the Reliability Rules.
7. Under adverse conditions (as defined above), the NYISO will direct the adjustment of Generator output levels in certain areas of the ~~system~~ NYS Power

System to reduce power flows across the vulnerable transmission lines to reduce the likelihood of a major power system disturbance. The NYISO shall have the authority to declare that adverse conditions are imminent or present and invoke the appropriate operating procedure(s) affecting the NYS Power Systems under NYISO control in response to those conditions. See Section 1.2.4 (item 5) below for adverse conditions associated with a Local Reliability Rule.

8. Maintain the safety and short-term reliability of the NYS Power System.
9. Coordinate the NYS Power System equipment outages and maintenance.
10. Approve maintenance schedules for A-ttachment A.1 facilities based on approved criteria.

~~iii.~~2.2.4. Transmission Owner Responsibilities and Authorities

The primary responsibilities and authorities of the TO are:

1. Implement the Reliability Rules for those portions of the NYS Transmission System not included in the NYISO Secured Transmission System.
2. Coordinate with the NYISO in the implementation of certain applications to the Reliability Rules where the NYISO lacks the necessary expertise and/or monitoring capabilities.
3. Physically maintain and operate A-ttachment A.1 facilities under direction and control of the NYISO to assure secure operation of the ~~transmission system.~~ NYISO Secured Transmission System.
4. Comply with maintenance schedules coordinated by the NYISO for A-ttachment A.1 ~~Facilities.~~ facilities.
5. Recommend activation of applicable procedures for adverse ~~condition~~ conditions associated with a Local Reliability Rule to the NYISO. The Transmission Owner and NYISO shall coordinate implementation of these procedures that impact A-ttachment A.1 ~~Facilities.~~ facilities.
6. Notify NYISO prior to any planned outage and must notify the NYISO of any change in status of A-ttachment A.2 facilities.
7. Physically maintain and operate A-ttachment A.2 facilities.
8. Has sole responsibility for operation of Local Area Transmission System Facilities provided ~~that~~ it does not compromise the reliable and secure operation of the NYS Transmission System.
9. Promptly comply, to the extent practical, with a request from the NYISO to take action with respect to coordination of the operation of its Local Area Transmission System ~~Facilities.~~ facilities.
10. Take action with respect to the operation of its facilities, as it deems necessary to maintain Safe Operations.
11. Promptly conduct investigations of equipment malfunctions and failures and forced transmission outages.

12. Determine the level of resources to be applied to restore facilities to service following a failure, malfunction, or forced transmission outage.

13. Each Transmission Owner shall continue to receive telemetry from existing Generators in its control center and provide for the receipt of such information from new Generators. Each Transmission Owner will maintain a strict Code of Conduct to prevent such information from reaching any generation Affiliate it may have.

~~NORMAL and Warning OPERATING STATES~~

~~In this manual we are concerned with the criteria for the Normal and Warning States.~~

~~1.1.1. Definition of Normal State Criteria~~

~~The Normal state exists when all conditions are within their normal boundaries and rating limits or when facilities have returned to within their normal operating limits. Imminent or immediate operator action is not necessary.~~

~~1.1.2. Normal State Criteria~~

~~All of the following criteria must be met for the NY Control Area to be operating in the Normal State:~~

- ~~Pre Contingency (Actual) Flow Criteria~~

~~8. Normal Transfer Criteria: Actual loading of equipment defined as the NYS Transmission System do not exceed their associated Normal ratings.~~

~~5. Post Contingency Flow Criteria~~

~~9. Single Circuit and Two adjacent circuits on same structure Criteria :~~

~~Normal Transfer Criteria: Loss of any single generator, single circuit, or adjacent circuits on the same structure, together with other facilities which will trip at the same time due to pre-set automatic devices, will not cause any portion of the NYS Transmission System to exceed its LTE rating. The following are exceptions to the criteria.~~

~~The Post-Contingency loading of any underground cable may exceed its LTE rating, but not its STE rating, provided 10 minute reserve or phase angle control is available to return its post-contingency loading to its LTE rating within 15 minutes, without causing another facility to be loaded beyond its LTE rating.~~

~~With prior approval of the NYISO, the post-contingency loading of any portion of the NYS Transmission System may exceed its LTE rating, provided sufficient control is available to return the loading on the facility to its LTE rating within 15 minutes, without causing another facility to exceed its LTE rating.~~

~~Multiple circuit towers used only for station entrance and exit purposes, which do not exceed five towers at each station, are not considered adjacent circuits on the same structure. (For specific exceptions, see Appendix B-5 in the Transmission and Dispatching Operations Manual.)~~

2.2.5. ~~Actual voltages on all busses listed in Appendix A-~~Generator Response during Reserve Activation

Units with or without a reserve award:

All units that are NOT "self-scheduled fixed" are expected to respond to a reserve pickup 10-minute basepoint at its emergency response rate as bid. If the unit exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However the unit must return to its RTD basepoint, which will be consistent with the LBMP, within 3 RTD intervals (15 min) following termination of the reserve pickup. The unit will also be paid for overgeneration during that grace period.

~~1. On Dispatch *with or without a reserve award:*~~
~~An on-dispatch unit is expected to respond to a reserve pickup 10-minute basepoint at its stated response rate[1] as bid. If the unit exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However, the unit must return to its SCD basepoint, which will be consistent with the LBMP, within 3 and Appendix B SCD intervals following termination of the reserve pickup. The unit will also be paid for overgeneration during the 3-SCD interval grace period.~~

On Control with or without a reserve award:

An on-control unit is expected to respond to a reserve pickup 10-minute basepoint at its stated response rate~~a~~s bid. If the unit exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However, the unit must return to its ~~SCD~~RTD/AGC basepoint, which will be consistent with the LBMP, within 3 ~~SCD~~RTD intervals following termination of the reserve pickup. The unit will be paid for overgeneration during the 3-~~SCD~~RTD interval grace period.

~~3. Off Dispatch *without a reserve award:*~~
~~An off-dispatch unit is expected to respond to a reserve pickup by maintaining current generating output, or increasing output if possible, regardless of the current basepoint. Under no circumstances should the unit decrease generation during a reserve pickup unless otherwise directed. If the unit exceeds its schedule within the reserve pickup, it will be paid for the overgeneration. However, the unit must return to a point that is consistent with the LBMP if the unit is price-following; or to its schedule within 3 SCD intervals following termination of the reserve pickup. The unit will be paid for overgeneration during the 3-SCD interval grace period. An off dispatch unit without a reserve award will not be notified when a reserve pickup is initiated.~~
~~4,. Off Dispatch *with a reserve award:*~~
~~An off-dispatch unit with a reserve award will receive a basepoint that will dispatch the unit above its DAM/HAM schedule and into its bid reserve margin at its stated response rate[1]. If the unit exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However, the unit must return to a point that is consistent with the LBMP if the unit is price following or to its schedule within 3 SCD intervals following termination of the reserve pickup. The unit will be paid for overgeneration during the 3-SCD interval grace period.~~

~~1 When referring to stated response rate during a reserve pickup the following is intended:~~

~~A unit awarded reserve is expected to respond at emergency rates.~~
~~A unit not awarded reserve is expected to respond at normal rates.~~

2.3. Normal and Warning Operating States

This section of the manual mainly discusses the criteria for the Normal and Warning States.

2.3.1. Definition of Normal State

The Normal state exists when all conditions are within their normal boundaries and rating limits or when facilities have returned to within their normal operating limits. Imminent or immediate operator action is not necessary.

2.3.2. Normal State Criteria

All of the following criteria must be met for the NY Control Area to be operating in the Normal State:

1. Pre Contingency (Actual) Flow Criteria:

- Normal Transfer Criteria: Actual loading of equipment defined as the NYS Transmission System do not exceed their associated Normal ratings.

14. Post Contingency Flow Criteria:

- Single Circuit and Two adjacent circuits on same structure Criteria:
  a. Normal Transfer Criteria: Loss of any single generator, single circuit, or adjacent circuits on the same structure, together with other facilities, which will trip at the same time due to pre-set automatic devices, will not cause any portion of the NYS Transmission System to exceed its LTE rating. The following are exceptions to the criteria.
  b. The Post-Contingency loading of any underground cable may exceed its LTE rating, but not its STE rating, provided 10-minute reserve or phase angle control is available to return its post- contingency loading to its LTE rating within 15 minutes, without causing another facility to be loaded beyond its LTE rating.
  c. With prior approval of the NYISO, the post-contingency loading of any portion of the NYS Transmission System may exceed its LTE rating, provided sufficient control is available to return the loading on the facility to its LTE rating within 15 minutes, without causing another facility to exceed its LTE rating.
  d. Multiple circuit towers used only for station entrance and exit purposes, which do not exceed five towers at each station, are not considered adjacent circuits on the same structure. (For specific exceptions, see Attachment B.4 of ~~this manual~~this Manual.)

  - Actual voltages on all busses listed in Attachment A.3 and Attachment A.4, of this Manual are within pre-contingency limits.

- Sufficient Operating Reserve exists to meet the requirements specified by the NYSRC.
- NYS Power System stability limits and post-contingency flow limits associated with a voltage collapse are not exceeded.
- Area Control Error is no greater than +/- 100 MW, but not more than +/- 500 MW for more than 10 minutes.
- Power system frequency is not less than 59.95 Hz or greater than 60.05 Hz.
- All communications facilities, computers, control, and indication equipment necessary to monitor these criteria are available.
- All neighboring Control Areas are operating under Normal State conditions.

~~i.~~2.3.3. Definition of Warning State

The Warning state exists when specified limits have transgressed beyond the Normal state but do not severely impact or limit the operation of the NYISO Secured Transmission System unless they remain unchecked. Operator action may be required to return the system to the Normal state.

~~ii.~~2.3.4. Warning State Criteria

The Warning State exists when any of the following conditions occur:

1. Pre Contingency (Actual) Flow Criteria~~.~~:
   a. Normal Transfer Criteria: The actual loading on any portion of NYISO Secured Transmission System is 105% or more of its associated Normal Rating, but is less than the LTE for not more than 30 minutes or exceeds its Normal Rating by less than 5% and corrective actions are not effective within 10 minutes.~~.~~
   b. Emergency Transfer Criteria are invoked~~.~~: The actual loading of any NYISO Secured Transmission System facility does not exceed its associated Normal rating.

~~2.~~2.3.5. Post Contingency Flow Criteria~~.~~:

~~2.~~15. Single Circuit Criteria:

a. Normal Transfer Criteria~~.~~: A condition exists for not more than 30 minutes and the predicted post-contingency loading of a NYISO Secured Transmission System facility will exceed its associated LTE rating but not its STE rating.~~.~~

b. Emergency Transfer Criteria are invoked: The loss of any single generator or circuit, together with other facilities, which will trip at the same time due to pre-set automatic devices, will not cause any NYS Transmission System facility to exceed its STE rating.

- Two adjacent circuits on same structure Criteria: Emergency Transfer Criteria are invoked; Post Contingency flow may exceed STE rating.
- Sufficient Operating Reserve exists to meet the requirements specified by the NYSRC, but only using Emergency Transfer Criteria.
- Area Control Error is greater than +/- 100 MW, but not more than +/- 500 MW for more than 10 minutes.
- A neighboring Control Area is not operating under Normal State conditions, but has not implemented voltage or load reduction.
- An Operating Reserve deficiency is predicted for the NYCA peak load forecast and reserve purchases are not available.

~~LBMP~~

~~b.~~2.4. Market Operations Time Line

Operation of the NY Control Area and the LBMP Market involves many activities that are performed by different operating and technical personnel. These activities occur in parallel on a continuous basis, 24 hours a day ~~and can be grouped into two overlapping time frames:~~ .

- Exhibit 2.4-1 summarizes the important events that characterize the day-~~ahead scheduling~~
- ~~real-time operations~~

~~In~~ to-day operation of the NYISO LBMP market. Although this ~~manual~~Manual ~~we focus~~focuses mainly on ~~the~~ dispatch day activities ~~that take place during real-time operations, which begin 90 minutes prior to the start of the operating hour of the Dispatch Day (See Exhibit 1.1).~~ , it is important to understand how day-ahead activities can impact real-time operation.

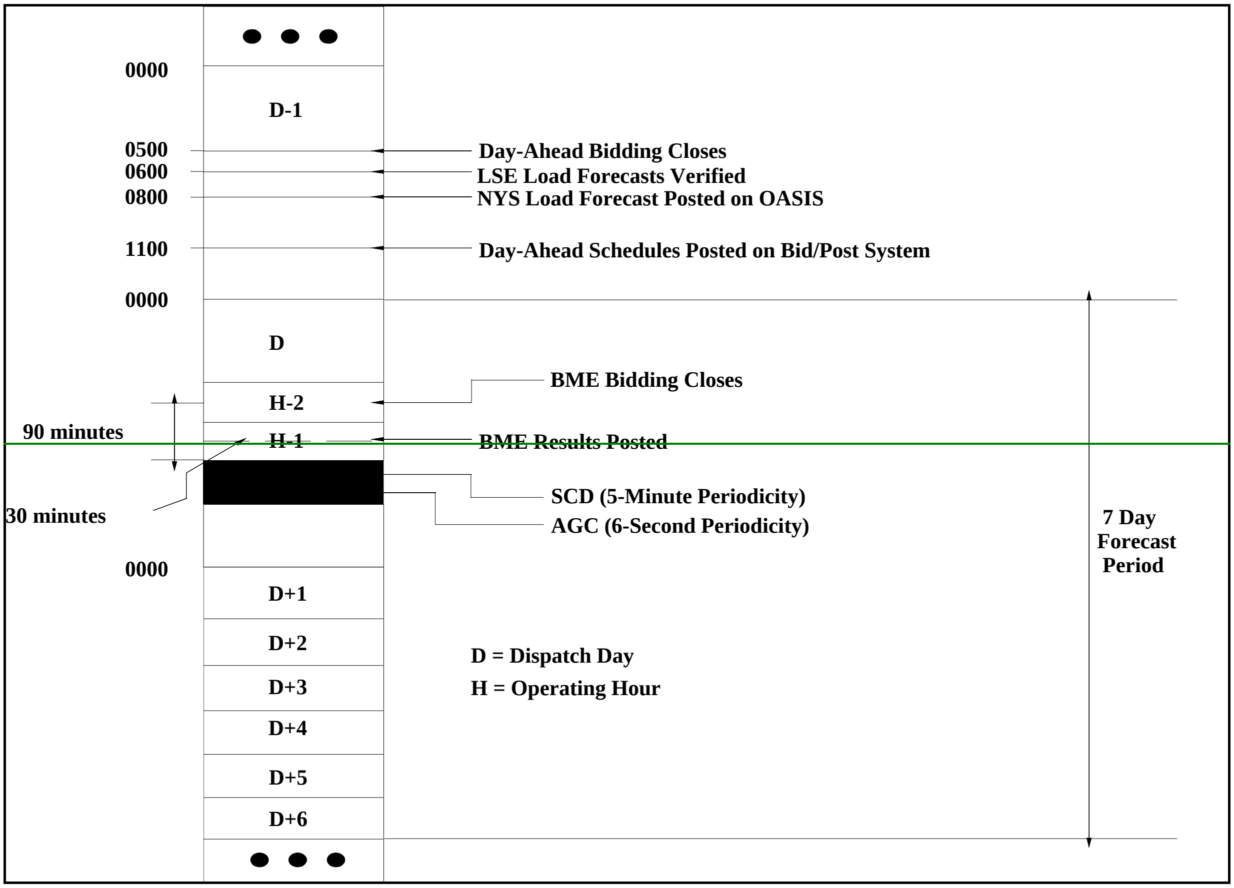
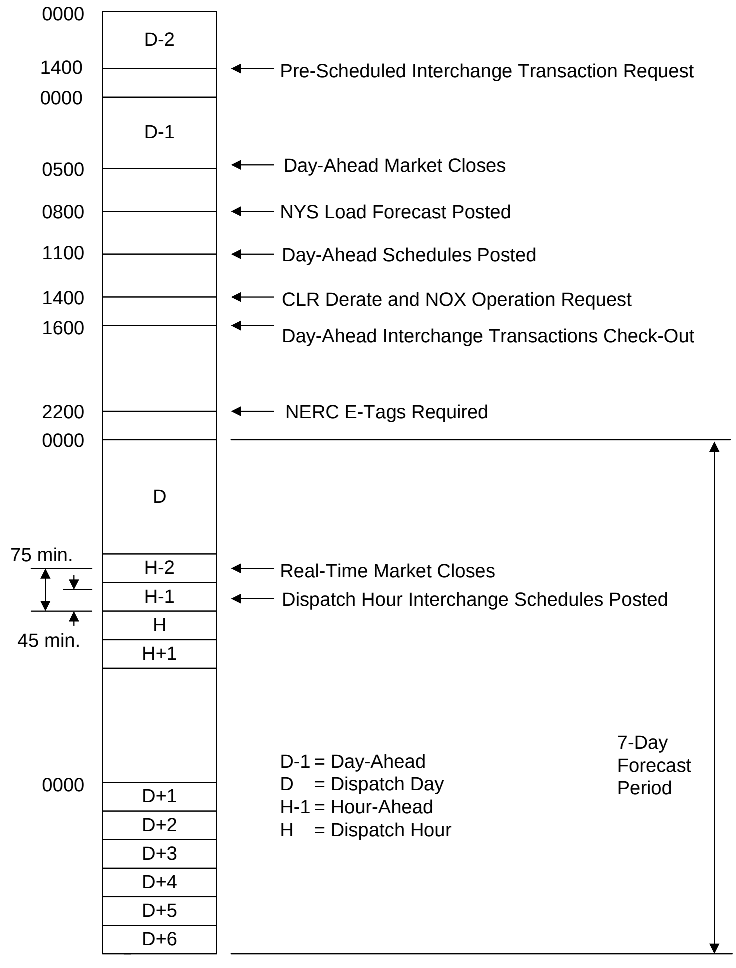


Exhibit ~~1.1- LBMP~~2.4-1:: Energy Market Operations Time Line



For more information~~, see~~: See NYISO~~ Day-Ahead Scheduling~~ Manual ~~Exhibit 1.1 shows the time line~~ for Day- Ahead Scheduling.

The activities shown by the time line are described briefly as follows:

1. **1400 (D-2):** Deadline for submitting pre-scheduled external interchange transaction requests to the ~~activities that occur a~~ NYISO.
2. **0500 (D-1):** Closing time of the day-ahead ~~of the Dispatch Day. These include the~~ energy market.
3. **0800 (D-1):** The load forecast for the State of New York is posted.
4. **1100 (D-1):** The results of the day-ahead ~~evaluation that is performed to produce a~~security constrained unit commitment ~~schedule to be used for the following day's operations. The commitment is derived from the bid information~~(SCUC) are posted.
5. **1400 (D-1):** Deadline for capacity limited resources (CLRs) to submit requests for derates and ~~generator parameters. The resulting commitment and dispatch~~

~~schedule is then posted on the Bid/Post System, allowing Market Participants to prepare for the following day's operation.~~

~~7.~~

~~8. Exhibit 1.1 also shows the time line for the following Dispatch Day activities:~~

6. ~~The Balancing Market Evaluation (BME) for the upcoming hour begins 90 minutes prior~~for NOX impacted entities to ~~the start of the hour. The day-ahead scheduled~~ submit requests for steam unit operation.

7. 1600 (D-1): Day-ahead external interchange transaction checkout has been completed.

~~7.~~8.7. 2200 (D-1): Deadline for NERC E-Tags to be submitted for external interchange transactions ~~and the candidate hour-ahead transactions are screened to assure that the interface ATCs are respected. Candidate external transactions are also evaluated against their decremental bids.~~ .

~~8.~~9.8 ~~Thirty minutes prior to the start~~ xx45 (H-2): Closing time of the ~~operating hour the results of the BME are posted on the Bid/Post System as the schedule for the upcoming operating hour.~~ real-time energy market.

10. ~~During the current operating hour, Security Constrained Dispatch (SCD) software uses the bid curves of the scheduled generators to~~ xx15 (H-1): The real-time commitment (RTC) application, that executes periodically every 15 minutes and posts the upcoming "Dispatch Hour" external interchange transaction schedules.

~~10.~~11. 10 xxxx (H): The dispatch ~~the NY Control Area, while observing transmission constraints.~~ hour with locked offers/bids and interchange transactions.

~~AGC is also executed during the current operating hour. AGC regulates resources throughout the NY Control Area so that the load and generation balance and the frequency is maintained.~~

~~Prior to 10 minutes into the next hour, the~~

Dispatch Day

The 24-hour period commencing at the beginning of each day (0000 hour).

Dispatch Hour

The 60-minute period commencing at the beginning of each hour of the dispatch day (xx00 hour).

Real-Time ~~generator and zonal LBMPs for the previous hour which are used for billing are posted.~~

~~The details on how these activities are performed and the NYISO and Transmission Owner responsibilities are the focus of this manual~~this Manual ~~and described~~ The following applications are said to execute in ~~more detail in the other sections~~"real-time":

- ***Real-Time Commitment (RTC)*** – executes every 15 minutes as described in Section 4 of ~~this manual~~ this Manual.

- ***Real-Time Automated Mitigation Process (RT-AMP)*** – executes every 15 minutes as described in Section 4 of ~~this manual~~ this Manual.

~~Operations Functions~~

~~The following areas are covered by the operations functions described in this manual :~~

- ~~Power system monitoring~~
- ~~ISO Secured Transmission System~~
- ~~Balancing Market, dispatch, and control~~
- ~~Manual~~***Real-Time Dispatch (RTD)*** – executes every 5 minutes as described in Section 5 of ~~this manual~~this Manual.
- ~~10.~~ ***Real-Time* Dispatch** ~~System~~ ***/Corrective Auction Mode (RTD-CAM)*** – executes on demand as described in Section 5 of ~~this manual~~this Manual
- ***Automatic Generation Control (AGC)*** – executes every 6 seconds as described in the NYISO Ancillary Services Manual.

2.5. Operations Functions

The following areas are covered by the operations functions described in ~~this manual~~this Manual:

- NYISO Secured Transmission System Monitoring
- Transmission System Operation
- Energy Market Overview
- Energy Market Functions
- Backup Dispatch System

~~i.~~2.5.1. NYISO Secured Transmission System Monitoring

The NYISO Secured Transmission System is monitored on a continuous basis in order to evaluate its current operating state. The first step in this process is to determine in which of the five States the NYISO Secured Transmission System is. ~~This manual~~This Manual covers the Normal and Warning States.

The monitored conditions of critical concern include:

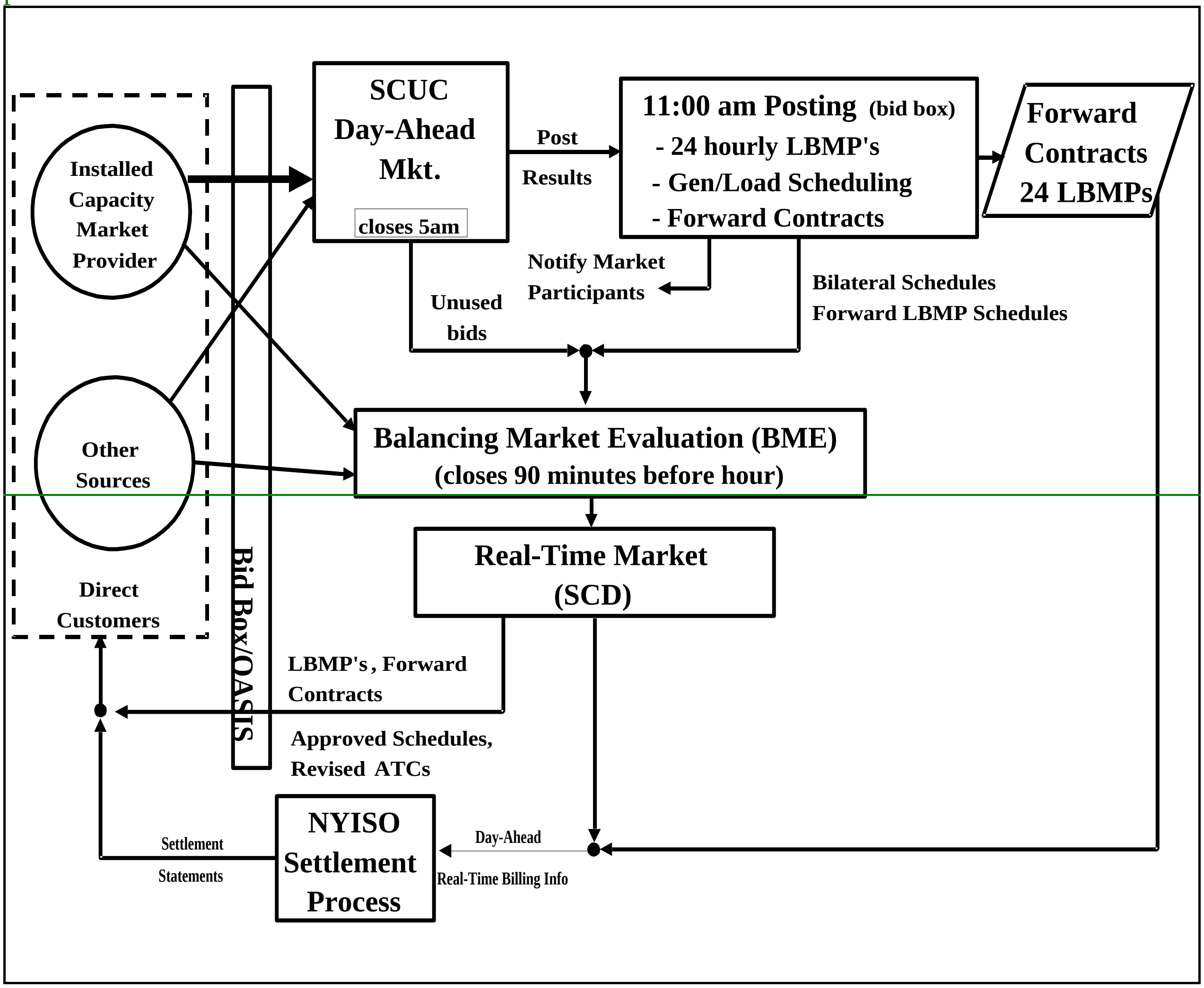
1) ~~System Load and Operating Reserves~~
2) ~~Regulation capability~~
3) ~~ISO Secured Transmission System flows and voltages~~
4) ~~NYCA Control Error~~

~~Section 2 of this manual discusses the power system monitoring requirements and procedures in further detail.~~

~~Transmission System Operation~~

~~The operation of the ISO Secured Transmission System reflects the criteria that have been established for existing conditions as well as for anticipated contingency conditions. This manual defines the secure operation of the ISO Secured Transmission System as well as the corrective measures that need to be taken to maintain secure operation.~~

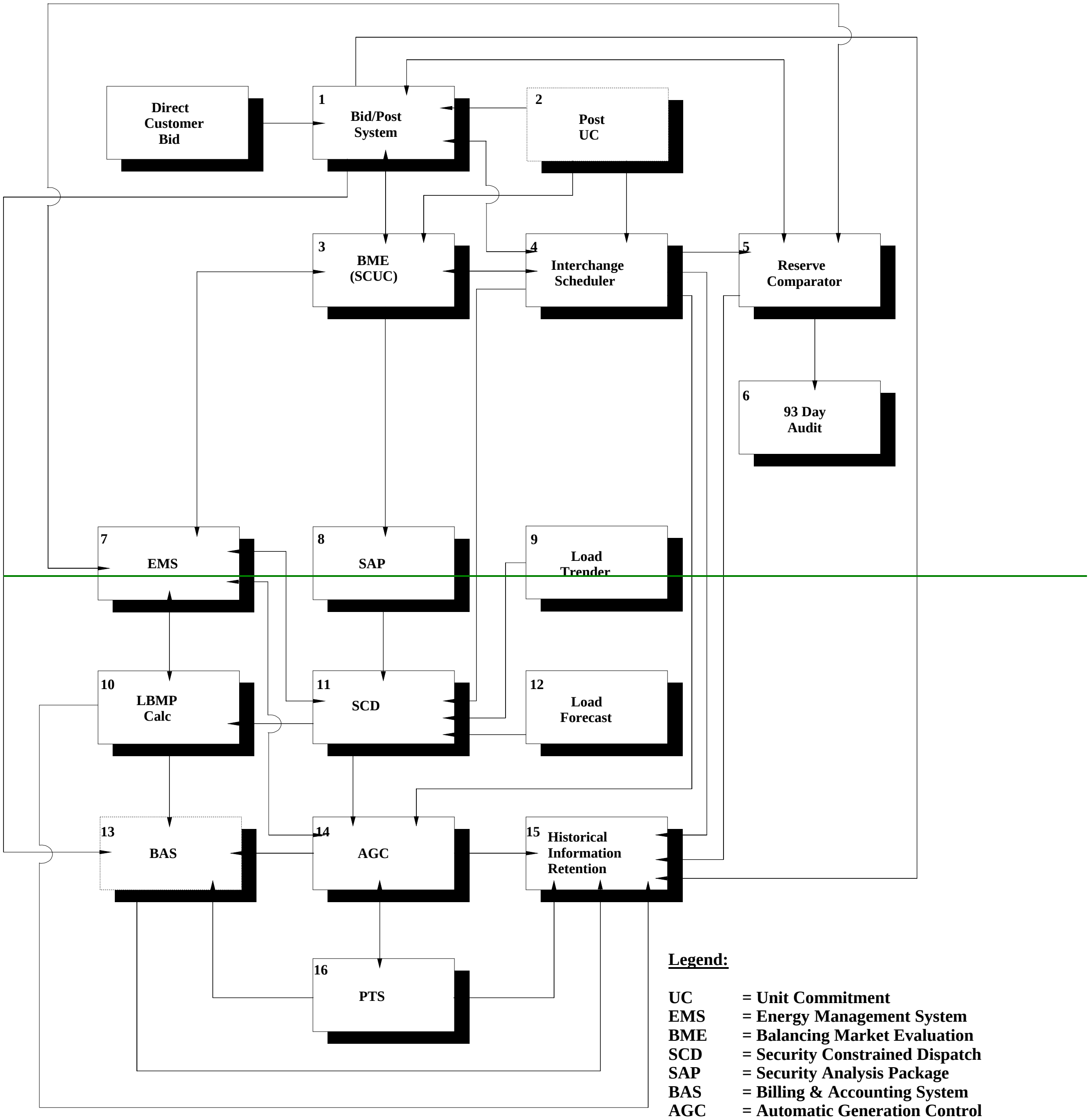
~~Section 3 of this manual discusses the transmission system operational requirements and procedures in further detail.~~



~~Balancing Market, Dispatch, & Control~~

~~A review of market mechanics is presented in Exhibit 1.2 as an introduction to the dispatch day functions.~~

~~**Exhibit 1.2: Market Mechanics**~~



Legend:

UC	= Unit Commitment
EMS	= Energy Management System
BME	= Balancing Market Evaluation
SCD	= Security Constrained Dispatch
SAP	= Security Analysis Package
BAS	= Billing & Accounting System
AGC	= Automatic Generation Control
PTS	= Performance Tracking System

~~**Exhibit 1.3. Exhibit 1.3: Dispatch Day Functions**~~

~~The interrelationships and flow of data among the energy related operations functions are shown by Exhibit 1.3.~~

~~The following is a brief summary of each function block in Exhibit 1.3. The dotted boxes are described in more detail in other NYISO Manuals:~~

- ~~Bid/Post System — The Bid/Post System provides the means by which Eligible Customers of the LBMP Market can electronically receive information and enter Bids for generation, transactions, load, and Ancillary Services.~~

- ~~Post Unit Commitment — The post unit commitment function collects Day- Ahead scheduling results, which includes the commitment schedule, accepted generator and transaction Bids, load Bids, and operating limits. Refer to the NYISO Manual for Day-ahead Scheduling for a detailed description.~~
- ~~Balancing Market Evaluation — The BME function allows NYISO personnel to evaluate generation and transaction Bids submitted for consideration in the 90 minute ahead Balancing Market time window.~~
- ~~Interchange Scheduler — The Interchange Scheduler allows NYISO personnel to monitor ongoing energy transactions and to adjust transactions in real time to address security problems.~~
- ~~Reserve Comparator — The Reserve Comparator resides on the EMS and keeps track of actual NY Control Area Operating Reserve and NY Control Area Operating Reserve requirements.~~
- ~~93 Day Audit — Operating Reserve and data used to calculate the reserves in the Reserve Comparator function are saved for auditing purposes.~~
- ~~Energy Management System — The EMS is a legacy system that operates on the IBM Mainframe and provides the primary source of real time data from the NY Control Area.~~
- ~~Security Analysis Package — The Security Analysis Package provides line and transfer limits for use by the SCD function.~~
- ~~Load Trender — The Load Trender uses instantaneous Area loads to provide 10-minute forecasts which are used by the real-time SCD function.~~
- ~~LBMP Calculation — The LBMP calculation produces marginal LBMP bus prices, loss prices, congestion prices, and zonal load prices.~~
- ~~Security Constrained Dispatch — The real-time SCD executes nominally every five minutes and produces generation base points in order to maintain power system security.~~
- ~~Load Forecast — The Load Forecast function is executed on demand and forecasts the hourly load for each Zone for the current day and up to six days in the future.~~
- ~~Billing & Accounting System — The Billing & Accounting System itemizes those data elements stored or produced by the various subsystems so that line item settlement statements can be calculated after the fact on a monthly basis. Refer to the NYISO Manual for Accounting & Billing for a detailed description.~~
- ~~Automatic Generation Control — The AGC program regulates the generation resources throughout the NY Control Area so that load, generation, and interchanges balance and Interconnection frequency is maintained.~~
- ~~Historical Information Retention — A Historical Information Retention schema (not a specific function) is used to archive and maintain data required for accounting and billing purposes, as well as information required to support auditing.~~
- ~~Performance Tracking System — The PTS monitors the on/off-line status of generating units. Regulation performance of the Transmission Owners or Generation suppliers is monitored.~~

~~Communications~~

~~This subsection describes the hotline and NPCC communications systems.~~

- System Load and Operating Reserves
- Regulation capability
- NYISO Secured Transmission System flows and voltages
- NYCA Control Error
- Section 2 of ~~this manual~~this Manual discusses the power system monitoring requirements and procedures in further detail.

2.5.2. Transmission System Operation

The operation of the NYISO Secured Transmission System reflects the criteria that have been established for existing conditions as well as for anticipated contingency conditions. ~~This manual~~This Manual defines the secure operation of the NYISO Secured Transmission System as well as the corrective measures that need to be taken to maintain secure operation.

Section 3 of ~~this manual~~this Manual discusses the transmission system operational requirements and procedures in further detail.

2.5.3. Energy Market Overview

A review of market mechanics is presented in Exhibit 1-2 as an introduction to the dispatch day functions. Sections 4 and 5 of ~~this manual~~this Manual provide further detail.

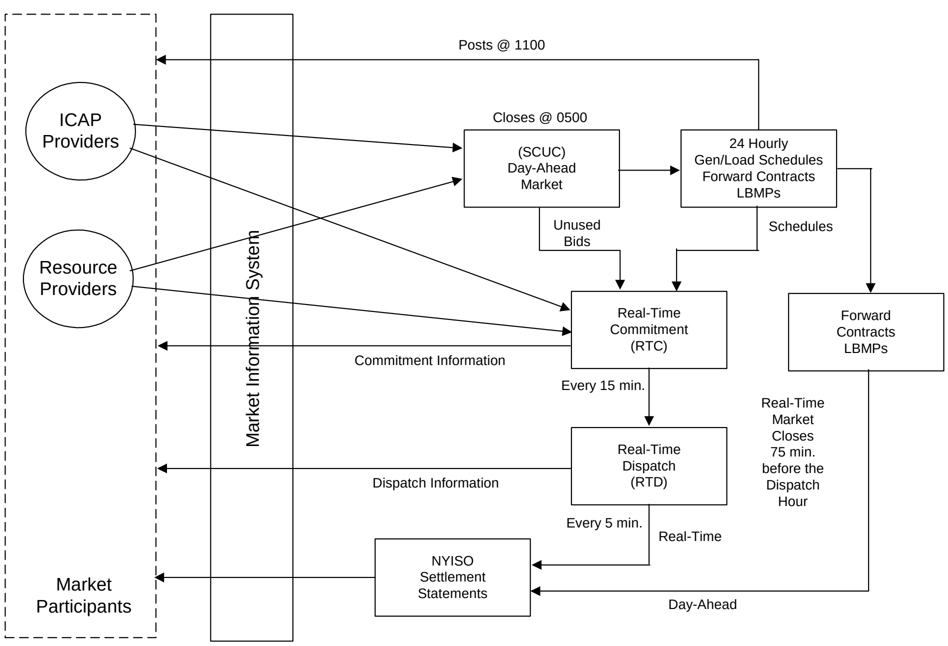


Exhibit 2-1: Market Overview

2.5.4. Energy Market Functions

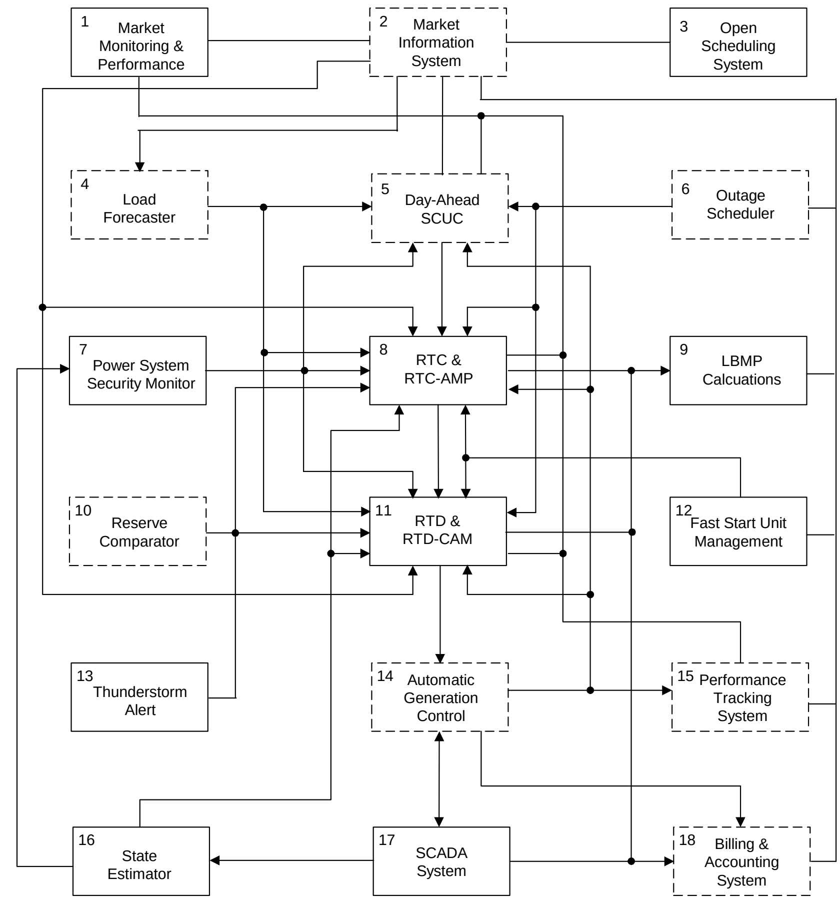


Exhibit 2-2: Day-Ahead and Dispatch Day Functions

The following is a brief summary of each function block in Exhibit 1-3. The dotted boxes are described in more detail in other NYISO Manuals:

1. **Market Monitoring & Performance (MMP):** The MMP Unit is charged with analyzing market participant bids and their impact on energy market prices. MMP applies mitigation measures in the event that it detects conduct that is inconsistent with competition, e.g., physical withholding.
2. **Market Information System (MIS):** The MIS is the primary user interface between market participants and the NYISO. Market information is received and posted via the MIS. Refer to the *NYISO Market Participant User's Guide* for details.
3. **Open Scheduling System (OSS):** The OSS is a "one-stop shopping" tool enabling inter-regional transactions. It is a distributed system with a "node" in

each control area for inter-area communications for coordinating and approving interchange transaction requests.

4. **Load Forecaster (LF):** The LF application produces NYCA load forecasts for SCUC, RTC, and RTD. Refer to the *NYISO Day-Ahead Scheduling Manual* for details.

5. **Day-Ahead Security Constrained Unit Commitment (SCUC):** The SCUC program establishes the outcome of the day-ahead market (DAM) based on forecast conditions and NYS power system reliability requirements. SCUC executes over a 24-hour load forecast horizon to produce startup, shutdown, and hourly energy schedules for the resources that have bid into the DAM. Refer to the *NYISO Day-Ahead Scheduling Manual* for details.

6. **Outage Scheduler (OS):** The OS function maintains a record of planned and forced power system facility outages and their scheduled return to service. Outage information is available to the market applications and to the power system analysis applications. Refer to the *NYISO Outage Scheduling Manual* for details.

7. **Power System Security Monitor:** The power system security monitoring applications assess forecasted and actual power system conditions and the impact of potential contingencies. These applications also establish the list of facilities whose operating constraints must be observed by the market applications.

8. **Real-Time Commitment (RTC) & Real-Time Automated Mitigation Process (RT-AMP):** The RTC and RT-AMP functions execute periodically on a 15-minute basis with a 2¼-hour look-ahead horizon, and post their commitment and scheduling results on the quarter hour (15, 30, 45, 00). Refer to Section 4 of ~~this Manual~~this Manual for details.

9. **LBMP Calculations:** The RTC and RTD programs produce LBMPs for market advisory and settlement purposes. Refer to Attachment E of ~~this Manual~~this Manual for details.

10. **Reserve Comparator (RC):** The RC program compares actual New York control area reserves, by category, against their corresponding requirements. Refer to the *NYISO Ancillary Services Manual* for details.

11. **Real-Time Dispatch (RTD) & RTD-Corrective Action Mode (CAM):** The RTD function executes periodically on a 5-minute basis with a 50, 55, or 60-minute look-ahead horizon, and posts its results on the five-minute clock times. The RTD-CAM functions override the normal RTD executions, as determined by the NYISO Operators, to deal with “off-normal” power system conditions. Refer to Section 5 of ~~this Manual~~this Manual for details.

12. **Fast Start Unit Management (FSM):** The FSM function provides the facility for the NYISO Operators to coordinate the commitment schedules produced by RTC and RTD-CAM. The FSM is used to approve/disapprove commitment schedules from RTC/RTD-CAM, and to manually commit/decommit other fast-start units.

13. **Thunderstorm Alert (TSA):** TSA is declared by NYISO Operators when severe operating conditions are detected. A predetermined set of pre- and post-

contingency constraints are passed to the RTC and RTD programs while TSA is in effect.

14. **Automatic Generation Control (AGC):** The AGC program regulates the generation resources to balance load, generation, and interchange and help to maintain the Eastern Interconnection power system frequency. Refer to the *NYISO Ancillary Services Manual* for details.

15. **Performance Tracking System (PTS):** The PTS monitors the on/off-line status of generating units and their actual MW output versus their scheduled output. Refer to the *NYISO Ancillary Services Manual* for details.

16. **State Estimator (SE):** The SE produces an accurate real-time model of the NYS power system, including a representation (equivalent) of the power system external to the NYISO. The SE is used to verify metered data and to estimate conditions that are not metered. The SE model also serves as the basis for deriving the transmission loss and congestion sensitivity coefficients that are used by other applications.

17. **Supervisory Control & Data Acquisition (SCADA) System:** The SCADA system provides direct communications between the NYISO control center and the remote transmission owner and power plant control centers. The NYISO transmits (telemeters) desired control actions to the remote control centers and receives current operational feedback data from these control centers.

18. **Billing & Accounting System (BAS):** The BAS itemizes those data elements that are stored or produced by the various subsystems so that line item settlement statements can be calculated after-the-fact on a monthly basis. Refer to the *NYISO Accounting & Billing Manual* for details.

2.5.5. Backup Dispatch System

The Backup Dispatch System (BDS) is a comprehensive set of procedures that address the possible loss of functionality of the NYISO Control Center, Transmission Owners' Control Centers, and NYISO/TO communications facilities. The BDS is comprised of the following principle components and procedures:

- Manual Dispatch Systems – NYISO Power Control Center (PCC) & NYISO Alternate Control Center (ACC)
- Market Suspension Criteria
- Interim NY Control Area Operation – Transition period between PCC and ACC operation
- NYISO Alternate Control Center

Exhibit 1-4 illustrates the components that comprise the BDS. Refer to the *NYISO Backup Dispatch System Manual* for details.

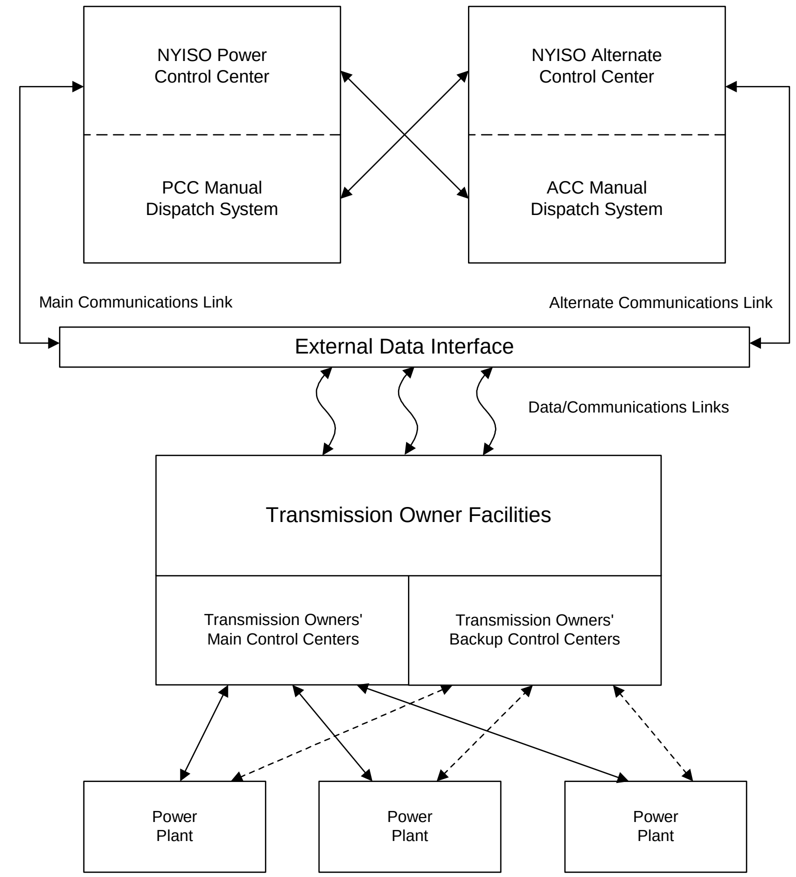


Exhibit 2-3: Backup Dispatch System Configuration

2.6. Communications

This subsection describes the NYISO hotline and interregional communications systems.

~~ii.~~2.6.1. Hotline Communications

The NYISO Hotline can be operated in two ways:

~~11.~~• ~~initiated~~Initiated by the NYISO Shift Supervisor

~~12.~~• ~~initiated~~Initiated by a Local Transmission Owner Control Center

Initiated by the NYISO Shift Supervisor~~:~~

A single pushbutton is used by the NYISO Shift Supervisor to ring a hotline phone in each local Transmission Owner control center. The communications is two-way broadcast. That is, if a local Transmission Owner control center operator speaks, it is heard by all the hotline phones. Typically, the local Transmission Owners control center operators do not speak during a NYISO Shift Supervisor initiated transmission.

Initiated by a Local Control Center System Operator~~:~~

A local Transmission Owner control center System Operator can call the NYISO Shift Supervisor on the hotline. In this situation, the NYISO Shift Supervisor hotline is the only hotline phone that rings. Transmission ~~Owners~~Owners' control center System Operators should only use this method of communication with the NYISO Shift Supervisor under urgent conditions.

~~i.NPCC~~Interregional Communications Network

When the NYISO receives information via the NERC conference feature, it is relayed to Ontario Hydro, Hydro-Quebec, and New England by means of automatic ringdown leased lines. If the information is of an emergency nature, those three locations may be conferenced together for one announcement. NEPEX relays the information to the Maritimes via automatic ringdown leased line to New Brunswick.

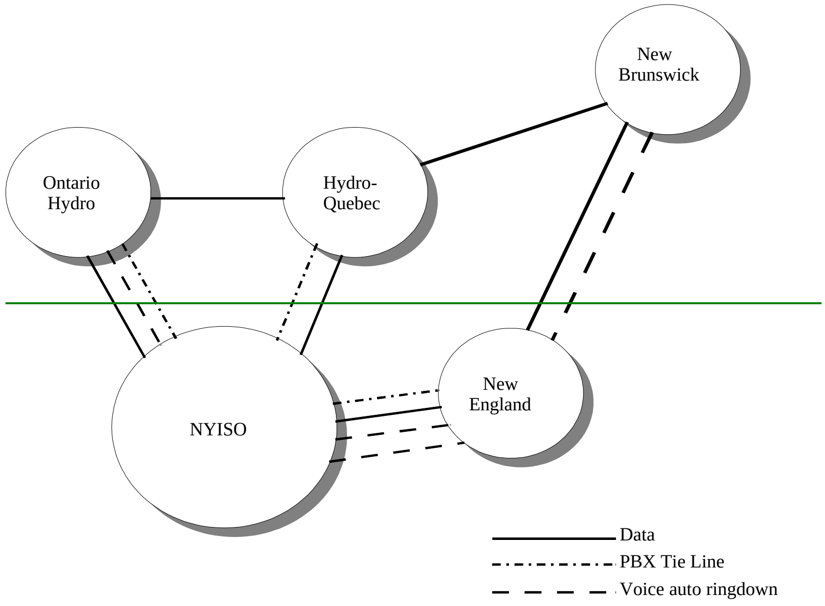


Exhibit 1~~.4: NPCC Communications Network~~

2. ~~OPERATIONS MONITORING~~

~~This section describes how~~ 5 illustrates the interregional communications network.

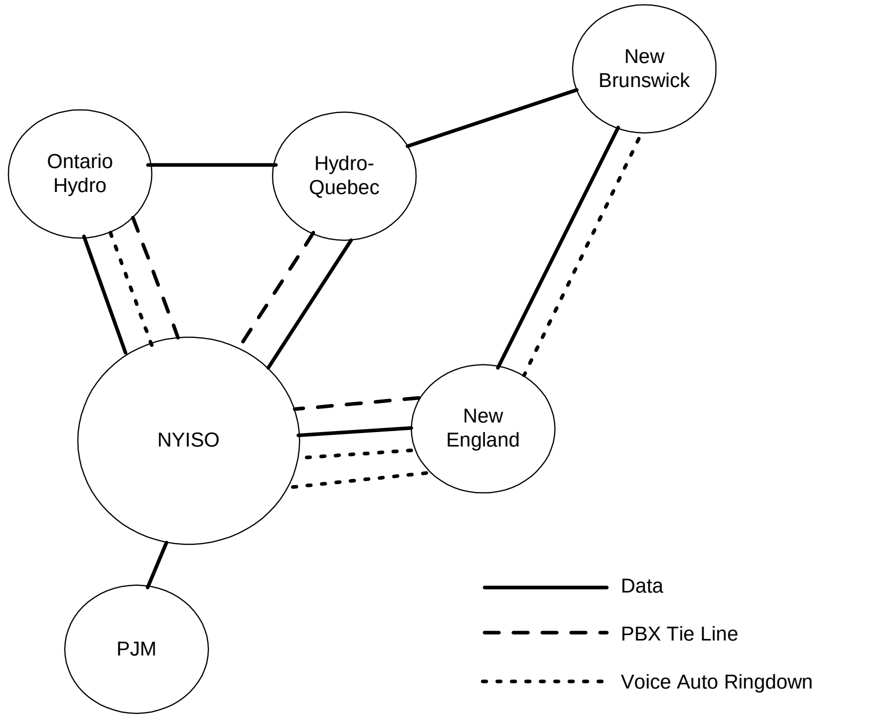


Exhibit 2-1: Interregional Communications Network

3. Operations Monitoring

~~—~~This section describes the NYS power system ~~is monitored~~operations monitoring requirements and procedures.

~~b.~~3.1. Operations Monitoring Requirements

This section identifies the requirements for monitoring the operation of the NY Control Area. The conditions that are monitored include the following:

- ~~13.~~ Current Operating State
- ~~14.~~ System Load
- ~~15.~~ Operating Reserve
- ~~16.~~ Regulation
- ~~17.~~ NYISO Secured Transmission System
- ~~18.~~ Ancillary Services
- ~~19.~~ Communications
- ~~20.~~ Weather Conditions
- ~~21.~~ Telemetered Data

Reliability Assessment~~:~~

The NYISO performs a Real-Time assessment of the reliability of the ISO Secured Power System periodically or, upon status change, and upon operator demand. The main functions that are performed are:

- ~~22.~~ ~~•~~Real-Time Data Monitoring and Alarming
- ~~23.~~ ~~•~~DC Thermal Security Analysis
- ~~• AC Thermal/Voltage Security Analysis~~
- ~~24.~~ ~~•~~Reserve Calculation
- Regulation Requirement

~~i.~~3.1.1. Real-Time Data Monitoring and Alarming

This function is executed, nominally every ~~6~~ ~~30~~6 seconds for SCADA data and 30 seconds for state estimated values. ~~, based on SCADA data ; State estimated values and NYISO inputs.~~

NYISO Actions~~:~~

The following are performed:

1. Determines whether to use: (1) metered values ~~or (~~(2) ~~NYISO~~state estimated values or (3) NYISO override/substitution values for:

~~25.switch~~ a. Switch status data
~~26.analog~~ b. Analog data

2. Checks the analog data against limits for voltage, flows on lines and transformer banks, and interface flows.

3. Finds and opens "modeled" breakers corresponding to non-metered outaged facilities, based on NYISO activation.

4. Executes the network configuration function, which processes the user switch data from (1) and (3) above.

5. Derives confirmation page alarms for NYISO review and validation.

6. Produces the following results:

   ~~27.~~a. ~~• user~~User analog data
   ~~28.~~b. ~~• audible~~Audible alarms, text alarms, mimic board outputs
   ~~29.~~c. ~~• confirmed~~Confirmed switch status
   ~~30.~~d. ~~• updated~~Updated outage schedules

~~i.~~3.1.2. ~~DC Thermal~~ Security Assessment

The ~~DC thermal~~ security assessment is triggered to execute on:

- ~~31.~~ ~~switch~~Network configuration status change
- ~~32.~~ ~~periodic~~Periodic, nominally every ~~5 minutes~~30 seconds
- ~~33.~~ ~~operator~~Operator demand

NYISO Actions~~:~~

The following are performed:

1. Executes the ~~Real-Time Security Assessment (RTSA)~~network configurator and state estimator functions based on confirmed switch status ~~and the RTSA model (which was produced "offline")~~

~~1.~~2. ~~Computes distribution and generation shift factors to be used by SCD and the LBMP calculation.~~

~~2.~~3. Performs a contingency analysis based on ~~an approximate direct current (DC) representation~~the state estimator solution of the NYS Transmission System, using:

   ~~34.~~a. ~~• pre~~Pre-defined single and multiple contingencies
   ~~35.~~b. ~~• line~~Line and transfer constraints
   c. Active RTD constraints

~~3.~~4. Produces a list of contingency violations for ~~NYISO~~ISO Operations review.

~~Produces a list of active constraints to be used by SCD.~~

~~i.~~3.1.3. Reserve Calculation

The NYISO monitors NY Control Area reserve ~~both prior to an hour (as part of the BME process) and~~ every five minutes ~~within an hour~~ (Reserve Monitor Program using actual generation). These reserve ~~checks calculate~~calculations indicate the reserve available for the NY Control Area~~, and also check to see that the reserve is not "bottled" up by transmission limitations~~. Corrective action is taken by the NYISO only if the New York Control Area is deficient in reserve~~ or if a bottling situation is found~~. Reserve calculations and constraints are also ~~done in SCD.~~performed by RTC and RTD.

~~MINIMUM OPERATING RESERVE REQUIREMENT~~

Minimum Operating Reserve Requirement

The Minimum Operating Reserve Requirement of the NYCA is defined as:

1. ~~A.~~ Sufficient Synchronized Reserve Available in 10 minutes to replace one-half of the operating capability loss caused by the most severe contingency observed under Normal Transfer Criteria.
2. ~~B.~~ Sufficient Reserve Available in 10 minutes (which includes synchronous reserve available in 10 minutes) to replace the operating capability loss caused by the most severe contingency observed under Normal Transfer Criteria.
3. ~~C.~~ Sufficient Reserve Available in 30 minutes (which includes reserve available in 10 minutes) equal to one and one-half times the operating capability loss caused by the most severe contingency observed under Normal Transfer Criteria.
4. ~~D.~~ Sufficient Reserve in 10 minutes to return the system to a normal state following the most severe transmission contingency.

At all times sufficient 10 Minute Reserve shall be maintained to cover the energy loss due to the most severe Normal Transfer Criteria contingency within NYCA or the energy loss of energy purchased from another control area, whichever is greater.

~~NOTE:~~

~~***Note to Reader***~~

~~1.All of the above values are on a net basis (i.e., excluding unit auxiliaries)~~

~~2.Generators having a single tower connection to the grid will be summed and considered as one unit for reserve and contingency evaluation purposes.~~

~~3.~~1.~~Units whose values (Operating Capability and Basepoints) are the sum of individual generators at a site are not considered to the extent that they are not a single contingency.~~

~~ii.~~3.1.4. Regulation Requirement

~~NY Control Area~~ The NYCA Regulation requirements, in MW/minute, are established by result of analysis of NY Control Area daily load patterns and ~~tests performed under~~ of actual operating conditions. Tables are prepared by the NYISO, which show the

Regulation requirements for the NY Control Area for Summer and Winter capability periods and various periods of the day.

Section 5.1 of ~~this manual~~this Manual describes the process by which the NYCA regulation requirement is allocated to the generating units~~ and how performance is measured. ~~.

The NYISO will determine the amount of regulation required for different time periods and load conditions based upon empirical experience and engineering judgement and in accordance with the Ancillary Services Manual.

~~b.~~3.1.5. Operations Monitoring Procedures

This section describes the procedures associated with monitoring the operation of the NYS power system. General procedures dealing with the Normal State and Warning State are given first (~~Aappendix~~refer to Attachment B~~-~~.1), followed by specific procedures to be carried out under Normal and Warning State conditions. Specific procedures cover the following:

- ~~Telemetering~~
- Response to Normal State Conditions
- Response to Warning State Conditions
- Reliability Assessment Support
- ~~36.~~ Automatic Voltage Regulators
- ~~Phase Angle Regulators~~
- ~~37.~~ ~~Communications~~Communication of NY Control Area Operating Conditions
- ~~38.~~ Hourly Inadvertent Accounting
- ~~39.~~ Local Reliability Rules
- Applications of the NYSRC Reliability Rules
- Daily Operation for Monitoring Operating Reserve

~~i.~~3.1.6. Response to Normal State ~~Condition~~ Conditions

NYISO Actions~~:~~

The NYISO shall monitor NYS power system conditions at all times, and determine and apply the applicable ~~the~~ actions listed below that are necessary to remain in the Normal State~~.~~:

1. Coordinate actions with Transmission Owners and other Control Areas.
2. ~~2.~~ Initiate one or more of the following actions:
   a. Adjust phase angle regulators.

b. Shift or start generation ~~via SCD or~~ by NYISO request in order to obtain additional reactive power (MVAr) control.
c. Activate reserves.
d. Adjust reactive sources and transformer taps.
e. Perform Generation shifts.
f. Modify ~~Physical~~Interchange Schedules.
g. Request NYS Transmission System facilities that are out of service for maintenance to be returned to service.
h. For high voltage conditions only, request NYS Transmission System facilities that are in service to be removed from service where appropriate.
i. Implement manual voltage reduction.
j. May call for a reserve pickup to return to schedule if the NYISO Area Control Error exceeds -100 MW ~~(import)~~.
k. Take actions to maintain operating reserve, in accordance with the procedures described in Section 4.~~2~~3 of ~~this Manual~~this Manual.

~~A.~~ Transmission Owner Actions

NYISO contact is generally with the Transmission Owner. The Transmission Owners are responsible for controlling or coordinating the operation of Generators connected to their systems, as follows:

1. Coordinate and implement corrective actions, as requested by the NYISO Shift Supervisor.
~~2.~~2. Monitor conditions, with respect to their own systems.
~~3.~~3. Perform the following actions when the NY Control Area is operating in the Normal State and Normal State Criteria are not met:

~~i.~~a. Notify the NYISO Shift Supervisor.

~~ii.~~b. Request assistance from the NYISO Shift Supervisor, as required.

~~iii.~~ c. Initiate unilateral corrective action, if the violation is severe enough to require immediate action.

Other Considerations

1. All schedule changes should be analyzed in advance of implementation in an effort to avoid violation of these criteria.

2. The NYISO shall dispatch the system such that, the removal of any facility for scheduled work will not result in the violation of these criteria. Transmission Owners are responsible for providing appropriate advance notice of such switching.

3. During periods when adverse conditions, such as tornadoes or hurricanes~~, exists~~ exist, or ~~is~~ are forecast to occur within the service area of the NYISO Systems, it may be necessary to take steps in addition to those procedures normally followed to maintain system security.

It is the responsibility of the NYISO to monitor weather conditions and forecasts issued by the National Weather Bureau~~-~~. Should local adverse conditions occur or they are predicted to occur~~-~~, it is the responsibility of the Transmission Owner to inform the NYISO. If a situation involving impending severe weather exists, the NYISO shall notify all Transmission Owners and consider declaration of the Alert State.

4. The actual voltage on all busses listed in Attachment A.3 and A.4 shall be ~~monitored~~ monitored by the NYISO and Transmission Owners. It shall be the Transmission Owner ~~(TO)~~ responsibility to maintain ~~voltage~~voltage levels within limits specified in Attachment A.3 and A.4 and to coordinate actions, which would affect voltage levels on busses of other ~~TO~~ TOs or Neighboring Systems.

   If the NYISO anticipates conditions, which would cause the voltage at any bus listed in Attachment A.3 and A.4 to violate Normal State Criteria, the NYISO shall notify the TOs and together they shall formulate a corrective strategy. If, implementation of the corrective strategy does not produce the desired result, and the NYISO determines that further corrective action is necessary to remain in the normal state, the NYISO shall request such actions in accordance with Normal State Responses. TOs must coordinate and implement corrective actions as requested by the NYISO.

5. Occasionally it may become necessary to import energy from other ~~systems~~control areas for security reasons.

~~ii.~~3.1.7. Response to Warning State Conditions

NYISO Actions~~:~~

The NYISO shall monitor system conditions at all times and determine the action~~s~~ (s) listed below that are necessary to return the system to the Normal State~~.~~:

1. Coordinate actions with Transmission Owners and other Control Areas.
2. ~~2.Initiate~~2. Initiate one or more of the following actions:
   a. Adjust phase angle regulators.
   b. Shift or start generation ~~via SCD or~~ by NYISO request in order to obtain additional reactive power (MVAr) control.
      a. -Activate reserves.
   ~~d.~~c. Adjust reactive sources and transformer taps.
      ~~Activate reserves.~~
   ~~e.~~d. Perform Generation shifts.
   ~~f.~~e. Modify ~~Physical~~Interchange Schedules.
   ~~g.~~f. -Request NYS Transmission System facilities that are out of service for maintenance to be returned to service.
   ~~h.~~g. ~~Request~~For high voltage conditions only, request NYS Transmission System facilities that are in service to be removed from service ~~for high voltage conditions~~ where appropriate.

~~i.~~h. -Implement manual Voltage Reduction.

b. -May call for a reserve pickup to return to schedule if the NYISO Area Control Error exceeds 100 MW ~~(import)~~.

c. Take actions to maintain operating reserve, in accordance with the procedures described in Section 4.3 of ~~this manual~~this Manual.

~~l.~~i. Curtail non-essential ~~Transmission Owner~~Market Participant load.

~~m.~~j. Order Generation to full operating capability.

3. 3. Take the following actions if the above measures are insufficient to comply with Normal Transfer Criteria within 30 minutes or Operating Reserve cannot be delivered due to transmission limitations for 30 minutes:

   a. Notify all Transmission Owners, via the Hotline communications system, that Emergency Transfer Criteria are in effect for the ~~facility(~~facility (ies) involved.
   b. Take actions, as required, to stay within Emergency Transfer Criteria.
   c. Confer with Transmission Owners that will have Post-Contingency loading or voltage conditions that exceed allowable limits. Jointly develop strategies to be followed in the event a contingency occurs, including preparation for a rapid Voltage Reduction and/or Load Shedding.

4. If following the implementation of the actions listed above all Normal State criteria cannot be achieved, satisfy as many of the Normal State criteria as possible.

Transmission Owner Actions~~:~~

Transmission Owners shall perform the following actions:

1. Coordinate and implement corrective actions, as requested by the NYISO Shift Supervisor.

2. Monitor conditions, with respect to their own systems.

3. Perform the following actions when the NY Control Area is operating in the Warning State and Warning State Criteria are not met:

   a. Notify the NYISO.
   b. Request assistance from the NYISO-, as required.
   c. Initiate unilateral corrective action, if the violation is severe enough to require immediate action

Other Considerations

1. For all contingencies, which would result in a violation of the Warning State criteria, corrective action, which would be necessary if the contingency occurs shall be ~~determine~~determined through coordination between the NYISO and the affected Transmission Owner.

2. If the NYISO foresees an extended period of operation in the Warning State, a canvass of the Transmission Owner Systems shall be made to determine if assistance can be provided.

3. If the situation involving impending adverse conditions exists, the NYISO shall notify all Transmission Owners and consider declaration of the Alert State.

~~iii.~~3.1.8. Reliability Assessment Support

NYISO Actions~~:~~

The NYISO shall perform the following actions in support of the Reliability Assessment function:

1. Execute the Reliability Assessment function on demand following a power system disturbance, instead of waiting for the periodic execution~~-~~.
2. Override and substitute SCADA analog and status data that is incorrect or missing.
3. Activate outages in the network model by ~~"~~"opening~~"~~" the appropriate breakers or switches in the model.
4. Review and acknowledge any alarm messages.
5. Review the ~~"~~"Confirmation~~"~~" display and make any necessary corrections or adjustments to the incoming data.
6. Review and acknowledge the contingency list produced by the ~~DC Thermal~~ state estimator and Security Analysis functions.

~~Review and acknowledge the contingency list produced by the AC Thermal & Voltage Security Analysis function~~

~~2.2.4.~~3.1.9. ~~Execute the Dispatcher~~Automatic Voltage Regulator / Power ~~Flow program as desired to investigate the effects of hypothetical power system scenarios~~System Stabilizer Equipment

~~Automatic Voltage Regulators~~

NYISO Actions~~:~~

The NYISO shall perform the following actions:

1. Coordination of generating unit Automatic Voltage Regulator (AVR) and Power System Stabilizer (PSS) outage requests provided the following criteria have been met:

   No more than six AVRs shall be allowed out-of-service simultaneously throughout the NY Control Area, with a limit of three in the Area east of the Central/East Interface, and three more west of the Central/East Interface.

No more than one generating unit PSS shall be allowed out-of-service throughout the NY Control Area. If a generating unit PSSs is out-of-service, then ensure all applicable system transmission limits have been adjusted to account for such outages.

2. Maintain a log of the AVRs and PSSs taken out-of-service, and their return to service. The form is shown in Attachment D and shall be included with the daily transmission outage summary sheets.

Generator Owner Actions~~:~~

~~Generators~~Generator Owners shall coordinate the outage of AVRs and PSSs on generating units with 40 MW capability or larger with the ~~ISO~~NYISO.

~~i.~~3.1.10. 2.2.5Communication of NY Control Area ~~In-Day~~ Operating Conditions

NYISO Actions~~:~~

The NYISO shall perform the following actions:

1. Obtain the following data for the NY Control Area Status Report, prior to 0530 hours:
   a. Generator anticipated operating capability for the NY Control Area peak hour, including all purchases and sales.
   b. ~~LSE anticipated~~Forecast NY Control Area load~~.~~ requirements.

~~Major unit outages of 300 MW or larger and the anticipated return date.~~

~~Major critical facility outages.~~

~~Any condition or lesser outage that may cause limitations on the transmission system or affect the interchange capabilities of an Area or the NY Control Area.~~

2. ~~Calculate and enter~~Determine the following information ~~on~~for the NY Control ~~Area~~Capacity Status Report display, using the acquired data~~.~~:
   a. ~~Total anticipated~~ NY Control Area forecast peak hour load
   b. b.~~Required~~ NY Control Area reserve requirements
   c. c.NY Control Area generation available capability
   d. d.Interchange summary and peak hour DNI
   e. Total anticipated reserve for the NY Control Area peak hour
   f. Previous day~~'~~'s peak load and hour
   ~~a. The unit names, capability and return dates of all units of over 300 MW that are forced out of service~~
   ~~b. Miscellaneous outages in SENY (not including SENY major unit outages)~~
   ~~c. Miscellaneous outages in UPNY (not including UPNY major unit outages)~~
   ~~d. Total NY Control Area outages~~

~~e. Critical facility outages and the anticipated return times~~

~~f. Operating problems, if any~~

~~g. Any anticipated problems in neighboring Control Areas that might affect NY Control Area operations.~~

~~3.~~g. Post the NY Control Area ~~Status~~Capacity Report.

~~4.~~h. Immediately report any critical change in the status of the NY Control Area, either via the Emergency telephone system or the NY Control Area Status Report.

~~5.~~i. Report all NY Control Area disturbances, e.g., loss of a major generator, when appropriate.

~~6.~~j. Notify the NYISO designated Media contact (or the designated alternate) when system conditions exist which would result in general public awareness of an actual or impending situation.

~~ii.~~3.1.11. Hourly Inadvertent Accounting

The following procedures apply only to the NYISO. The *NYISO* ~~Manual for~~ *Accounting & Billing Manual* describes the Inadvertent Interchange accounting procedure in further detail.

NYISO Actions~~:~~

The NYISO shall perform the following ~~actions: Perform the following~~ checks on an hourly basis:

1. Prior to each hour ~~—~~ – The sum of External transaction schedules should be equal to the NY Control Area desired net interchange (DNI) schedule ~~(DNI)~~.
2. After each hour ~~—~~ – The sum of the interconnection readings should be equal to the NY Control Area actual net interchange (ANI).
3. After each hour ~~—~~ – The NY Control Area Inadvertent Interchange should be equal to difference between the DNI and ANI.
4. ~~.~~After each hour ~~—~~ – Reconcile any inadvertent variances with neighboring Control Areas.
5. After each day ~~—~~ – Reconcile any inadvertent variances with neighboring Control Areas.

~~iii.~~3.1.12. Local Reliability Rules

~~The NYISO shall coordinate with the appropriate~~ Transmission Owners in the NYCA have defined various local rules required to ~~implement the~~ maintain system reliability in their respective areas. These requirements are referred to as Local Reliability Rules~~.~~

~~Applications of Reliability Rules~~

~~The NYISO shall coordinate with the appropriate Transmission Owners to implement the Applications of~~ (LRR). These LRRs are defined in the New York State Reliability Rules~~.~~, maintained by the New York State Reliability Council (NYSRC).

LRRs are more stringent than the general New York-Specific Reliability Rules and apply to certain NYCA zones, recognizing unique local area characteristics or reliability needs.

Transmission Owner Responsibilities

Transmission Owners are responsible for developing and maintaining procedures and requirements necessary to meet these local reliability rules.

At times, TOs may propose a new local rule for a system reliability concern that had not been previously observed. This new LRR should be presented to the NYSRC for consideration to be included with the NYSRC Reliability Rules.

NYISO Responsibilities

The NYISO is responsible for review and approval of any modifications to these procedures or additional procedures developed by the TOs to meet the LRRs.

This responsibility also requires the review and approval of any study or analysis that was completed that warranted modifications of existing procedures or the need for new procedures.

3.1.13. Applications of the NYSRC Reliability Rules

In order to ensure the reliability of the NYISO Secured Transmission System, the NYISO complies with, and enforces the reliability rules. However, there are specific system locations and conditions for which the NYISO cannot secure. These system locations and conditions are secured by the Transmission Owners. Security constraints that are applied by the Transmission Owners are defined as "Transmission Owner Applications of the NYSRC Reliability Rules."

Details

Transmission Owner applications of the NYSRC Reliability Rules (or Applications of the NYSRC Reliability Rules) were assembled before NYISO startup from existing operating procedures and local reliability rules as applied by the Transmission Owners. They consist of procedures that apply to very specific system locations or conditions. The current list of Applications of the NYSRC Reliability Rules is posted on the NYISO web site.

The NYISO will perform periodic compliance reviews to ensure ~~that the~~the Transmission Owners are meeting the intent of the Transmission Owner applications of the NYSRC Reliability Rules. The Annual NYSRC Compliance Program determines the frequency and schedule for the compliance reviews.

Transmission Owner Responsibilities

Transmission Owners are responsible for implementing the Transmission Owner applications of the NYSRC Reliability Rules for those portions of the NYS transmission system not included in the NYISO Secured Transmission System. Implementation of certain Applications of the NYSRC Reliability Rules must be coordinated with the NYISO where the NYISO lacks the necessary analysis and/or monitoring capabilities.

A Transmission Owner, or the NYISO, may define new or modified Applications of the NYSRC Reliability Rules. New or modified Applications of the NYSRC Reliability Rules, proposed by a Transmission Owner are subject to approval by the NYISO. Upon approval by the NYISO, the NYISO will revise the Applications of the NYSRC Reliability Rules to include the change and advise the NYSRC of the change.

~~iv.~~3.1.14. Daily Operation for Monitoring Operating Reserve

The NYISO Shift Supervisor is ~~It is the responsibility of the NYISO Shift Supervisor to~~for monitoring the ~~monitor~~ Operating Reserve both in a forecasted mode for the expected system peak each day and as the day progresses.

Peak Load Forecast

The NYISO Shift Supervisor (or ~~his~~ designee) shall prepare the NYISO daily status report twice daily, in anticipation of the morning peak and evening peak~~. Eligible Customers will supply forecasted loads and operating capacity, including maximum generating capability and all firm transactions for the hours~~ as indicated in Section 2.2.5 of ~~expected peak. The SPD shall also provide a forecasted peak load based on NYISO data for comparison to that supplied by the Eligible Customers~~.

If a shortage of energy, reserves, or Ancillary Services is projected, the NYISO will take actions as directed in Section 4.4 of the *NYISO Emergency* ~~Operation~~*Operations Manual*~~, Section 4.4.~~.

4. Transmission Operations

This section describes the NYS Transmission System operations~~.~~ requirements and procedures.

~~b.~~4.1. Transmission Operations Requirements

This section addresses the operation of the NYISO Secured Transmission System when it is in the Normal State or Warning State (refer to ~~Appendix~~Attachment B~~-~~.1). The following requirements and guidelines are discussed:

- ~~41.~~ NYISO Secured Transmission System Operating Limits
- ~~42.~~ Corrective Control Strategies
- ~~43.~~ Transmission Service Reduction & Curtailment
- ~~Leeds and Fraser SVCs - Voltage Control~~
- ~~Phase Angle Regulators~~
- ~~44.~~ Solar Magnetic Disturbances

The Transmission Facilities Under NYISO Operational Control and subject to *Orders* from the NYISO are listed in ~~Appendix B-~~Attachment A.1. The Transmission Facilities Requiring NYISO Notification ~~are~~is listed in ~~Appendix A-~~Attachment A.2.

~~i.~~4.1.1. NYISO Secured Transmission System Operating Limits

Limits that are used in the operation of the NY Control Area are classified as follows:

1. Thermal (Summer/Winter): MW
   - ~~45.~~a. Normal: Continuous
   - ~~46.~~b. Long Term Emergency (LTE): 4-hours within 24-hour period
   - ~~47.~~c. Short term Emergency (STE): 15-minutes

~~5)~~

2. 2Voltage: kV
   - ~~48.~~a. Pre-contingency High/Low
   - ~~49.~~b. Post-contingency High/Low

~~3.Stability~~

~~4.~~3.3Frequency: Hz
   - ~~50.~~a. Normal High
   - ~~51.~~b. Normal Low

~~5.~~4. 4. ~~Post-Contingency~~ Interface Transfer: MW
   - ~~52.Total Transfer Capability~~
   - ~~53.~~a. ~~Available Transfer Capability~~Stability
   - ~~54.~~b. Voltage Collapse

~~i.~~4.1.2. 3.1.2 Corrective Control Strategies

The major electrical network problems that can occur in the NY Control Area and the primary (or most effective) means of overcoming these problems are identified in Exhibit 3.-1. The major problems are:

- ~~55.~~ ~~facility~~Facility overloads and excessive transfers
- ~~56.~~ NYISO Secured Transmission System low voltage conditions
- ~~57.~~ NYISO Secured Transmission System high voltage conditions
- ~~58.~~ ~~system~~System low frequency conditions
- ~~59.~~ ~~system~~System high frequency conditions

Exhibit ~~3.1~~4-1: Corrective Control Strategies

~~**NY Control Area Problems**~~

	NY Control Area Problems				
Typical Means of Control	**Overloads & Excess Transfer**	**Low Transmission Voltage**	**High Transmission Voltage**	**Low Frequency**	**High Frequency**
Generator MW	✔	✔	✔	✔	✔
Phase Angle Regulator (PAR)	✔	✔	✔		
Control Area Interchange	✔		✔		
Generator MVAr (AVR)		✔	✔		
Transformer Tap (LTC)		✔	✔		
Shunt Capacitor		✔	✔		
Shunt Inductor		✔	✔		
Synchronous Condenser MVAr (AVR)		✔	✔		
Static Var Compensation (SVC)		✔	✔		
Transmission Lines	✔		✔		
Circuit Breaker	✔			✔	✔
PS Pump Operation	✔	✔	✔	✔	✔
PS Generator Operation	✔	✔	✔	✔	✔
Voltage Reduction	✔	✔		✔	
Load Curtailment	✔	✔		✔	

Load Shed	✔	✔		✔	

~~Typical Means of Control~~	~~Overloads & Excess Transfer~~	~~Low Transmission Voltage~~	~~High Transmission Voltage~~	~~Low Frequency~~	~~High Frequency~~
~~Generator MW~~	—	—	—	—	—
~~Phase Angle Regulator (PAR)~~	—	—	—		
~~Control Area Interchange~~	—		—		
~~Generator MVAr (AVR)~~		—	—		
~~Transformer Tap (LTC)~~		—	—		
~~Shunt Capacitor~~		—	—		
~~Shunt Inductor~~		—	—		
~~Synchronous Condenser MVAr (AVR)~~		—	—		
~~Static Var Compensator (SVC)~~		—	—		
~~Transmission Lines~~	—		—		
~~Circuit Breaker~~	—			—	—
~~PS Pump Operation~~	—	—	—	—	—
~~PS Generator Operation~~	—	—	—	—	—
~~Voltage Reduction~~	—	—		—	
~~Load Curtailment~~	—	—		—	
~~Load Shed~~	—	—		—	

Some of the controls listed in Exhibit 3~~.~~-1 are automatically applied by local closed-loop control while other controls are acted on by the Transmission Owners upon NYISO request. The NYISO has no direct means (via SCADA) of controlling the generation, transmission, and distribution systems.

~~i.~~4.1.3. ~~3.1.3~~ ~~Transmission~~3.1.3 Transmission Service Reduction & Curtailment

Firm Transmission Service

If a Transmission Customer's Firm Transmission Service is supporting a Bilateral Transaction supplied by an Internal Generator and that Generator is dispatched downward, the NYISO shall not curtail the Transmission Service. The NYISO shall continue to supply the Load or Transmission Customer in an Export with Energy from the Real-Time LBMP Market. (See ~~Exhibit~~Section 4.2.3, Exhibit 4-~~1~~4 of ~~this manual~~this Manual.)

Non~~-~~-Firm Transmission Service

If the Transmission Customer was receiving non-Firm Transmission Service and its Transmission Service was Reduced or Curtailed, the replacement Energy will be purchased in the Real~~-~~-Time LBMP Market by the Internal Load. An Internal Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed will sell its Energy in the Real~~-~~-Time LBMP Market.

The NYISO will not automatically reinstate non~~-~~-Firm Transmission Service that was Reduced or Curtailed. Transmission Customers need to submit new schedules to restore the Transmission Service associated with their Transaction in the next ~~BME~~RTC execution. (See ~~Exhibit 4.~~Section 4~~)~~.2.3, Exhibit 4-4 of ~~this manual~~this Manual.)

Negative Congestion

The following rules apply to negative congestion and non-firm transmission service:

1. Non-Firm transmission service that encounters negative congestion will not be curtailed. The rationale for this is that any transaction that relieves congestion should not be curtailed.
2. Non-Firm transmission service that encounters negative congestion will not be paid for the negative congestion. The rationale for this is as follows:
   a. A non-firm transaction is not willing to pay positive congestion (and thereby reduce overall transmission costs); therefore, it should not be entitled to receive negative congestion costs. Furthermore, a payout of negative congestion to non-firms would increase overall uplift.
   b. A transaction wishing to receive a payment for negative congestion can request firm transmission service for that transaction.

~~Section 3.2.6 describes the procedures for reducing or curtailing transactions and rescheduling generation to relieve security violations.~~

~~ii.3.1.4 Solar Magnetic Disturbances~~

~~Overview:~~

~~The sun emits streams of charged protons and electrons known as the solar wind. The intensity of the solar wind is determined by sunspot activities (solar flares, disappearing filaments, and coronal holes). The solar wind interacts with the earth's magnetic field producing auroral currents at altitudes of 100 kilometers that follow circular paths around the earth's geomagnetic poles. These non-uniform currents then cause time-varying fluctuations in the earth's magnetic field, which in turn induce a potential difference on the surface of the earth. This earth-surface potential (ESP) is measured in volts per kilometer and its magnitude and direction are functions of the change in magnetic field, earth resistivity, and geographic latitude. ESP increases with increasing latitudes and its gradient is highest on facilities having an east-west orientation. ESP is highest in igneous rock areas. The resulting ESP appears as an ideal voltage source applied between grounded neutrals of wye-connected transformers in a power system, causing geomagnetically induced current (GIC) to flow between grounded neutrals via transmission lines.~~

~~During a severe Solar Magnetic Disturbance (SMD), the quasi-dc ground induced current superimposed on the normal 60 Hertz power flow can result in half-cycle saturation of the cores of grounded, wye-connected power transformers. This overexcitation may cause the following power system problems:~~

60. ~~transformerTransformer overheating resulting in premature transformer failure~~
61. ~~increasedIncreased system reactive losses resulting in the depletion of MVAr reserve~~
62. ~~decreasedDecreased bus voltages resulting in a possible system voltage collapse~~
63. ~~increasedIncreased 60 Hertz harmonics resulting in overheating and eventual tripping of static var compensators (SVCs) and shunt capacitors, protective relay misoperations, and interference with communication systems~~
64. ~~saturationSaturation of current transformers resulting in metering errors and relay misoperations~~
65. ~~systemSystem voltage distortions resulting in improper operation of generator automatic voltage regulators and commutation failures in HVDC terminals and SVCs.~~

~~Monitoring:~~

~~The NYISO receives SMD forecasts and alerts from twothree agencies:~~

- ~~Electronically, via the Solar Terrestrial Dispatch Geomagnetic Storm Mitigation System (STD GSMS).~~

66. ~~National Oceanic and Atmospheric Administration (NOAA), Space Environment Services Center (SESC) in Boulder, Colorado via the NERC Time Error Channel Network (TECN) in accordance with NERC Operating Guide No. 12, Appendix 12D.~~
67. ~~Geographic Division, Geographical Survey of Canada, Energy, Mines, and Resources (EMR) in Ottawa, Canada via Ontario Hydro'sIMO's Control Center.~~

~~An SMD forecast indicates that the condition is expected. An SMD alert indicates that the condition has occurred.~~

~~BothThese agencies measure the disruption in the horizontal component of the earth's magnetic flux with magnometer. The STD GSMS is kept continuously up to date by Solar Weather Specialists located at www.spacew.com. SESC measures the geomagnetic activity in Boulder, Colorado and EMR measures the geomagnetic activity from 13 observatories in the Canadian Automatic Magnetic Observation System (AMOS). This information is quantified into A and K~~

indices for forecasting and alerting purposes. The impact of an SMD on the power system increases with the intensity of the storm.

SMD Forecasts:

STD through the GSMS allows for continuous updating on current Solar Magnetic Disturbance activity, as well as 24, 48 and 72 hour predictions on SMD activity. Currently, the STD uses a Kp Index, but does not specify by level what Forecast or an Alert is issued, merely they are issued depending on the activity seen by their satellite in regards to predicted SMD activity vs. actual observed SMD activity.

SESC (Boulder) issues forecasts in the form of a daily "A" index for up to three days in advance. The "A" index is a measure of the expected geomagnetic activity at Fredericksburg, Virginia. SESC (Boulder) transmits forecasts of the following two classifications of geomagnetic activity to the NYISO:

69. Minor Storm ("A" index 30-_49)
70. Major Storm ("A" index above 50)

EMR (Ottawa) issues forecasts based on daily range predictions for up to three days in advance in the sub-_auroral zone in which most of the NPCC Areas are located. Ontario HydroIMO and Hydro Quebec receive forecasts for the auroral zones separately. EMR (Ottawa) transmits forecasts of the following two classifications of geomagnetic activity to the NYISO:

1. Active Conditions (approximate "K" index of 5 or 6)
2. Major Storm Conditions (approximate "K" index of 7, 8 or 9)

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STD through the GSMS allows for continuous updating on current Solar Magnetic Disturbance activity, as well as 24-, 48- and 72-hour predictions on SMD activity. Currently, the STD uses a Kp Index, but does not specify by level what a Forecast or an Alert is issued, merely they are issued depending on the activity seen by their satellite in regards to predicted SMD activity vs. actual observed SMD activity.

SESC (Boulder) issues alerts in the form of a three three-hour "K" index that is based on the average of the last three hours of disruption in the horizontal component of the earth's magnetic flux measured in Boulder, Colorado. SESC (Boulder) transmits alerts of the following classification of geomagnetic activity to the NYISO:

"K" index of K5 or greater

EMR (Ottawa) issues alerts based on a three hour average range index for the last three hours of disruption in the X (geographical northward) component of the earth's magnetic flux measured by the AMOS system. EMR (Ottawa) issues alerts for the following two classifications of geomagnetic activity to the NYISO:

72. Active Conditions (approximate "K" index of 5 or 6)
73. Major Storm Conditions (approximate "K" index of 7, 8 or 9)

All time references in SMD Forecasts and SMD Alerts received from SESC (Boulder) and EMR (Ottawa) are to Universal Time (which is the same as Greenwich Mean Time), a constant scientific time reference. Eastern Standard Time lags Universal Time by 5 hours. The NYISO converts all time references to prevailing Eastern time Time (Standard Time or Daylight Saving Time) as shown in Exhibit 3.-2.

~~Exhibit 3.23-2: Conversion from Universal Time~~

~~If the prevailing Eastern time is:~~ ~~Then 0600 UTC (GMT) converts to:~~

~~If the prevailing Eastern time is:~~	~~Then 0600 UTC (GMT) converts to:~~
~~Standard Time~~	~~0100 EST~~
~~Daylight Savings Time~~	~~0200 EDT~~
~~Standard Time~~	~~0100 EST~~
~~Daylight Saving Time~~	~~0200 EDT~~

~~a.~~4.2. 3.2 Transmission Operations Procedures

These procedures apply mainly to the operation of the NYISO Secured Transmission System network facilities. Procedures dealing with generation and load are covered in Sections 4.2 and 5.2. Procedures for the following are covered:

- ~~74.~~ Developing & Approving Operating Limits
- ~~75.~~ Voltage Control
- Guidelines for Leeds and Fraser SVCs to Control Voltage
- ~~76.~~ Phase Angle Regulators – ConEd/PSE&G
- Phase Angle Regulators Operations
- ~~77.~~ Implementing Special Multiple Contingencies
- ~~Exceptions to Standards for Planning and Operating the NYS Power System~~
- Exceptions to the NYS Reliability Council Reliability Rules
- ~~78.~~ Security Violation Relief
- ~~Severe Weather~~
- Operating Under Adverse Conditions
- ~~79.~~ Solar Magnetic Disturbances

~~i.~~4.2.1. 3.2.1 Developing & Approving Operating Limits

Procedures have been established for:

~~80.~~1. ~~the~~ The approval and implementation of operating limits developed from off-line computer studies conducted by the NYISO

~~81.~~2. ~~the~~The collection of operating data required to determine voltage limits for selected buses in the NY Control Area.

NYISO Actions~~:~~

The NYISO shall perform the following actions:

1. Prepare Summer thermal transfer limits for the "all-lines in" condition.

2. Prepare daily thermal transfer limits for anticipated power system conditions for the ““all-lines in”” condition.
3. Prepare stability transfer limits for the ““all-lines in”” condition. These limits will be used for the secure operation of the NYISO Secured Transmission System.
4. Prepare pre-contingency (high/low) and post-contingency (high/low) voltage limits for the ““all-lines in”” and prevailing conditions. These limits will be used for the secure operation of the NYISO Secured Transmission System.
5. Review and update the data maintained by the NYISO Data Bank program. This data will be used for network, stability, and voltage control parameters, in preparation of seasonal and/or specific operating studies base cases.

NYISO Operating Committee Actions~~:~~

The NYISO Operating Committee shall review and approve the recommended limits developed by the NYISO staff.

~~i.~~4.2.2. 3.2.2Voltage Control

These procedures are for coordinating and controlling the voltage of the NYISO Secured Transmission System and define the respective actions to be taken by the NYISO and the Transmission Owners. The purpose is to provide adequate voltages necessary to maintain power transfer capabilities and to keep voltages within prescribed limits to avoid damage to equipment.

NYISO Actions ~~-~~– General~~:~~

The NYISO shall perform the following actions:

1. Anticipate the effects, voltage levels, and trends in the NY Control Area and adjacent Control Areas.
2. Determine and request corrective actions that need to be taken to remain in the Normal State.
3. Coordinate requests for corrective actions with the Transmission Owners and adjacent Control Areas that can assist in adjusting voltage on the buses being corrected.
4. Inform the affected Transmission Owners of anticipated changes in the reactive support from pumped hydro units, Static Var Compensators, or neighboring Control Areas.
5. Request Generators (via their TOs) to adjust machine excitation, as required to maintain desired NYISO Secured Transmission System voltages within limits.

Transmission Owner Actions ~~-~~– General~~:~~

The Transmission Owner shall perform the following actions:

1. Observe the status and availability of major reactive resources on its system and determine any restrictions on those sources.
2. Control the voltage on its transmission system to be within its internal limits. Under normal conditions, maintain reactive power flows on tie lines with adjacent Control Areas in accordance with mutually agreed upon schedules and NPCC Inter Area Voltage Control Procedures.
3. Provide assistance (consistent with its internal limits) to other TOs as requested by the NYISO.
4. Coordinate and notify the operation (prior to execution) of the following devices with the NYISO and TOs: (1) switching of shunt capacitors and inductors and (2) changing of SVC mode or state. Under Emergency conditions a TO may perform the control actions prior to notification of the NYISO TO and affected ~~TOs ,~~TOs, but shall inform them as soon as possible.

NYISO Actions ~~-~~– High Voltage Conditions~~:~~

The NYISO shall request the Transmission Owners to perform the following normal steps to alleviate high voltage conditions:

~~82.~~1. Switch out shunt capacitors

~~83.~~2. Switch in shunt inductors

~~84.~~3. Request that machine excitation be decreased to decrease the reactive power output

~~85.~~4. Adjust load tap changing (LTC) transformer tap positions

~~86.~~5. Reschedule pumped hydro units to pump

~~87.~~6. Adjust SVC output

~~88.~~7. Start fast response units with reactive power absorption capability

~~89.~~8. Switch out lines, as a last resort, without dropping load or generation

NYISO Actions ~~-~~– Low Voltage Conditions~~:~~

The NYISO shall request the Transmission Owners to perform the following normal steps to alleviate low voltage conditions:

~~90.~~1. Switch in shunt capacitors

~~91.~~2. Switch out shunt inductors

~~92.~~3. Request that machine excitation be increased to increase the reactive power output

~~93.~~4. Adjust load tap changing (LTC) transformer tap positions

~~94.~~5. Reschedule pumped hydro units to generate

~~95.~~6. Motor pumped hydro units to produce reactive power

~~96.~~7. Adjust SVC output

~~97.~~8. Start fast response units with reactive power export capability in order to help raise the system voltage

~~98.~~9. Switch in lines where available

Transmission ~~Owner~~Owners Actions ~~-~~– SVC Operation~~:~~

Static Var Compensators (SVCs) are intended to be used for mitigating post-contingency voltage oscillations and voltage control when the power system is loaded close to the transfer limits. SVCs are not intended for steady state pre-contingency voltage support. The Transmission Owner shall perform the following actions:

1. Maintain the SVC in the automatic mode and in the minimum output state within a deadband around zero reactive power output, under normal conditions.
2. Return the SVC to its minimum output state, after a disturbance has been cleared.
3. Coordinate the use of the SVC for bus voltage regulation with the NYISO and other affected Transmission Owners.

~~i.~~4.2.3. Guidelines for Leeds and Fraser SVCs to Control High Voltage

The guidelines for the operation of the Leeds and Fraser SVCs to control high voltage are given as follows:

1. ***General Requirements:***
   a. The HQ/NY Import/Export on the Chateauguay - Massena 7040 line is at or below 1000 MW.
   b. Central - East and Total - East transfers are at or below transfer limits that assume the SVCs are unavailable.
   c. All appropriate switchable shunt capacitors have been taken out-of-service. All appropriate switchable inductors have been placed in-service.
   d. The maximum reactive capability of any Gilboa units or pumps currently in-service is being used. The effect of a Gilboa unit or pump to go in-service should be taken into account.
   e. The SVCs must be able to automatically respond to contingencies.

~~2.~~2 ***Specific Conditions to Use the Fraser SVC:*** Subject to the above general requirements, the inductive capability of the Fraser SVC may be used to control high voltage in the area of the Marcy-South transmission lines subject to the following specific conditions:

   a. The capacitors at Marcy, Fraser, Coopers Corners, and Rock Tavern are out-of-service.
   b. The Marcy inductor is in-service.

c. The capacitors at Gilboa should also be switched out-of-service, and any Gilboa units/pumps currently in-service should be absorbing maximum reactive power, provided that this does not cause unacceptably low voltage at Gilboa, New Scotland, or Leeds.
d. The Oakdale 345 kV bus voltage is maintained above its pre-contingency low voltage limit.

~~3.~~3 ***Specific Conditions to Use the Leeds SVC:*** Subject to the above general requirements, the inductive capability of the Leeds SVC may be used to control high voltage on the Eastern New York 345 kV transmission system where it would be effective subject to the following specific conditions:

a. The Marcy inductor is in-service.
b. The Fraser capacitors should be switched out-of-service, provided this does not cause unacceptably low voltage at Fraser, Oakdale, Marcy, Edic, or Coopers Corners.

~~4.~~***Specific Conditions for the 7040 Line Out-of-Service:*** Subject to the above requirements and conditions, the inductive capability of the Leeds and/or Fraser SVCs may be used to control high voltage when the 7040 line is out-of-service, with the additional provision that either both ~~inductors~~shunt reactors on the Massena-Marcy MSU-1 line are in-service, or the MSU-1 line is out-of-service.

~~ii.~~4.2.4. 3.2.4Phase Angle Regulators – Con Ed/PSE&G

Con Edison and PSE&G are interconnected at several locations with the capacity Co transfer up to 1000 MW. The following Phase Angle Regulators (PARs) are installed to control the transfer of power over the circuits connecting the two companies~~.~~:

~~99.~~1. A 345 kV phase angle regulating transformer with a range of ~~"~~± 25° installed at the Con Edison Goethals substation.

~~100.~~2. Two 345 kV phase angle regulating transformers each with a range of ~~"~~± 30°, installed at the Con Edison Farragut substation.

~~101.~~3. A 230 kV phase angle regulating transformer with a range of ~~"~~± 25°, installed in the Waldwick-Hillsdale-New Milford Circuit located at the PSE&G Waldwick Switching Station.

~~102.~~4. A 230 kV phase angle regulating transformer with a range of ~~"~~± 25°, installed in the Waldwick-Fair Lawn Circuit located at the PSE&G Waldwick Switching Station.

~~103.~~5. A 230 kV phase angle regulating transformer with a range of ~~"~~± 25°, installed in the Waldwick-Hawthorne Circuit located at the PSE&G Waldwick Switching Station.

ConEd/PSE&G Responsibilities

Con Edison and PSE&G are responsible for the operation and maintenance of the facilities located in their respective states.

Data acquisition facilities provide real-time information to Con Edison and PSE&G for continuous on-line monitoring and analysis of operating conditions.

Under ~~"~~"normal conditions~~"~~," PSE&G can transfer up to 1000 MW. PSE&G can curtail when critical bulk power system outages in the northern portion of PSE&G system preclude such transfer.

~~i.~~4.2.5. 3.2.5Phase Angle Regulators Operations

Normal Operating Conditions~~:~~

Under normal operating conditions, Transmission Owners shall determine power flow schedules on all PAR controlled lines. Significant schedule changes (100 MW or more) on inter-Control Area or inter-company tie lines shall be coordinated with the NYISO. However, small changes of 1 or 2 taps during changing load conditions, such as morning load pickup or evening load drop, that are within operating guidelines on inter-Control Area or ~~intercompany~~inter-company ties may be coordinated between the affected companies.

The maximum loading of overhead lines controlled by PARs shall be the lesser of the normal rating or a level such that the post-contingency flow will not exceed its LTE rating. The post-contingency loading of any underground cable may exceed its LT E rating, but not its STE rating, provided 10 minute reserve or phase angle control is available to return its post-contingency loading to its LTE rating within 15 minutes without causing another facility to be loaded beyond its LTE rating.

Power flows on PAR controlled lines ~~which~~ that are within a Transmission Owner~~'~~'s system shall be monitored and controlled by that Transmission Owner. Power flows on other PAR controlled lines shall be monitored by the NYISO and appropriate action shall be coordinated with the Transmission Owners.

The following PAR actions apply to normal conditions. ~~Other procedures for alleviating flow violations are given in Section 3.2.6 of this manual~~.

NYISO Actions~~:~~

The NYISO shall perform the following actions:

1. Coordinate the operation of the PARs that affect the transfer of power between the NY Control Area and adjacent Control Areas.
2. Request the Transmission Owners and adjacent Control Areas to adjust PAR taps.

Transmission Owner Actions~~:~~

Transmission Owners shall perform the following actions:

~~1. Coordinate PAR tap changes with the NYISO and adjacent Transmission Owner - Con Ed - PSEG Agreement.~~

1. Set the PAR taps.
2. Coordinate PAR tap changes with the NYISO and adjacent Transmission Owner - Con Ed - PSEG Agreement.

~~ii.~~4.2.6. 3.2.6 Implementing Special Multiple Contingencies

The Multiple Contingency Evaluation (MCE) program and Day-Ahead analysis normally incorporate the contingencies that are applicable to the power system as it is being operated. These procedures apply to special operating conditions when additional contingencies are required.

NYISO Actions~~:~~

The NYISO shall perform the following actions:

1. Incorporate the special contingency in the Contingency Analysis Program (CAP) and MCE ~~programs~~ program so long as program requirements such as metering, representation, and applicability can be met~~;~~ -- following notification by the Transmission Owner.
2. Determine the need for special contingencies and request the Transmission Owners to submit the required information.

Transmission Owner Actions~~:~~

The Transmission Owner shall perform the following actions:

1. Notify the NYISO and request the monitoring of special contingencies.
2. Supply a description of the special operating condition, a list of the components making up the multiple contingency, the limiting element(s)~~,~~ the date/time to initiate the monitoring and the date/time to terminate the monitoring.
3. Observe the following lead times in order to implement such a contingency:
   - ~~i.~~a. For Day-Ahead analysis, the necessary data must be available at the PCC at least by the morning of the previous working day, prior to the closing of the Day-Ahead Market.
   - ~~ii.~~b. For MCE, the necessary data must be available at the PCC at least one hour prior to implementation.
4. ~~Make arrangements~~Arrange through the Outage Coordinator at the NYISO PCC~~.~~ during normal working hours, for incorporating special contingencies in both Day-Ahead analysis and MCE.

5. Provide, the NYISO, during other hours and when there is only a short ~~lead~~ lead-time, with the contingencies for incorporation in the MCE program.

6. Provide special contingency data when required and requested by the NYISO.

~~iii.~~4.2.7. 3.2.7 Exceptions to the NYS Reliability Council Reliability Rules

~~Duties of the~~ NYSRC Responsibilities

The NYSRC is responsible for developing Reliability Rules, which the NYISO must maintain to assure the safety and short-term reliability of the NYS Power System.

If the NYSRC determines that the operation of the NYS Power System by the NYISO has not been in compliance with the Reliability Rules or the NYISO has improperly implemented the Reliability Rules, the NYSRC will discuss such non-compliance or improper implementation with the NYISO. If a satisfactory resolution of the matter cannot be reached within 30 days, the issue may be referred by either Party to dispute resolution.

The NYSRC develops Reliability Rules for implementation by the NYISO to ensure that sufficient Operating Capacity is committed on a Day-Ahead basis to ensure the reliable operation of the NYS Power System during the next day. The NYSRC also determines the statewide Installed Capacity requirement on an annual basis.

NYISO Reliability Rule Dispute Resolution

If the enactment of a new Reliability Rule or a modification of an existing Rule leads to a dispute, the NYISO Board of Directors may request that the effectiveness of the new Reliability Rule or the modification be suspended pending the outcome of the dispute resolution process. Upon such a request by the NYISO Board, the NYSRC shall suspend implementation of the new Reliability Rule or the enactment of the modification pending resolution of the dispute by the PSC. Disputes between the NYISO and NYSRC may be submitted to the PSC by either Party in a written statement describing the nature of the dispute and the issues to be resolved. Notwithstanding the foregoing, the PSC may direct that the new Reliability Rule or modification go into effect immediately upon a finding that suspension of the rule could put the reliability of the NYS Power System at risk. Refer to the NYISO/NYSRC Agreement for additional details.

Local Reliability Rule Dispute Resolution

Local Reliability Rules cannot be modified or eliminated without the consent of the Transmission Owner promulgating such Local Reliability Rule unless so ordered by the PSC or FERC. The NYISO Board or the NYSRC may protest a new Local Reliability with the PSC or request that the PSC review an existing Local Reliability Rule. The NYISO Board or the NYSRC may also request that FERC review a Local Reliability Rule. Upon such review, the PSC or FERC may determine that a specific Local

Reliability Rule should be modified or eliminated. Upon the issuance of an order by the PSC or FERC such Local Reliability Rule will then be modified or eliminated.

Local Reliability Rules cannot be suspended pending PSC or FERC review of such rule unless so ordered by FERC or the PSC.

~~iv.~~4.2.8. 3.2.8Security Violation Relief

When a security violation occurs, or is anticipated to ~~occurr on~~occur on the NYISO Secured Transmission System, the NYISO shall attempt to relieve the violation by using the following procedures:

~~**ISO Actions:**~~

1. Reduce non-Firm Transmission Service.
2. Curtail non-Firm Transmission Service. Refer to Section 4.2.3 of ~~this manual~~this Manual for details.
3. Re-dispatch internal Generators, based on Incremental and Decremental Bids.
4. Adjust the NYCA's Desired Net Interchange (DNI) by manually curtailing Firm Transmission Service associated with Transactions supplied by External Generators. The NYISO shall decide which Transmission Service is to be curtailed ~~on the basis of~~based on the Decremental Bids in conjunction with NERC procedures, and shall curtail Transmission Service until the transmission violation is relieved or all such Transmission Service has been curtailed.
5. Request Internal Generators to voluntarily operate in manual mode below minimum dispatchable levels. ~~When operating in the manual mode, Generators will not be required to adhere to the one percent minimum ramp rate nor will they be required to respond to the SCD Base Point Signals.~~
6. Decommit Internal Generators based on their minimum generation Bid rate in descending order.
7. Attempt to purchase emergency energy from other ~~CA'~~control areas that will provide relief to the security violation.

4.2.9. Procedure for Relief of Potential Overloads on Non-Bulk Power System Facilities

The NYISO Security Analysis Program identifies and alerts the dispatchers to actual and potential overloads on the NYISO transmission system. Occasionally actual or post-contingency potential overloads on Non-Bulk Power System facilities occur which, if uncorrected, could lead to cascading outages and subsequent overloads on BPS facilities.

This procedure defines actions to be taken by the NYISO Shift Supervisor (NYISO SS) when such conditions exist in order to coordinate an appropriate action plan.

PROCEDURE

1. During normal operation, the SS shall monitor the state of the system utilizing the NYISO Security Analysis Program. Whenever the actual or predicted post-contingency power flow on a monitored Non-BPS facility exceeds its applicable limit, the SS shall notify the Transmission Owner (rating authority).
2. If the predicted post-contingency loading is greater than LTE, but less than or equal to the STE rating of the facility, an action plan should be formulated, or refer to previously agreed upon operating practice for implementation by the Transmission Owner.
3. If the predicted post-contingency flow exceeds the STE rating of the facility, the SS shall determine if the loss of the facility would cause other facilities to exceed their STE post-contingency ratings. If the affected facility's loss would cause other non-BPS facilities to exceed their STE rating or any BPS facilities to exceed their LTE rating* the SS shall inform the TO (rating authority) and they shall jointly develop a strategy for correcting the condition. The TO shall carry out the corrective action to relieve the condition within 30 minutes, excluding voltage reduction and load shedding.
4. If the TO can not relieve the problem using its own resources, the TO Dispatcher shall request the SS to obtain assistance from other systems.
5. If the condition cannot be corrected within 30 minutes of the initial violation the SS shall, through coordination with the TO and neighboring systems, determine and request the actions necessary to provide relief. Such actions shall include:
    a. Modifications of energy transactions.
    b. Phase angle regulator adjustments.
    c. Generation Shift.
    d. Reserve activation.
    e. Generation may be ordered to full operating capability and transmission facilities out of service for maintenance may be ordered restored to serve.
6. If these measures are insufficient to comply with Normal Transfer Criteria on BPS facilities or Emergency Transfer Criteria for non-BPS facilities within 30 minutes of the initial violation or Operating Reserve cannot be delivered due to transmission limitations for 30 minutes, the SS shall take the following actions:
    a. Notify all TOs Systems via the Emergency Alarm System (Hot Line) that Emergency Transfer Criteria are in effect, for the ~~facility(~~facility (ies) involved.
    b. Take action as required to stay within Emergency Transfer Criteria.
    c. The Shift Supervisor shall confer with affected Transmission Owners. They shall jointly develop strategies to be followed in the event a contingency occurs. Strategies may include preparation for rapid Voltage Reduction and/or Load Shedding.

*Except where post-contingency flows up to STE ratings are permitted by exceptions noted in Emergency Operations Manual Appendix Exhibit A-2.

SCHEDULING

The NYISO Outage Coordinator shall attempt to avoid scheduling outages which might result in conditions wherein the security of the non-BPS Facilities may become jeopardized.

~~v.~~4.2.10. Operating Under Adverse Conditions

The NYISO shall operate the NYISO Secured Transmission System during adverse conditions, including but not limited to thunderstorms, hurricanes, tornadoes, solar magnetic flares and threat of terrorist activities, in accordance with the Reliability Rules, inclusive of Local Reliability Rules and related PSC orders. Consistent with such Rules, the NYISO shall maintain reliability of the NYISO Secured Transmission System by directing the adjustment of the Generator output levels in certain areas of the system to reduce power flows across transmission lines vulnerable to outages due to these adverse conditions, thereby reducing the likelihood of major power system disturbances.

The NYISO shall have the sole authority to declare that adverse conditions are imminent or present and invoke the appropriate operating procedure(s) affecting the NYISO Secured Transmission System in response to those conditions. Activation of a procedure in compliance with a Local Reliability Rule shall involve a two step process. The Transmission Owner, directly involved with such Local Reliability Rule, such as Storm Watch shall advise the NYISO that adverse conditions are imminent or present and recommend to the NYISO the activation of applicable procedures in support of that rule. Consistent with the Local Reliability Rule, the NYISO shall declare the activation of the appropriate procedures. The Transmission Owner and the NYISO shall coordinate the implementation of the applicable procedures to the extent that NYISO Secured Transmission System facilities are impacted. Records pertaining to the activation of such procedures and the response in accordance with those procedures shall be maintained and made available upon request.

Adjusted generation levels in response to activation of these procedures shall set the real time LBMPs. Revenue shortfalls may occur if the redispatch of the system curtails energy scheduled Day~~-~~-Ahead and more expensive energy is dispatched subsequent to the Day~~-~~-Ahead settlement. These revenue shortfalls shall be recovered through the NYISO~~'~~'s Scheduling, System Control, and Dispatch Service (Ancillary Service) charges.

~~vi.~~4.2.11. Solar Magnetic Disturbances

Background

The sun emits streams of charged protons and electrons known as the solar wind. The intensity of the solar wind is determined by sunspot activities (solar flares, disappearing filaments, and coronal holes). The solar wind interacts with the earth's magnetic field producing auroral currents at altitudes of 100 kilometers that follow circular paths around the earth's geomagnetic poles. These non-uniform currents then cause time-varying fluctuations in the earth's magnetic field, which in turn induce a potential difference on the surface of the earth. This earth-surface potential (ESP) is measured in volts per kilometer and its magnitude and direction are functions of the change in magnetic field, earth resistivity, and geographic latitude. ESP increases with increasing latitudes and its gradient is highest on facilities having an east-west orientation. ESP is highest in igneous rock areas. The resulting ESP appears as an ideal voltage source applied between grounded neutrals of wye-connected transformers in a power system, causing geomagnetically induced current (GIC) to flow between grounded neutrals via transmission lines.

During a severe Solar Magnetic Disturbance (SMD), the quasi-dc ground induced current superimposed on the normal 60 Hertz power flow can result in half-cycle saturation of the cores of grounded, wye-connected power transformers. This over-excitation may cause the following power system problems:

1. Transformer overheating resulting in premature transformer failure
2. Increased system reactive losses resulting in the depletion of MVAr reserve
3. Decreased bus voltages resulting in a possible system voltage collapse
4. Increased 60 Hertz harmonics resulting in overheating and eventual tripping of static var compensators (SVCs) and shunt capacitors, protective relay misoperations, and interference with communication systems
5. Saturation of current transformers resulting in metering errors and relay misoperations
6. System voltage distortions resulting in improper operation of generator automatic voltage regulators and commutation failures in HVDC terminals and SVCs.

Monitoring

The NYISO receives SMD forecasts and alerts from three agencies:

1. Electronically, via the Solar Terrestrial Dispatch Geomagnetic Storm Mitigation System (STD GSMS).
2. National Oceanic and Atmospheric Administration (NOAA), Space Environment Services Center (SESC) in Boulder, Colorado via the NERC Time Error Channel Network (TECN) in accordance with NERC Operating Guide No. 12, Appendix 12D.
3. Geographic Division, Geographical Survey of Canada, Energy, Mines, and Resources (EMR) in Ottawa, Canada via IMO's Control Center.

In event of failure of the STD GSMS, the Space Environment Center (SEC) in Boulder, Colorado will verbally contact the NYISO to relay the SMD information.

An SMD forecast indicates that the condition is expected. An SMD alert indicates that the condition has occurred.

These agencies measure the disruption in the horizontal component of the earth's magnetic flux with magnometer. The STD GSMS is kept continuously up to date by Solar Weather Specialists located at www.spacew.com. SESC measures the geomagnetic activity in Boulder, Colorado and EMR measures the geomagnetic activity from 13 observatories in the Canadian Automatic Magnetic Observation System (AMOS). This information is quantified into A and K indices for forecasting and alerting purposes. The impact of an SMD on the power system increases with the intensity of the storm.

Information pertaining to Solar Magnetic Disturbances and the level of the disturbance will be disseminated by means of the Solar Terrestrial Dispatch Geomagnetic Storm Mitigation System (STD GSMS).

SMD Forecasts

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~~Information pertaining to Solar Magnetic Disturbances and the level of the disturbance will be disseminated by means of the Solar Terrestrial Dispatch Geomagnetic Storm Mitigation System (STD GSMS). In event of failure of the STD GSMS, the Space Environment Center (SEC) in Boulder, Colorado will verbally contact the NYISO to relay the SMD information.~~

No NYISO actions are required if:

- ~~104.~~ SMD Forecast of an ~~“~~A~~”~~ -index is equal to or less than 29 and
- ~~105.~~ SMD Alert is equal to K4 or less

Minor storm active conditions exist when:

- ~~106.~~ ~~“~~A~~”~~-index is greater 29 but less than or equal to 50 and
- ~~107.~~ Alert is greater than K4 but less than or equal to K6

NYISO Actions~~:~~

The NYISO shall perform the following actions:

1. Complete the Solar Magnetic Disturbance Form shown in Attachment C of ~~this manual~~this Manual, upon notification of an SMD Forecast of an ~~"~~A~~"~~ -index greater than 50 or an SMD Alert of ~~K7~~K6 or greater.
2. Notify all Transmission Owners and NPCC Control Areas.~~Request Transmission Owners to implement appropriate Emergency Procedures, when a contingency occurs.1.~~
3. If an Alert of K7 or greater has been issued on the STD with significant GIC (Ground Induced Currents) activity observed by a neighboring Control Area or a Transmission Owner, the NYSIO shall initiate the following actions:
   a. Declare Alert State
   b. Notify Transmission Owners to reduce normal limits on inter-area and internal NYS Power System transmission lines and transformers to a maximum of 90% of the normal rating where appropriate.
   c. Request generators (via their TOs) to adjust machine excitation, in order to maintain the ISO Secured Transmission System voltages within acceptable operating ranges to protect against voltage swings.
   d. Reduce RTC/RTD Stability Transfer Limits and RTC/RTD Central East Voltage Contingency Limits to 90% of the Stability Transfer Limit and Central East Voltage Contingency Limits where appropriate.
4. Request Transmission Owners to implement appropriate emergency procedures, when a contingency occurs.
5. Reduce flows on inter~~-~~-area and internal ISO Secured Transmission System transmission lines to a maximum of 90% of the Normal Rating.
6. Activate Thunder Storm Warning cases (TSW) when an alert of K9 has been issued and significant GIC activity has been observed.

Transmission Owner Actions~~:~~

Upon notification of an SMD Forecast or an SMD Alert of a Major Storm Condition (K7~~-~~-K9), Transmission Owners shall perform the following actions:

1. Restore out~~-~~-of~~-~~-service transmission facilities, where possible, and avoid taking long transmission lines out of service.
2. 2Review all in~~-~~-service work, evaluate the impact of the loss of these facilities on the NYISO Secured Transmission System, and cancel in~~-~~-service work on critical facilities.
3. Monitor the MVAr and voltage displays on their SCADA systems for unusual voltage and/or MVAr variations.
4. Keep area substation capacitor banks in service, where possible, and evaluate the impact of the loss of transmission shunt capacitor banks.

5. Notify the NYISO of all actions taken related to this section.

6. Implement Emergency procedures, as requested by the NYISO.

~~SCHEDULING OPERATIONS~~

5. Scheduling Operations

—This section describes the ~~Operating~~Dispatch Day scheduling process~~.~~, covering the following:

- Real-Time Commitment
- ~~a.~~ Scheduling Operations Requirements

~~This subsection describes the requirements for the Operating Day scheduling of generation, transactions, load, and Ancillary Services. The principal functions are:~~

  - ~~In-Day Scheduling Changes~~
  - ~~Balancing Market Evaluation~~

- Scheduling Operations Procedures
- Supplemental Resource Evaluation Procedures

5.1. Real-Time Commitment

Real-Time Commitment (RTC) is a multi-period security constrained unit commitment and dispatch process that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least as-bid production cost basis over a two hour and fifteen minute optimization period. The optimization evaluates the next ten points in time separated by fifteen minute intervals. Each RTC run within an hour shall have a designation indicating the time at which its results are posted; “RTC_{00},” RTC_{15},” RTC_{30},” and RTC_{45}” post on the hour, and at fifteen, thirty, and forty-five minutes after the hour, respectively. Each RTC run will produce binding commitment instructions for the periods beginning at fifteen and thirty minutes after its scheduled posting time and will produce advisory commitment guidance for the remainder of the optimization period. RTC_{15} will also establish External Transaction schedules. Exhibit 4-1 presents the timeline for RTC_{15}.

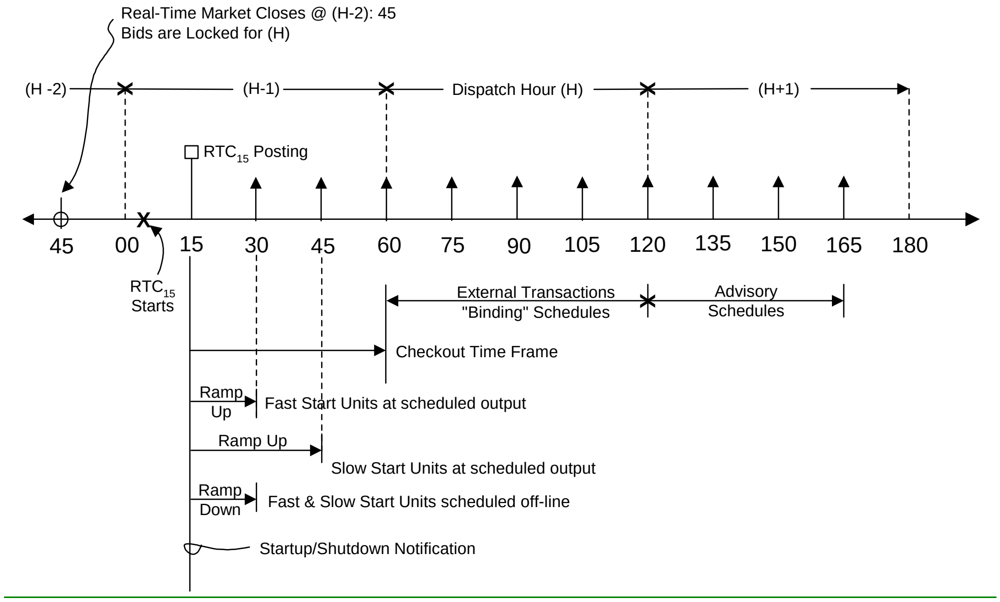


Exhibit 5-1: RTC_{15} Time Line

5.1.1. Real-Time Commitment Process

RTC will make binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of Resources that can respond in ten minutes) and thirty minutes (in the case of Resources that can respond in thirty minutes) after the scheduled posting time of each RTC run, will provide advisory commitment information for the remainder of the two and a half hour optimization period, and will produce binding schedules for External Transactions to begin at the start of each hour. RTC will co-optimize to solve simultaneously for all Load, Operating Reserves and Regulation Service requirements and to minimize the total as-bid production costs over its optimization timeframe. RTC will consider SCUC's Resource commitment for the day, load forecasts from the load forecasting program and loss forecasts that RTC itself will produce each quarter hour, binding transmission constraints, and all Real-Time Bids and Bid parameters.

After the Day-Ahead schedule is published and no later than 75 minutes before each hour, Customers may submit Real-Time Bids into RTC for real-time evaluation.

Real-Time Bids to Supply Energy and Ancillary Services

Eligible Customers may submit new or revised Bids to supply Energy, Operating Reserves and/or Regulation Service. Customers that submit such Bids may specify different Bid parameters in RTC than they did Day-Ahead. However, NYISO-Committed Fixed Generators and NYISO-Committed Flexible Generators may not increase their Incremental Bids, Minimum Generation Bids, or Start-Up Bids for hours in which they received a Day-Ahead Energy schedule. Bids to supply Energy or

Ancillary Services shall be subject to the rules set forth in Section 6 of the *NYISO Ancillary Services Manual.*

Generators that did not submit a Day-Ahead Bid for a given hour may offer to be NYISO-Committed Flexible, Self-Committed Flexible, or Self-Committed Fixed in real-time. Generators that submitted a Day-Ahead Bid but did not receive a Day-Ahead schedule for a given hour may change their bidding mode for that hour in real-time without restriction. Generators that received a Day-Ahead schedule for a given hour may change their bidding mode between Day-Ahead and real-time subject to the following restrictions:

1. Generators that were scheduled Day-Ahead in NYISO-Committed Flexible mode may not switch to NYISO-Committed Fixed or Self-Committed Fixed mode unless a real-time physical operating problem makes it impossible for them to bid in any other mode.
2. Generators that were scheduled Day-Ahead in Self-Committed Flexible mode may not switch to NYISO-Committed Fixed or NYISO-Committed Flexible mode and may only switch to Self-Committed Fixed mode if a real-time physical operating problem makes it impossible for them to bid in any other mode.
3. Generators that were scheduled Day-Ahead in NYISO-Committed Fixed mode may not switch to NYISO-Committed Flexible or Self-Committed Flexible mode in real-time.
4. Generators that were scheduled Day-Ahead in Self-Committed Fixed mode may not switch to a different bidding mode in real-time.

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

Bids Associated with Internal and External Bilateral Transactions

Customers may seek to modify Bilateral Transactions that were previously scheduled Day-Ahead or propose new Bilateral Transactions, including External Transactions, for economic evaluation by RTC. Bids associated with Internal Bilateral Transactions shall be subject to the rules set forth above in Section 4.2.3 of ~~this manual~~this Manual.

Sink Price Cap Bids or Decremental Bids for External Transactions may be submitted into RTC up to 75 minutes before the hour in which the External Transaction would flow. External Transaction Bids must have a one-hour duration, must start and stop on the hour, and must have constant magnitude for the hour. Intra-hour schedule changes, or Bid modifications, associated with External Transactions will not be accommodated.

Self-Commitment Requests

Self-Committed Flexible Resources must provide the NYISO with schedules of their expected minimum operating points in quarter hour increments. Self-Committed Fixed

Resources must provide their expected actual operating points in quarter hour increments.

External Transaction Scheduling

RTC_{15} will schedule External Transactions on an hour-ahead basis as part of its development of a co-optimized least-bid cost real-time commitment. RTC will alert the NYISO when it appears that scheduled External Transactions need to be reduced for reliability reasons but will not automatically Curtail them. Curtailment decisions will be made by the NYISO, guided by the information that RTC provides.

Posting Commitment/De-Commitment and External Transaction Scheduling Decisions

Except as specifically noted in Section 5.4.2, RTC will make all Resource commitment and de-commitment decisions. RTC will also produce advisory commitment information and advisory real-time prices. RTC will make decisions and post information in a series of fifteen-minute “runs” which are described below.

RTC_{15}

RTC_{15} will begin at the start of the first hour of the RTC co-optimization period and will post its commitment, de-commitment, and External Transaction scheduling decisions no later than fifteen minutes after the start of that hour. During the RTC_{15} run, RTC will:

1. Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their minimum generation levels by that time.
2. Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at their minimum generation levels by that time.
3. De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time.
4. Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information.
5. Schedule Pre-Scheduled Transactions and economic External Transactions to run during the entirety of the next hour.

Subsequent RTC Runs

All subsequent RTC runs in the hour, i.e., RTC_{30}, RTC_{45}, and RTC_{00} will begin executing at fifteen minutes before their designated posting times (for example, RTC_{30} will begin in the 15th minute of the hour), and will take the following steps.

1. Commit Resources with 10 minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at that time.
2. Commit Resources with 30 minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at that time.
3. De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected at that time.
4. Issue advisory commitment, de-commitment, and dispatching guidance for the period from 30 minutes in the future until the end of the RTC co-optimization period.
5. Either reaffirm that the External Transactions scheduled by RTC_{15} to flow in the next hour should flow, or inform the ISO that External Transactions may need to be reduced.

External Transaction Settlements

RTC_{15} will calculate the Real-Time LBMP for all External Transactions if constraints at the interface associated with that External Transaction are binding. In addition, RTC_{15} will calculate Real-Time LBMPs at Proxy Generator Buses for any hour in which:

1. Proposed economic Transactions over the Interface between the NYCA and the External Control Area that the Proxy Generator Bus is associated with would exceed the Available Transfer Capability for that Interface.
2. Proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole.
3. Proposed interchange schedule changes pertaining to the Interface between the NYCA and the External Control Area that the Proxy Generator Bus is associated with would exceed any Ramp Capacity limit imposed by the NYISO for that Interface.

Finally, RTC_{15} will also calculate Real-Time LBMPs at certain times at Non-Competitive Proxy Generator Buses as is described in Attachment E.3 of ~~this manual~~this Manual.

Real-Time LBMPs will be calculated by RTD for all other purposes, including for pricing External Transactions during intervals when the interface associated with an External Transaction is not binding.

5.1.2. Real-Time Automated Mitigation Process

The real-time automated mitigation process (RT-AMP) incorporates both conduct tests (performed in the MIS) and impact tests (performed in RTC-AMP sequence). The conduct test compares the price of each energy offer, including start-up and minimum generation costs, to references. When reference prices have been exceeded by a significant amount the conduct test is said to have “tripped.”

The first impact test examines the change in prices that would prevail if offer prices were mitigated. This test “trips” if mitigation of offers would significantly change prices. A variation of the first impact test applied to designated constrained areas examines a localized change in congestion and “trips” if the change in LBMP is significant. This first impact test will be performed following a full recommitment and dispatch.

A second impact test examines the change in guarantee payments to an energy supplier with mitigation of offer prices. The second test “trips” if the change in guarantee payments is significant.

There are many rules, parameters, limits, and thresholds that have been defined ~~associated~~ ~~the~~associated the automated mitigation ~~process .~~process. These include:

1. Definition of super-zones in the NYCA and load pockets in constrained areas
2. Definition of a threshold values for each load pocket of a constrained area
3. Arming of an automated mitigation process
4. Portfolio exclusion that may be applied to super-zones and load pockets.

RT-AMP Process

Automated mitigation relies on a second unit commitment evaluation to assess the impact of mitigation. Thus, two unit commitment executions are required at each time step. The first determines the prices and schedules that would occur with the original set (Base-Set) of offers. The second determines the prices and schedules that would occur with a mitigated set (Ref-Set) of offers. The combined execution times of the unit commitments needed to evaluate both Base-Set and Ref-Set is likely longer than the RTC interval (15 minutes). However, each commitment can be executed as a separate process so they can be run in parallel as shown in Exhibit 4-2. The advantage is that a full RTC cycle (15 minutes) can be used to evaluate impact; hence, timing concerns are minimized. When done in parallel, the possibility of mitigation would be tested for the next RTC cycle (15 minutes) in the future. RTC$_{15}$ and RT-AMP$_{15}$ would perform unit commitment evaluations simultaneously. Results of RTC$_{15}$ and RT-AMP$_{15}$ would then evaluate for impact and, if mitigation were necessary, mitigated offers would be sent to RTC$_{30}$. Mitigation of offers for RTC$_{15}$ would have been decided previously by RT-AMP$_{00}$.

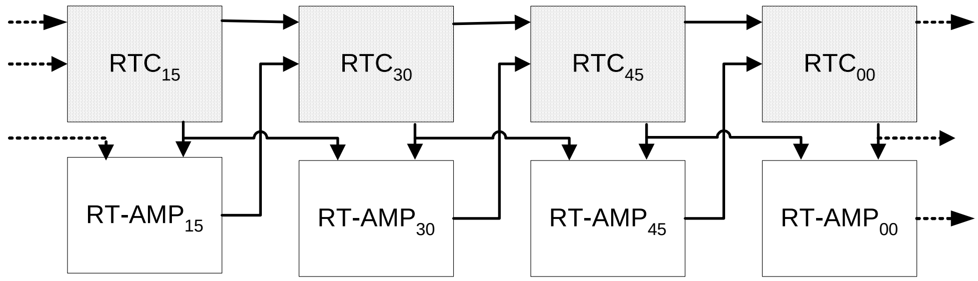


Exhibit 5-2: Parallel Impact Test

A third unit commitment is required to assure that prices and schedules are consistent with the final set of offers, some of which may be mitigated. When the test is conducted in parallel, only one, instead of two, additional unit commitments are required in each RTC cycle. As shown in Exhibit 4-3, for the time period 15 to 30, Base-Set and Mit-Set are identical. RTC15 provides the base case unit commitment. Simultaneously RT-AMP15 calculates the reference unit commitment, conducts the impact test, and determines the actual set of resources whose offers are to be mitigated (Mit-Set). Finally, RTC30 ensures that the commitment is consistent with the set of mitigated offers. Subsequently Mit-Set is used as the Base-Set and RTC30 would provide the base case for RT-AMP30 and so on.

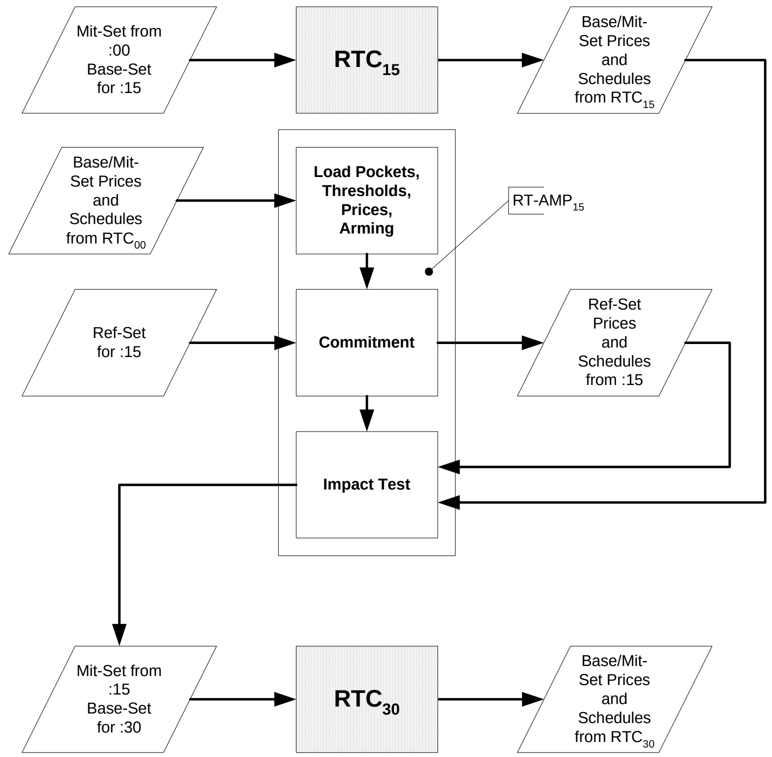


Exhibit 5-3: Parallel Impact Test 15 to 30 Minutes

Arming

The arming test makes an initial determination of whether mitigation is likely to result in a material price impact. Subsequently the impact test verifies a material price impact, whether on LBMP or on a portion of the congestion component of LBMP.

Conduct Test

The conduct tests compare offers of suppliers for start-up, minimum generation, and incremental energy with references for those quantities. Differences are compared to thresholds to determine whether conduct suggests the economic withholding of resources or the attempt to exercise market power. A subsequent impact test, tests the market power hypothesis.

An energy resource may be associated with several load pockets, each of which has a threshold value. In such a case the conduct test shall use the smallest threshold value from the group of actively constrained load pockets.

Price Impact

The impact test compares prices (or local congestion) determined with two sets of offers:

1. An original set called the Base-Set and
2. A set resulting from the mitigation of offers tripping the conduct test (subject to the arming criteria), called the Ref-Set.

The price impact test is evaluated at each time interval. The test will trip for an interval if the difference in energy price (or local congestion) is significant. Ultimately a one-hour granularity, aligned with the one-hour offer periods, shall be used and the price impact shall trip for an entire hour if it trips for any interval during the hour.

Mitigation Duration

Mitigation will be applied for whole hours, or, if the need for mitigation is detected during the current hour, for the remainder of the current hour. Mitigation of individual intervals during an hour will lead to erratic schedules for energy resources so mitigation will not be applied to individual 15-minute intervals.

An energy resource may be associated with several load pockets, any of which may trip the impact test. To be mitigated for the remainder of the current hour, or all of the next hour, a resource must be in at least one load pocket that trips the impact test for the appropriate time period. If a resource is in two or more load pockets that trip the impact test, the mitigated offer shall be prepared using the smallest of the load pockets' thresholds.

Mitigation will be applied for the remainder of the current hour and/or all of the next hour when the need for mitigation is detected. Mitigated offers shall be used by both RTC and RTD. Both $RT\text{-}AMP_{15}$ and $RT\text{-}AMP_{30}$ are able to mitigate offers for all or part of 2 hours. $RT\text{-}AMP_{45}$ is able to mitigate offers for an hour. $RT\text{-}AMP_{00}$ is able to mitigate offers for part of an hour.

~~4.1.3.~~5.1.3. Real-Time Commitment Information Posting.

The public information and ~~private~~secure Market Participant data ~~information~~ to be posted from the execution of RTC is described in this subsection.

Public Information

The following information will be produced and posted by RTC:

1. External bus Proxy Prices for the binding hour, when constrained, from RTC_{15}. Other prices will be produced by RTD.
2. Updated ATCs and TTCs for each RTC_{15} interval.
3. Advisory prices for Zones and Generators. These prices will be posted together with advisory RTD prices.
4. Limiting constraints and shadow prices for RTC_{15} for each 15-minute increment that corresponds to the Proxy Prices.
5. Advisory Ancillary Services prices. Other prices will be produced by RTD. The following incremental prices are posted:
   a. 10-min Spinning Reserve (West and East)
   b. 10-min Non-Spinning Reserve (West and East)
   c. 30-min Spin/Non-Spin Reserve (West and East)
   d. NYISO Regulation.

Secure Data to Market Participant

~~**Private**~~

The following information will be produced by RTC and will be made available to authorized MPs:

1. Economically Evaluated External Transaction MW schedules for the binding hour, from RTC_{15}.
2. Advisory MW commitment schedules for generators for each RTC 15-minute increment beyond the time frame covered by RTD.

5.2. Scheduling Operations Requirements

This subsection describes the requirements for the Dispatch Day scheduling of generation, transactions, load, and Ancillary Services. The principal functions are:

- Dispatch Day Scheduling Changes

~~108.•~~ Interchange Scheduling

- ~~OASIS Posting~~
- ~~In~~ Scheduling and Curtailment of Bilateral Transactions
- Scheduling and Dispatching LBMP Suppliers and Loads
- Capacity Limited and Energy Limited Resources
- Inter-Control Area ICAP Energy
- Emergency Demand Response Program and Special Case Resources.

~~i.~~5.2.1. Dispatch Day Scheduling Changes

After the Day-~~-~~Ahead schedule is published, the NYISO evaluates any events, including but not limited to the loss of significant Generators or transmission facilities that may cause the NYCA dispatch to be inadequate to meet the requirements established in the Reliability Rules.

The NYISO ~~will modify~~may augment, as necessary, the Day-~~-~~Ahead commitment schedules to achieve a reliable next-~~-~~day schedule ~~while minimizing total Bid Production Cost over the remainder of the day to meet Load scheduled Day-Ahead~~by performing a Supplemental Resource Evaluation (SRE). The NYISO may use the following ~~emergency~~ resources:

~~109.~~1. Bids submitted to the NYISO that were not previously accepted but were designated by the bidder as continuing to be available for emergency needs

~~110.~~2. ~~new~~New Bids from all Suppliers, including neighboring systems

~~111.~~3. ~~cancellation~~Cancellation of/or rescheduling of transmission facility maintenance outages where ~~SCD can~~ RTC/RTD is not expected to solve security constraints.

Actions taken by the NYISO in performing Supplemental Resource Evaluation (SRE) will not change any financial commitments that resulted from the Day-~~-~~Ahead SCUC. When a supplier on forced outage becomes available for service again, it may submit a new bid in~~-~~ the dispatch day for potential commitment by ~~BME~~RTC or SRE or day ahead for potential commitment by SCUC. The procedures for supplemental resource evaluation for energy and ancillary services are covered in Section 4.~~2~~4 of ~~this manual~~ this Manual.

~~Balancing Market Evaluation (Hour-Ahead)~~

~~The commitment of generating units in the Day-Ahead time frame was based on a load forecast and equipment outage schedule that is subject to change. Unforeseen events can cause loads to change. In addition, unplanned equipment outages may occur. Since the NYISO has the obligation to maintain reliability, a mechanism to augment and adapt the Day-Ahead schedules was created and named the Balancing Market. The bidding for this market is finalized 90 minutes prior to the beginning of the Operating Hour. A Balancing Market Evaluation (BME) tool was created to balance an updated load forecast (performed by the NYISO) with generation~~

~~commitment from the Day-Ahead market plus energy bidding in the Balancing Market. Exhibit 4.1 shows how the total generation requirement for the Balancing Market is defined.~~
~~After the Day-Ahead schedule is published, and up to 90 minutes prior to each dispatch hour, Eligible Customers and Suppliers may:~~

6) ~~submit additional bids to the NYISO for Energy from:~~
    - ~~Generators or other resources that are dispatchable within five minutes and that can be included in and respond to the NYISO's SCD program~~
    - ~~fixed block Energy (non-dispatchable) Bids available for the next hourlower their Bid Price for Energy from Generators committed by the NYISO in the Day-Ahead Market~~
7) ~~change their Bid Price for additional Energy from Generators that were committed by the NYISO in the Day-Ahead Market~~
8) ~~modify Bilateral Transactions that were accepted by the NYISO in the Day-Ahead schedule~~
9) ~~propose new Bilateral Transactions~~
10) ~~submit Bids to purchase Energy from the Real-Time Market.~~

~~The Bids submitted up to 90 minutes before the dispatch hour are referred to as Hour-Ahead-Bids. The NYISO uses the Balancing Market Evaluation 90 minutes before each dispatch hour to determine schedules for the LBMP Market and Bilateral Transactions including Exports, Imports and Wheels-Through. In developing these schedules, the BME will consider updated Load forecasts and evaluate the impact on reliability of the proposed schedules and commitments. The BME will adjust firm Bilateral Transaction schedules based on Incremental and Decremental Bids and all Generator schedules, based on their Bids, to maintain reliability. The BME will not determine any prices but will schedule on a least total Bid Production Cost basis.~~
~~A generator which needs to remain on-line past the end of the Dispatch Day or Dispatch Hour to fulfill its minimum run time will have the responsibility to structure its bid in such a way as to continue to be economic as evaluated by SCUC or BME, respectively, so it is scheduled to remain on-line.~~
~~If the Market Participant wishes to schedule or run its own generation for the transaction, it must submit a decremental bid that it expects to be below either the HAM LBMP at the POI (for non-dispatchable generators) or the real-time LBMP at the POI (for dispatchable generators). To the extent the HAM or real-time LBMPs exceed the decrfemental bid, the generator will support the transaction.~~

~~Generator/Transaction Bid~~

~~i.~~5.2.2. Interchange Scheduling

The Interchange Scheduling (IS+) function allows NYISO personnel to monitor ongoing energy transactions. These transactions are bids accepted in either the Day-

Ahead scheduling process or the ~~BME~~RTC scheduling/dispatch process. The IS+ program provides facilities for entering transactions and reviewing existing transaction information. The following basic calculations are performed:

~~112.~~1. Desired Net Interchange (DNI): This calculation provides the net interchange schedule between the NY Control Area and each of the External Control Areas. ~~This is the net sum of all the External transactions.~~

~~113.~~2. Instantaneous Net Interchange: This is the ~~net~~metered control area interchange between the NY Control Area and each of ~~all external transaction schedules, but varies with time over the hour to allow for the ramping of transactions~~the External Control Areas.

DNIs which reflect scheduled energy interchanges between the NYCA and neighboring Control Areas will need to be coordinated and verified by neighboring Control Areas as specified in interconnection agreements between the NYISO and other Control Areas.

~~OASIS Posting~~

~~The NYISO Manual for Market Information Systems describes the scheduling data that is posted on the OASIS.~~

~~i.~~5.2.3. Scheduling and Curtailment of Bilateral Transactions

Bilateral transactions may be requested as Firm or Non-Firm. A Firm transaction is willing to pay congestion, so that an accepted Day-Ahead Firm transaction receives a forward contract for its schedule and Transmission Usage Charge (TUC = Congestion Price + Incremental Losses). A Non-Firm transaction is unwilling to pay congestion, so its schedule is advisory only and subject to curtailment.

Firm transactions from a source (specific bus for which a generation shift factor exists and at which LBMP is calculated) to a sink (load zone) will be scheduled as financial bilateral transactions, provided they result in a physically feasible flow-based solution (i.e., generation matches load energy with no security violations). A load being supplied by a Firm transaction will have a physical delivery schedule (subject to possible curtailment under emergency conditions or for wheel-throughs to relieve a security violation) equal to the transaction amount. However, a generator supplying a Firm bilateral transaction will have an operational physical schedule based upon its decremental price bid. Thus, a load being served by a Firm bilateral transaction will have a financial transaction schedule; but the generator supplying that transaction will have a separate operational physical schedule.

In general, under NYISO/LBMP operation, if ~~the~~ a Firm bilateral transaction is physically cut~~/~~ or curtailed, its financial schedule will remain intact. Thus, generation may be dispatched down, and DNI schedules may be reduced (as is currently done to cut transactions), but the financial obligations will remain.

If a Non-Firm transaction is physically cut~~/~~ or curtailed, the transaction is eliminated. As a default, except in the case of wheel-throughs, a generator previously supplying a cut Non-Firm transaction will bid into the LBMP Energy Market, and a load previously being supplied by a Non-Firm transaction will be served by the LBMP Energy Market.

Self Cancellation (Withdrawal) of Bilateral Transactions

A supplier and load may agree to reduce or eliminate a bilateral transaction previously scheduled in the Day-Ahead Market. In this case, they must submit a revised schedule through ~~BME~~RTC. The full Day-Ahead Transmission Usage Charge (TUC) will still accrue. The change in schedule will be settled with Real-Time LBMP Energy and/or the Real-Time TUC.

The following tables will describe the conditions listed below:

- Exhibit 4~~.~~-1~~—~~: Scheduling and Physically Curtailing Firm Bilateral Transactions
- Exhibit 4~~.~~-2~~—~~: Scheduling and Curtailment of Non-Firm Bilateral Transactions
- Exhibit 4~~.~~-3~~—~~: NYISO Curtailment Steps
- Exhibit 4~~.~~-4~~—~~: Re-Instatement of Curtailed ~~bilateral~~Bilateral Transactions
- Exhibit 4~~.~~-5~~—~~: Transaction Conversion and Curtailment Notifications Required by NYISO
- Exhibit 4~~.~~-6~~—~~: Scheduling and Dispatching LBMP Suppliers and Loads

~~**Exhibit 4.1**~~

~~**Scheduling and Physically Curtailing Firm Bilateral Transactions**~~

~~**Summary Table**~~

Exhibit 5-4: Scheduling and Physically Curtailing Firm Bilateral Transactions

	~~Internal Source~~				~~External Source~~			
	~~Internal Load~~		~~External Load (Export)~~		~~Internal Load (Import)~~		~~External Load (Wheel-Through)~~	
	~~(1) Financial Transaction Schedule~~	~~(2) Operational Physical Schedule~~	~~(3) Financial Transaction Schedule~~	~~(4) Operational Physical Schedule~~	~~(5) Financial Transaction Schedule~~	~~(6) Operational Physical Schedule~~	~~(7) Financial Transaction Schedule~~	~~(8) Operational Physical Schedule~~
~~A. Day-Ahead~~	~~Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids for Price Capped Loads*~~	~~Source Scheduled up to Day-Ahead Financial Schedule based on Decremental Bids~~	~~Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids for Price Capped Loads*~~	~~Source Scheduled Up to Day-Ahead Financial Schedule based on Dec Bids with Total Exports Limited to ATC~~	~~Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids for Price Capped Loads*~~	~~Up to Day-Ahead Financial Schedule with Total Imports Limited to ATC w/Schedules based on Dec Bids~~	~~Up to Full Requested MW based upon Source's Day-Ahead Dec Bid with Total Imports and Exports Limited to Applicable ATC. Wheel-Throughs may not bid Price Capped Loads~~	~~Same as Financial Transaction Schedule~~
~~B. Hour-Ahead~~	~~Same as above for comparable Day-Ahead case **except** using Hour-Ahead bilateral schedule requests **and** no Forward Contract is issued.~~							
~~C. Day-Ahead or Hour-Ahead~~	~~Day-Ahead Schedule and~~	~~Supplier Dispatched Down~~	~~Day-Ahead Schedule and~~	~~Supplier Dispatched Down~~	~~Day-Ahead Schedule and~~	~~No Re-Dispatch of Supplier and~~	~~Day-Ahead Schedule and~~	~~No Re-Dispatch of Supplier and~~

~~Scheduled Supplier is Uneconomic in Real-Time~~	~~TUC are Fixed; Hour-Ahead Schedule is Fixed~~	~~in Real-Time~~	~~TUC are Fixed; Hour-Ahead Schedule is Fixed.~~	~~in Real-Time. No change in DNI takes place.~~	~~TUC are Fixed; Hour-Ahead Schedule is Fixed.~~	~~no change in DNI takes place.~~	~~TUC are Fixed; Hour-Ahead Schedule and TUC are also Fixed.~~	~~no change in DNI takes place.~~

Summary Table
Scheduling and Physically Curtailing Firm Bilateral Transactions

	Internal Source				**External Source**			
	Internal Load		**External Load (Export)**		**Internal Load (Import)**		**External Load (Wheel-Through)**	
	(1) Financial Transaction Schedule	**(2) Operational Physical Schedule**	**(3) Financial Transaction Schedule**	**(4) Operational Physical Schedule**	**(5) Financial Transaction Schedule**	**(6) Operational Physical Schedule**	**(7) Financial Transaction Schedule**	**(8) Operational Physical Schedule**
A. Day-Ahead	Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids for Price Capped Loads*	Source Scheduled up to Day-Ahead Financial Schedule based on Decremental Bids	Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids for Price Capped Loads*	Source Scheduled Up to Day-Ahead Financial Schedule based on Dec. Bids with Total Exports Limited to ATC	Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids for Price Capped Loads*	Up to Day-Ahead Financial Schedule with Total Imports Limited to ATC w/ Schedules based on Dec. Bids	Up to Full Requested MW based upon Source's Day-Ahead Dec. Bid with Total Imports and Exports Limited to Applicable ATC*. Wheel-Throughs may not bid Price Capped Loads	Same as Financial Transaction Schedule
B. Hour-Ahead	Same as above for comparable Day-Ahead case **except** using Hour-Ahead bilateral schedule requests **and** no Forward Contract is issued*.							
~~D. Security Violation Occurs in Real-Time~~C. Day-Ahead or Hour-Ahead Scheduled Supplier is Uneconomic in Real-Time	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed	Supplier ~~Dis-patched~~Dispatched Down ~~and/or decommitted~~ in Real-Time ~~if Needed. No Change takes place in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures~~	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed~~.~~	Supplier ~~Dispatched~~ Dispatched Down ~~and/or decommitted~~ in Real-Time ~~if Needed.~~. No ~~Change~~ change in DNI takes place ~~in Load Schedule and DNI in Real-Time unless Energy Transaction is curtailed under Emergency Procedures~~.	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed.	~~Supplier Re-Scheduled Down ("Cur-tailed") in Real-Time if Needed; DNI also changed. No Change in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures~~No Re-Dispatch of Supplier and no change in DNI takes place.	Day-Ahead Schedule and TUC ~~refunded if curtailed~~are Fixed; Hour-Ahead Schedule and TUC are also Fixed.	~~Supplier Re-Scheduled Down ("Cur-tailed") and Energy Transaction is curtailed in Real-Time if Needed; DNI changed to reflect both curtailments.~~No Re-Dispatch of Supplier and no change in DNI takes place.
~~E. Day-Ahead or Hour-Ahead Schedule is Self Canceled (Withdrawn) by Supplier (Source) or LSE (Sink)~~D. Security	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed	~~Source and Sink update schedule in BME~~Supplier Dispatched Down and/or decommitted in Real-Time if	Day-Ahead Schedule and ~~Price~~TUC are Fixed; Hour-Ahead Schedule is Fixed.	~~Source and Sink update schedule in BME.~~Supplier Dispatched Down and/or decommitted in Real-Time if	Day-Ahead Schedule and ~~Price~~TUC are Fixed; Hour-Ahead Schedule is Fixed.	~~Source and Sink update schedule~~Supplier Re-Scheduled Down ("Curtailed") in ~~BME.~~Real-	~~Day-Ahead Schedule and Price are Fixed; Hour-Ahead Schedule is Fixed.~~Day-Ahead TUC refunded if curtailed	~~Source~~Supplier Re-Scheduled Down ("Curtailed") and ~~Sink update~~

Summary Table Scheduling and Physically Curtailing Firm Bilateral Transactions								
	Internal Source				External Source			
	Internal Load		External Load (Export)		Internal Load (Import)		External Load (Wheel-Through)	
	(1) Financial Transaction Schedule	(2) Operational Physical Schedule	(3) Financial Transaction Schedule	(4) Operational Physical Schedule	(5) Financial Transaction Schedule	(6) Operational Physical Schedule	(7) Financial Transaction Schedule	(8) Operational Physical Schedule
Violation Occurs in Real-Time		Needed. No Change takes place in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures		Needed. No Change takes place in Load Schedule and DNI in Real-Time unless Energy Transaction is ~~changed.~~curtailed under Emergency Procedures.		Time if Needed; DNI ~~is~~ also changed. No Change in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures.		~~schedule~~Energy Transaction is curtailed in ~~BME.~~Real-Time if Needed; DNI ~~is~~ changed~~.~~ to reflect both curtailments.

~~Financial Transaction Schedule must result in a physically feasible flow-based solution in SCUC or BME; determination of Firm transactions that can not be scheduled will be based on the Sources' Decremental Bids.~~
~~ATC = Available Transfer Capability of applicable transmission flow-gate.~~
~~Day-Ahead supplier scheduled for less than its scheduled transactions buys replacement energy at its bus at Day-Ahead LBMP (transaction pays Day-Ahead TUC).~~
~~Day-Ahead supplier that is off-schedule in supporting a scheduled transaction settles up with Real-Time Energy LBMP.~~
~~Day-Ahead Transmission Customer load that is off-schedule in its scheduled transaction settles up with Real-Time TUC.~~

~~Exhibit 4.2~~

~~Scheduling and Curtailment of Non-Firm Bilateral Transactions~~

~~Both SCUC and BME perform a screening function by looking ahead and not "scheduling" a Non-Firm Bilateral Transaction if it anticipated to contribute to positive congestion.~~

E. Day-Ahead or Hour-Ahead Schedule is Self Canceled (Withdrawn) by Supplier (Source) or LSE (Sink)	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed	Source and Sink update schedule in RTC	Day-Ahead Schedule and Price are Fixed; Hour-Ahead Schedule is Fixed.	Source and Sink update schedule in RTC. DNI is changed.	Day-Ahead Schedule and Price are Fixed; Hour-Ahead Schedule is Fixed.	Source and Sink update schedule in RTC. DNI is changed.	Day-Ahead Schedule and Price are Fixed; Hour-Ahead Schedule is Fixed.	Source and Sink update schedule in RTC. DNI is changed.

~~**Scheduling and Curtailment of Non-Firm Bilateral Transactions**~~* Financial Transaction Schedule must result in a physically feasible flow-based solution in SCUC or RTC; determination of Firm transactions that cannot be scheduled will be based on the Sources' Decremental Bids.

ATC = Available Transfer Capability of applicable transmission flow-gate.

Day-Ahead supplier scheduled for less than its scheduled transactions buys replacement energy at its bus at Day-Ahead LBMP (transaction pays Day-Ahead TUC).

Day-Ahead supplier that is off-schedule in supporting a scheduled transaction settles up with Real-Time Energy LBMP.

Day-Ahead Transmission Customer load that is off-schedule in its scheduled transaction settles up with Real-Time TUC.

~~**Condition**~~	~~**Results**~~

Exhibit 5-5: Scheduling and Curtailment of Non-Firm Bilateral Transactions

Both SCUC and RTC perform a screening function by looking ahead and not "scheduling" a Non-Firm Bilateral Transaction if it is anticipated to contribute to positive congestion.

Scheduling and Curtailment of Non-Firm Bilateral Transactions	
~~Non-Firm is anticipated by SCUC or BME to contribute to Negative Congestion~~ Condition	~~Non-Firm is "scheduled" on advisory basis subject to future curtailment. Not paid for negative congestion as Firm Transaction would be.~~ Results
Non-Firm is ~~not~~ anticipated by SCUC or ~~BME~~RTC to contribute to ~~Positive~~**Negative** **Congestion**	Non-Firm is ~~partially or fully~~ "scheduled" on advisory basis subject to future curtailment. Not paid for negative congestion as Firm Transaction would be.
Non-Firm **is** **not** anticipated by SCUC or ~~BME~~RTC to contribute to Positive Congestion	Non-Firm is ~~not~~ partially or fully "scheduled~~. Non-Firm previously "scheduled" Day-Ahead by SCUC is partially or fully "unscheduled" by BME.~~" on advisory basis subject to future curtailment.
Non-Firm ~~transaction that was previously "scheduled"~~is anticipated by SCUC or ~~BME actually contributes~~RTC to contribute to **Positive Congestion** ~~**in Real-Time** for one SCD interval~~	~~If the~~ Non-Firm ~~transaction~~ is ~~an Internal, Import or Export transaction, no physical curtailment will be invoked. Rather, the NYISO will partially or fully convert the generator and load to Real-Time LBMP Energy Market Participants (with notifications made) for the remainder of their "schedule" (rest of day or hour).~~ ~~If the Non-Firm transaction is a Wheel-Through transaction, the NYISO will partially or fully physically curtail the transaction for both the Source and Sink with appropriate DNI schedule changes (with notifications made) for the remainder of its "schedule" (rest of day or hour).~~~~not~~Not scheduled~~.~~ Non-Firm previously "scheduled" Day-Ahead by SCUC is partially or fully "unscheduled" by RTC.
~~Generator or load associated with an Import or Export Non-Firm Transaction (that was previously converted to the Real-Time LBMP Energy Market due to positive congestion) contributes to an **Operating Security Violation** occurs~~ Non-Firm transaction that was previously "scheduled" by SCUC or RTC actually contributes to **Positive Congestion in Real-Time** for one RTD interval	~~DNI schedule is changed to reduce or eliminate the import and/or export.~~If the Non-Firm transaction is an Internal, Import or Export transaction, no physical curtailment will be invoked. Rather, the NYISO will partially or fully convert the generator and load to Real-Time LBMP Energy Market Participants (with notifications made) for the remainder of their "schedule" (rest of day or hour). If the Non-Firm transaction is a Wheel-Through transaction, the NYISO will partially or fully physically curtail the transaction for both the Source and Sink with appropriate DNI schedule changes (with

Scheduling and Curtailment of Non-Firm Bilateral Transactions	
~~Non-Firm is anticipated by SCUC or BME to contribute to Negative Congestion~~ Condition	~~Non-Firm is "scheduled" on advisory basis subject to future curtailment. Not paid for negative congestion as Firm Transaction would be.~~ Results
	notifications made) for the remainder of its "schedule" (rest of day or hour).
~~NYISO initiates Backup Dispatch System (BDS)~~ Generator or load associated with an Import or Export Non-Firm Transaction (that was previously converted to the Real-Time LBMP Energy Market due to positive congestion) contributes to an **Operating Security Violation** occurs	~~All Non-Firm previously "scheduled" by SCUC or BME is fully physically curtailed for the remainder of their "schedule" (rest of day or hour)~~ DNI schedule is changed to reduce or eliminate the import and/or export.

~~**Exhibit 4.3**~~

~~**NYISO Curtailment Steps**~~

~~NYISO Curtailment Steps~~		
~~Corresponding TLR Level~~	~~Condition~~	~~Action~~
~~TLR 1~~	~~Congestion is anticipated~~	~~Issue notification of potential problems time permitting~~

NYISO initiates **Backup Dispatch System** (BDS)	**All** Non-Firm previously "scheduled" by SCUC or RTC is fully physically curtailed for the remainder of their "schedule" (rest of day or hour)

Exhibit ~~5-~~6: NYISO Curtailment Steps

NYISO Curtailment Steps		
Corresponding TLR ~~2~~Level	~~Congestion is projected~~Condition	~~Hold Non-Firm Interchange Transactions at current levels to prevent Operating Security Limit Violation~~Action
~~TLR 3~~	~~Congestion Occurs~~	~~Immediately convert generators and loads associated with Internal, Import and/or Export Non-Firms that are contributing to positive congestion to LBMP Energy market participants. Also immediately physically curtail (by changing DNI schedules) Wheel-through Non-Firm transactions that are contributing to positive congestion.~~
	~~Operating Security Violation Occurs~~	~~Partially or fully physically curtail External Non-Firms (Imports, Exports and Wheel-Throughs) using IS+ by~~

		~~changing DNI schedules to: (1) curtail those in lowest NERC Priority first; (2) curtail within each NERC Priority based on Decremental Bids; and (3) prorate curtailment if Decremental Bids within a Priority are equal.~~
	~~Operating Security Limit Violation~~	~~Curtail (through DNI schedule change) unscheduled loop-flow Non-Firm transactions contributing to the violation starting with those with the lowest NERC Priority first.~~
~~TLR 4~~	~~Operating Security Limit Violation~~	~~Perform Re-Dispatch~~
~~TLR 5~~	~~Operating Security Limit Violation Remains Even After Re-Dispatch~~	~~Curtail External Firms Until Constraint is Relieved by: (1) curtailing based on Decremental Bids; and (2) prorating curtailment if Decremental Bids are equal.~~

~~Exhibit 4.4~~

~~Re-Instatement of Curtailed Bilateral Transactions~~

~~Re-Instatement of Physically Curtailed Transactions~~	
~~Type of Curtailment~~	**~~Re-Instatement~~**
~~Non-Firm transaction previously "scheduled" (on advisory basis) by SCUC or BME that is curtailed in Real-Time~~	~~Must Re-Submit Schedule Request thru BME (may already be in cue)~~
~~Firm Inter-Control Area transaction previously scheduled by scuc that is physically curtailed (DNI schedule change) by BME or in Real-Time to solve a security violation~~	~~Has option of: (1) automatically being re-evaluated by BME for re-scheduling, and receiving Day-Ahead TUC refund for the duration of the curtailment; or (2) canceling the originally scheduled transaction for the remainder of the day, receiving a Real-Time TUC true up, and resubmitting a new schedule request thru BME if and when desired.~~

TLR 1	Congestion is anticipated	Issue notification of potential problems time permitting
TLR 2	Congestion is projected	Hold Non-Firm Interchange Transactions at current levels to prevent Operating Security Limit Violation
TLR 3	Congestion occurs	Immediately convert generators and loads associated with Internal, Import and/or Export Non-Firms that are contributing to positive congestion to LBMP Energy market participants. Also immediately physically curtail (by changing DNI schedules) Wheel-through Non-Firm transactions that are contributing to positive congestion.

	Operating Security Violation occurs	Partially or fully physically curtail External Non-Firms (Imports, Exports and Wheel-Throughs) using IS+ by changing DNI schedules to: (1) curtail those in lowest NERC Priority first; (2) curtail within each NERC Priority based on Decremental Bids; and (3) prorate curtailment if Decremental Bids within a Priority are equal.
	Operating Security Limit Violation	Curtail (through DNI schedule change) unscheduled loop-flow Non-Firm transactions contributing to the violation starting with those with the lowest NERC Priority first.
TLR 4	Operating Security Limit Violation	Perform Re-Dispatch
TLR 5	Operating Security Limit Violation remains even after Re-dispatch	Curtail External Firms Until Constraint is Relieved by: (1) curtailing based on Decremental Bids; and (2) prorating curtailment if Decremental Bids are equal.

Exhibit 5-7: Re-Instatement of Curtailed Bilateral Transactions

Re-Instatement of Physically Curtailed Transactions	
~~Firm Inter-Control Area transaction previously scheduled by BME that is physically curtailed (DNI schedule change) in Real-Time to solve a security violation~~**Type of Curtailment**	~~May Re-Submit Schedule Request thru BME (may already be in cue)~~**Re-Instatement**
~~Transaction~~**Non-Firm** transaction previously "scheduled" (on advisory basis) by SCUC or ~~BME~~RTC that is ~~**self canceled** by Supplier or LSE~~curtailed in Real-Time	~~May~~Must Re-Submit Schedule Request thru ~~BME~~RTC (may already be in cue)

~~Exhibit 4.5~~

~~Transaction Conversion and Curtailment Notifications Required by NYISO~~

~~**Transaction Conversion and Curtailment Notifications Required by NYISO**~~	
Firm Inter-Control Area transaction previously scheduled by **SCUC** that is physically curtailed (DNI schedule change) by RTC or in Real-Time to solve a security violation	Has option of: (1) automatically being re-evaluated by BME for re-scheduling, and receiving Day-Ahead TUC refund for the duration of the curtailment; or (2) canceling the originally scheduled transaction for the remainder of the day, receiving a Real-Time TUC true up, and resubmitting a new schedule request thru RTC if and when desired.
~~Action~~**Firm** Inter-Control Area transaction previously scheduled by **RTC** that is physically curtailed (DNI schedule change) in Real-Time to solve a security violation	~~Notification~~May Re-Submit Schedule Request thru RTC (may already be in cue)
~~Conversion of generators and loads associated with Internal, Import and/or Export Non-Firms to LBMP Energy market participants (TLR).~~ Transaction previously scheduled by SCUC or RTC is **self canceled** by Supplier or LSE	~~Automatic E-Mail to Source and Sink~~May Re-Submit Schedule Request thru RTC (may already be in cue)
~~Physical curtailment (through DNI schedule change) of Inter-Control Area Non-Firm transactions (TLR 2c)~~	~~Automatic E-Mail to Source and Sink; Phone call to the affected Control Areas (which in turn should notify the Source and Sink); Phone call to affected Transmission~~

	~~Provider(s) for exports; otherwise E-Mail to affected Transmission Providers~~
~~Physical curtailment (through DNI schedule change) of unscheduled loop-flow Non-Firm transactions (TLR 3)~~	~~Phone call to the affected Control Areas (which in turn should notify the Source and Sink)~~

Exhibit 5-8: Transaction Conversion Curtailment Notifications Required by NYISO

Transaction Conversion and Curtailment Notifications Required by NYISO	
~~Physical curtailment (through DNI schedule change) of Firm External Source to Internal Sink Transaction (Import)~~Action	~~Phone call to affected Control Area (which in turn should notify the Source), and E-Mail to affected Transmission Provider(s) and the Sink~~ Notification
~~Physical curtailment (through DNI schedule change) of Firm Internal Source to External Sink Transaction (Export)~~ Conversion of generators and loads associated with Internal, Import and/or Export Non-Firms to LBMP Energy market participants (TLR).	~~Phone call to affected Control Area (which in turn should notify the Sink), and phone call to affected Transmission Provider (which in turn should notify the Source)~~ Automatic E-Mail to Source and Sink
Physical curtailment (through DNI schedule change) of Inter-Control Area Non-Firm ~~External Source to External Sink Transaction (Wheel-Through)~~ transactions (TLR 2c)	Automatic E-Mail to Source and Sink; Phone call to the affected Control Areas (which in turn should notify the Source and Sink~~),~~ ~~and E-Mail to~~); Phone call to affected Transmission Provider(s) for exports; otherwise E-Mail to affected Transmission Providers

~~Source = Supplier at Point of Injection (POI)~~
~~Sink = Load at Point of Withdrawal (POW)~~
~~Scheduling and Dispatching LBMP Suppliers and Loads~~

~~Exhibit 4.6~~

~~Scheduling and Dispatching LBMP Energy Market Suppliers and Loads~~								
	~~Internal Suppliers~~		~~Internal Loads~~		~~External Suppliers (Import with Marcy as Point-of-Withdrawal - POW)~~		~~External Loads (Export with Marcy as Point-of-Injection - POI)~~	
	~~(1) Financial Schedule~~	~~(2) Operational Schedule~~	~~(3) Financial Schedule~~	~~(4) Operational Schedule~~	~~(5) Financial Schedule~~	~~(6) Operational Schedule~~	~~(7) Financial Schedule~~	~~(8) Operational Schedule~~
~~A. Day-Ahead~~	~~Based on Day-Ahead Incremental Bids~~	~~Same as Day-Ahead Financial Schedule~~	~~Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids~~	~~Same as Day-Ahead Financial Schedule~~	~~Based on Day-Ahead Incremental Bid with Total Imports Limited to ATC~~	~~Same as Day-Ahead Financial Schedule~~	~~Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids for~~	~~Same as Day-Ahead Financial Schedule~~

			~~for Price Capped Loads*~~				~~Price Capped Loads*. Total Exports Limited to ATC.~~	
~~B. Hour-Ahead~~	~~Based on Hour-Ahead Incremental Bids~~	~~Dispatched in SCD~~	~~Not Available~~		~~Based on Hour-Ahead Incremental Bids with Total Imports Limited to ATC~~	~~Same as Hour-Ahead Financial Schedule~~	~~Up to Full Requested Amount for Fixed MW Loads*; or Based on Hour-Ahead Bids for Price Capped Loads* with Total Exports Limited to ATC~~	~~Same as Hour-Ahead Financial Schedule~~
~~C. Day-Ahead or Hour-Ahead Supplier is Uneconomic in Real-Time~~	~~Day-Ahead Schedule and Price are Fixed~~	~~Supplier Dispatched Down in Real-Time; settled in Real-Time~~	~~Day-Ahead Schedule and Price are Fixed~~		~~Day-Ahead DNI Schedule and Price are Fixed~~	~~No Re-Dispatch of Supplier and no change in DNI takes place.~~	~~Day-Ahead DNI Schedule and Price are Fixed; Hour-Ahead DNI schedule are Fixed~~	
~~D. Security Violation Occurs in Real-Time~~	~~Day-Ahead Schedule and Price are Fixed~~	~~Supplier Dispatched Down and/or de-committed in Real-Time if Needed~~	~~Day-Ahead Schedule and Price are Fixed~~	~~No Change takes place in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures~~	~~Day-Ahead Schedule and Price are Fixed; Hour-Ahead Schedule is Fixed.~~	~~Supplier Re-Scheduled Down ("Curtailed") in Real-Time if Needed; Also DNI is changed~~	~~Day-Ahead Schedule and Price are Fixed; Hour-Ahead Schedule is Fixed.~~	~~No Change in Load Schedule in Real-Time unless Energy Export is Curtailed under Emergency Procedures; then DNI is also changed~~
~~E. Day-Ahead or Hour-Ahead Schedule is Self Canceled by Supplier or LSE~~	~~Day-Ahead Schedule and Price are Fixed~~	~~Supplier updates schedule in BME; NYISO updates SCD or Outage Scheduler~~	~~Day-Ahead Schedule and Price are Fixed~~		~~Day-Ahead Schedule and Price are Fixed~~	~~Supplier updates schedule in BME; NYISO updates DNI and SCD or Outage Scheduler~~	~~Day-Ahead Schedule and Price are Fixed~~	~~LSE updates schedule in BME; NYISO updates DNI~~
~~* Financial Schedule must result in a physically feasible flow-based solution in SCUC or BME.~~ ~~ATC = Available Transfer Capability of applicable transmission flow-gate.~~ ~~Internal Suppliers are dispatchable in Real-Time.~~ ~~External Suppliers are pre-schedulable Day-Ahead or Hour-Ahead, but not dispatchable in Real-Time.~~ ~~Marcy is used as a reference bus where noted.~~								

~~SCHEDULING OPERATIONS PROCEDURES~~

~~These procedures are intended for the scheduling operations that occur during the Dispatch Day, but prior to real-time operations which occur during the Operating Hour. There are two processes:~~

- ~~Periodic Hour-Ahead Scheduling~~
- ~~A periodic Supplemental Scheduling~~

~~Hour-Ahead Scheduling~~

~~Hour-ahead scheduling is performed on a periodic basis and is completed at least 30 minutes prior to the beginning of the next hour.~~

~~NYISO Actions:~~

Physical curtailment (through DNI schedule change) of unscheduled loop-flow Non-Firm transactions (TLR 3)	Phone call to the affected Control Areas (which in turn should notify the Source and Sink)
Physical curtailment (through DNI schedule change) of Firm External Source to Internal Sink Transaction (Import)	Phone call to affected Control Area (which in turn should notify the Source), and E-Mail to affected Transmission Provider(s) and the Sink
Physical curtailment (through DNI schedule change) of Firm Internal Source to External Sink Transaction (Export)	Phone call to affected Control Area (which in turn should notify the Sink), and phone call to affected Transmission Provider (which in turn should notify the Source)
Physical curtailment (through DNI schedule change) of Firm External Source to External Sink Transaction (Wheel-Through)	Phone call to the affected Control Areas (which in turn should notify the Source and Sink), and E-Mail to affected Transmission Provider(s)

Source = Supplier at Point of Injection (POI)

Sink = Load at Point of Withdrawal (POW)

Scheduling and Dispatching LBMP Suppliers and Loads

Exhibit 5-9: Scheduling and Dispatching LBMP Suppliers and Loads

Scheduling and Dispatching LBMP Suppliers and Loads								
	Internal Suppliers		**Internal Loads**		**External Suppliers (Import with Marcy as Point-of-Withdrawal – POW)**		**External Loads (Export with Marcy as Point-of-Injection – POI)**	
	(1) Financial Schedule	**(2) Operational Schedule**	**(3) Financial Schedule**	**(4) Operational Schedule**	**(5) Financial Schedule**	**(6) Operational Schedule**	**(7) Financial Schedule**	**(8) Operational Schedule**
A. Day-Ahead	Based on Day-Ahead Incremental Bids	Same as Day-Ahead Financial Schedule	Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids for Price Capped Loads*	Same as Day-Ahead Financial Schedule	Based on Day-Ahead Incremental Bid with Total Imports Limited to ATC	Same as Day-Ahead Financial Schedule	Up to Full Requested Amount for Fixed MW Loads*; or Based on Day-Ahead Bids for Price Capped Loads*. Total Exports Limited to ATC.	Same as Day-Ahead Financial Schedule
B. Hour-Ahead	Based on Hour-Ahead Incremental Bids	Dispatched in RTD	Not Available		Based on Hour-Ahead Incremental Bids with Total Imports Limited to ATC	Same as Hour-Ahead Financial Schedule	Up to Full Requested Amount for Fixed MW Loads*; or Based on Hour-Ahead Bids for Price Capped Loads* with Total Exports Limited to ATC	Same as Hour-Ahead Financial Schedule
C. Day-Ahead or Hour-Ahead Supplier is Uneconomic in Real-Time	Day-Ahead Schedule and Price are Fixed	Supplier Dispatched Down in Real-Time; settled in Real-Time	Day-Ahead Schedule and Price are Fixed		Day-Ahead DNI Schedule and Price are Fixed	No Re-Dispatch of Supplier and no change in DNI takes place.	Day-Ahead DNI Schedule and Price are Fixed; Hour-Ahead DNI schedule are Fixed	
D. Security Violation Occurs in Real-Time	Day-Ahead Schedule and Price are Fixed	Supplier Dispatched Down and/or de-committed in Real-Time if Needed	Day-Ahead Schedule and Price are Fixed	No Change takes place in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures	Day-Ahead Schedule and Price are Fixed; Hour-Ahead Schedule is Fixed.	Supplier Re-Scheduled Down ("Curtailed") in Real-Time if Needed; Also DNI is changed	Day-Ahead Schedule and Price are Fixed; Hour-Ahead Schedule is Fixed.	No Change in Load Schedule in Real-Time unless Energy Export is Curtailed under Emergency Procedures; then DNI is

Scheduling and Dispatching LBMP Suppliers and Loads								
	Internal Suppliers		Internal Loads		External Suppliers (Import with Marcy as Point-of-Withdrawal – POW)		External Loads (Export with Marcy as Point-of-Injection – POI)	
	(1) Financial Schedule	(2) Operational Schedule	(3) Financial Schedule	(4) Operational Schedule	(5) Financial Schedule	(6) Operational Schedule	(7) Financial Schedule	(8) Operational Schedule
								also changed
E. Day-Ahead or Hour-Ahead Schedule is Self Canceled by Supplier or LSE	Day-Ahead Schedule and Price are Fixed	Supplier updates schedule in RTC; NYISO updates RTD or Outage Scheduler	Day-Ahead Schedule and Price are Fixed		Day-Ahead Schedule and Price are Fixed	Supplier updates schedule in RTC; NYISO updates DNI and RTD or Outage Scheduler	Day-Ahead Schedule and Price are Fixed	LSE updates schedule in RTC; NYISO updates DNI

* Financial Schedule must result in a physically feasible flow-based solution in SCUC or RTC.

ATC = Available Transfer Capability of applicable transmission flow-gate.

Internal Suppliers are dispatchable in Real-Time.

External Suppliers are pre-schedulable Day-Ahead or Hour-Ahead, but not dispatchable in Real-Time.

Marcy is used as a reference bus where noted.

5.2.4. Capacity Limited and Energy Limited Resources

Many generating units have limitations on their ability to operate for a period of time over all, or a portion, of their operating range. Classification as a Capacity Limited Resource or the sub-classification of Energy Limited Resource may qualify such generating units for special balancing energy and ICAP consideration while making energy and/or capacity limited MWs available to the Day-Ahead, In-Day, and Real-Time Markets.

CLR

A Capacity Limited Resource (CLR) is defined as a generator that is unable to run in a region at the top of its operating range for operational, or plant configuration reasons, except for emergency situations.

ELR

An Energy Limited Resource (ELR) is defined as a generator that is unable to operate continuously on a daily basis due to design considerations, environmental restrictions on operations, cyclical requirements (such as the need to recharge or refill), or other non-economic reasons, but is able to operate for at least four consecutive hours each day.

Application for Classification

Application for classification as a CLR and/or ELR is required. To be eligible for special balancing energy and ICAP considerations associated with the CLR/ELR classification, a generator must register and justify, with the NYISO, their CLR or ELR status, as appropriate. Technical Bulletin # 75 describes the CLR/ELR application process.

The application process for a CLR includes the registration of a normal Upper Operating Limit (UOL) that is the upper limit for regular and continuous operation or the limit above which lies the CLR capacity and an emergency UOL.

An ELR is a CLR that has unique settlement and operations rules. Units considered to be Energy Limited Resources include: hydro units subject to recharge periods, and GTs with NOx and/or SOx restrictions. The application for ELR status includes a description of the unit's physical energy limiting characteristics, as well as the magnitude of the feasible energy output of the unit over a twenty-four hour day. This maximum production is its "energy limitation."

5.2.5. Inter-Control Area ICAP Energy

With few exceptions, all NYISO ICAP providers have an obligation to submit bids into the NYISO Day-Ahead Market on a daily basis. This obligation applies to ICAP providers located both within and external to the New York Control Area (NYCA). Rules governing the obligations associated with NYISO ICAP contracts are defined in the *NYISO Installed Capacity Manual*.

PJM, ISO-NE, and the NYISO have agreed to a number of "General Principles" to facilitate access to the energy associated with ICAP contracts with suppliers located in external control areas in the event of a capacity shortage within a control area.

NYISO ICAP suppliers located in PJM or New England

In the event that energy from a NYISO ICAP resource located in PJM or New England is required to resolve a capacity deficiency in the NYCA, the NYISO dispatcher will contact the ICAP resource's designated contact. The NYISO dispatcher will instruct the designated contact to ensure that all necessary measures are taken to facilitate delivery of the ICAP backed energy to the NYCA in response to a Supplemental Resource Evaluation (SRE) request, or through the next Real-Time Commitment (RTC).

Resources from Quebec

In the event that NYISO ICAP backed energy is required from Quebec, the NYISO Dispatcher will contact the designated resource contact and instruct the contact to take the actions necessary to facilitate the delivery of the ICAP backed energy in response to an SRE request, or through the next RTC.

Resources from NYISO

The NYISO is committed to a high level of deliverability for energy from the NYCA that supports an ICAP contract in an external control area. In the event that a neighboring control area has an in-day forecasted or actual reserve shortage (e.g. a PJM Maximum Generation Emergency), the affected control area dispatcher will contact their ICAP resource(s) located within the NYCA to request their ICAP contract energy. They will also notify the NYISO dispatcher of the situation. The ICAP resource is expected to follow the NYISO bidding rules required to get the ICAP backed energy scheduled for export. In the event that the export transaction(s) is not accepted by RTC due to a NYISO reserve shortage, the NYISO dispatcher will input the transaction using IS+.

Wheel-Through

In the event that an ICAP transaction between two neighboring control areas must pass through the NYCA the NYISO dispatcher will take the steps necessary to ensure delivery of the associated energy.

Interface Limit Reductions

System transmission conditions at times may require a reduction in the external interface limits for a specific control area. In the event that the ICAP entitlement associated with a specific external control area is less than or equal to the reduced interface limit, then the external control area will be entitled to the contracted ICAP amount. In the event that the ICAP entitlement for an external control area is greater than the reduced interface limit, then the NYISO will schedule the deliverable quantity based on the RTC where time permits. In real time, the external control area dispatcher may contact the NYISO dispatcher and identify the specific external ICAP transactions that they wish to curtail. If the external control area dispatcher does not specify the ICAP transactions to be curtailed, then the NYISO dispatcher will perform curtailments based upon existing operational procedures for locational curtailment. In either event, the export transactions will be scheduled or curtailed to a level consistent with the reduced interface limits.

5.2.6. Emergency Demand Response Program and Special Case Resources

The Emergency Demand Response Program (EDRP) provides a mechanism for load reduction during emergency conditions, thereby facilitating the reliability of the New York State bulk power system. The *NYISO Emergency Demand Response Program Manual* provides a complete description.

Retail end users who agree to participate in the EDRP can be accommodated through one of four types of Curtailment Service Providers (CSPs):

1. Load Serving Entities (LSEs), either that currently serving the load or another LSE

2. Through NYISO-approved Curtailment Customer Aggregators
3. As a Direct Customer of the NYISO
4. As a NYISO-approved Curtailment Program End Use Customer.

Curtailment Customer Aggregators and Curtailment Program End Use Customers must register with the NYISO as Limited Customers.

CSPs should be able to provide load reduction of at least 100 kW per Zone and be able to respond within two hours of emergency notification.

Voluntary Participation

Participation in the EDRP is voluntary and no penalties are applied if a CSP fails to respond to a NYISO notice to reduce load.

Retail end users participating in the EDRP cannot participate in the NYISO's Special Case Resources Program. SCRs that have registered with the NYISO but not sold their capacity will be added to the list of EDRP participants for that period of time when their capacity is unsold, and will be called with EDRP participants if an EDRP event is activated.

The NYISO will allow participation by aggregations of smaller customers, the curtailed usage of which will be determined by using an alternative to the basic provisions regarding the metering and measurement of performance. Distributed Generation (DG) and self-generation resources are not eligible. Direct serve customers are also prohibited from operating under alternative performance measures.

NYISO Notification

CSPs will be given notice no less than two hours in advance of the time specified to reduce load, pursuant to NYISO emergency operations procedures. If the NYISO activates the Emergency Demand Response Program for more than four hours, each CSP shall be paid the higher of $500/MWh, or the zonal Real-Time LBMP per MWh of demand reduced, starting with the hour specified by the NYISO as the starting time of the activation~~. Or~~ or~~,~~ in the event that the NYISO specified that the demand reduction begin as soon as possible, starting with the hour that the CSP began its response.

If the NYISO activates the EDRP for four hours or less, each CSP shall be paid as if the EDRP had been activated for four hours. Each CSP that reduces demand shall be paid the higher of $500/MWh or the zonal Real-Time LBMP per MWh of demand reduced, for the duration of the NYISO activation of the EDRP or for two hours whichever is greater, starting with the hour specified by the ISO as the starting time of the activation, or, in the event that the NYISO specified that the demand reduction begin as soon as possible, starting with the hour that the CSP began its response. Each CSP shall be paid the zonal Real-Time LBMP per MWh of demand reduced for the remainder of the four-hour minimum payment period, provided a verified demand reduction was effectuated by the time specified in the NYISO's notice.

The EDRP will be effective May 1, 2001 and will continue through October 31, 2005. At the end of each Capability Period, the program will be evaluated and changes recommended as necessary.

Special Case Resources

Special Case Resources (SCRs) are Loads capable of being interrupted upon demand, and distributed generators, rated 100 kW or higher, that are not visible to the NYISO's Market Information System. The Unforced Capacity of a Special Case Resource corresponds to its pledged amount of Load reduction as adjusted by historical performance factors and as increased by the Transmission District loss factor. Refer to the *NYISO Installed Capacity Manual* for details.

5.3. Scheduling Operations Procedures

The following procedures are intended for the scheduling operations that occur during the Dispatch Day, but prior to operations, which occur during the Dispatch Hour:

- Interaction with Real-Time Commitment
- Interaction with Real-Time Automated Mitigation Process
- Interaction with Fast Start Management
- Anticipated Operating Reserve Shortages
- Out-of-Merit Generation
- Supplemental Commitment Process

5.3.1. Interaction with Real-Time Commitment

Hour-ahead scheduling is performed on a periodic basis and is completed at least 45 minutes prior to the beginning of the dispatch hour.

NYISO Actions

The NYISO performs the following:

1. Updates the dispatch model based on the latest outage schedule.
2. Updates the load forecast based on the latest load information.
3. Accepts the updated reserve requirements.
4. Accepts the day-ahead schedules and firm transaction schedules.
5. Accepts the hour-ahead generation bids and firm transaction bids
6. Accepts the telemetered phase shifter and tap settings from SCADA.
7. Executes the ~~Balancing Market Evaluation (BME~~Real-Time Commitment (RTC) using SCUC with a ~~three~~2½ hour horizon.

8. Selects feasible non-firm transactions from the day-ahead and hour-ahead bids, based on the updated ATCs from the ~~BME~~RTC.

9. Posts the following results:

~~114.~~a. ~~approved~~Approved hour-ahead non-firm transactions

~~115.~~b. ~~revised~~Revised generator schedules for the next hour

~~116.~~c. ~~revised~~Revised firm transaction schedules for the next hour.

Market Participant Actions~~:~~

Market Participants shall request the NYISO for any changes in generation, load, and transactions schedules.

5.3.2. Interaction with Real-Time Automated Mitigation Process

The periodic execution of the RT-AMP is under the control of the NYISO and will be enabled under normal power system and real-time market conditions.

The RT-AMP program may be disabled under the following conditions:

1. Emergency power system operation
2. RT-AMP program execution errors
3. Market rule change, requiring RT-AMP software modifications.

Only authorized market monitoring personnel will be allowed to change RT-AMP program parameters, such as:

- Conduct test thresholds
- Impact test thresholds

5.3.3. Interaction with Fast Start Management

The fast start management (FSM) function allows NYISO operations staff to start or stop, or delay the turning on or turning off of specified “fast start” generators (typically, gas turbines). The FSM function will normally operate in a mode where all first time fast start unit basepoints are held back until the system operators give an explicit approval for the basepoints to be sent to the unit.

Additionally, all fast start units’ startups and shutdowns must be first approved by system operators. There will be messages to the operators indicating when a fast start unit has met its minimum run time and is not economic to run.

In the Reserve Pickup and Maximum Generation Pickup (RTD-CAM) modes the default will be for fast start units’ schedules to be sent out without system operator approval.

Exhibit 4-10 summarizes the startup characteristics for real-time commitment.

Exhibit 5-10: Unit Startup Characteristics

Unit Classification	Startup Characteristics
Fast Start Units*	▪ 10-15 minute startup notice ▪ ¼ hour starts by RTC ▪ On-Demand starts by RTD-CAM
Slow Start Units	▪ 30-minute startup notice ▪ ¼ hour starts by RTC
** Also known as Quick Start Units*	

~~i.~~5.3.4. Anticipated Operating Reserve Shortages

The NYISO prepares the NYISO daily status report twice daily, in anticipation of the morning peak and the evening peak. Forecasted loads and operating capacity, including maximum generation capability and all firm transactions for the hours of the expected peak are provided by the Eligible Customers of the NYISO. The NYISO also provides a forecasted peak load based on NYISO data for comparison to that supplied by the Transmission Owners.

Resource Categories

There are ten Resource Categories as shown by Exhibit 4-11.

Exhibit 5-11: Resource Categories

~~(R1) Energy~~	~~(R2) AGC Regulation Reserve~~	~~(R3) 10 Min Spin Reserve~~	~~(R4) 10 Min Non-Synch Reserve~~	~~(R5) 30 Min Reserve (Internal, or External Reserve Activation)~~	~~(R6) FRED*~~	~~(R7) Shared Activ of Reserves and/or External Emergency Purchases~~	~~(R8) Unexpired Unaccepted Day-Ahead Bids~~	~~(R9) Unexpired Unaccepted Hour-Ahead Bids~~	~~(R10) Involuntary Load Curtailment~~
Resource Categories									
~~On-Control or On Dispatch or Off-Dispatch~~ (R1) Energy	~~On-Control~~(R2) AGC Regulation Reserve	~~On-Dispatch or Off-Dispatch~~ (R3) 10 Min Spin Reserve	~~On-Dispatch or Off-Dispatch and Off-Line but Available(~~ R4) 10 Min Non-Synch	~~On-Dispatch~~ (R5) 30 Min Reserve (Internal or ~~Off-Dispatch or Off-Line but Available~~ External	~~On-Dispatch or Off-Dispatch or Off-Line but Available(~~ R6) FRED*	~~Invoked Manually~~(R 7) Shared Activ of Reserves and/or External Emergency Purchases	~~Off-Dispatch or Off-Line but Available~~(R8) Unexpired Un-accepted Day-Ahead Bids	~~Off-Dispatch or Off-Line but Available~~(R9) Unexpired Un-accepted Hour-Ahead Bids	~~Invoked Manually~~(R 10) Involuntary Load Curtailment

			Reserve	Reserve Activation)					

~~FRED = Forecast Required Energy for Dispatch~~
~~FRED = capacity to supply energy to meet NYISO forecasted load that is in excess of the sum total of Day-Ahead load bids.~~
~~FRED each hour should at least equal...~~
~~NYISO NYCA Load Forecast minus Sum of Day-Ahead Internal Load Bids and Bilateral Schedules with Internal Sinks.~~

~~Existing Real-Time Non-SRE Resource Adjustments (Not Necessarily in Order Shown)~~

On-Control or On - ~~Dispatch~~ ~~or~~Dispatcher Off-Dispatch	On-Control	On-Dispatch or Off-Dispatch	On-Dispatch or Off-Dispatch and Off-Line but Available	On-Dispatch or Off-Dispatch and Off-Line but Available	On-Dispatch or Off-Dispatch and Off-Line but Available	Invoked Manually	Off-Dispatch or Off-Line but Available	Off-Dispatch or Off-Line but Available	Invoked Manually

FRED = **F**orecast **R**equired **E**nergy for **D**ispatch

FRED = capacity to supply energy to meet NYISO forecasted load that is in excess of the sum total of Day-Ahead load bids.

FRED each hour should at least equal: NYISO NYCA Load Forecast minus Sum of Day-Ahead Internal Load Bids **and** Bilateral Schedules with Internal Sinks.

Existing Real-Time Non-SRE Resource Adjustments are listed as follows:

1. AGC moves "On-Control" resources from (R2) to (R1) and from (R1) to (R2) to maintain regulation.

2. ~~SCD~~RTD moves "On-Dispatch" (On-Line or Off-Line) resources between (R1), (R2), (R3), (R4), (R5) and (R6) to balance load with generation and maintain reserves.

3. If ~~SCD~~RTD can't solve rapidly enough for an energy deficiency, Reserve Pickup is invoked to move some "On-Dispatch" and "Off-Dispatch" resources from (R2), (R3), and (R4) at Emergency Response Rates (and from Internal (R5) and (R6) at Normal Response Rates or faster) into (R1) to rapidly eliminate the deficiency. During a Reserve Pickup ~~- Security Constrained Dispatch (SCD)~~ RTD-CAM is used to convert 10-Minute Operating Reserve to energy using Emergency Response Rates for some or all suppliers providing operating reserve ~~(with their Upper SCD Limit changed to their Upper Operating Limit)~~ and normal response rates for some or all other suppliers if needed. Reserve Pickup, which only dispatches suppliers upwards, looks at control error and load trending approximately ~~8~~10 minutes ahead, and allows approximately 10 minutes for the reserve pickup to occur.

   Reserve pickup may occur if energy becomes deficient due to the loss of a large generator; if the ~~Pool~~Area Control Error (~~PCE~~ACE) is greater than 3Ld (approximately 200 MW); or if a faster ramp rate is required to solve a transmission security violation.

During Reserve Pickup, no regulation penalty is invoked for generators that exceed their ~~SCD~~RTD basepoint (i.e., over-generation is encouraged and rewarded). Reserve Pickup will ~~terminate~~be terminated by the Operator when a sufficient level of energy has been replaced. Upon this termination, generator basepoints will be initialized at their ending actual levels.

Locational Reserve Pickup may be invoked to solve a specific locational energy deficiency or transmission violation.

4. For losses of large generators, Shared Activation of Reserves may be invoked to move resources from (R7) into (R1) to rapidly eliminate the energy deficiency.

   Shared Activation of Reserves is utilized for a condition in which a number of neighboring control areas performs a Reserve Pickup to replace energy on a regional basis. The control area that required the replacement of energy will ultimately pay back the energy to neighboring control areas as an inadvertent payback.

5. If Steps #3, #4, and/or #5 are insufficient, External Reserve Activation may be invoked to move resources from External (R5) and (R6) into (R1) to rapidly eliminate the energy deficiency.

   Upon an External Reserve Activation, Interchange Scheduler Plus (IS+) is used to perform an evaluation to change Desired Net Interchanges (DNIs) with neighboring control areas to allow interruptible exports to be cut, and to allow externally procured operating reserves to be converted to energy and imported.

6. If Reserve Pickup is (or is expected to be) insufficient, Max Gen Pickup may be invoked manually through phone notifications to Transmission Owners to move "On-Dispatch" and "Off-Dispatch" resources (R2), (R3), and (R4) at Emergency Response Rates (and Internal (R5) and (R6) at Normal Response Rates or faster) into (R1) to rapidly eliminate the energy deficiency.

   A Maximum Generation Pickup is an emergency energy pickup as directed by the NYISO outside ~~an SCD~~a normal RTD run. At the NYISO's ~~judgement~~judgment, generators will be instructed via voice communication to increase output to their upper operating limits as soon as possible until directed otherwise. This is typically invoked to relieve a transmission violation rapidly.

7. If a reliability violation continues to occur~~s~~, prescribed corrective actions should be taken which may include postponement or cancellation of scheduled transmission outages according to procedures defined in the *NYISO Outage Scheduling Manual*. This may also include curtailment of external transactions.

8. If a reliability violation continues, External Emergency Purchases may be invoked to move resources from (R7) to (R1).

9. If other steps are insufficient in quantity and/or speed, Involuntary Load Curtailment (including possibly Load Shedding) may be invoked according to

prescribed procedures to move (R10) into (R1) to rapidly eliminate the energy deficiency.

10. As a follow-up to the above steps, subsequent ~~SCD~~RTD runs will move Internal "On-Dispatch" resources (R5) and (R6) into (R1) to replenish diminished regulation and 10 minute reserves.

If the data indicates that the NY Control Area will be short of Operating Reserve, the NYISO shall perform the actions described for supplemental commitment and scheduling (see Sections 4.2.3 and 4.2.4 of ~~this manual~~this Manual).

5.3.5. 4.3.5 Out-of-Merit Generation

From time to time, generators must be operated out of economic order or at levels that are inconsistent with the calculated schedules. Any NYISO-authorized deviation from the schedule is considered Out-of-Merit Generation and is not subject to regulation penalties. A unit that is out-of-merit is balanced at actual output and may be eligible for a supplemental payment if its bid production cost is not met.

NYISO Requests for Out-of-Merit Generation

Out-of-Merit Generation, either up or down, can be requested by the NYISO for security of the bulk power system, during communication failures, or because the Real-Time Commitment does not successfully run. The energy provided during the out-of-merit condition will be paid at the Real-Time Market Locational Based Marginal Pricing (LBMP) rates, but out-of-merit units may not set LBMP rates. The unit will be provided a supplemental payment, if required to recover its bid cost, consistent with the rules for bid production cost guarantees.

Any supplemental payments will be charged to all NYISO Loads through the Schedule 1 Ancillary Service. The generator will be put back in merit by the NYISO when conditions warrant.

Transmission Owner Requests for Out-of-Merit Generation

Transmission Owners in the NYISO system can request that a generator be run out-of-merit, either up or down, for local reliability. The specific generator and reason for the request must be identified by the Transmission Owner at the time of the request. The energy provided by the generator will be paid at the Real-Time Market LBMP rates, but out-of-merit units may not set LBMP rates. The unit will be provided a supplemental payment, if required to recover its bid cost, consistent with the rules for bid production cost guarantees. Any supplemental payments will be charged to the Loads within the Transmission Owner's area. The generator will remain out-of-merit until the Transmission Owner requests that the NYISO put it back in merit.

Generator Operator Requests for Out-of-Merit Generation

Generator operator requests for Out-of-Merit Generation must be made through the Transmission Owner. The specific reason for the request is required at the time the request is relayed by the Transmission Owner to the NYISO. The generator will remain out-of-merit until the generator operator requests, via the Transmission Owner, that the NYISO put it back in merit.

A generator operator may request out-of-merit operation to perform a Dependable Maximum Net Capability (DMNC) test. The process for this test is described in Technical Bulletin #29, "Scheduling Generator Dependable Maximum Net Capability Tests." During a DMNC test, energy that is provided by the generator and scheduled in the Day-Ahead Market (DAM) is covered by a bid production cost guarantee. Energy that is not scheduled in the DAM will be paid for at the Real-Time Market LBMP rate and will not receive an in-day bid production cost guarantee. Out-of-Merit Generation will not set LBMP rates.

Derated generation can also be requested by a generator operator for extenuating circumstances that require reduced operation or shutdown. This includes equipment failure or pollution episodes. In these situations, the process described in Section 5.3.1 of ~~this manual~~this Manual should be used. The generator remains responsible for balancing energy.

~~ii.~~5.3.6. Supplemental Commitment Process

When certain conditions occur, the NYISO must reschedule generation and Ancillary Services and perform the following:

1. If there is a loss of transmission or generation facility and an Emergency results, then invoke Emergency procedures (see *NYISO* ~~Manual for~~ *Emergency Operations Manual*) and estimate the duration (go to Item 4 below).
2. If there is a loss of transmission or generation facility and there is no Emergency then estimate the duration (go to Item 4 below)
3. If there is a NYISO load forecast error then estimate the duration (go to Item 4 below).
4. After the NYISO estimates the duration:
   - ~~117.~~a. If there is a generation shortage or transmission constraint violation on the NYISO Secured Transmission System, then perform Supplemental Resource Evaluation (SRE) and post the Supplemental Schedules.
   - ~~118.~~a. If there is an Ancillary Service Deficiency, then procure Supplemental Ancillary Services and post the Supplemental Services Schedules.
5. If there is a Day-Ahead Regulation supply deficiency, then procure Supplemental Ancillary Services and post the Supplemental Services Schedules.

6. If a Reserve deficiency has been detected, then procure Supplemental Ancillary Services and post the Supplemental Services Schedules.

~~i.~~5.3.7. Supplemental Resource Evaluation Procedures

~~BACKGROUND~~

~~SCUC, BME, and SCD Time-Frames and Functions~~

Commitment refers to the NYISO scheduling a generator that bid into the LBMP market to start-up to run at or above its minimum generation level, and thereby be guaranteed recovery of start-up and minimum generation bid prices for the remainder of the day.

SCUC commits resources for the next day, and ~~Balancing Market Evaluator (BME~~Real-Time Commitment (RTC) can commit resources ~~for~~ in the ~~next hour. BME~~Dispatch Day. RTC begins ~~(90 minutes before the operating hour)~~ with SCUC Day-Ahead generator and load schedules, non-expired/non-accepted/non-updated ~~BME~~ (but not SCUC) bids, updated or new ~~BME~~ bids, updated transaction requests, updated load forecasts, updated outage schedules, and updated status changes. It then uses the SCUC software to evaluate conditions for the next ~~three~~2 ½ hours, performs a supplemental commitment (if needed) optimized for the next ~~operating~~ dispatch hour, and schedules newly requested transactions for the next ~~operating~~dispatch hour.

The objective function of SCUC is not intended to evaluate energy costs and/or start-up/min gen costs for Day-Ahead capacity forward contracts for non-synchronized reserves. However, ~~SCD~~RTC will consider start-up costs ~~for generators with short start-up times (eg., Gas Turbines)~~. A generator started by ~~SCD~~RTC will be assumed to run at least one hour, so that its start-up bid price will be spread over one hour and added it to its bid energy price in ~~SCD~~RTC. For the purposes of setting LBMP, only the generator's energy price bid will be used. As with other start-ups, these generators will be eligible for supplemental payments to insure their start-up and minimum generation (for the remainder of the dispatch day) price bids are recovered.

Need for Supplemental Resource Evaluation (SRE)

A method to commit supplemental resources at other times is also needed. This includes: ~~(a) deficiencies~~

1. Deficiencies anticipated two to seven days ahead which will require long lead time generators to start-up in advance (i.e., too early for SCUC); ~~(b)~~
2. Day-Ahead deficiencies anticipated after SCUC has begun or completed its Day-Ahead evaluation (i.e.: too late for SCUC); ~~(c) In-~~

3. Dispatch Day deficiencies anticipated more than ~~90 minutes~~about 2 hours ahead (i.e~~.: too early for BME to run); or (d) Real-Time deficiencies that occur after BME has begun or completed its Hour-Ahead evaluation (i.e.: too late for BME to run) and SCD/Reserve Pick-Up has run.~~ ., beyond the RTC look-ahead window).

Similarly, a method to decommit resources is also needed.

~~SRE Objectives~~

~~The primary objective~~~~objectives~~ ~~of SRE Procedures should be: (1) effectiveness~~

~~Effectiveness~~ ~~in eliminating resource deficiencies, and (2) execution~~

~~Execution~~ ~~simplicity (i.e., "user friendliness"; with due regard for economic efficiency.~~

~~SRE Procedures~~

~~SRE procedures should answer these two general questions: (1)~~

~~How do you know when resources need to be moved from one resource category to another? and (2)~~

~~2.How do you decide which resources get moved from one category to another?~~

~~Minimal Use of SRE~~

~~To the extent feasible, the need for the Supplemental Resource Evaluation described above should be minimized. This may be accomplished through the development of new techniques such as starting the execution of SCUC later, executing supplemental SCUCs, and/or executing BME~~~~RTC~~ ~~that looks further ahead.~~

~~SRE Pre-Calculated Resource Replacement Charts~~

~~The NYISO will prepare pre-calculated SRE electronic charts (rather than paper) for available resource replacements. The charts would be computed and updated from current input to (but not output from) SCUC and BME~~~~RTC~~~~. They would consist of a matrix of available resources sorted by:~~

~~Type (i.e.: energy~~ ~~Resource Category:~~

~~(R1), regulation)~~ ~~Energy~~

~~(R2), operating reserves)~~ ~~Regulation~~

~~(R3)/)~~ ~~10 minute Spin Reserve~~

~~(R4)/)~~ ~~10 minute Non Synch Reserve~~

~~(R5), and)~~ ~~30 minute Reserve~~

~~f.(R6)~~ ~~FRED (R6)~~

~~2.Location~~

~~3.Start-up time~~

~~4.Availability in MW by hour.~~

~~Within each of these categories, resources would be sorted in order of average price for a given number of hours expected to be required. The price would include start-up and minimum generation price bids, and would take minimum run times into consideration (an example is included below).~~

~~Bid Changes~~

~~If a resource is selected by SRE and is committed for a designated number of hours of operation, it may not raise (but it may lower) its bid price for energy for the duration of that commitment.~~

~~Use of Day-Ahead and Hour-Ahead Bids for SRE~~

~~Unexpired/Unaccepted Day-Ahead Bids (Resource R8) and Unexpired/Unaccepted Hour-Ahead Bids (Resource R9) are distinct and need to be treated separately, as follows:~~

~~1.ThreeTwo types of supplemental resource bids can exist:~~

~~119."D": Day-Ahead Market Bids, which are unexpired and unaccepted.~~

~~120."H": Hour-Ahead Market Bids, which are unexpired and unaccepted.~~

~~2.Unexpired Day-Ahead Market Bids automatically expire when the BMEReal-Time Market closes (i.e., 9075 minutes before the Dispatch Hour).~~

~~3.Bids will be used in commitments as follows:~~

~~Exhibit -: Bids versus Commitment~~

~~Commitment~~

~~Bid Used~~

~~Commitment~~	~~Bid Used~~
~~2 to 7 Day-Ahead SRE Commitment~~	~~“D”~~
~~SCUC~~	~~“D”~~
~~Post-SCUC Day-Ahead SRE Commitment~~	~~“D”~~
~~Dispatch Day SRE Commitment~~	~~“D”~~
~~RTC~~	~~“H”~~
~~RTD-CAM~~	~~“H”~~

~~2 to 7 Day-Ahead SRE Commitment~~	~~"D"~~
~~SCUC~~	~~"D"~~
~~Post-SCUC Day-Ahead SRE Commitment~~	~~"D"~~
~~Pre-BME In-Day SRE Commitment~~	~~"D"~~
~~BME~~	~~"H"~~
~~Post-BME/Pre-Dispatch Hour SRE Commitment~~	~~"H"~~
~~SCD and Reserve Pick-Up Real-Time Commitments~~	~~"H"~~
~~Real-Time SRE Commitment~~	~~"H"~~

4. ~~It is important to understand that so-called "Day-Ahead" Bids "D" may actually be submitted during the Dispatch Day for use by SRE during that Dispatch Day. Also, as shown in the above chart, Day-Ahead Bids "D" and Hour-Ahead Bids "H" are not applicable at the same time.~~

Resource Monitoring Procedures

1. ***Monitor Regulation/Reserve Levels*** ~~-~~ – The NYISO should monitor the level of regulation and reserve resources available to meet anticipated NYCA requirements.
2. ***Monitor Adequacy of Bids*** ~~-~~ – The NYISO should also track the level of unexpired/unaccepted resource bids (R8 and R9) by location as potential replacements for Resources (R1), (R2), (R3), (R4), (R5), and (R6). If certain bid categories are deemed insufficient, the NYISO should post an announcement to market participants to solicit additional bids.

~~i.~~5.3.8. General SRE Commitment ~~Procedures~~

SRE should only be used to address resource deficiencies; it should not be used solely to reduce costs. The general SRE commitment procedure is as follows:

1. ***Initiate SRE*** ~~-~~ – The NYISO should proceed with an SRE~~...~~:
   a. If a resource deficiency occurs (or is anticipated to occur), and
   b. If the Existing Real-Time Non-SRE Resource Adjustments Steps #1 through #7 (in Section 4.2.2) are (or are anticipated to be) inadequate, and ~~if~~
   c. If the problem is outside the windows of evaluation for both SCUC and ~~BME.~~RTC.
2. ***Resource Deficiency –*** The resource deficiency may be a result of: ~~(a) the~~
   a. The subsequent loss of an energy, regulation, or reserve resource; ~~(b) the~~
   b. The loss of a transmission facility; ~~(c) a~~
   c. A load forecasting anomaly; and/or ~~(d) a~~
   d. A resource deficiency forecast but not evaluated by ~~BME~~RTC.

More detailed steps are subsequently listed below to specifically describe Day-Ahead~~,~~ ~~In-Day,~~ and ~~Real-Time~~Dispatch Day SRE procedures.

3. ***Define Replacement Required*** ~~-~~ – Based on the deficiency, the NYISO will determine:
   a. Type of replacement required (i.e., regulation capability, operating reserve capability, or energy resource). In general, as shown in ~~the table below~~Exhibit 4-9, the replacement to be selected should match the resource lost.
   b. Location that the replacement is needed
   c. How soon the replacement is required
   d. Amount in MW needed by hour

e. How long the replacement will be required.

SRE Replacement Decision	
Type of Resource Deficiency	**Type of Replacement Required** (To be Selected from Resources R8 or R9)
~~(R1) Energy Resource Deficiency~~	~~(R1) Energy in Acceptable Location~~
(R2) Regulation Resource Deficiency	(R2) Regulation in Acceptable Location
(R3)/(R4)/(R5) Operating Reserve Deficiency	(R3)/(R4)/(R5) Same Kind Replacement of Operating Reserves in Acceptable Location
(R6) FRED Deficiency	(R6) FRED - Acceptable Location

Exhibit 5-12: SRE Replacement Decision

SRE Replacement Decision	
Type of Resource Deficiency	**Type of Replacement Required** (To be Selected from Resources R8 or R9)
(R1) Energy Resource Deficiency	(R1) Energy in Acceptable Location
(R2) Regulation Resource Deficiency	(R2) Regulation in Acceptable Location
(R3)/(R4)/(R5) Operating Reserve Deficiency	(R3)/(R4)/(R5) Same Kind Replacement of Operating Reserves in Acceptable Location
(R6) FRED Deficiency	(R6) FRED - Acceptable Location

4. ***Select Replacement Resources*** ~~-~~ – Based on the requirements determined above, the NYISO will select replacement resources from the pre-calculated SRE charts for available unexpired/unaccepted resources (see example chart further below).

~~5.5)~~ **Note Exceptions** ~~-~~ – If the NYISO's selection for supplemental resources diverges from the merit order indicated on the applicable chart, the NYISO will need to formally justify and log the exception.

~~6)~~ Solve ~~Real-Time, In-~~Dispatch Day~~,~~ (First) and Day-Ahead Deficiencies ~~First, (~~Second~~, then Third~~ ~~)~~ – In the case in which SCUC has begun or already completed its execution, and a combination of ~~Real-Time,~~

~~6.~~5.~~In-~~Dispatch Day and/or Day-Ahead resource deficiencies are subsequently anticipated, SRE should be used to solve any ~~Real-Time~~Dispatch Day problems independently first. ~~Conditions should then be re-evaluated, and if needed, a second SRE should be used to solve any In-Day problems next.~~ This should be followed, if necessary, by another re-evaluation and a ~~third~~second SRE to solve any remaining Day-Ahead problems.

7.6.*Allow ~~But~~ but Don't Guarantee "Self"-Replacement by Resource Suppliers* – A resource that is financially obligated to serve a bilateral transaction or the LBMP spot market may wish to procure its own replacement if possible. In this case, it would need to arrange a Contract-For-Differences (CFD) contract with another resource that would agree to bid into the LBMP market. If that replacement resource were selected through SRE, the original resource would reach a side settlement with it. While the NYISO will not interfere with this type of arrangement, it will also be under no obligation to help facilitate this arrangement by delaying the implementation of SRE. Alternately, the SRE may select another source for the replacement;, presumably, because it is a more economical and/or more effective replacement choice.

~~ii.~~5.3.9. Two to Seven Day Ahead SRE ~~Procedures~~

A two to seven day ahead SRE should be performed if operating capacity deficiencies are anticipated two to seven days ahead which will require long lead time generators to start-up in advance, i.e., too early for SCUC.

1. ***Post Announcement*** – If a Pre-SCUC SRE is anticipated, and if time permits, the NYISO should post an announcement to market participants that a Supplemental Resource Evaluation is planned, —and that additional resource bids are being solicited.
2. ***Two to Seven Day-Ahead Operating Capacity*** – If any deficiencies in Operating Capacity Resources are expected to exist that require long lead-time start-ups (longer than Day-Ahead):
   a. Determine the amount, location and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.
   b. Determine how soon the Supplemental Resource will be needed.
   c. Determine how long, i.e., the Supplemental Commitment Period (SCP) in hours up to the end of the Dispatch Day the Supplemental Resource is likely to be needed.
   d. Select and schedule the move of Supplemental Resources from available Resource Category (R8) to Category (R6) on a least cost basis where least cost equals lowest composite start-up and minimum generation costs (if start-up will be required) spread over the SCP for resources that will be available soon enough to meet the need. In cases in which all other factors are equal, the bid energy price will be used as a tie--breaker.

~~**SCUC Re-Adjustment** - Following Step #2 above, a subsequent SCUC run may re-adjust resources.~~

~~iii.~~5.3.10. Post-SCUC Day-Ahead SRE ~~Procedures~~

A Day-Ahead SRE would be performed after SCUC has begun its Day-Ahead evaluation when it becomes too late for SCUC to run.

1. ***Post Announcement*** – If a Day-Ahead SRE is anticipated, and if time permits, the NYISO should post an announcement to market participants that a

Supplemental Resource Evaluation is planned, and that additional resource bids are being solicited.

2. ***Day-Ahead Regulation or Reserve Deficiency*** ~~-~~ – If any deficiencies in Resources (R2), (R3), (R4), (R5), and/or (R6) are expected to exist Day-Ahead after SCUC execution begins and after allowing for Regular Real~~time~~-Time Non-SRE Resource Adjustment Steps #2 through #7 (Section 4.2.2):

   a. Determine the amount, location and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.
   b. Determine how soon the Supplemental Resource will be needed.
   c. Determine how long, i.e., the Supplemental Commitment Period (SCP) in hours up to the end of the Dispatch Day, the Supplemental Resource is likely to be needed.
   d. Select and schedule the move of Supplemental Resources from Resource Category (R8) to Categories (R2), (R3), (R4), (R5) and/or (R6) on a least cost basis where least cost equals lowest composite availability, and start-up costs and minimum generation costs (if start-up will be required) spread over the SCP for resources that will be available soon enough to meet the need. In cases in which all other factors are equal, the bid energy price will be used as a tie breaker.

3. ***Day-Ahead Energy Deficiency*** ~~-~~ – If an energy deficiency (R1) is expected to exist Day-Ahead (after SCUC executes) which would result in a reserve deficiency after allowing for Existing Real~~time~~-Time Non-SRE Resource Adjustments:

   a. Determine the amount and location of Supplemental Resources required to eliminate the energy deficiency.
   b. Determine how soon the Supplemental Resource will be needed.
   c. Determine how long, i.e., the Supplemental Commitment Period (SCP) in hours up to the end of the Dispatch Day, the Supplemental Resource is likely to be needed.
   d. Select and schedule the move of Supplemental Resources from Resource Category (R8) to (R1) on a least cost basis where least cost equals lowest composite energy and start-up costs (if start-up is required) spread over the SCP for resources that will be available soon enough to meet the need.

4. ~~***BME***~~***RTC Re-Adjustment*** ~~-~~ – Following Steps #2 and/or #3 above, subsequent ~~BME~~RTC runs may re-adjust resources.

~~Pre-BME In-Day~~

~~iv.~~5.3.11. Dispatch Day SRE ~~Procedures~~

~~An In-~~A Dispatch Day SRE would be performed ~~more than 90 minutes ahead when it is too soon for BME to run.~~as follows:

1. ***Post Announcement*** ~~-~~ – If ~~an In-~~a Dispatch Day SRE is anticipated, and if time permits, the NYISO should post an announcement to market participants that a Supplemental Resource Evaluation is planned, and that additional resource bids are being solicited.

2. ~~**In**~~***Dispatch-Day Regulation or Reserve Deficiency*** ~~-~~ – If any deficiencies in Resources (R2), (R3), (R4), (R5), and/or (R6) are expected to exist ~~In-~~in the Dispatch Day ~~more than 90 minutes ahead~~ after allowing for Regular Real~~time-~~-Time Non-SRE Resource Adjustments:

   a. Determine the amount, location and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.
   b. Determine how soon the Supplemental Resource will be needed.
   c. Determine how long, i.e., the Supplemental Commitment Period (SCP) in hours up to the end of the Dispatch Day, the Supplemental Resource is likely to be needed.
   d. Select and schedule the move of Supplemental Resources from Resource Category (R8) to Categories (R2), (R3), (R4), (R5) and/or (R6) on a least cost basis where least cost equals lowest composite availability, and start-up costs and minimum generation costs (if start-up is required) spread over the SCP for resources that will be available soon enough to meet the need. In cases in which all other factors are equal, the bid energy price will be used as a tie-~~-~~breaker.

3. ~~In-~~***Dispatch Day Energy Deficiency*** ~~-~~ – If an energy deficiency (R1) is expected to exist ~~In-~~in the Dispatch Day~~ more than 90 minutes ahead~~, which would result in a reserve deficiency after allowing for Regular Real~~time-~~-Time Resource Adjustments:

   a. Determine the amount and location of Supplemental Resources required to eliminate the energy deficiency.
   b. Determine how soon the Supplemental Resource will be needed~~-~~.
   c. Determine how long, i.e., the Supplemental Commitment Period (SCP) in hours up to the end of the Dispatch Day the Supplemental Resource is likely to be needed.
   d. Select and schedule the move of Supplemental Resources from Resource Category (R8) to (R1) on a least cost basis where least cost equals lowest composite energy and start-up costs (if start-up is required) spread over the SCP for resources that will be available soon enough to meet the need.

4. ~~BME~~***RTC Re-Adjustment*** ~~-~~ – Following Steps #2 and/or #3 above, subsequent ~~BME~~RTC runs may re-adjust resources.

~~v.~~5.3.12. ~~Post-BME and/or~~ Real-Time SRE ~~Procedures~~

A ~~Post-BME and/or~~ Real-Time SRE would be performed ~~in Real-Time when it is too late for BME to run.~~as follows:

1. ***Optionally Post Announcement*** ~~-~~ – If a ~~Post-BME and/or~~ Real-Time SRE is needed, the NYISO may post ~~(if time permits),~~ but will not be obligated to post an announcement to market participants that a ~~Supplemental Resource Evaluation~~SRE is being invoked.

2. ***Real-Time Regulation or*** ~~Reserve~~***~~Revenue~~Reserve*** ***Deficiency*** ~~-~~ – If any deficiencies in Resources (R2), (R3), (R4), ~~(R5),~~ and/or (R6) are expected to exist in Real-Time after ~~Regular Realtime~~ Non-SRE Resource ~~Adjustments~~adjustments Steps #1 through #7 (Section 4.2.2) have been invoked:

   a. Determine the amount, location, and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.
   b. Select and move Supplemental Resources from Category (R9) to Categories (R2), (R3), (R4), (R5~~)~~), and/or (R6) ~~on~~ or a least cost basis where least cost equals lowest composite availability, and start-up and minimum generation costs (if start-up is required) are spread over ~~1~~one hour (in cases in which all other factors are equal, the bid energy price will be used as a tie breaker) as follows:

      - 1st ~~-~~ – Least ~~Cost~~cost Supplemental Resources ~~Available~~available in 10 minutes~~.~~
      - 2nd ~~-~~ – Least ~~Cost~~cost Supplemental Resources ~~Available~~available in 30 minutes if additional Supplemental Resources are still needed.
      - 3rd ~~-~~ – Least ~~Cost~~cost Supplemental Resources ~~Available in Greater Than~~available in greater than 30 minutes if additional Supplemental Resources are still needed.

3. ***Real-Time Energy Deficiency*** ~~-~~ – If an energy deficiency (R1) continues (or is expected to continue) to exist in Real-Time even with ~~Regular Realtime~~RTC Resource Adjustments~~.~~:

   a. Determine the amount and location of Supplemental Resources required.
   b. Select and move Supplemental Resources from ~~Category~~category (R9) to (R1) on a least cost basis where ~~least cost equals lowest composite energy and~~ start-up costs (if start-up is required) are spread over ~~1~~one hour as follows:

      - 1st ~~-~~ – Least ~~Cost~~ cost Supplemental Resources ~~Available in~~ available in 10 minutes~~.~~
      - 2nd ~~-~~ – Least ~~Cost~~cost Supplemental Resources ~~Available in~~ available in 30 minutes if additional Supplemental Resources are still needed.
      - 3rd ~~-~~ – Least ~~Cost~~cost Supplemental Resources ~~Available~~available in ~~Greater Than~~greater than 30 minutes if additional Supplemental Resources are still needed.

4. ~~BME~~***RTC*** ***Re-Adjustment*** ~~-~~ – Following Steps #2 and/or #3 above, subsequent ~~BME~~RTC runs may re-adjust resources.

~~4.4.6.Example of SRE Pre-Calculated Resource Charts~~

~~The following are examples of SRE pre-calculated resource charts and are designated as Exhibit 4-14:~~

~~Chart #1: Input from Unexpired/Unaccepted Bids~~

~~Chart #2: SRE Sorted Chart of Unexpired/Unaccepted Bids – Energy Bids Available in 4 hours in Zone Z for a duration of 1 hour~~

~~Chart #3: SRE Sorted Chart of Unexpired/Unaccepted Bids – Energy Bids Available in 10 minutes in Zone Z for a duration of 1 hour~~

~~Chart #4: SRE Sorted Chart of Unexpired/Unaccepted Bids – Energy Bids in 100 MW Blocks available in 10 minutes in Zone Z for duration of 1 hour.~~

~~Exhibit -: SRE Charts~~

~~Chart #1 –: Input from Unexpired/Unaccepted Bids~~

~~Gen~~	*~~Zone~~*	~~Min MW~~	~~Max MW~~	~~Start-Up Cost $~~	~~Start-Up Time~~	~~Energy Bid $/MWh~~
~~A~~	~~Z~~	~~100~~	~~500~~	~~$1,000~~	~~3 hr.s.~~	~~$20~~
~~B~~	~~Z~~	~~100~~	~~100~~	~~0~~	~~10 min.~~	~~50~~
~~C~~	~~Z~~	~~20~~	~~50~~	~~200~~	~~30 min.~~	~~19~~
~~D~~	~~Z~~	~~100~~	~~200~~	~~2,000~~	~~30 min.~~	~~42~~
~~E~~	~~Z~~	~~25~~	~~25~~	~~100~~	~~10 min.~~	~~70~~
~~F~~	~~Z~~	~~50~~	~~100~~	~~500~~	~~2 hr.s.~~	~~30~~
~~G~~	~~Z~~	~~100~~	~~100~~	~~0~~	~~10 min.~~	~~100~~
~~H~~	~~Z~~	~~50~~	~~50~~	~~100~~	~~10 min.~~	~~90~~
~~I~~	~~Z~~	~~0~~	~~400~~	~~0~~	~~10 min.~~	~~27~~
~~J~~	~~Z~~	~~0~~	~~300~~	~~0~~	~~1 hr.~~	~~29~~

~~Assumptions:~~ ~~For simplicity, assume ramp rates are such that all generators can go from Min to Max in 1 hour; ignore operating reserve bids, and ignore any other complications.~~

~~Chart #2 –: SRE Sorted Chart of Unexpired/UnacceptedUnacceptable Bids~~
~~Energy Bids Available in 4 Hours in Zone Z for a Duration of~~
~~1 Hour~~

~~Economic Order RanRun~~	*~~Gen~~*	*~~Total Energy Cost $~~*	~~Available MW~~	~~Energy Bid Including Start-Up in $/MWh~~
~~1~~	~~A2~~	~~$11,000~~	~~500~~	~~$22~~
~~2~~	~~C2~~	~~1,150~~	~~50~~	~~23~~
~~3~~	~~I~~	~~10,800~~	~~400~~	~~27~~

~~Chart #2 – :~~ ~~SRE Sorted Chart of Unexpired/~~Unaccepted~~Unacceptable Bids~~
~~Energy Bids Available in 4 Hours in Zone Z for a Duration of 1 Hour~~

~~Economic Order~~ Ran~~Run~~	~~Gen~~	~~Total Energy Cost $~~	~~Available MW~~	~~Energy Bid Including Start-Up in $/MWh~~
~~4~~	~~C1~~	~~580~~	~~20~~	~~29~~
~~5~~	~~J~~	~~8,400~~	~~300~~	~~29~~
~~6~~	~~A1~~	~~3,000~~	~~100~~	~~30~~
~~7~~	~~F2~~	~~3,500~~	~~100~~	~~35~~
~~8~~	~~F1~~	~~2,000~~	~~50~~	~~40~~
~~9~~	~~B~~	~~5,000~~	~~100~~	~~50~~
~~10~~	~~E~~	~~1,850~~	~~25~~	~~74~~
~~11~~	~~H~~	~~4,600~~	~~50~~	~~92~~
~~12~~	~~G1~~	~~5,000~~	~~50~~	~~100~~
~~13~~	~~G2~~	~~10,000~~	~~100~~	~~100~~

~~***Notes:*** A = Gen A when Min = Max; A1 = Gen A @ Min; A2 = Gen A @ Max. Accepting all of A2 precludes A1.~~

~~Chart #3 – :~~ ~~SRE Sorted Chart of Unexpired/~~Unaccepted~~Unacceptable Bids~~

~~Energy Bids Available in 10 Minutes in Zone Z for a Duration of 1 Hour~~

~~Economic Order Rank~~	~~Gen~~	~~Total Energy Cost $~~	~~Available MW~~	~~Energy Bid Including Start-Up in $/MWh~~
~~1~~	~~B~~	~~5,000~~	~~100~~	~~50~~
~~2~~	~~E~~	~~1,850~~	~~25~~	~~74~~
~~3~~	~~H~~	~~4,600~~	~~50~~	~~92~~
~~4~~	~~G1~~	~~5,000~~	~~50~~	~~100~~
~~5~~	~~G2~~	~~10,000~~	~~100~~	~~100~~

~~***Notes:*** A = Gen A when Min = Max; A1 = Gen A @ Min; A2 = Gen A @ Max. Accepting all of A2 precludes A1.~~

~~Chart #4 – :~~ ~~SRE Sorted Chart of Unexpired/~~Unaccepted~~Unacceptable Bids~~

~~Energy Bids in 100 MW Blocks Available in~~ 10 Minutes in ~~Zone Z for a Duration of 1~~ Hr~~Hour~~

~~Economic Order Rank~~	~~Gen~~	~~Total Energy Cost $~~	~~Available MW~~	~~Energy Bid Including Start-Up in $/MWh~~
~~1~~	~~B~~	~~5,000~~	~~100~~	~~50~~
~~2~~	~~H and G1~~	~~4,600~~ ~~5,000~~	~~50~~ ~~50~~	~~96~~
~~3~~	~~G1~~~~G2~~	~~510,000~~	~~50100~~	~~96~~ ~~100~~
~~3~~	~~G2~~	~~10,000~~	~~100~~	~~100~~
~~A = Gen A when Min = Max; A1 = Gen A @ Min; A2 = Gen A @ Max. Accepting all of A2 precludes A1.~~				
~~***Notes:*** A = Gen A when Min = Max; A1 = Gen A @ Min; A2 = Gen A @ Max. Accepting all of A2 precludes A1.~~				

~~vi.~~5.3.13. SRE Decommitment ~~Using SRE Procedures~~

A Day-Ahead committed resource that is no longer economic at the end of its Dispatch Day will be scheduled off by a subsequent SCUC. Likewise, ~~an Hour-Ahead~~ a Dispatch Day committed resource that is no longer economic at the end of its Dispatch Hour will be scheduled off by a subsequent ~~BME~~RTC. In some instances, SRE will need to be employed to ~~decommitt~~decommit a resource ~~In-~~in the Dispatch Day or ~~In-~~Dispatch Hour (e.g., during over-generation conditions in which all generators are at minimums and additional reductions are required, or when previously committed peaking resources are no longer needed to meet requirements). This decommitment process should proceed using SRE in reverse. In this case, the NYISO should:

1. Determine the type, amount, and location of resources, which need to be reduced.
2. Determine how soon the reduction will be needed.
3. Determine how long the reduction will need to take place (e.g., remainder of the ~~dispatch day~~Dispatch Day, next two hours, etc.).
4. Select and schedule the reduction of resources (i.e., decommit) on a maximum cost reduction basis where maximum cost equals the highest total energy cost and/or reserve availability cost over the duration of the reduction.

~~vii.~~5.3.14. SRE Pricing and Cost Allocations

~~Energy Payments - Resources committed by BME or SRE will be paid the real time LBMP for Energy and will be guaranteed recovery of start up and minimum generation costs (for the balance of the day). As previously stated, a resource committed by SRE can not raise (but may lower) its price bid for the duration of time it was committed.~~

~~Availability Payments - Resources committed by BME or SRE will be paid the higher of Day-Ahead or the Real-Time Marginal Clearing Price for reserve availability.~~

~~Cost Allocation – Assignment of replacement costs that result from a SRE will be as follows:~~

~~Assignment of SRE Replacement Costs~~		
~~Cause for SRE~~	~~Cost Assignment for Replacement Energy, Operating Reserves and/or Regulation~~	~~Cost Assignment for Supplemental Payments for Start-Up and Min Gen (if any)~~
~~Loss of SCUC Day-Ahead Committed Resource~~	~~Charged to Lost Resource~~	~~Schedule 1 Uplift~~
~~Loss of BME and/or SRE Committed Resource~~	~~Affects Real-Time Energy LBMP and/or Marginal Clearing Prices for Ancillary Services~~	~~Schedule 1 Uplift~~
~~Loss of Transmission that Results in Locational Resource Deficiency~~	~~Affects Real-Time Energy LBMP and/or Marginal Clearing Prices for Ancillary Services~~	~~Schedule 1 Uplift~~
~~Unexpected Load Increase~~	~~Affects Real-Time Energy LBMP and/or Marginal Clearing Prices for Ancillary Services~~	~~Schedule 1 Uplift~~
~~Simultaneous Combinations of Above~~	~~Pro-rata basis~~	~~Pro-rata basis~~

~~DISPATCHING OPERATIONS~~

~~Security Constrained Dispatch~~

~~The function of the SCD program is to determine the least cost dispatch of generation within the NYCA to meet its load and net interchange schedule, subject to generation, transmission, operating reserve, and regulation constraints. SCD performs this function nominally every five minutes as part of the real-time operation of the NYS Power System.~~

~~SCD does not dispatch all the generation within New York State. Exceptions may be Distributed Generation to be considered as a Load Modifer. It dispatches only that generation that the Market Participants make available to the NYCA for the purpose of control area economic dispatch (i.e., generation designated as "dispatchable" or "on-dispatch"). The Market Participants specify which generating units are on-dispatch, and the dispatchable range (i.e., dispatch maximum and minimum limits) of each of those units. SCD recognizes, but does not dispatch fixed generation (i.e., generation that is "off-dispatch" or "not on-dispatch").~~

~~Since SCD operates in a five-minute timeframe, its function is generally limited to dispatching generation that is already in operation. SCD does not generally consider starting generating units that are not running, or shutting down units that are running. The exception to this limitation is that SCD can consider startup or shutdown of gas turbine units, which have a shorter lead time for startup and shutdown than steam units.~~

~~In addition to allowing them to be started or shutdown, SCD treats gas turbine units differently than steam units in other respects. Whereas steam units may be dispatched at any level within their allowable range, gas turbine units can only be dispatched as either off-line with zero output, or on-line at their "base load" level, which is the same as the unit's dispatch~~

~~maximum limit. Also, response rate limitations are not applied to gas turbine units as they are for steam units. Rather, it is assumed that gas turbine units can start and achieve their base load level, or shutdown, with the five-minute dispatch period.~~

~~Another restriction imposed by the five-minute timeframe is that SCD must consider the maximum change in the output of steam units that is achievable within that timeframe. A response rate for each generating unit, expressed in megawatts per minute, is used to determine this maximum change in output. The minimum response rates required for suppliers is one percent of its maximum operating capability per minute. However, SCD can only dispatch in MW interger increments. Therefore, the minimum response rates are determined as follows:~~

2. ~~For suppliers with Maximum Operating Capabilities (Op Caps) up to 100 MW the minimum response rates allowed will be as follows:~~

Op Cap	Minimum Response Rate
Up to 19 MW	0.0 MW per minute
~~20 MW to 39 MW~~	~~0.2 MW per minute~~
40 MW to 59 MW	0.4 MW per minute
60 MW to 79 MW	0.6 MW per minute
80 MW to 99 MW	0.8 MW per minute

~~For suppliers with Op Caps of 100 MW or higher, the minimum response rates allowed will be equal to 1 MW per minute for each full 100 MW of Op Cap plus the amount shown above for additional Op Caps less than 100 MW.~~

~~SCD's objective of minimizing cost is limited to minimizing the incremental bid cost (i.e., marginal cost) of generation participating in that spot market.~~

~~SCD attempts to dispatch generation such that, at the end of the next five-minute period, the total generation output within the NYCA, including both dispatchable and fixed generation, will equal the total electric load and transmission losses within the NYCA, less the NYCA net interchange schedule. This objective of SCD is referred to as the "load constraint". A short-term load forecasting program provides a five-minute load forecast to SCD. SCD treats this load forecast as a fixed quantity. SCD uses a mathematical model referred to as the general total transmission loss equation (which uses a matrix of coefficients known as the "B-matrix") to calculate transmission losses, including the change in transmission losses due to its dispatching activities. The NYCA net interchange schedule is the aggregate of all power transactions in effect between the NYCA and the neighboring systems. SCD treats the NYCA net interchange schedule as a fixed quantity.~~

~~SCD also attempts to dispatch generation in such manner as to respect all applicable "security constraints", which include transmission constraints and reserve constraints. These constraints relate to NYCA, NPCC, and NERC reliability standards and criteria for operation of the ISO Secured Transmission System.~~

~~The transmission constraints are expressed as limits on the amount of power flow, either pre-contingency or post-contingency, allowed on individual transmission facilities (lines or~~

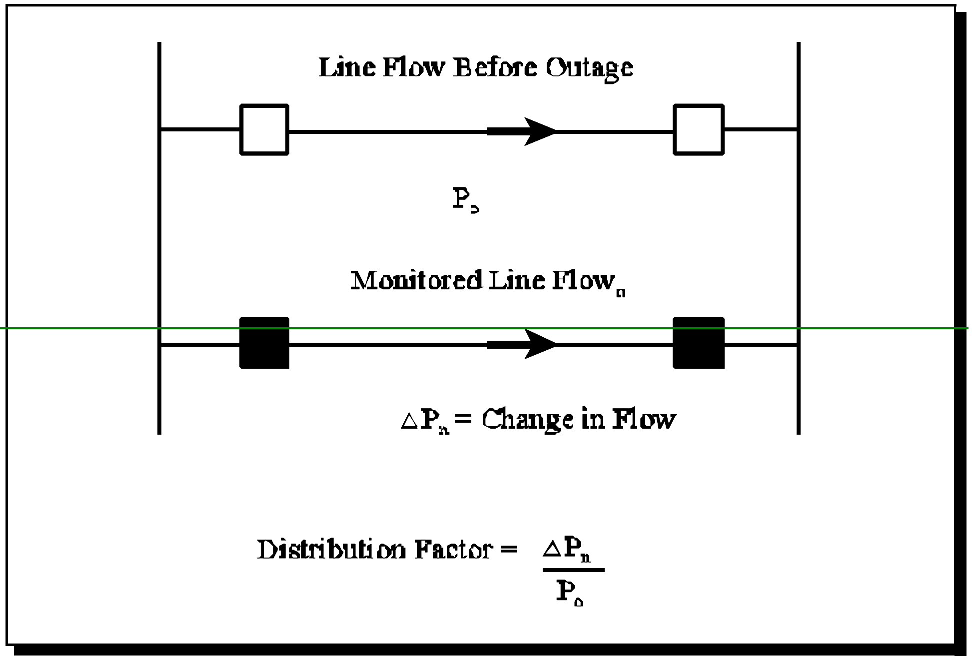
~~transformers), or sets of transmission lines referred to as "transmission interfaces" (referred to by NERC as "flow gates"). Pre-contingency power flows are power flows associated with the power system operating in a postulated post contingency state that assumes one or more elements of the power system have been lost or forced out of service. For each transmission constraint, factors referred to as "distribution factors" or "generation shift factors" are used to model the relationship between the output of generating units and the power flow associated with the transmission constraint. Those generation shift factors are the factors that specifically apply to that particular constraint in terms of the system state (whether it be the pre-contingency or a particular post-contingency state) and the constrained facilities (whether it be an individual line or transformer, or a transmission interface).~~

~~Security Analysis~~
~~Every five minutes, or by exception, SCD performs the following functions, utilizing a linear network model:~~

- ~~Evaluation of all single line and generator outage contingencies on all monitored transmission facilities based on current telemetered values of generator output and transmission line flows.~~
- ~~Evaluation of pre-defined multiple contingency cases, also based on current telemetered values. Refer to Appendix B-5 and B-6 of this manual~~
- ~~Tabulation of a list of security constraints consisting of violations or near violations of security criteria.~~

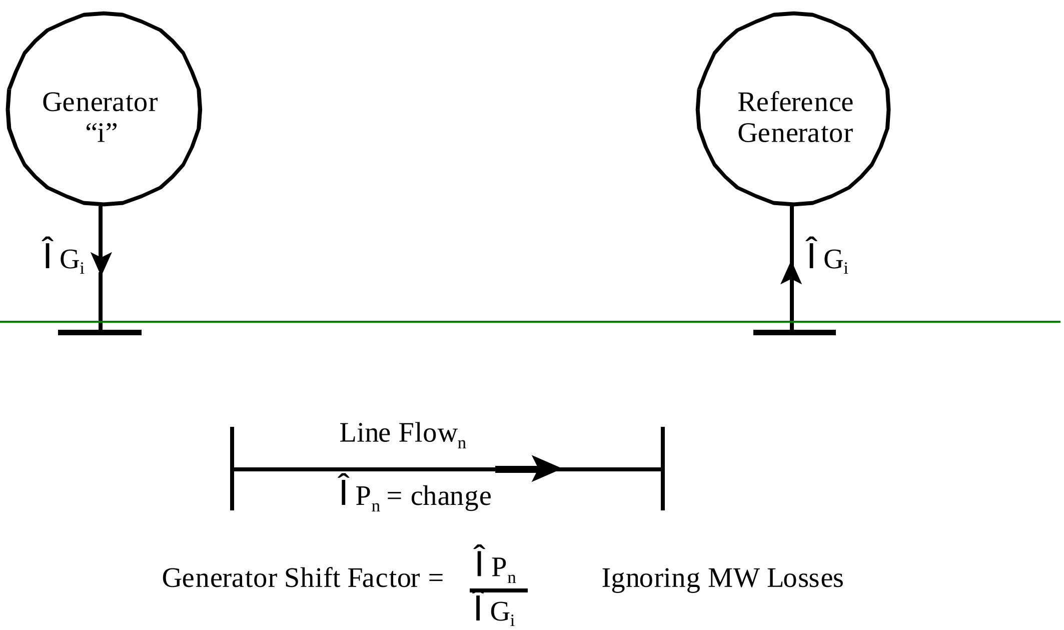
~~Some of the security constraints are automatically selected to be used by the SCD. Other constraints are not solved through SCD because they may be controlled more effectively by other means such as: phase angle regulator control or changing the output level of non-dispatchable generation sources.~~
~~Post-contingency line flows are predicted by applying distribution factors to the pre-contingency values of the outaged facilities, and superimposing the effects of the lost facilities onto the pre-contingency flows of the monitored facilities. The distribution factors and generator shift factors are computed by a program initiated by a dispatcher at the NYISO whenever there is a change in the transmission network configuration. Exhibit 5.3 illustrates the distribution factor for the case of two parallel lines.~~

~~Exhibit 5.3 Distribution Factor~~



~~Generation shift factors are applied to the changes in area loads, external interchange schedules, and generation schedules to project the precontingency line flows used to analyze system security. Exhibit 5.4 defines the generator shift factor with respect to generator "i" and transmission line "n", ignoring transmission MW losses.~~

~~Exhibit 5.4: Generator Shift Factor~~



~~If any of the external transactions have been delivered on phase shifter controlled lines, phase shifter shift factors are used in the same way as the generation shift factors to determine the flow effects of the level to level phase shifter changes. Security analysis will decide if this activity causes violations.~~

~~All real-time security constraints, whether selected for SCD or not, are displayed to the NYISO . A security constraint is added to the display if the power flow (pre-contingency, post-contingency, transfer interface) exceeds 90% of the appropriate limit or rating. Two contingency case constraints, but no more than two, may be shown for a given monitored transmission facility: the worst case contingency; and, conditionally, the worst single outage contingency if the worst case contingency is a multiple outage case. An exception which results in two multiple contingencies may occur if the worst case contingency is classified for monitoring only (not secured) and the second worst case is a multiple contingency.~~

~~Reserve Constraints~~

~~The reserve constraints relate to the three categories of NYCA minimum reserve requirements: ten-minute synchronized reserve, total ten-minute reserve, and total operating (ten-minute and thirty-minute) reserve. These minimum reserve requirements are NYCA requirements intended to provide the capability to quickly respond to a sudden loss of generation within the NYCA, or to provide emergency assistance to another system. For each reserve constraint, factors are used to model the relationship between the output and reserve of the generating units.~~

~~Regulation Constraints~~

~~Regulation constraints are additional limitations applied to the dispatchable range of those generating units designated by the NYCA member systems as being "On-Control" (i.e., on "automatic generation control", as opposed to "manual control"). The purpose of the regulation constraints is to provide a margin of generation capability for use by the NYCA to perform the regulation function, which is a responsibility of the NYCA.~~

~~SCD Limits and Status~~

~~3. Definitions~~

~~121. Limits~~

~~122. SCD Low Limit – lowest operating point that SCD will dispatch a unit.~~

~~123. SCD High Limit – highest operating point that SCD will dispatch a unit under normal operating conditions.~~

~~124. Upper Operating Limit – highest operating point that SCD will dispatch a unit under emergency operating conditions. The upper operating limit is constrained at the lesser of the bid upper operating limit or the upper point on the bid cost curve.~~

~~125. Lower Operating Limit - Lowest operating point that SCD will dispatch a unit under emergency operating conditions. The lower operating limit is constrained at the lesser of the bid lower operating limit or the lowest point on the bid cost curve.~~

126. ~~In all cases the Upper Operating Limit SCD High Limit SCD Low Limit that Lower Operating Limit~~

127.

128. ~~Unit Status~~

129. ~~Available – Resource is available for dispatch and may be called upon by the NYISO for energy.~~

130. ~~On Line – Unit is in service and scheduled for energy in the real time dispatch either as an hourly fixed schedule or a variable energy schedule calculated by SCD.~~

131. ~~On Dispatch – Unit is dispatchable and able to receive variable energy schedules from SCD.~~

132. ~~On Control – Unit is a regulating unit and receives a variable energy schedule from AGC.~~

~~In all cases, except for 10 minute non synchronous units, a unit must have a status of Available to be On Line, must be On Line to be On Dispatch, but need not be on dispatch to be on control. 10 Minute non synchronous units can have a status of Available/On Dispatch.~~

4. ~~Rules for Setting Limits~~

133. ~~Class A 10 Minute Synchronous Reserve Units – All units selected to provide class A synchronous reserve will have their status set to 'On Line' and 'On Dispatch'. The SCD high limit will be set as follows:~~

134. ~~SCD High Limit = Upper Operating limit – 10 Minute Reserve Availability Mws~~

135. ~~Class B 10 Minute Synchronous Reserve Units – All units selected to provide class B synchronous reserve will have their status set to 'On Line' and ' Off Dispatch'. The SCD High and SCD low limits will be set to the unit hourly fixed schedule. All class B units will have a zero cost for energy and will not set LBMP. The Upper Operating limit will be set as follows:~~

136. ~~Upper Operating Limit = Units Fixed Schedule + 10 Min. Reserve Availability MW~~

~~10 Minute Non-Synchronous Units~~

h. ~~For units selected to provide 10 minute non-synchronous reserve availability:~~

137. ~~The unit status will be set to Available/On Dispatch and the SCD High and SCD Low limits will be set to 0. The Upper Operating limit will be set to the lesser of the bid upper operating limit or the upper point on the bid cost curve. Units that have been selected to receive 10 minute non-synchronous~~

~~reserve availability payments are required to remain available for all hours that they have been selected to receive payments.~~

~~For units not selected to provide energy or reserve availability but have an active bid that was evaluated in the Hour-ahead market:~~

~~138. The unit status will be set to 'Available/On Dispatch', the SCD low limit will be set = 0 and the SCD high limit will be set = to the upper operating limit, which will be set to the lesser of the bid upper operating limit or the upper point on the bid cost curve. SCD will include these units in the dispatch and if needed for energy these units will be committed by SCD.~~

~~139. 30 Minute Synchronous Reserve for Units with Status of 'On Dispatch' – The SCD low limit is set to the bid minimum generation value, the SCD High limit and the Upper Operating Limit will be set equal to the lesser of the bid upper operating limit or the upper point on the bid cost curve.~~

~~140. 30 Minute Synchronous Reserve for Units with Status of 'Off Dispatch' – The unit will have a status set to 'On Line' and the SCD High and SCD Low limits will be set to the unit hourly fixed schedule. The Upper Operating limit will be set as follows:~~

~~141. Upper Operating Limit = Units Fixed Schedule + Reserve Availability MW~~

~~142. NOTE: Units that have been selected for both 10 minute synchronous (class B) and 30 minute synchronous reserve availability, the limits will be set based on the rules for Class B units. The NYISO dispatchers will have to view the 30 minute MW amounts using the reserve accounting views on the NYISO EMS. When the unit is requested to supply energy based on a 30 minute (operating reserve) request, the NYISO dispatcher will modify the SCD High limit in the NYISO EMS.~~

~~143. 30 Minute Non-Synchronous Reserve – The unit status will be set to 'Available' and the SCD high and SCD Low limits will be set to 0. The Upper Operating limit will be set as follows:~~

~~144. Upper Operating Limit = Lesser of the bid upper operating limit or the upper point on the bid cost curve.~~

~~145. Synchronous Units Not Selected for Reserve Availability~~

~~146. Unit bids to be 'On Dispatch' – The SCD High limit will be set equal to the Upper Operating limit and the SCD Low limit will be set to the minimum generation MW value.~~

~~147. Unit bids to be 'Off Dispatch' – The unit status will be set to 'On Line', the SCD High, SCD Low and Upper Operating limits will be set to the unit hourly fixed schedule.~~

~~148.~~

~~**Use of SCD Limits During Reserve Pick Up**~~

~~149. On invocation of a Reserve Pick-Up dispatch, as directed by the NYISO, all units can be dispatched to the upper operating limit. From above all of these units will have a status of 'On Dispatch' (Synch class A), (Synch class B) or 'Available/On Dispatch' (10 minute Non-Synchronous) and SCD will be allowed to dispatch to the upper operating limits. The reserve pick up dispatch will use all dispatchable and class B units, which includes units that are not being paid reserve availability. Units suppling reserve availability will have base points calculated using emergency response rates while others have base points based on normal response rates, while all others will be based on normal response rates.~~

~~150. SCD Operation during Locational Reserve Pick-Up – is defined as a pick up to solve a security constraint which SCD is unable to solve with its available 'on dispatch' units using SCD High Limits or one that cannot be solved by other means (moving taps etc.).~~

~~151. On initiation of a Locational Reserve Pick-Up, as directed by the NYISO, all units can be dispatched to the upper operating limit within the designated area SCD will be allowed to dispatch these units to their upper operating limit and units being paid 10 minute reserve availability will have their base point calculated using emergency response rates.~~

~~152. Once either a Reserve Pick-Up or Locational Reserve Pick-Up is invoked, the NYISO will begin making arrangements to either replace the reserve availability or to schedule additional energy so that they may re-establish the required 10 minute reserve. This task may require the use of the Supplemental Resource Evaluation process.~~

~~Real-Time Limit and Status Updates~~

Energy Payments

Resources committed by RTC, RTD-CAM, or SRE will be paid the real time LBMP for Energy and will be guaranteed recovery of start up and minimum generation costs (for the balance of the day). As previously stated, a resource committed by SRE cannot raise (but may lower) its price bid for the duration of time it was committed.

Reserve Payments

Resources committed by RTC, RTD-CAM, or SRE will be paid the higher of Day-Ahead or the Real-Time Marginal Clearing Price for Reserve.

Cost Allocation

Assignment of replacement costs that result from a SRE will be as given in Exhibit 4-15.

Exhibit 5-13: Assignment of SRE Replacement Costs

Assignment of SRE Replacement Costs		
Cause for SRE	**Cost Assignment for Replacement Energy, Operating Reserves and/or Regulation**	**Cost Assignment for Supplemental Payments for Start-Up and Minimum Generation (if any)**
Loss of SCUC Day-Ahead Committed Resource	Charged to Lost Resource	Schedule 1 Uplift
Loss of RTC, RTD-CAM, and/or SRE Committed Resource	Affects Real-Time Energy LBMP and/or Marginal Clearing Prices for Ancillary Services	Schedule 1 Uplift
Loss of Transmission that Results in Locational Resource Deficiency	Affects Real-Time Energy LBMP and/or Marginal Clearing Prices for Ancillary Services	Schedule 1 Uplift
Unexpected Load Increase	Affects Real-Time Energy LBMP and/or Marginal Clearing Prices for Ancillary Services	Schedule 1 Uplift
Simultaneous Combinations of Above	Pro-rata basis	Pro-rata basis

6. Dispatching Operations

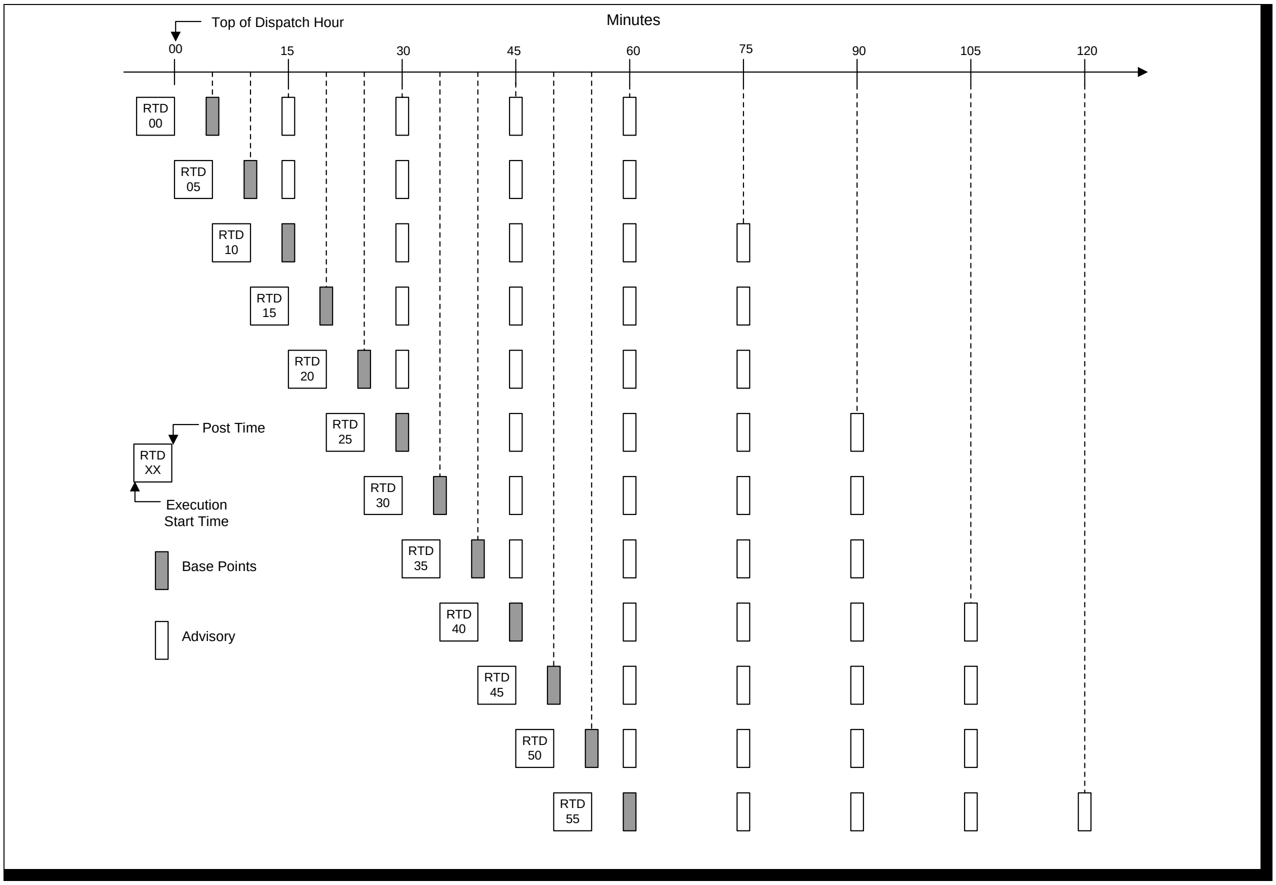
This section describes the real-time dispatching operations and covers the following:

- Real-Time Dispatch
- Real-Time Dispatch – Corrective Action
- Dispatching Operations Requirements
- Dispatching Operations Procedures.

6.1. Real-Time Dispatch

Real-Time Dispatch (RTD) is a multi-period security constrained dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least-as-bid production cost basis. ~~over a fifty, fifty-five or sixty-minute period (depending on when each RTD run occurs within an hour).~~ The RTD dispatches, but does not commit, Generators, and shall dispatch, but not commit, Demand Side Resources to the extent that it can support their participation. Real-Time Dispatch runs will normally occur every five minutes. Exhibit 5-1 presents the RTD time line for a period of one hour.

Exhibit 6-1: Real-Time Dispatch Time Line



6.1.1. Real-Time Dispatch Process

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and, to the extent that the NYISO's software can support their participation, Demand Side Resources, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Regulation Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions. Each Real-Time Dispatch run will co-optimize to solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon. In addition to producing a binding schedule for the next five minutes, each Real-Time Dispatch run will produce advisory schedules for the remaining four time steps of its bid-optimization horizon. RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

6.1.2. Real-Time Dispatch Information Posting

The public information and secure Market Participant data~~private~~ ~~information~~ to be posted from the execution of RTD is described in this subsection.

Public Information

The following information will be produced by RTD and will need to be posted:

1. 5-minute look ahead zonal and generator prices from the first increment of RTD.
2. Advisory zonal and generator LBMPs for each 15-min look-ahead interval of RTD.
3. Ancillary Services prices for the 5-min look-ahead interval of RTD. The following incremental prices are posted:
    a. 10-min Spinning Reserve (West and East)
    b. 10-min Non-Spinning Reserve (West and East)
    c. 30-min Spin/Non-Spin Reserve (West and East)
    d. NYISO Regulation.
4. Advisory Ancillary Services prices for each 15-min look-ahead interval of RTD. The following incremental prices are posted:
    a. 10-min Spinning Reserve (West and East)
    b. 10-min Non-Spinning Reserve (West and East)
    c. 30-min Spin/Non-Spin Reserve (West and East)
    d. NYISO Regulation.
5. The following additional information will be posted as required:

a. Phase Angle Regulator (PAR) schedules for internal NYISO PARs (These will either be based upon pre-determined schedules or as determined by RTC/RTD, depending on agreed-upon RTC/RTD program options).

b. Limiting Constraints on transmission network MW flows (Constraint Type [Base/Contingency] and Shadow Price).

c. Transmission Interface Flows

6. A set of real-time prices produced by the MIS will also be posted periodically at a NYISO specified time. These prices may be corrected and reposted as required

7. The following Time Weighted/Integrated LBMP information will be produced by the MIS, using the 5-minute real-time prices, also from the MIS. The time weighted/integrated LBMPs will be posted on an hourly basis within 10-minutes after top-of-hour:

   a. Zonal

   b. Generator

~~Private~~ Secure Data to Market Participant

The following information will be produced by RTD and will need to be made available to authorized MPs:

MW base points for each look--ahead interval of RTD. The first base point from RTD is a 5-minute look-ahead and is immediately passed on to the Automatic Generation Control (AGC) program. The remaining base points are considered to be advisory, and are given at 15-minute intervals.

~~**Note to Reader**~~

Market Participants must examine the RTD 15-minute advisory base points in order to get advance notice of upcoming Unit Startups and Shut Downs. The beginning and end of a Startup period or Shutdown period always occurs at the 15-minute clock times as established by RTC. Note: this does not apply for RTD-CAM functions such as Reserve Pickup (section 5.2.1), Max Gen Pickup (section 5.2.2), and Base Points ASAP- Commit as Necessary (section 5.2.4)

Startup of quick start units is also communicated via ICCP telemetered signals, when scheduled on by RTC, by setting a "startup flag" approximately 15 or 30 minutes ahead, depending on the unit's startup time.

6.2. Real-Time Dispatch – Corrective Action Modes

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

The NYISO shall have discretion to determine which specific RTD-CAM mode should be activated in particular situations. In addition, RTD-CAM may require all Resources to run above their normal UOLs, up to the level of their emergency UOLs. Self-Scheduled Fixed Resources will not be expected to move in response to RTD-CAM Base Point Signals except when a maximum generation pickup is activated.

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

~~Calculating Real-Time LBMPs~~

~~Except when it is in reserve pickup mode, when RTD-CAM is activated it shall calculate ex ante Real-Time LBMPs at each Generator bus and for each Load Zone every five minutes. When it is in reserve pickup mode, RTD-CAM will calculate ex ante Real-Time LBMPs for a single ten minute interval.~~

~~Posting Commitment Decisions - Private~~

~~To the extent that RTD-CAM makes commitment and de-commitment decisions, they will be posted at the same time as Real-Time LBMPs.~~

6.2.1. Reserve Pickup Mode

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

The NYISO will have discretion to classify a reserve pickup as a “large event” or a “small event.” In a small event, RTD-CAM may reduce Base Point Signals in order to reduce transmission line loadings. In a large event, RTD-CAM will not reduce Base Point Signals.

6.2.2. Maximum Generation Pickup

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

6.2.3. Base Points ASAP – No Commitments

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

6.2.4. Base Points ASAP – Commit As Needed

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

6.2.5. Re-Sequencing Mode

When the NYISO is ready to de-activate RTD-CAM, it will often need to transition back to normal Real-Time Dispatch operation. In this mode, RTD-CAM will calculate normal five-minute Base Point Signals and establish five minute schedules. Unlike the normal RTD-Dispatch, however, RTD-CAM will only look ahead 10-minutes. Basepoints issued in the RTD-CAM re-sequencing mode are updated as soon as a normal Real-Time Dispatch run has executed and produced Base Point signals thus completing the transition back to normal RTD execution intervals and optimization horizons~~.~~.

6.3. Dispatching Operations Requirements

The following dispatching operations requirements are covered:

~~i. Limit Updates~~

~~At the top of each hour the real-time upper operating limit will be compared with the projected upper operating limit, which is based on the accepted bid parameters. The TO limit will be used by SCD. A text alarm will be sent to the TO and to the NYISO alarm screen. The TO will resolve any discrepancy with the appropriate generator.~~

~~If the unit requires a modification to real-time limits which results in a derating of the unit do to operational problems, the TO or NYISO can lower the upper operating limit. The corresponding SCD high limit will be adjusted based on the above rules.~~

~~At the units request the unit can be forced to operate at its derated upper operating limit and when doing so will forfeit all reserve availability payments. To do this the unit must request that the TO or NYISO modify the SCD high limit to equal the upper operating limit.~~

~~ii.Status Updates~~

~~At the top of each hour the real-time status will be compared with the projected status, which is based on the accepted bid parameters. The TO status will be set from existing real time or projected status which will be used by SCD and AGC. The TO will resolve any discrepancies with the appropriate generator. A text alarm will be sent to the TO and to the NYISO alarm screen. The corresponding status will be adjusted accordingly based on the rules defined above. Additionally:~~

12) ~~A unit that has not been accepted for regulation cannot be placed 'On Control'.~~
13) ~~If a supplier is a 10 minute non-synchronous unit that does not have a 10 minute non-synchronous reserve availability contract and wishes not to be dispatched or started in real-time by SCD to provide energy then the supplier must update the real time status to 'unavailable'.~~
14) ~~Suppliers that do not update the limits and or status to equal the projected status or limits as bid and accepted are subject to reserve and regulation balancing payments. This is based on the units real-time indications that they are not able to provide the service if called upon to do so. The suppliers are subject to replacing the service at the at the supplemental clearing prices as determined for each market.~~

~~iii.NYISO~~NYIS~~-TO-Power Supplier Communications Requirements~~

~~Units that bid such that they will be scheduled at fixed hourly points can obtain their hourly schedules from the MIS posting. Additionally the base points will be transmitted to the TO by the NYISO.~~

~~Units that are On Dispatch, Class B units and non-synchronous units that can be committed by SCD must be prepared to receive mid-hour schedule changes. The unit schedules (base points) that are sent to the Transmission Owners as a result of a reserve pick up or locational reserve pick up will be tagged to indicate that the base points were calculated based on emergency response criteria This is an indication that the Class B and Non-synchronous units may be receiving a mid-hour schedule change and that the base points were calculated using emergency response rate criteria. Power Suppliers will have to make arrangements with the TO's to receive these mid-hour schedule changes.~~

~~iv.SCD~~RTD Solution ~~Process~~

~~SCD calculates a short-term generation schedule, referred to as a "base point", for each of the generating units designated to be on-dispatch. The process used by SCD in performing this calculation is as follows:~~

5. ~~SCD retrieves the information it needs to perform the calculation from data maintained in the NYCA databases. This information includes incremental bid cost~~

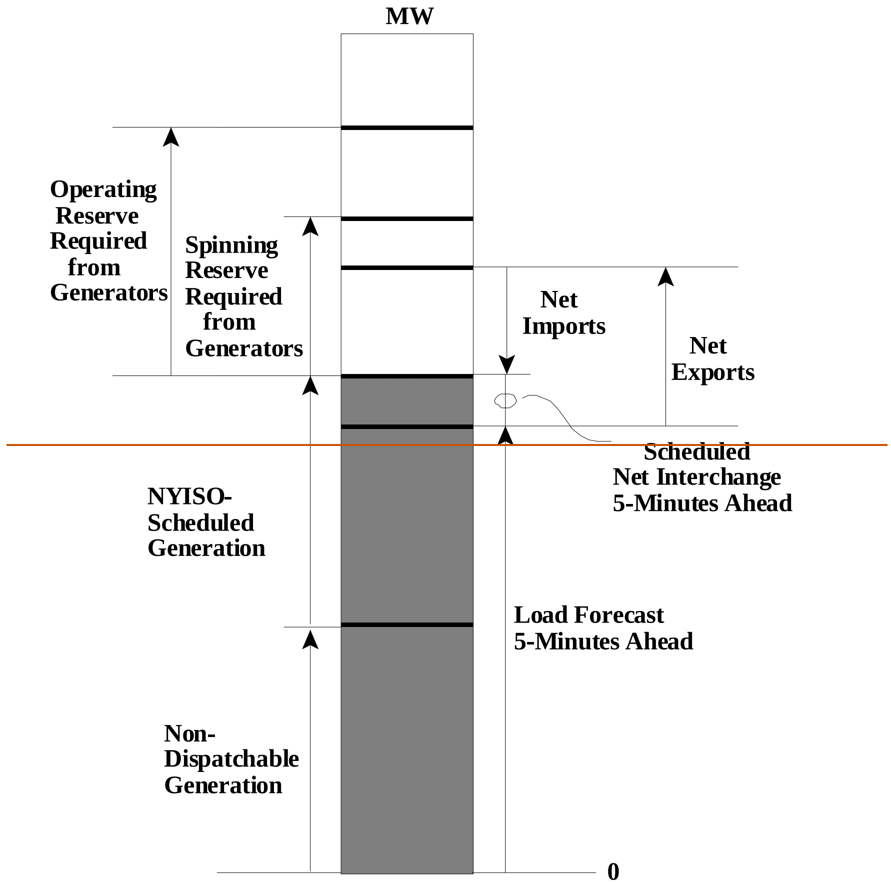
~~curves of the generating units, telemetry data, and other data needed to model each of the constraints as previously described.~~

6. ~~SCD determines the initial conditions to begin the dispatch calculation. These initial conditions include:~~

15) ~~A snapshot of the telemetry values of generation output and power flows on the transmission system, which represent the present state of the NYCA.~~
16) ~~Initial values of total system generation, load, actual net interchange, and transmission losses are computed based on the snapshot of telemetry data.~~
17) ~~Generation shift factors are used to adjust the initial values of power flows for the difference between the present actual system load and the five-minute load forecast provided by the short-term load forecasting program.~~
18) ~~Initial values of power flows associated with the transmission constraints are calculated.~~
19) ~~Generation "penalty factors" (i.e.: "delivery factors", which are the reciprocal of penalty factors) are calculated, and are used to approximate the effects of changes in generation on system transmission losses. These penalty factors are treated as fixed quantities throughout the dispatch process.~~
20) ~~The allowable dispatch range (maximum and minimum limits) of the dispatchable generating units for the five-minute period are determined considering maximum and minimum limits specified by the Market Participants, regulation constraints, and the response rates of the steam units.~~
21)

~~SCD sets up the dispatch problem as a "constrained linear programming" problem. The cost objective function, and all constraints, are expressed as linear functions of the output of the generating units.~~

~~SCD takes a first pass at solving the dispatch problem. All dispatchable generating units, including gas turbine units, are considered in this first pass. All constraints, except the reserve constraints, are considered in this first pass.~~



~~SCD solves the dispatch problem in two major steps: the "feasibility step", and the "optimization" step.~~

~~SCD solves the dispatch problem in two major steps: the "feasibility step", and the "optimization" step.~~

~~Feasibility Step~~

~~In the feasibility step, SCD attempts to determine a feasible generation dispatch that satisfies all the constraints, disregarding cost. SCD first attempts to solve the load constraint by changing the output of generating units to match the load forecast, respecting the maximum and minimum dispatchable limits of the generating units, which are always enforced throughout the solution process. If SCD is unable to solve the load constraint (because the load cannot be met with the generation limits), the solution process is stopped because no feasible solution exists. Once the load constraint has been solved, SCD proceeds to attempt to solve the transmission constraints by shifting generation between locations to reduce the power flows associated with the transmission constraints, respecting the load constraint and generation limits. SCD tries to solve the transmission constraints one at a time, always considering the constraint having the largest violation. In shifting generation to solve a constraint, SCD does not consider generation shifts~~

~~that would violate any previously solved constraints. This process continues until either all constraints have been solved, or until SCD determines that no feasible solution exists after considering all possible generation shifts.~~

~~Optimization Step~~

~~Upon completion of the feasibility step, SCD proceeds to the optimization step, unless the load constraint was not solved, in which case this step is by-passed. If any transmission constraints are unsolved, SCD resets the limits of the violated constraints equal to the power flows of those constraints at the end of the feasibility step (forcing the problem to be "feasible"), and proceeds to the optimization step. This allows for the possibility that SCD may be able to shift generation to reduce cost without increasing the violation of any unsolved transmission constraints.~~

~~In the optimization step, SCD shifts generation from higher cost generators to lower cost generators insofar as it is able to do so without violating any constraints. SCD considers the slopes of the incremental cost curves of the generating units, the penalty factors, and the generation shift factors of all "active" security constraints, to evaluate the best locations for shifting generation. Active constraints are constraints that are at their limits, as opposed to inactive constraints that are within, but not at their limits. SCD continues to shift generation to reduce cost until no additional shifts are possible without violating constraints. At this point, the constrained linear programming problem has been solved.~~

~~Note that, even though the dispatch problem is set up and solved as a linear programming problem, SCD deals with two nonlinear functions during the solution process. The generators' incremental bid cost curves are represented as piece-wise linear curves. Therefore, as SCD redispatches generation, it recognizes when generators have been moved onto different segments of their incremental cost curves. The second nonlinear function concerns the model for transmission losses. Although SCD uses penalty factors to approximate the effects of generation changes on transmission losses in the formulation of the linear programming problem, SCD also uses the B-matrix to calculate these losses more accurately during the solution process. Additional small shifts in generation are used as necessary to adjust for the difference between the losses estimated using the penalty factors and the losses calculated using the B-matrix.~~

22) ~~Upon completion of the first pass dispatch, SCD tests the conditions of that dispatch to determine if it qualifies as the "final dispatch", or if additional steps are necessary to determine the final dispatch. Three conditions must be met for the first pass dispatch to be considered the final dispatch:~~

23) ~~the load constraint and all transmission constraints must be met~~

24) ~~all three NYCA reserve requirements must be met~~

25) ~~no gas turbine units were dispatched. If all three conditions have been met, the results of the first pass dispatch are considered final. If not, SCD will take additional steps to determine the final dispatch as follows:~~

- ~~If either the load constraint or one or more transmission constraints were not met after the first pass dispatch, SCD relaxes the regulation constraints placed on generating units in the first pass dispatch, and attempts a second pass dispatch. The other~~

~~generation constraints — the dispatch maximum and minimum limits and response rate restrictions — continue to be enforced. This second pass dispatch may or may not qualify as the final dispatch.~~

- ~~If any of the NYCA reserve requirements are not met, SCD adds the reserve constraints (which were not considered in the first pass dispatch) to the constrained linear programming problem, and attempts a second pass dispatch to solve this reformulated problem. This second pass dispatch may or may not qualify as the final dispatch.~~
- ~~If gas turbine units were dispatched in the first pass dispatch, SCD proceeds through a set of rules regarding startup, shutdown, and base loading of gas turbine units. This activity, referred to as "GT Dispatch", may result in setting the dispatched generation of the gas turbine units to values that differ from the first pass dispatch. When this occurs, SCD attempts a second pass dispatch with the gas turbine units "blocked" at these new values. This second pass dispatch may or may not qualify as the final dispatch.~~

~~The above conditions and corresponding SCD activities are not mutually exclusive. Thus, depending on the circumstances, SCD may perform multiple "dispatches" before arriving at the "final" dispatch.~~

~~When the SCD program has completed the solution process, the final basepoints are sent to the on-line ORACLE database for use by the LBMP Calculation module and sent out to the Transmission Owners and/or individual generating units. Data concerning the active security and reserve constraints, and a list of the units that were used to solve the security constraints are also audited for use by the billing program and archived.~~

~~Reference Bus~~

~~When the SCD program is not able to solve all the constraints, alarm messages are issued to the NYISO Shift Supervisor, or his designee. The NYISO Shift Supervisor, or his designee, may elect to take alternative action, if necessary, to bring the constraints under control.~~

~~To achieve an appropriate weighting of these three LBMP components (energy, losses, and congestion), the reference bus for both delivery factors and generation shift factors should be the same, and that reference bus should be at or near the "electrical center" of the system (in this case, the center of the New York Control Area). Therefore, the reference for the delivery factors and generation shift factors used by SCD is the Marcy 345 kV bus located at Utica, New York.~~

~~LBMP Information from SCD~~

~~As previously described, SCD may perform multiple "dispatches" before arriving at the "final" dispatch. The information needed to compute LBMPs will normally be based on SCD's first pass~~

~~dispatch, unless a second dispatch is performed to solve one or more reserve constraints, in which case the information needed to compute LBMPs will be based on this second dispatch.~~

v.~~Phase Shifter Models~~

~~The SCD program assumes that the pre-contingency active power flows on phase shifter controlled transmission lines are fixed at their telemetered values observed at the start of the dispatch interval, i.e., phase shifter controlled lines are said to be "block loaded", with one exception. The phase shifter on Y-49 is treated in the NYISO modeling as free flowing because it is operated to a set tap and the flow is permitted to vary as per the dispatch. Once steady state operation is reached, the tap is then changed to balance flow with its parallel free flowing tie Y-50.~~

~~However, for contingency case security constraints, the post-contingency flows on phase shifter controlled lines varies as a function of the precontingency values of the outaged facilities. For contingency analysis, phase shifter controlled lines are allowed to "free-flow".~~

~~Locational Reserve Requirements~~

~~Locational reserve requirements will be determined by the NYISO. Operating reserves will not be locationally priced.~~

~~SCD will maintain Operating Reserves on suppliers that were selected by SCUC or BME to provide these reserves and meet locational reserve requirements. Thus, operating limits in SCD will be "shaved" to retain both Class A and Class B 10 Minute Reserves, 10 Minute Non-Synchronized Reserves, and 30 Minute Reserves. These reserves will only be converted to energy using Reserve Pickup. In that event, the reserve suppliers will be dispatched upward at Emergency Response Rates. It should be noted that Reserve Pickup may often be run with only Class B providers of Spinning Reserve (which will have no energy price bid), or may consist of generators initially operating at their maximum ramp-up rates followed by generators operating at their maximum ramp-down rates (both producing ill-defined prices). To avoid these price discontinuities, the LBMP during all Reserve Pickups will be held constant from the time just prior to initiation of a Reserve Pickup until the time SCD is re-initialized.~~

~~During a Reserve Pickup, the NYISO will notify the Transmission Owners, who in turn will notify providers of operating reserves that a Reserve Pickup is taking place.~~

~~With respect to 30 Minute Reserves, Reserve Pickup will dispatch 30 Minute Spinning Reserve Upward but not 30 Minute non-synchronized Reserve. This would need to be done through Supplemental Resource Evaluation (SRE).~~

~~Reserve Comparator~~

~~The Reserve Comparator (RC) function executes nominally every five minutes and resides on the on-line EMS to track actual system reserves and system reserve requirements. The purpose of the RC program is to monitor the locational reserves and capability in the real time system and for interchange evaluation in the NY Control Area. RC monitors NY Control Area reserves in three categories: 10-minute synchronous reserve, total 10-minute reserve, and total 30-minute reserve. Currently it also calculates the reserves and capability from units and transactions for each Zone and the NY Control Area. The RC function also determines if the 10-minute synchronous reserve is bottled due to line constraints. RC also calculates reserve requirements in each of the three categories based on the most severe Normal Transfer Criteria contingency~~

~~within the NY Control Area or the energy loss caused by the cancellation of an interruptible energy purchase from another system and capability requirements based on the largest unit, area load and own load losses. The RC program is required to monitor Zones because the Unit Commitment program must commit enough units in each Zone to cover reserve requirements for the NY Control Area and each Zone.~~

~~Locational Reserves~~
~~Reserve Comparator~~
~~Reserve Calculations~~

6.3.1. Limit Updates

All generator-operating limits are taken from generator bid information. The only changes that are made to unit operating limits are via the Out of Merit (OOM) package. This is done by a NYISO operator using information received from the TO or the Generator.

At the top of each hour, the real-time upper operating limit will be compared with the projected upper operating limit, which is based on the accepted bid parameters. The OOM limit will be used by RTD. A text alarm will be sent to the TO and to the NYISO alarm screen. Any discrepancy will be resolved with the appropriate generator.

If the unit requires a modification to real-time limits which results in a derating of the unit due to operational problems, the NYISO can lower the upper operating limit. The corresponding RTD high limit will be ~~adjusted .~~adjusted.

~~At the unit's request, the unit can operate at its derated upper operating limit and when doing so will forfeit all reserve payments. To do this the unit must request that the NYISO modify the RTD high limit to equal the upper operating limit~~

Status Updates

At the top of each hour, the real-time unit status will be compared with the projected status, which is based on the accepted bid parameters. The unit status will be set from existing real time or projected status, which will be used by RTD and AGC. Additionally:

1. A unit that has not bid for regulation cannot be placed 'On Control'
2. If a supplier is a 10-minute non-synchronous unit that does not have a 10-minute non-synchronous reserve availability contract and wishes not to be dispatched or started in real-time by RTD-CAM to provide energy then the supplier must update the real time status to 'unavailable'
3. Suppliers that do not update the limits and or status to equal the projected status or limits as bid and accepted are subject to reserve and regulation balancing payments.

6.3.2. NYISO-TO-Power Supplier Communications

Units that bid such that they will be scheduled at fixed ¼ hour points can obtain their schedules from the MIS posting in addition to the base points that will be transmitted to the TO by the NYISO.

Units that are dispatchable and non-synchronous units that can be committed by RTD-CAM must be prepared to receive real-time schedule changes. The unit schedules (base points) that are sent to the Transmission Owners as a result of a reserve pick up or locational reserve pick up will be tagged to indicate that the base points were calculated based on the higher of normal or emergency response criteria. This is an indication that the dispatchable and Non-synchronous units may be receiving a RTD-CAM schedule change and that the base points may reflect emergency response rate criteria. ~~Power Suppliers will have to make arrangements with the TO's to receive these real-time schedule changes.~~

6.3.3. RTD Solution Process

RTD calculates a short-term generation schedule, referred to as a "base point," for each of the generating units designated as flexible or "on-dispatch." The process used by RTD in performing this calculation is as follows:

1. RTD retrieves the information it needs to perform the calculation from data maintained in the NYCA databases. This information includes incremental bid cost curves of the generating units, telemetry data, and other data needed to model each of the constraints.
2. RTD determines the initial conditions to begin the dispatch calculation. These initial conditions include:
    a. A snapshot of the real-time telemetry values for generation output which represents the present state of the NYCA.
    b. Initial values of total system generation, load, actual net interchange based on the snapshot of telemetry data, and the last RTC powerflow transmission losses.
    c. The RTC powerflow solution determines the initial values of unconstrained power flows based on the five-minute load forecast provided by the short-term load forecasting program.
    d. Initial unconstrained values of power flows associated with the transmission constraints are calculated.
    e. Generation delivery factors are calculated, and are used to approximate the effects of changes in generation on system transmission losses.
    f. The allowable dispatch range (maximum and minimum limits) of the dispatchable generating units for the five-minute period are determined considering maximum and minimum limits specified by the Market Participants, regulation constraints, and the response rates of the units.

3. RTD sets up the dispatch problem as a "constrained linear programming" problem. The cost objective function and all constraints are expressed as linear functions of the output of the generating units.

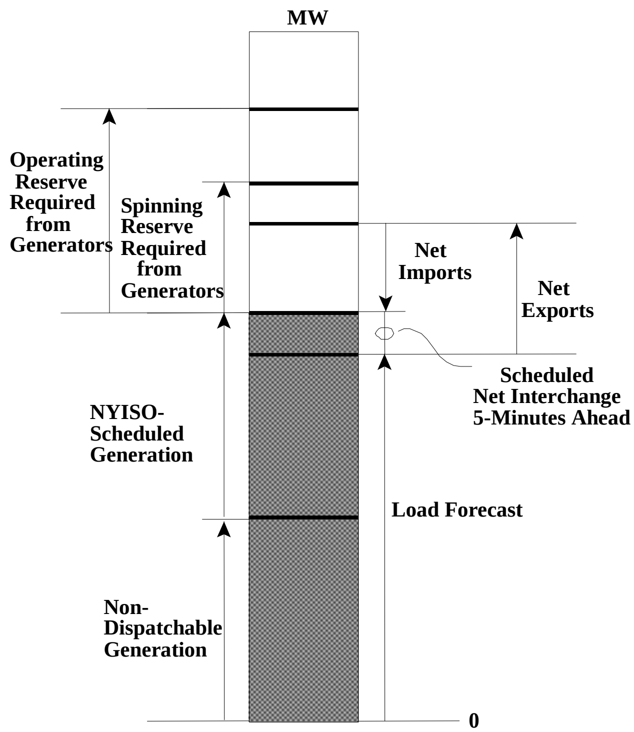


Exhibit 6-2: Control Area Constraints

~~RTD solves the dispatch problem in two major steps: the "feasibility step," and the "optimization" step.~~

RTD attempts to determine a feasible generation dispatch that satisfies all system load and locational reserve and regulation constraints, including, transmission constraints by shifting generation between locations to reduce the power flows associated with the transmission constraints, respecting generation operating limits.

RTD shifts generation from higher cost generators to lower cost generators insofar as it is able to do so without violating any constraints. RTD considers the incremental energy bid of the generating units, the generation delivery factors, and the generation shift factors of all "active" security constraints, to evaluate the best locations for shifting generation.

The generators' incremental energy bid is represented by a series of ~~monotonically~~ increasing constant cost incremental energy steps. RTD uses delivery factors to approximate the effects of generation changes on transmission losses in the formulation of the linear programming problem, based on the corresponding RTC power flow to determine these losses more accurately during the solution process.

When the RTD program is not able to solve all the constraints, alarm messages are issued to the NYISO Control Room Operators~~Shift Supervisor, or designee~~.

6.3.4. Phase Shifter Models

The RTD program assumes that the pre-contingency active power flows on phase shifter controlled transmission lines are fixed at their telemetered values observed at the start of the dispatch interval, i.e., phase shifter controlled lines are said to be "block loaded"., However, for contingency case security constraints, the post-contingency flows on phase shifter controlled lines varies as a function of the pre-contingency values of the facilities described in the contingency and forecast system topology. For contingency analysis, phase shifter controlled lines are said to be allowed to "free-flow."

6.3.5. Locational Reserves

Operating reserves will be locationally priced and the locational reserve requirements will be determined by the NYISO.

Reserves are scheduled as part of each RTD run and are co-optimized, nominally every five minutes, along with energy and regulation schedules. These reserves may be converted to energy in any normal dispatch or during a Reserve Pickup and replacement reserves scheduled on other available resources. During a reserve pickup event, dispatchable suppliers will be dispatched upward at the higher of their normal response rate curve or their Emergency Response Rates. During a Reserve Pickup, the NYISO will notify the Transmission Owners, who in turn will notify dispatchable resources that a Reserve Pickup is taking place. A RPU “flag” will be sent with the basepoints via ICCP.

With respect to 30-minute Reserves, Reserve Pickup will dispatch 30-minute Spinning Reserve Upward but not 30-minute non-synchronized Reserve. This would be done at the next RTC execution or through a Supplemental Resource Evaluation (SRE).

6.3.6. Reserve Comparator

The Reserve Comparator (RC) function executes nominally every five minutes and resides on the on-line EMS to track actual system reserves and system reserve requirements. The purpose of the RC program is to monitor the locational reserves and capability in the real time system and for interchange evaluation in the NY Control Area. RC monitors NY Control Area reserves in three categories: 10-minute synchronous reserve, total 10-minute reserve, and total 30-minute reserve. Currently it also calculates the reserves and capability from units and transactions for each Zone and the NY Control Area.

~~vi.~~6.3.7. Reserve Calculations

The following reserve calculations are implemented for the LBMP Market:

~~153.~~1. Reserves are calculated on a ~~zonal~~locational basis.

~~154.~~2. There are reserve requirements for each of the ~~LBMP zones~~locational reserve areas with the appropriate alarming.

~~155.~~3. Non-synchronous reserve can only be counted on units that have an accepted bid and have been committed for non-synchronous reserve. This applies for both 10-minute and Operating Reserve.

26) ~~All On-dispatch (on-line) units are counted for 10-minute synchronous reserve, whether or not they have an accepted reserve availability bid.~~

27) ~~Other units with accepted and committed spinning reserve block bids are counted for synchronous reserve in 10-minute and/or Operating Reserve according to reserve type provided.~~

28) ~~Reserves are counted on accepted and committed interruptible load bids for reserve by type.~~

~~Reserve Bottling~~

~~Checks are made to determine if the 10-minute synchronous reserve could potentially be bottled due to line constraints. The RC program outages the largest unit in each of the six reserve bottling Areas and attempts to pick up generation with available spinning reserve. RC does this until sufficient generation is picked up. If line limits would be violated, signifying that bottling would occur in this situation, SCD will re-dispatch generation so that the appropriate amount of reserve is restored in the bottled region.~~

~~Bus LBMP Calculation Method~~

~~The Locational Based Marginal Prices (LBMPs) for Generators and Loads are based on the system marginal costs produced by either the Security Constrained Dispatch (SCD) program for Real-Time Market prices, or the Security Constrained Unit Commitment (SCUC) program for Day-Ahead Market prices. These are utilized in an ex post computation to produce LBMP bus prices using the following equations. Attachment E of this manual presents a numerical example to illustrate the concepts and calculations.~~

~~The LBMP at bus "i" is written as:~~

~~?i = ?R + ?L i + ?C i~~

~~Where:~~

~~?i = LBMP at bus "i" in $/MWh~~

~~?R = the system marginal price at the Reference Bus~~

~~?L i = Marginal Losses Component of the LBMP at bus "i" which is the marginal cost of losses at bus "i" relative to the Reference Bus~~

~~?C i = Congestion Component of the LBMP at bus "i" which is the marginal cost of Congestion at bus "i" relative to the Reference Bus~~

~~Marginal Losses Component~~

~~The Marginal Losses Component of the LBMP at any bus "i" within the NY Control Area is calculated using the equation:~~

~~?L i = (DFi - 1) ?R~~

~~DFi = delivery factor for bus "i" from the system Reference Bus~~

~~DFi = (1 - . L / . Pi) = 1 / PFi~~

~~Where:~~

~~L = system losses~~

~~Pi = generation injection at bus "i"~~

~~PFi = the incremental fraction of power delivered to the Reference Bus resulting from an increment of generation at bus "i"~~

~~Congestion Component~~

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

~~?C i = - (. GFik µk) kK~~

~~Where:~~

~~K = the set of thermal or interface Constraints~~

~~GFik = Shift Factor for the Generator at bus "i" on Constraint "k" in the pre- or post-Contingency case which limits flows across that Constraint. The Shift Factor measures the incremental change in flow on Constraint "k", expressed in per unit, for an increment of generation at bus "i" and a corresponding decrement of generation at the Reference Bus~~

~~µk = the reduction in system cost that results from an incremental relaxation of Constraint "k" expressed in $/MWh~~

~~Substituting the equations for ?L i and ?C i into the first equation yields:~~

~~?i = ?R + (DFi - 1) ?R - . GFik µk~~
~~kK~~

~~SCD Process~~

~~The SCD program execution in a given interval may terminate without observing the limits on all Constraints, usually due to Generator ramp rate limitations on the dispatch. Under these conditions, rules have been developed which the NYISO uses to set Generator output levels and to calculate LBMPs. These rules state that the LBMPs are to be calculated from the output of the SCD execution in which Constraints were violated. Prices calculated in this manner closely reflect the marginal cost of Energy on the system. However, the Generator output levels are set by a second SCD execution in which Generator ramp rate constraints are relaxed. This execution of SCD usually eliminates the Constraint violations and provides the NYISO with information to~~

~~correct the situation. Often Generators will be able to operate at the levels set in the second SCD execution, since they frequently can change their output levels at rates exceeding those included in the Bid data provided to the NYISO. Failure to achieve the output levels determined in the second SCD execution will not cause the Generator's performance ratings in the Performance Tracking System to be adversely affected.~~

~~The Real-Time LBMPs are calculated and posted for each execution of SCD.~~

~~Zonal LBMP Calculation Method~~

~~The computation described in Section 5.1.5 is performed at the bus level. This is suitable for Generator buses because adequate metering is normally available to measure Real-Time injections. Due to the current lack of necessary metering for Load at the bus level, an Eleven zone model will be used for the LBMP billing related to Loads.~~

~~The LBMP Load Zones and Sub-Zones are defined in the NYISO Transmission Services Manual. The designated Zones and associated Sub-Zones are specifically defined in the NYISO Transmission Services Manual, and are listed as follows:~~

Zone A - West Zone
- Sub-Zone 1 - NMPC West
- Sub-Zone 5 - NYSEG West

Zone B - Genesee Zone
- Sub-Zone 9 - RG&E
- Sub-Zone 29 - NMPC Genesee

Zone C - Central Zone
- Sub-Zone 2 - NMPC Central
- Sub-Zone 6 - NYSEG Central

Zone D - North Zone
- Sub-Zone 14 - NYPA North
- Sub-Zone 19 - NYSEG North
- Sub-Zone 31 - NMPC NT
- Sub-Zone 34 - CRT

Zone E - Mohawk Valley Zone
- Sub-Zone 3 - NMPC MVN
- Sub-Zone 7 - NYSEG East
- Sub-Zone 33 - CH Central

Zone F - Capital Zone
- Sub-Zone 4 - NMPC East
- Sub-Zone 21 - NYSEG M'ville

Zone G - Hudson Valley Zone
- Sub-Zone 8 - NYSEG Hudson
- Sub-Zone 10 - Central Hudson
- Sub-Zone 11 - O&R
- Sub-Zone 32 - Con Ed Mid Hud

Zone H - Millwood Zone
- Sub-Zone 23 - Con Ed North
- Sub-Zone 30 - NYSEG Brewster

Zone I - Dunwoodie Zone
- Sub-Zone 25 - Con Ed Central

Zone J - New York City Zone
- Sub-Zone 15 - Con Ed NYC

Zone K - Long Island Zone
- Sub-Zone 12 - LIPA

Zone O - Ontario Hydro Zone
Zone M - HQ Zone
Zone N - NEPEX Zone
Zone P - PJM & Equiv Zone

~~The LBMP for a zone is a load weighted average of the Load bus LBMPs in the zone. The load weights which sum to unity are predetermined by the NYISO. Each component of the LBMP for a zone is calculated as a load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone "j" is written as:~~

$$?^{Z}_{j} = ?^{R} + ?^{L,Z}_{j} + ?^{C,Z}_{j}$$

Where:

$?^{Z}_{j}$ = LBMP for zone "j"

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

$?^{C,Z}_{j} = \sum_{i=1}^{n} W_i \; ?^{C}_{i} =$ the Congestion Component of the LBMP for zone "j"

n = number of load buses in zone "j" for which LBMPs are calculated

~~The preferred method for calculating zonal LBMPs (when sufficient telemetering and data development is completed) is to ultimately use a NYISO state estimator to compute load weights. As an interim phase, load weightings for zonal LMBP calculations will be computed starting with the NYISO base case power flow, and using the accompanying Network Equivalence Program to reduce the power flow base case to a generator bus only case.~~

~~LBMP Prices for External Locations~~

~~External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. External Generators may arrange Bilateral Transactions with Internal or External Loads and External Loads may arrange Bilateral Transactions with Internal or External Generators. External to External bilateral transactions that have flows through the NYCA are called wheels-through.~~

~~The Generator and Load locations for which External LBMPs are calculated will initially be limited to a pre-defined set of buses External to the NY Control Area. The three components of LBMP are calculated from the results of SCD and posted in the Day-Ahead and Real-Time Markets as described above, except that the Marginal Losses Component of LBMP are calculated differently for External locations.~~

~~The Marginal Losses Component of the LBMP at each bus, as described above, includes the difference between the marginal cost of losses at that bus and the Reference Bus. If this formulation were employed for an External bus, then the Marginal Losses Component would include the difference in the cost of Marginal Losses for a section of the transmission system External to the NY Control Area. Since the NYISO does not charge for losses incurred externally, the formulation excludes these loss effects. To exclude these External loss effects, the Marginal Losses Component is calculated from points on the boundary of the NY Control Area to the Reference Bus.~~

~~The Marginal Losses Component of the LBMP at the External bus is a weighted average of the Marginal Losses Components of the LBMPs at the Interconnection Points. To derive the~~

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

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

$$?^{L}_{E} = \sum_{b \in I} F_{Eb} \left(DF_b - 1 \right) ?^{R}$$

Where:

I = The set of Interconnection buses between the NYCA and adjacent Control Areas

$?^{L}_{E}$ = Marginal Losses Component of the LBMP at an External bus "E"

F_{Eb} = Shift Factor for the tie line going through Interconnection Point bus "b", computed for a hypothetical Bilateral Transaction from bus "E" to the Reference Bus

$(DF_b - 1)\ ?^{R}$ = Marginal Losses Component of the LBMP at bus "b"

~~Fixed Block Suppliers Setting LBMP~~

~~The following describes treatment of fixed block suppliers that are preschedulable (schedules can be varied in advance), but not dispatchable in Real-Time by SCD (e.g.: suppliers such as GTs whose minimum output equals their maximum output, or suppliers external to the NY Control Area serving NYISO load):~~

~~Day Ahead~~

7. ~~If a fixed block (pre-schedulable over a continuous range but nondispatchable) supplier is committed by BME or Supplemental Resource Evaluation (SRE), it may set Real-Time LBMP. In the interim, this is only feasible for fixed block suppliers internal to the NYCA.~~

8. ~~When a fixed block supplier is committed, another lower priced supplier may be dispatched down out-of-merit to balance the load. In this case, the fixed block supplier will set LBMP (subject to and consistent with payment schemes of Local Reliability Rules) only when it is needed to economically serve load while maintaining adequate operating reserves as specified on the table below. Economic need will be determined by an *ideal dispatch* in which the fixed block is allowed to be dispatched continuously from zero to its Operating Capability. When a committed fixed block supplier is no longer economic, but continues to run to satisfy its~~

~~minimum run time, it will no longer set LBMP. Then the incremental supplier (i.e.: the supplier that serves the next MW of load) will set the LBMP.~~

9. ~~As with other committed suppliers, a committed fixed block supplier will be paid LBMP. Additionally, it will be guaranteed its start-up and minimum generation bid price through the Commitment Day (using a supplemental payment if necessary).~~

Summary of Suppliers That Can Set LBMP

Supplier	Internal Suppliers		External Suppliers	
	Can Set LBMP	**Can Set LBMP in Current Software**	**Can Set LBMP**	**Can Set LBMP in Current Software**
Suppliers **On-Dispatch** that are not pinned to an upper or lower operating limit	Yes	Yes	N/A	N/A
10 Minute Non-Synch Operating Reserve supplier**** whose reserves have been converted to energy which is shown to be economical in an ideal dispatch	Yes	Yes	Yes*	No
30 Minute Non-Synch Operating Reserve supplier**** whose reserves have been converted to energy which is shown to be economical in an ideal dispatch	Yes	No	Yes**	No
Minimum Generation Segment of a supplier whose Minimum Operating Level is less than its Maximum Operating Level	No***	No	N/A	N/A
Non-Schedulable Fixed Block supplier whose Minimum Operating Level is equal to its Maximum Operating Level (not dispatchable in real-time, and not continuously schedulable Day-Ahead and Hour-Ahead)	No	No	No	No
Schedulable Fixed Block supplier**** whose Minimum Operating Level is equal to its Maximum Operating Level (not dispatchable in real-time, but continuously pre-schedulable within a range Day-Ahead and Hour-Ahead)	Yes	No	Yes	No

Notes:

* External 10 Min. Non-Synch Operating Reserves will need to be sanctioned through Inter-Control Area agreements.

** External 30 Min. Non-Synch Operating Reserves will need to be sanctioned through Inter-Control Area agreements.

*** The minimum generation segment of a committed generator that can be dispatched higher will not set LBMP unless this minimum is equal to its upper operating limit.

**** Maximum honored run times for Non-Synch Reserve suppliers and Schedulable Fixed Block suppliers must be 1 hour for BME or SCD committed resources, and the remainder of the Dispatch for SRE committed resources

~~DISPATCHING OPERATIONS PROCEDURES~~

~~These procedures are intended for the dispatching and control of generation that occurs in real-time, during the Operating Hour. The following conditions are covered:~~

29) ~~Interaction with Automatic Generating Control~~

30) ~~Interaction with Security Constrained Dispatch~~

~~Interaction with Automatic Generation Control~~

~~NYISO Actions:~~

~~The NYISO shall perform the following:~~

10. ~~Ramp the NY Control Area DNI over a specified time period to permit a smooth transition, as desired.~~
11. ~~Receive and process notifications of changes to generating unit operating limits and control statuses.~~
12. ~~Review and change, as required by system conditions, the NY Control Area requirements for Regulation; for each hour of the day and for each day of the week.~~

~~Market Participant Actions: Generation providers shall perform the following:~~

13. ~~Notify the NYISO whenever there are changes to generating unit operating limits and control statuses.~~
14. ~~Notify their host Transmission Owner whenever there are changes to generating unit operating limits and control statuses.~~

~~Interaction with Security Constrained Dispatch~~
~~The following actions apply whenever there are security problems, such as:~~

31) ~~generator trip~~

32) ~~transmission facility trip~~

33) ~~shared activation of reserve~~

34) ~~generation/load imbalance~~

~~NYISO Actions:~~

~~The NYISO shall perform the following:~~

15. ~~Execute SCD on demand in the event that the NY Control Area first violates any of the system security criteria. The new run of SCD will automatically shift the 5-minute cycle.~~
16. ~~Execute the Synchronous Reserve Pickup mode of SCD in the event of non-emergency under-generation conditions. Normal Response Rates are invoked by SCD.~~
17. ~~Execute the Reserve Pickup mode of SCD in the event of emergency under-generation conditions. Emergency response rates are invoked by SCD.~~
18. ~~Restart the normal SCD cycle after the reserve pickup is completed.~~
19. ~~Recognize and incorporate Local Reliability Rules where appropriate.~~

~~Execute shared activation of reserve.~~

~~Shared activation of reserve with neighboring Control Areas will be treated as inadvertent energy to be paid back in kind as soon as possible in accordance with NPCC procedures.~~
~~NYISO Override of Security Constrained Dispatch~~

~~**Circumstances**~~

~~The circumstances under which the NYISO may over-ride SCD are situations in which:~~

20. ~~**SCD Does Not Monitor or Model the Constraint** - this could include Transmission Owner requests for redispatches to solve local security violations.~~

21. ~~**SCD Can Not Solve the Constraint** - this could include cases in which:~~
    - i. ~~a. SCD results in an abnormal termination requiring operator over-ride~~
    - j. ~~Pool Control Error (PCE) is positive by a large value~~
    - k. ~~Bus Voltage Limits are violated requiring additional reactive power from generators by reducing MW output~~
    - l. ~~Resources available in SCD are insufficient~~

22. ~~**SCD Horizon is Insufficient** - changes anticipated past the end of the SCD interval contradict the current conditions for which SCD is solving. For instance, this could include cases in which:~~
    - m. ~~Large schedule change out of or into the New York Control Area (NYCA) may need to keep generation loading or reducing for a period just prior to the schedule change.~~
    - n. ~~Gas Turbines which are on-line prior to the peak are not currently needed, but will be required for the peak.~~

~~**Guidelines**~~

~~SCD over-rides should be:~~

23. ~~Justified and documented.~~

All On-dispatch (on-line) units are counted towards 10-minute synchronous reserve, whether or not they have an accepted reserve availability bid.

6.4. Dispatching Operations Procedures

~~These procedures are intended for the dispatching and control of generation that occurs in real-time, during the Dispatch Hour. The following conditions are covered:~~

~~Interaction with Real-Time Dispatch~~

~~Interaction with RTD-Corrective Action Modes~~

~~Shared Activation of Reserves~~

~~Desired Net Interchange Override~~

~~Interaction with Automatic Generating Control.~~

~~Interaction with Real-Time Dispatch~~

~~The following actions apply whenever there are security problems, such as:~~

~~Generator trip~~

~~Transmission facility trip~~

~~Shared activation of reserve~~

~~Generation/load imbalance.~~

~~***NYISO Actions***~~

~~The NYISO shall perform the following:~~
~~Execute the Reserve Pickup mode of RTD-CAM in the event of non-emergency under-generation conditions. Normal Response Rates are invoked.~~
~~Execute the Reserve Pickup mode of RTD-CAM in the event of emergency under-generation conditions. The higher of the normal response rate curve or single emergency response rate will be used.~~
~~Restart the normal RTD cycle after the reserve pickup is completed.~~
~~Recognize and incorporate Local Reliability Rules where appropriate.~~
~~Execute shared activation of reserve.~~
~~Shared activation of reserve with neighboring Control Areas will be treated as inadvertent energy and may be paid back in kind accordance with interregional procedures.~~

~~Override of RTD~~

~~The circumstances under which the NYISO may over-ride RTD are situations in which:~~
~~RTD Does Not Monitor or Model the Constraint – this could include Transmission Owner requests for redispatches to solve local security violations.~~
~~RTD Can Not Solve the Constraint – this could include cases in which:~~

~~RTD results in an abnormal termination requiring operator over-ride~~

~~Area Control Error (ACE) is positive (import) by a large value~~

~~Bus Voltage Limits are violated requiring additional reactive power from generators by reducing MW output~~

~~d.Resources available in RTD are insufficient~~

~~Guidelines~~

~~RTD over-rides should be:~~
~~Justified and documented.~~
~~2.Non-discriminatory.~~
~~3.Economically efficient using BMERTC and/or SRE to determine In-Dispatch Day/Real-Time commitments and de-commitments.~~
~~4.Communicated to Transmission Owners along with the pertinent circumstances.~~

~~Appendix~~
~~Interaction with RTD – Corrective Action Modes~~
~~NYISO Operators interact as follows with the RTD-Corrective Action Modes:~~

~~Reserve Pickup~~

~~The Operator can select to execute either a Large Event or Small Event reserve pickup mode. In either case, the RTD-CAM program executes one-time only. The Operator must request the re-sequencing mode of RTD-CAM to return to normal RTD execution.~~

~~Maximum Generation Pickup~~

~~The Operator can select to execute the maximum generation pickup mode. This mode of RTD-CAM will repeat itself every 5 minutes until cancellation by the Operator. The Operator must request the re-sequencing mode of RTD-CAM to return to normal RTD execution.~~

~~**Basepoints ASAP – No Commitments**~~

~~The Operator can select to execute the basepoints as soon as possible with no unit commitments. This mode of RTD-CAM will execute one time and then automatically resynchronize to normal RTD execution.~~

~~**Basepoints ASAP – Commit as Needed**~~

~~The Operator can select to execute the basepoints as soon as possible mode with unit commitment as needed. This mode of RTD-CAM will execute one time and then automatically resynchronize to normal RTD execution.~~

6.4.1. Shared Activation of Reserves

The shared activation of reserves (SAR) is a mutual agreement among the following participating areas to provide 10-minute reserve assistance:

- ~~Ontario Hydro~~IMO
- Hydro Quebec
- New England/New Brunswick
- NYISO
- PJM

The NYISO acts as the coordinator for the SAR procedure and will ensure that allocations assigned to the participating areas are within their response capabilities.

Procedure

The following is a summary of the SAR procedure, which is described in detail in the Northeast Power Coordinating Council (NPCC) Document C-12 (August 20, 2002):

1. **Preliminary Reserve Assignment:** On a continuing basis, Maritimes, ISO-NE, IMO, and PJM dispatchers shall keep the NYISO informed of the largest, single generation or energy purchase contingency on its system and changes thereof.

   Information pertaining to an Area's inability to participate, reserve limitations (such as "bottled" reserve or reserves used to deliver economy energy sales) and transmission limitations shall be reported to Maritimes, ISO-NE, IMO, and PJM by the NYISO Shift Supervisor as those conditions arise.

2. **Notification of Contingency:** Immediately following a sudden loss of generation or energy purchase in the Maritimes, ISO-NE, NYISO, IMO, or PJM, the Contingency Area shall report the following information to the NYISO via the interregional direct telephone lines:

   a. Name of generation or purchase lost.
   b. Total number of megawatts lost.
   c. Time that contingency occurred (time zero T+0).

d. Any transmission or security problems that affect allocations to Assisting Areas.

3. **Activation of Reserve:** After receiving notification of the contingency, the NYISO Shift Supervisor shall:

   a. Determine each Area's reserve allocation

   b. By the direct inter-Area telephone lines, immediately inform each Area of its reserve allocation, the time that the schedule change is effective, and the time that the contingency occurred.

   The reserve allocation shall become part of the interchange schedule and shall be implemented at a zero ramp rate immediately following notification.

4. **Provision of Reserve Assistance:** Assisting Areas shall respond as quickly as possible, assuming the same obligation as if the contingency occurred within its Area. Assisting Areas shall complete a report that documents the Reserve Assistance provided.

   The Contingency Area shall initiate immediate action to provide its share of reserve to recover from the generation or energy purchase loss, prepare for the replacement of the reserve assistance assigned to assisting Areas, and proceed to re-establish 10-minute reserve at least equal to its next largest contingency.

5. **Termination of Shared Reserve:** As soon as the Contingency Area has provided its reserve allocation, it will notify the NYISO. The NYISO shall establish a conference call between all participating Areas and confirm the time that the assistance shall be terminated. Revised interchange schedules will be mutually established as required to ensure that the Assisting Areas properly recall assistance. The Contingency Area shall replace the reserve assistance assigned to assisting Areas in a manner consistent with mutually established interchange schedules.

   a. In the event that a Contingency Area is not prepared to replace the remaining portion of its reserve obligation within time zero + 30 minutes, the Contingency Area shall arrange for additional assistance in accordance with applicable policies and agreements covering interchange and emergency assistance.

   b. In the event that the security of an Assisting Area becomes jeopardized, that Area may cancel all or part of its allocation by notifying the NYISO, which will then request the Contingency Area to pick up the required additional amounts of reserve. The Contingency Area shall complete a report that documents the recovery provided for the contingency.

6. **Subsequent Contingencies:** In the event that a subsequent loss of generation or energy purchase, regardless of the size of the contingency, occurs during the period when a reserve pick-up is in progress, the second Contingency Area may, at its discretion, withdraw assistance and request the NYISO to reallocate the assistance in accordance with the provisions of this shared activation of reserve procedure.

a. Upon such notification, the NYISO will notify the first Contingency Area of the amount of withdrawal. Both Contingency Areas will immediately enter new interchange schedules that reflect the loss of the assistance, using a zero time ramp.

b. In the event that the second Contingency Area experiences a contingency that qualifies for shared activation of reserve, the NYISO will allocate assistance from the remaining Assisting Areas in accordance with this procedure, upon the request of that Area.

c. If the second contingency occurs in the Area that has incurred the first contingency, that Area may request assistance, in accordance with this procedure, regardless of the size of the contingency.

7. **Disturbance Control Standard (DCS) Reporting of Shared Activation Reserve Events:** The evaluation of DCS compliance for an Area shall utilize the NERC Disturbance Recovery Period applicable at the time of the reportable event (15 minutes). The evaluation of compliance for the purpose of determining Area synchronized reserve requirements shall utilize a recovery period established by the NPCC (15 minutes).

NYISO Operator Action

The NYISO Operator interacts with SAR as follows:

1. The NYISO Operator calls up the SAR display and enters the following information:

   a. Neighboring SAR area

   b. MW amount of SAR

   c. Import to NYISO or export from NYISO

   d. Activation (Immediate) or Termination (Immediate or Scheduled Time)

2. When a SAR is activated, the SAR MW value shall immediately take on the Operator entered SAR MW amount, regardless of any existing SAR value or if termination was already in progress,

3. When a SAR is terminated, the current (or scheduled) SAR value shall be ramped to zero over a 10-minute period, even if termination was already in progress.

4. SAR MW values are automatically converted to 1-minute values for input to the RTD/RTD-CAM and AGC programs.

   a. RTC will not have a direct SAR MW input.

   b. AGC will record the application of the SAR MW inputs.

~~Desired Net Interchange Override~~
~~NYISO Operators have the ability to change the New York Control Area's desired net interchange (DNI) with the individual external control areas (i.e., Ontario Hydro, Hydro Quebec, New England/New Brunswick, and PJM). DNIs are automatically converted to 1-minute values for input to the RTD/RTD-CAM and AGC programs.~~

~~DNI Ramp Configuration Override~~

~~Operators have the ability to enter the following ramp configuration parameter information via the MIS for the current and pending top-to-the-hour DNI change and in-hour DNI changes separately:~~

- ~~Call up display and select an individual external control area (OH, HQ, NE/NB, PJM) or NYCA~~
- ~~Enter the desired lead time in "minutes" prior to the DNI scheduled change time (which typically occurs on the hour)~~
- ~~Enter the desired ramp duration time in "minutes"~~
- ~~Select "Submit" command: Ramp parameters will not be submitted to the MIS, nor impact the DNI profile, until the Operator selects the "Submit" command. Operators will be able to change any parameters without first having to terminate the existing parameters.~~
- ~~Select "Terminate" command: Will cause the current ramp to be immediately terminated if it is progress, and the scheduled DNI to be immediately entered, regardless of the submitted ramp configuration parameters.~~

~~DNI MW Value Override~~

~~Operators have the ability to override the DNI values from the MIS prior to input to the RTD/RTD-CAM and AGC applications. The following information can be entered by Operators on the DNI override display:~~

- ~~Select only "one-at-a-time" desired control area (OH, HQ, NE/NB, PJM, or NYCA).~~
- ~~Enter the DNI MW value (Import or Export) for the selected control area.~~
- ~~Choose the desired action for the selected control area or global:~~
  - ~~Submit Override~~
  - ~~Terminate Override~~
  - ~~Terminate All Overrides~~

~~Processing Rules~~

~~The following processing rules will be applied:~~

- ~~The override DNI value remains in effect until terminated by the Operator.~~
- ~~If an Operator submits an override for a control area without specifying a DNI MW value, then the last known one-minute DNI value for that interface from the MIS will be used and indicated to the Operator as an override value.~~
- ~~Upon Operator termination, the MIS DNI value(s) will take effect immediately.~~

~~Interaction with Automatic Generation Control~~

~~*NYISO Actions*~~

~~The NYISO shall perform the following:~~

- ~~Ramp the NY Control Area DNI over a specified time period to permit a smooth transition, as desired.~~
- ~~Receive and process notifications of changes to generating unit operating limits and control statuses.~~
- ~~Review and change, as required by system conditions, the NY Control Area requirements for Regulation; for each hour of the day and for each day of the week.~~

~~*Market Participant Actions*~~

~~Generation providers shall perform the following:~~

- ~~Notify the NYISO whenever there are changes to generating unit operating limits and control statuses.~~
- ~~Notify their host Transmission Owner whenever there are changes to generating unit operating limits and control statuses.~~

A~~—~~. Transmission Facilities

- ~~Appendix~~ A~~-~~.1 presents a listing of Transmission Facilities Under NYISO Operational Control.
- A~~ppendix A-~~.2 presents a listing of Transmission Facilities Requiring NYISO Notification.
- A~~ppendix A-~~.3 lists Bus Voltage Limits for NYISO Secured Transmission System.

~~**Appendix A-1: Listing of Transmission Facilities under NYISO Operational Control**~~

- A.4 lists Bus Voltage Limits for HQ-NYISO transfers.

A.1 - Listing of Transmission Facilities Under NYISO Operational Control

Circuit ID	From	kV	To	kV
~~Circuit ID~~7040	~~From~~CHATEAUGAY	~~kV~~765	~~To~~MASSENA	~~kV~~765
~~7040~~BK1	~~CHATEAUGAY~~ MARCY	765	~~MASSENA~~ MARCY	~~765~~345
BK ~~1~~ 2	MARCY	765	MARCY	345
~~BK 2~~ MSU1	~~MARCY~~ MASSENA	765	MARCY	~~345~~765
~~MSU1~~ BK 1	MASSENA	765	~~MARCY~~ MASSENA A	~~765~~230
BK ~~1~~ 2	MASSENA	765	MASSENA ~~A~~ B	230
~~BK 2~~ 5018	~~MASSENA~~ BRANCHBURG	~~765~~500	~~MASSENA B~~ RAMAPO	~~230~~500
~~5018~~ BK 1500	~~BRANCHBURG~~ RAMAPO	500	RAMAPO S.	~~500~~345
~~BK 1500~~ 393	~~RAMAPO~~ ALPS	~~500~~345	~~RAMAPO S.~~ BERKSHIRE	345
~~Y50~~ PA301	~~DUNWOODIE~~ BECK A	345	~~SHORE RD~~ NIAGARA	345
~~PAR3500~~ PA302	~~RAMAPO S.~~ BECK B	345	~~RAMAPO~~ NIAGARA	345
~~PAR4500~~ 67-1	~~RAMAPO S.~~ BOWLINE 1	345	~~RAMAPO~~ W. HAVERSTRAW	345
~~PA301~~ W93	~~BECK A~~ BUCHANAN N.	345	~~NIAGARA~~ EASTVIEW 2N	345
~~PA302~~ W97	~~BECK B~~ BUCHANAN S.	345	~~NIAGARA~~ MILLWOOD	345
~~393~~ W98	~~ALPS~~ BUCHANAN S.	345	~~BERKSHIRE~~MILLWOOD	345
~~67-1~~ 13	~~BOWLINE 1~~ CLAY	345	~~W.HAVERSTRAW~~ DEWITT	345
~~W93~~ 1-16	~~BUCHANAN N.~~ CLAY	345	~~EASTVIEW 2N~~ EDIC	345
~~W97~~ 2-15	~~BUCHANAN S.~~ CLAY	345	~~MILLWOOD~~ EDIC	345
~~W98~~ BK 2	~~BUCHANAN S.~~ COOPERS CRNS	345	~~MILLWOOD~~ COOPERS CRNS	~~345~~115
~~1~~BK 3	~~CLAY~~ COOPERS CRNS	345	~~DEWITT~~ COOPERS CRNS	~~345~~115

Circuit ID	From	kV	To	kV
~~1-16~~ CRT-34	~~CLAY~~COOPERS CRNS	345	~~EDIC~~ ROCK TAVERN	345
~~2-15~~ CRT-42	~~CLAY~~ COOPERS CRNS	345	~~EDIC~~ ROCK TAVERN	345
~~BK 2~~ 22	~~COOPERS CRNS~~ DEWITT	345	~~COOPERS CRNS~~ LAFAYETTE	~~115~~345
~~BK 3~~ F38	~~COOPERS CRNS~~ E.FISHKIL CE	345	~~COOPERS CRNS~~ WOOD ST	~~115~~345
~~CRT-34~~ F39	~~COOPERS CRNS~~ E.FISHKIL CE	345	~~ROCK TAVERN~~ WOOD ST	345
~~CRT-42~~ W64	~~COOPERS CRNS~~ EASTVIEW 1N	345	~~ROCK TAVERN~~ SPRAINBROOK	345
~~F38~~ W78	~~E.FISHKIL CE~~ EASTVIEW 1S	345	~~WOOD ST~~ SPRAINBROOK	345
~~F39~~ W79	~~E.FISHKIL CE~~ EASTVIEW 2N	345	~~WOOD ST~~ SPRAINBROOK	345
~~W64~~ W65	EASTVIEW ~~1N~~ 2S	345	SPRAINBROOK	345
~~W78~~ EF24-40	~~EASTVIEW 1S~~ EDIC	345	~~SPRAINBROOK~~ FRASER	345
~~W79~~ 14	~~EASTVIEW 2N~~ EDIC	345	~~SPRAINBROOK~~ NEW SCOTLAND	345
~~W65~~ FE-1	~~EASTVIEW 2S~~ FITZPATRICK	345	~~SPRAINBROOK~~ EDIC	345
~~EF24-40~~ FS-10	~~EDIC~~ FITZPATRICK	345	~~FRASER~~ SCRIBA	345
~~14~~ 33	~~EDIC~~ FRASER	345	~~NEW SCOTLAND~~COOPERS CRNS	345
~~17~~ BK 2	~~OSWEGO~~FRASER	345	~~LAFAYETTE~~ FRASER	~~345~~115
~~FE-1~~ GF5-35	~~FITZPATRICK~~ FRASER	345	~~EDIC~~ GILBOA	345
~~3~~GL-3	~~FRASER~~ GILBOA	345	~~COOPERS CRNS~~ LEEDS	345
~~BK 2~~ GNS-1	~~FRASER~~ GILBOA	345	~~FRASER~~ NEW SCOTLAND	~~115~~345
~~GF5-35~~ 37	~~FRASER~~ HOMER CITY	345	~~GILBOA~~ STOLLE RD	345
~~GL-3~~ 30	~~GILBOA~~HOMER CITY	345	~~LEEDS~~ WATERCURE	345
~~GNS-1~~ 303	~~GILBOA~~ HURLEY AVE	345	~~NEW SCOTLAND~~ROSETON	345
~~37~~ 26	~~HOMER CITY~~ INDEPENDENCE	345	~~STOLLE RD~~ CLAY	345
~~30~~ 25	~~HOMER CITY~~ INDEPENDENCE	345	~~WATERCURE~~ SCRIBA	345
~~303~~SR-1	~~HURLEY AVE~~ KINTIGH	345	~~ROSETON~~ ROCHESTER	345

Circuit ID	From	kV	To	kV
~~SR-1~~ 68	~~KINTIGH~~ LADENTOWN	345	~~ROCHESTER~~ BOWLINE 2	345
~~68~~ Y88	LADENTOWN	345	~~BOWLINE 2~~ BUCHANAN S.	345
~~Y88~~ 67-2	LADENTOWN	345	~~BUCHANAN S.~~W.HAVERSTRAW	345
~~67-2~~ 4-36	~~LADENTOWN~~ LAFAYETTE	345	~~W.HAVERSTRAW~~ OAKDALE	345
~~22~~ 301	~~DEWITT~~LEEDS	345	~~LAFAYETTE~~HURLEY AVE	345
~~4-36~~91	~~LAFAYETTE~~ LEEDS	345	~~OAKDALE~~ PLEASANT VALLEY	345
~~301~~ 92	LEEDS	345	~~HURLEY AVE~~ PLEASANT VALLEY	345
~~91~~ 398	~~LEEDS~~LONG MT	345	PLEASANT VALLEY	345
~~92~~ UCC2-41	~~LEEDS~~MARCY	345	~~PLEASANT VALLEY~~COOPERS CRNS	345
~~398~~ UE1-7	~~LONG MT~~MARCY	345	~~PLEASANT VALLEY~~EDIC	345
~~UCC2-41~~ 18	MARCY	345	~~COOPERS CRNS~~ NEW SCOTLAND	345
~~UE1-7~~ W99	~~MARCY~~ MILLWOOD	345	~~EDIC~~ EASTVIEW 1N	345
~~18~~ W85	~~MARCY~~ MILLWOOD	345	~~NEW SCOTLAND~~ EASTVIEW 1S	345
~~W99~~ W82	MILLWOOD	345	EASTVIEW ~~1N~~ 2S	345
~~W85~~ 2	~~MILLWOOD~~ NEW SCOTLAND	345	~~EASTVIEW 1S~~ ALPS	345
~~W82~~ 93	~~MILLWOOD~~ NEW SCOTLAND	345	~~EASTVIEW 2S~~ LEEDS	345
~~R81/R82~~94	NEW SCOTLAND	345	~~NEW SCOTLAND~~LEEDS	345
~~2~~ NS-1-38	~~NEW SCOTLAND~~NIAGARA	345	~~ALPS~~ KINTIGH	345
~~93~~ BK 3	~~NEW SCOTLAND~~NIAGARA	345	~~LEEDS~~ NIAGARA	~~345~~230
~~9~~BK 4	~~NEW SCOTLAND~~NIAGARA	345	~~LEEDS~~ NIAGARA	~~345~~230
~~NS-1-38~~ BK 5	NIAGARA	345	~~KINTIGH~~ NIAGARA	~~345~~230
~~BK 3~~NR2	NIAGARA	345	~~NIAGARA~~ ROCHESTER	~~230~~345
~~BK 5~~ 8	~~NIAGARA~~ NINE MILE PT 1	345	~~NIAGARA~~ CLAY	~~230~~345

Circuit ID	From	kV	To	kV
~~BK 4~~ 9	~~NIAGARA~~ NINE MILE PT 1	345	~~NIAGARA~~ SCRIBA	~~230~~345
~~NR2~~ 32	~~NIAGARA~~ OAKDALE	345	~~ROCHESTER~~ FRASER	345
~~8~~ BK 2	~~NINE MILE PT 1~~OAKDALE	345	~~CLAY~~ OAKDALE	~~345~~115
~~9~~BK 3	~~NINE MILE PT 1~~ OAKDALE	345	~~SCRIBA~~OAKDALE	~~345~~115
~~32~~ 17	~~OAKDALE~~ OSWEGO	345	~~FRASER~~ LAFAYETTE	345
~~BK 2~~ 11	~~OAKDALE~~OSWEGO	345	~~OAKDALE~~ VOLNEY	~~115~~345
~~BK 3~~ 12	~~OAKDALE~~ OSWEGO	345	~~OAKDALE~~VOLNEY	~~115~~345
~~1~~1	~~OSWEGO~~ PANNELL RD	345	~~VOLNEY~~ CLAY	345
~~1~~2	~~OSWEGO~~ PANNELL RD	345	~~VOLNEY~~ CLAY	345
~~1~~ F36	~~PANNELL RD~~ PLEASANT VLY	345	~~CLAY~~ E.FISHKIL CE	345
~~2~~ F37	~~PANNELL RD~~ PLEASANT VLY	345	~~CLAY~~ E.FISHKIL CE	345
~~F36~~ F30	PLEASANT VLY	345	~~E.FISHKIL CE~~ WOOD ST	345
~~F37~~ F31	PLEASANT VLY	345	~~E.FISHKIL CE~~ WOOD ST	345
~~F30~~ W90	~~PLEASANT VLY~~ PLEASNTVL E.	345	~~WOOD ST~~ DUNWOODIE	345
~~F31~~ W89	~~PLEASANT VLY~~ PLEASNTVL W.	345	~~WOOD ST~~ DUNWOODIE	345
~~W90~~ Q35L	~~PLEASNTVL E.~~ POLETTI	345	~~DUNWOODIE~~ E.13TH ST C	345
~~W89~~ Q35M	~~PLEASNTVL W.~~ POLETTI	345	~~DUNWOODIE~~E.13TH ST D	345
~~Q35L~~ Y94	~~POLETTI~~ RAMAPO	345	~~E.13TH ST C~~ BUCHANAN N.	345
~~Q35M~~ W72	~~POLETTI~~ RAMAPO	345	~~E.13TH ST D~~ LADENTOWN	345
~~Y94~~PAR3500	RAMAPO S.	345	~~BUCHANAN N.~~ RAMAPO	345
~~W72~~ PAR4500	RAMAPO S.	345	~~LADENTOWN~~ RAMAPO	345
RP1	ROCHESTER	345	PANNELL RD	345
RP2	ROCHESTER	345	PANNELL RD	345
77	ROCK TAVERN	345	RAMAPO	345
305	ROSETON	345	E.FISHKIL CE	345

Circuit ID	From	kV	To	kV
311	ROSETON	345	ROCK TAVERN	345
69	S.MAHWAH A	345	RAMAPO	345
70	S.MAHWAH B	345	RAMAPO	345
~~FS-10~~ 20	~~FITZPATRICK~~SCRIBA	345	~~SCRIBA~~VOLNEY	345
~~20~~ 21	SCRIBA	345	VOLNEY	345
~~21~~ W75	~~SCRIBA~~ SPRAINBROOK	345	~~VOLNEY~~ DUNWOODIE	345
BK ~~1~~ 3	~~SHORE~~STOLLE RD	345	~~SHORE~~STOLLE RD	~~138~~115
BK ~~2~~ 4	~~SHORE~~STOLLE RD	345	~~SHORE~~STOLLE RD	~~138~~115
~~W75~~ 6	~~SPRAINBROOK~~ VOLNEY	345	~~DUNWOODIE~~ CLAY	345
~~Y49~~ 19	~~SPRAINBROOK~~ VOLNEY	345	~~E.GARDEN CTY~~ MARCY	345
~~BK 3~~ J3410	~~STOLLE RD~~ WALDWICK	345	~~STOLLE RD~~S.MAHWAH A	~~115~~345
~~BK 4~~ K3411	~~STOLLE RD~~ WALDWICK	345	~~STOLLE RD~~ S.MAHWAH B	~~115~~345
~~6~~ 31	~~VOLNEY~~ WATERCURE	345	~~CLAY~~ OAKDALE	345
~~19~~ BK 1	~~VOLNEY~~ WATERCURE	345	~~MARCY~~ WATERCURE	~~345~~230
~~J3410~~ W80	~~WALDWICK~~ WOOD ST	345	~~S.MAHWAH A~~ MILLWOOD	345
~~K3411~~ W81	~~WALDWICK~~ WOOD ST	345	~~S.MAHWAH B~~ MILLWOOD	345
~~31~~ Y87	~~WATERCURE~~ WOOD ST	345	~~OAKDALE~~ PLEASNTVL E.	345
~~BK 1~~ Y86	~~WATERCURE~~ WOOD ST	345	~~WATERCURE~~ PLEASNTVL W.	~~230~~345
~~W80~~ BK 1	WOOD ST	345	~~MILLWOOD~~ WOOD ST	~~345~~115
~~W81~~BK 2	WOOD ST	345	~~MILLWOOD~~ WOOD ST	~~345~~115
~~Y87~~ 11	~~WOOD ST~~ ADIRONDACK	~~345~~230	~~PLEASNTVL E.~~ PORTER	~~345~~230
~~Y86~~ 12	~~WOOD ST~~ ADIRONDACK	~~345~~230	~~PLEASNTVL W.~~ PORTER	~~345~~230
~~BK 1~~ PA27	~~WOOD ST~~ BECK	~~345~~230	~~WOOD ST~~ NIAGARA	~~115~~230
~~BK 2~~ BP76	~~WOOD ST~~ BECK	~~345~~230	~~WOOD ST~~ PACKARD	~~115~~230
~~11~~ 68	~~ADIRONDACK~~ DUNKIRK	230	~~PORTER~~ S.RIPLEY	230

Circuit ID	From	kV	To	kV
~~12~~ 70	~~ADIRONDACK~~ E.TOWANDA	230	~~PORTER~~ HILLSIDE	230
~~E205W~~73	~~ROTTERDAM~~GARDENVILLE	230	~~BEAR SWAMP~~DUNKIRK	230
~~PA27~~ 74	~~BECK~~ GARDENVILLE	230	~~NIAGARA~~ DUNKIRK	230
~~BP76~~ T8-12	~~BECK~~ GARDENVILLE	230	~~PACKARD~~ GARDENVILLE	230
~~70~~ BK 6	~~E.TOWANDA~~ GARDENVILLE	230	~~HILLSIDE~~GARDENVILLE	~~230~~115
~~69~~ BK 7	~~S. RIPLEY~~GARDENVILLE	230	~~ERIE E.~~GARDENVILLE	~~230~~115
~~BK 6~~ 66	GARDENVILLE A	230	~~GARDENVILLE~~ STOLLE RD	~~115~~230
BK ~~7~~ 3	~~GARDENVILLE~~ HILLSIDE	230	~~GARDENVILLE~~ HILLSIDE	115
~~66~~BK 4	~~GARDENVILLE A~~ HILLSIDE	230	~~STOLLE RD~~ HILLSIDE	~~230~~115
~~73~~ 69	~~GARDENVILLE~~ HILLSIDE	230	~~DUNKIRK~~ WATERCURE	230
~~74~~ 79	~~GARDENVILLE~~ HUNTLEY	230	~~DUNKIRK~~ GARDENVILLE	230
~~T8-12~~ 80	~~GARDENVILLE~~ HUNTLEY	230	GARDENVILLE	230
~~BK 3~~ 68	~~HILLSIDE~~ MEYER	230	HILLSIDE	~~115~~230
BK 4	~~HILLSIDE~~ MEYER	230	~~HILLSIDE~~ MEYER	115
~~69~~ MA1	~~HILLSIDE~~ MOSES	230	~~WATERCURE~~ ADIRONDACK	230
~~79~~ MA2	~~HUNTLEY~~ MOSES	230	~~GARDENVILLE~~ADIRONDACK	230
~~80~~ MMS1	~~HUNTLEY~~ MOSES	230	~~GARDENVILLE~~MASSENA A	230
~~68~~ MMS2	~~MEYER~~ MOSES	230	~~HILLSIDE~~ MASSENA B	230
BK ~~4~~ 1	~~MEYER~~MOSES	230	~~MEYER~~ MOSES	115
~~MA1~~ BK 2	MOSES	230	~~ADIRONDACK~~ MOSES	~~230~~115
~~MA2~~ BK 3	MOSES	230	~~ADIRONDACK~~ MOSES	~~230~~115
~~MMS1~~ BK 4	MOSES	230	~~MASSENA A~~ MOSES	~~230~~115
~~MMS2~~ MW1	MOSES	230	~~MASSENA B~~ WILLIS	230
~~BK 1~~ MW2	MOSES	230	~~MOSES~~ WILLIS	~~115~~230
~~BK 2~~ N BUS	~~MOSES~~ NIAGARA	230	~~MOSES~~ NIAGARA	~~115~~230

Circuit ID	From	kV	To	kV
TIE				
~~BK 3~~ S BUS TIE	~~MOSES~~ NIAGARA	230	~~MOSES~~ NIAGARA	~~115~~230
BK ~~4~~ T1	~~MOSES~~ NIAGARA	230	~~MOSES~~ NIAGARA	115
~~MW1~~ BK T2	~~MOSES~~ NIAGARA	230	~~WILLIS~~ NIAGARA	~~230~~115
~~MW2~~ 61	~~MOSES~~ NIAGARA	230	~~WILLIS~~ PACKARD	230
~~64~~ 62	NIAGARA	230	~~ROBINSON RD~~ PACKARD	230
~~BK T1~~ 64	NIAGARA	230	~~NIAGARA~~ ROBINSON RD	~~115~~230
~~N BUS TIE~~ BK 1	~~NIAGARA~~ OAKDALE	230	~~NIAGARA~~ OAKDALE	~~230~~115
~~S BUS TIE~~ 77	~~NIAGARA~~ PACKARD	230	~~NIAGARA~~ HUNTLEY	230
~~BK T2~~ 78	~~NIAGARA~~ PACKARD	230	~~NIAGARA~~ HUNTLEY	~~115~~230
~~61~~BK 4	~~NIAGAR~~PLATTSBURGH A	230	~~PACKARD~~PLATTSBURGH	~~230~~115
~~62~~ BK 1	~~NIAGARA~~ PLATTSBURGH B	230	~~PACKARD~~ PLATTSBURGH	~~230~~115
~~BK 1~~ 30	~~OAKDALE~~ PORTER	230	~~OAKDALE~~ ROTTERDAM	~~115~~230
~~77~~ 31	~~PACKARD~~ PORTER	230	~~HUNTLEY~~ ROTTERDAM	230
~~78~~ BK 1	~~PACKA~~ROBINSON RD	230	~~HUNTLEY~~ ROBINSON RD	~~230~~115
~~BK 4~~ 65	~~PLATTSBURGH A~~ ROBINSON RD	230	~~PLATTSBURGH 1~~ STOLLE RD	~~115~~230
~~BK 1~~ E205W	~~PLATTSBURGH B~~ ROTTERDAM	230	~~PLATTSBURGH 1~~ BEAR SWAMP	~~115~~230
~~30~~ 69	~~PORTER~~S.RIPLEY	230	~~ROTTERDAM~~ ERIE E.	230
~~31~~ L 33P	~~PORTER~~ ST.LAW L33P	230	~~ROTTERDAM~~ MOSES	230
~~BK 1~~L 34P	~~ROBINSON RD~~ ST.LAW L34P	230	~~ROBINSON RD~~ MOSES	~~115~~230
~~65~~ 67	~~ROBINSON~~STOLLE RD	230	~~STOLLE RD~~ MEYER	230
~~68~~ 71	~~DUNKIRK~~WATERCURE	230	~~S. RIPLEY~~OAKDALE	230
~~PSL 33P~~ WP2	~~ST.LAW OH A~~ WILLIS	230	~~ST.LAW OH B~~ PLATTSBURGH A	230

Circuit ID	From	kV	To	kV
~~PSL 34P~~ WP1	~~ST.LAW OH C~~ WILLIS	230	~~ST.LAW OH D~~ PLATTSBURGH B	230
~~67~~ BK 1	~~STOLLE RD~~ WILLIS	230	~~MEYER~~ WILLIS	~~230~~115
~~71~~ BK 2	~~WATERCURE~~ WILLIS	230	~~OAKDALE~~ WILLIS	~~230~~115
~~WP2~~ 998	~~WILLIS~~ CODDINGTN RD	~~230~~115	~~PLATTSBURGH~~ ETNA	~~230~~115
~~WP1~~ 907	~~WILLIS~~ HARRISON RAD	~~230~~115	~~PLATTSBURGH B~~ ROBINSON RD	~~230~~115
~~BK 1~~ 964	~~WILLIS~~ HICKLING	~~230~~115	~~WILLIS~~ RIDGE RD	115
~~BK 2~~ 963	~~WILLIS~~ HILLSIDE	~~230~~115	~~WILLIS~~ RIDGE RD	115
~~PAR~~ 943	~~BARRETT 1~~ JENNISON	~~138~~115	~~BARRETT 2~~ KATTELVILLE	~~138~~115
~~459~~ 966	~~BARRETT 1~~ MEYER	~~138~~115	~~FREEPORT~~ BENNETT	~~138~~115
~~864~~ 968	~~BROOKHAVEN~~ MEYER	~~138~~115	~~RIVERHEAD~~ GREENIDGE	~~138~~115
~~361~~974	~~E.GARDEN CTY~~ MILLIKEN	~~138~~115	~~CARLE PLACE~~ ETNA	~~138~~115
~~462~~ 975	~~E.GARDEN CTY~~ MILLIKEN	~~138~~115	~~NEWBRIDGE RD~~ ETNA	~~138~~115
~~463~~ 982	~~E.GARDEN CTY~~ MONTOUR FLS	~~138~~115	~~NEWBRIDGE~~CODDINGTN RD	~~138~~115
~~465~~ 701	~~E.GARDEN CTY~~ NORTHEND	~~138~~115	~~NEWBRIDGE RD~~ PLATTSBURGH	~~138~~115
~~362~~ 939	~~E.GARDEN CTY~~ OAKDALE	~~138~~115	~~ROSLYN~~ GOUDEY	~~138~~115
~~461~~ 943	~~FREEPORT~~ OAKDALE	~~138~~115	~~NEWBRIDGE RD~~ KATTELVILLE	~~138~~115
~~366-1~~ PAR3	~~GLENWOOD GT~~ PLATTSBURGH	~~138~~115	~~GLENWOOD N~~ PLATTSBURGH	~~138~~115
~~364~~ PV20	~~GLENWOOD GT~~ PLATTSBURGH	~~138~~115	~~ROSLYN~~ SOUTH HERO, VT	~~138~~115
~~363~~ 906- 7X	~~GLENWOOD S~~ STA 162	~~138~~115	~~CARLE PLACE~~ S.PERRY	~~138~~115
~~674~~ 976	~~GREENLAWN~~ STATE ST	~~138~~115	~~ELWOOD E~~WRIGHT AVE	~~138~~115
~~889~~ BK 1	~~HAUPPAUG~~ W.WOODBOURNE	~~138~~115	~~CENTRAL ISLIP~~ W.WOODBOURNE	~~138~~69
~~887~~ 973	~~HOLBROOK~~ WRIGHT AVE	~~138~~115	~~BROOKHAVEN~~ MILLIKEN	~~138~~115
~~888~~ REA #1	~~HOLBROOK~~ MARCY	~~138~~765	~~HOLTSVILLE~~	~~138~~

Circuit ID	From	kV	To	kV
~~874~~ REA #1	~~HOLTSVILLE~~ MASSENA	~~138~~765	~~BROOKHAVEN~~	~~138~~
~~818~~ REA #2	~~HOLTSVILLE~~ MASSENA	~~138~~765	~~UNION AVE~~	~~138~~
~~563~~ CAP A	~~NEWBRIDGE RD~~ COOPERS CRNS	~~138~~345	~~PILGRIM 1~~	~~138~~
~~561~~ CAP B	~~NEWBRIDGE RD~~ COOPERS CRNS	~~138~~345	~~RULAND~~	~~138~~
~~562~~ CAP #`1	~~NEWBRIDGE RD~~ E. FISHKIL CE	~~138~~345	~~RULAND~~	~~138~~
~~672~~ CAP # 2	~~NORTHPORT~~ E~~-~~. FISHKIL CE	~~138~~345	~~PILGRIM 1~~	~~138~~
~~677~~ CAP # 1	~~NORTHPORT E~~ FRASER	~~138~~345	~~PILGRIM 1~~	~~138~~
~~679~~ CAP # 2	~~NORTHPORT E~~ FRASER	~~138~~345	~~PILGRIM 2~~	~~138~~
~~PAR 1~~ SVC	~~NORTHPORT NE~~ FRASER	~~138~~345	~~NORTHPORT E~~	~~138~~
~~681~~ CAP # 1	~~NORTHPORT W~~ GILBOA	~~138~~345	~~ELWOOD E~~	~~138~~
~~678~~ CAP # 1	~~NORTHPORT W~~ MARCY	~~138~~345	~~ELWOOD W~~	~~138~~
~~PS2~~ CAP # 2	~~NORTHPORT W~~ MARCY	~~138~~345	~~NORTHPORT E~~	~~138~~
~~1385~~CAP # 1	~~NORWALK HARB~~ ROCHESTER	~~138~~345	~~NORTHPORT NE~~	~~138~~
~~673~~ CAP # 1	~~OAKWOOD~~ ROCK TAVERN	~~138~~345	~~ELWOOD W~~	~~138~~
~~675~~ CAP # 2	~~OAKWOOD~~ ROCK TAVERN	~~138~~345	~~SYOSSET~~	~~138~~

A.2 - Listing of Transmission Facilities Requiring NYISO Notification

~~871~~ Circuit ID	~~PILGRIM 1~~ From	~~138~~kV	~~HAUPPAUG~~ To	~~138~~kV
~~881~~ BK TA5	~~PILGRIM 2~~ BUCHANAN N.	~~138~~345	~~HOLTSVILLE~~ BUCHANAN TA5	138
~~PAR~~ BK 1	~~PILGRIM 2~~ CLAY	~~138~~345	~~PILGRIM 1~~CLAY	~~138~~115
~~883~~ BK 2	~~PILGRIM 2~~ CLAY	~~138~~345	~~RONKONKOMA~~ CLAY	~~138~~115
~~862~~ BK 2	~~PORT JEFF~~ DEWITT	~~138~~345	~~HOLBROOK~~ DEWITT	~~138~~115
~~886~~ BK N1	~~PORT JEFF~~ DUNWOODIE	~~138~~345	~~HOLBROOK~~ DUNWOODIE N1	138
~~875~~ BK S1	~~RONKONKOMA~~ DUNWOODIE	~~138~~345	~~HOLBROOK~~ DUNWOODIE S1	138
~~882~~ 71	~~RULAND~~ DUNWOODIE	~~138~~345	~~HOLBROOK~~ RAINEY	~~138~~345
~~661~~ 72	~~RULAND~~ DUNWOODIE	~~138~~345	~~PILGRIM 1~~ RAINEY	~~138~~345
~~662~~ Y50	~~RULAND~~ DUNWOODIE	~~138~~345	~~PILGRIM 2~~ SHORE RD	~~138~~345
~~366-2~~ BK 14	~~SHORE RD~~ E. 13TH ST A	~~138~~345	~~GLENWOOD N~~ E. 13TH ST	138
~~365~~ BK 15	~~SHORE RD~~ E. 13TH ST A	~~138~~345	~~GLENWOOD S~~ E. 13TH ST	138
~~367~~ 45	~~SHORE RD~~ E. 13TH ST A	~~138~~345	~~LK SUCCESS E~~ FARRAGUT	~~138~~345
~~368~~ BK 12	~~SHORE RD~~ E. 13TH ST B	~~138~~345	~~LK SUCCESS~~ E. 13TH ST	138
~~861~~ BK 13	~~SHOREHAM~~ E. 13TH ST B	~~138~~345	~~BROOKHAVEN~~ E. 13TH ST	138
~~885~~ 46	~~SHOREHAM~~ E. 13TH ST B	~~138~~345	~~HOLBROOK~~ FARRAGUT	~~138~~345
~~863~~ BK 16	~~SHOREHAM~~ E. 13TH ST C	~~138~~345	~~WILDWOOD~~ E. 13TH ST	138
~~676~~ B47	~~SYOSSET~~ E. 13TH ST C	~~138~~345	~~GREENLAWN~~ FARRAGUT	~~138~~345
~~558~~ BK 10	~~SYOSSET~~ E. 13TH ST D	~~138~~345	~~LOCUST GROVE~~ E. 13TH ST	138
~~559~~ BK 11	~~SYOSSETT~~ E. 13TH ST D	~~138~~345	~~LOCUST GROVE~~ E. 13TH ST	138
~~291~~ 48	~~VALLEY STR 1~~ E. 13TH ST D	~~138~~345	~~BARRETT 1~~ FARRAGUT	~~138~~345
~~292~~ BK 1	~~VALLEY STR 2~~ E. FISHKILL CE	~~138~~345	~~BARRETT 2~~ E. FISHKILL CH	~~138~~115
~~262~~ BK 1	~~VALLEY STR 2~~ E.G.C. BNK 1	~~138~~345	E. GARDEN CTY	138
~~884~~ BK 2	~~WADING RIV~~ E.G.C. BNK 2	~~138~~345	~~HOLBROOK~~ E. GARDEN CTY	138

~~871~~ **Circuit ID**	~~PILGRIM 1~~ **From**	~~138~~**kV**	~~HAUPPAUG~~ **To**	~~138~~**kV**
~~891~~ PAR 1	~~WADING RIV~~ E. GARDEN CTY	~~138~~345	~~SHOREHAM~~ E.G.C. BNK 1	~~138~~345
~~890~~ PAR 2	~~WILDWOOD~~ E. GARDEN CTY	~~138~~345	~~RIVERHEAD~~ E.G.C. BNK 2	~~138~~345
~~966~~BK 1 N	~~BENNETT A~~EASTVIEW 1N	~~115~~345	~~MEYER~~EASTVIEW	~~115~~138
~~998~~ BK 1 S	~~CODDINGTN RD~~ EASTVIEW 1S	~~115~~345	~~ETNA~~ EASTVIEW	~~115~~138
~~974~~ BK 2 N	~~ETNA~~ EASTVIEW 2N	~~115~~345	~~MILLIKEN~~ EASTVIEW	~~115~~138
~~975~~ BK 2 S	~~ETNA~~ EASTVIEW 2S	~~115~~345	~~MILLIKEN~~ EASTVIEW	~~115~~138
~~939~~ BK 2	~~GOUDEY~~ EDIC	~~115~~345	~~OAKDALE~~ EDIC	~~115~~230
~~968~~ BK 3	~~GREENIDGE~~ EDIC	~~115~~345	~~MEYER~~EDIC	115
~~907~~ BK 4	~~HARRISON RAD~~ EDIC	~~115~~345	~~ROBINSON RD~~ EDIC	115
~~964~~ BK 1	~~HICKLING~~ ELBRIDGE	~~115~~345	~~RIDGE RD A~~ ELBRIDGE	115
~~963~~ 41	~~HILLSIDE~~ FARRAGUT	~~115~~345	~~RIDGE RD A~~ GOWANUS N41	~~115~~345
~~943~~ 42	~~JENNISON~~ FARRAGUT	~~115~~345	~~KATTELVILLE~~ GOWANUS S42	~~115~~345
~~943~~ BK 11	~~KATTELVILLE~~ FARRAGUT 2	~~115~~345	~~OAKDALE~~ FARRAGUT	~~115~~345
~~934~~ TA 1	~~MEYER~~ FRESHKILLS	~~115~~345	~~S.PERRY~~ FRESHKILLS R	~~115~~138
~~973~~ TB 1	~~MILLIKEN~~ FRESHKILLS	~~115~~345	~~WRIGHT AVE~~ FRESHKILLS R	~~115~~138
~~982~~ 22	~~MONTOUR FLS~~ GOETHALS N.1	~~115~~345	~~CODDINGTN RD~~ FRESHKILLS	~~115~~345
~~701~~ BK 1N	~~NORTHEND~~GOETHALS N.1	~~115~~345	~~PLATTSBURGH~~ GOETHALS N.2	~~115~~345
~~4(977)~~BK 1	~~PANNELL RD~~GOETHALS N.2	~~115~~345	~~GENEVA (BORDER CITY)~~GOETHALS	~~115~~230
~~PAR3~~ 21	~~PLATTSBURGH 1~~GOETHALS S.	~~115~~345	~~PLATTSBURGH 3~~ FRESHKILLS	~~115~~345
~~PV20~~G23L&M	~~PLATTSBURGH 3~~GOETHALS S.	~~115~~345	~~SOUTH HERO, VT~~LINDEN CE	~~115~~345
~~976~~ R41 S.REACT	~~STATE ST~~ GOWANUS	~~115~~345	~~WRIGHT AVE~~	~~115~~
~~906 7X~~R42 S.REACT	~~STA 162~~GOWANUS	~~115~~345	~~S.PERRY~~	~~115~~
~~BK 1~~ 25	~~W.WOODBOURNE~~ GOWANUS N.	~~115~~345	~~W.WOODBOURNE~~ GOETHALS N.1	~~69~~345

~~871~~ Circuit ID	~~PILGRIM 1~~ From	~~138~~kV	~~HAUPPAUG~~ To	~~138~~kV

~~Reactive Devices~~

~~CAP A~~	~~COOPERS CRNS~~	~~345~~
~~CAP B~~	~~COOPERS CRNS~~	~~345~~
~~CAP #1~~	~~E.FISHKIL CE~~	~~345~~
~~CAP #2~~	~~E.FISHKIL CE~~	~~345~~
~~CAP #1~~	~~FRASER~~	~~345~~
~~CAP #2~~	~~FRASER~~	~~345~~
~~SVC~~	~~FRASER~~	~~345~~
~~CAP #1~~	~~GILBOA~~	~~345~~
~~CAP #1~~	~~MARCY~~	~~345~~
~~CAP #2~~	~~MARCY~~	~~345~~
~~CAP #1~~	~~ROCHESTER 3~~	~~345~~
~~CAP #1~~	~~ROCK TAVERN~~	~~345~~
~~CAP #2~~	~~ROCK TAVERN~~	~~345~~
~~R1~~	~~MASSENA~~	~~765~~
~~R2~~	~~MASSENA~~	~~765~~
~~R1~~	~~MARCY~~	~~765~~

~~Appendix A-2: Listing of Transmission Facilities Requiring NYISO Notification~~

BK T2	GOWANUS N.	345	GOWANUS B	138
26	GOWANUS S.	345	GOETHALS S.	345
BK T14	GOWANUS S.	345	GOWANUS D	138
B3402	HUDSON A	345	FARRAGUT 1	345
C3403	HUDSON B	345	FARRAGUT 2	345
BK 1	HURLEY AVE	345	HURLEY AVE	115
TA 1	MILLWOOD	345	MILLWOOD	138
TA 2	MILLWOOD	345	MILLWOOD	138
R81/R82	NEW SCOTLAND	345	NEW SCOTLAND	345
BK 1	NEW SCOTLAND	345	NEW SCOTLAND	115
BK 2	NEW SCOTLAND	345	NEW SCOTLAND	115
BK S1	PLEASANT VLY	345	PLEASANT VLY	115
BK 2	PLEASANTVL E.	345	PLEASANTVL	13
BK 1	PLEASANTVL W.	345	PLEASANTVL	13
61	RAINEY	345	FARRAGUT	345
62	RAINEY	345	FARRAGUT	345
63	RAINEY	345	FARRAGUT	345
BK8W	RAINEY	345	RAINEY 1	138
BK 8E	RAINEY	345	RAINEY 2	138
BK1300	RAMAPO	345	RAMAPO	138
~~Circuit ID~~BK 2300	**~~From~~**RAMAPO	**~~kV~~**345	**~~To~~**RAMAPO	**~~kV~~**138
~~BK TR1~~ 1	~~ROCK TAVERN~~ REYNOLDS RD	345	~~ROCK TAVERN~~ ALPS	~~115~~345
BK ~~S1~~ 2	~~0PLEASANT VLY~~ REYNOLDS RD	345	~~PLEASANT VLY~~ REYNOLDS RD	115
~~TA~~BK 1	~~MILLWOOD~~ROCHESTER	345	~~MILLWOOD~~STA 80	~~138~~115
~~TA~~BK 2	~~MILLWOOD~~ROCHESTER	345	~~MILLWOOD~~STA 80	~~138~~115
BK ~~1~~ 3	~~E.FISHKIL CE~~ROCHESTER	345	~~E.FISHKIL CH~~STA 80	115
~~22~~ BK TR1	~~GOETHALS N.1~~ ROCK TAVERN	345	~~FRESHKILLS~~ ROCK TAVERN	~~345~~115
BK ~~1N~~ 258	~~GOETHALS N.1~~ S. MAHWAH A	345	~~GOETHALS N.2~~ S. MAHWAH	~~345~~138

NEW YORK INDEPENDENT SYSTEM OPERATOR

Appendix A~~-2: Listing of Transmission Facilities Requiring NYISO Notification~~

BK 1	~~GOETHALS N.2~~ SHORE RD	345	~~GOETHALS~~ SHORE RD	~~230~~138
BK ~~TA5~~ 2	~~BUCHANAN N.~~ SHORE RD	345	~~BUCHANAN TA5~~ SHORE RD	138
~~21~~ BK S6	~~GOETHALS S.~~ SPRAINBROOK	345	~~FRESHKILLS~~ DUNWOODIE N2	~~345~~138
~~TA 1~~ BK N7	~~FRESHKILLS~~ SPRAINBROOK	345	~~FRESHKILLS R~~ DUNWOODIE S3	138
~~TB 1~~ Y 49	~~FRESHKILLS~~ SPRAINBROOK	345	~~FRESHKILLS R~~ E. GARDEN CTY	~~138~~345
~~BK 1~~X28	~~CLAY~~SPRAINBROOK	345	~~CLAY~~TREMONT	~~115~~345
~~BK 2~~M51	~~CLAY~~SPRAINBROOK	345	~~CLAY~~W. 49TH ST	~~115~~345
~~BK 2~~M52	~~DEWITT~~SPRAINBROOK	345	~~DEWITT~~W 49TH ST	~~115~~345
~~BK 1~~M54	~~E.G.C. BNK1~~W 49TH ST	345	~~E.GARDEN CTY~~E 13TH ST A	~~138~~345
~~BK 2~~M55	~~E.G.C. BNK2~~W 49TH ST	345	~~E.GARDEN CTY~~E 13TH ST B	~~138~~345
~~PAR1~~BK 194	~~E.GARDEN CTY~~W. HAVERSTRAW	345	~~E.G.C. BNK1~~W.HAVERSTRAW	~~345~~138
~~PAR2~~BK 31	~~E.GARDEN CTY~~DUNKIRK	~~345~~230	~~E.G.C. BNK2~~DUNKIRK	~~345~~115
BK ~~2~~41	~~EDIC~~DUNKIRK	~~345~~230	~~EDIC~~DUNKIRK	~~230~~115
BK ~~3~~2	~~EDIC~~GARDENVILLE	~~345~~230	~~EDIC~~GARDENVILLE	115
BK ~~4~~3	~~EDIC~~GARDENVILLE	~~345~~230	~~EDIC~~GARDENVILLE	115
BK ~~1~~4	~~ELBRIDGE~~GARDENVILLE	~~345~~230	~~ELBRIDGE~~GARDENVILLE	115
BK ~~T2~~130	~~GOWANUS N.~~HUNTLEY	~~345~~230	~~GOWANUS B~~HUNTLEY	~~138~~23
BK ~~T14~~140	~~GOWANUS S.~~HUNTLEY	~~345~~230	~~GOWANUS D~~HUNTLEY	~~138~~23
~~BK 1~~A2253	~~HURLEY AVE~~LINDEN	~~345~~230	~~HURLEY AVE~~GOETHALS	~~115~~230
BK 2	~~NEW SCOTLAND~~PACKARD	~~345~~230	~~NEW SCOTLAND~~PACKARD	115
BK ~~1~~3	~~NEW SCOTLAND~~PACKARD	~~345~~230	~~NEW SCOTLAND~~PACKARD	115
BK ~~7~~4	~~OSWEGO~~PACKARD	~~345~~230	~~OSWEGO~~ PACKARD	115
BK 1	~~PANNELL RD~~PORTER	~~345~~230	~~PANNELL RD~~PORTER	115

~~**Appendix A-2: Listing of Transmission Facilities Requiring NYISO Notification**~~

BK 2	~~PANNELL RD~~PORTER	~~345~~230	~~PANNELL RD~~PORTER	115
BK ~~1300~~6	~~RAMAPO~~ROTTERDAM	~~345~~230	~~RAMAPO~~ROTTERDAM	~~138~~115
BK ~~2300~~7	~~RAMAPO~~ROTTERDAM	~~345~~230	~~RAMAPO~~ROTTERDAM	~~138~~115
BK ~~2~~8	~~REYNOLDS RD~~ROTTERDAM	~~345~~230	~~REYNOLDS RD~~ROTTERDAM	115
~~BK 1~~34124 L	~~ROCHESTER~~ ASTORIA E	~~345~~138	~~STA 80~~ASTORIA 4	~~115~~138
~~BK 2~~34125 L	~~ROCHESTER~~ ASTORIA E	~~345~~138	~~STA 80~~ASTORIA 5	~~115~~138
~~BK 3~~34181	~~ROCHESTER~~ ASTORIA E	~~345~~138	~~STA 80~~CORONA	~~115~~138
~~BK 258~~34182	~~S.MAHWAH A~~ASTORIA E	~~345~~138	~~S.MAHWAH~~CORONA	138
~~BK 194~~34183	~~W.HAVERSTRAW~~ASTORIA E	~~345~~138	~~W.HAVERSTRAW~~CORONA	138
~~71~~34184	~~DUNWOODIE~~ASTORIA E	~~345~~138	~~RAINEY~~CORONA	~~345~~138
~~72~~34185	~~DUNWOODIE~~ASTORIA E	~~345~~138	~~RIANEY~~CORONA	~~345~~138
~~41~~34186	~~FARRAGUT~~ASTORIA E	~~345~~138	~~GOWANUS N41~~CORONA	~~345~~138
~~42~~24121	~~FARRAGUT~~ASTORIA W	~~345~~138	~~GOWANUS S 42~~ASTORIA 3	~~345~~138
~~G23L&M~~24122	~~GOETHALS S~~ASTORIA W	~~345~~138	~~LINDEN CE S~~ASTORIA 3	~~345~~138
~~25~~24124M	~~GOWANUS N~~ASTORIA W	~~345~~138	~~GOETHALS N1~~ASTORIA 4	~~345~~138
~~26~~24125M	~~GOWANUS S~~ASTORIA W	~~345~~138	~~GOETHALS S~~ASTORIA 5	~~345~~138
~~61~~28241	~~RAINEY~~ASTORIA W	~~345~~138	~~FARRAGUT~~QUEENS BRDG	~~345~~138
~~62~~28242	~~RAINEY~~ASTORIA W	~~345~~138	~~FARRAGUT~~QUEENS BRDG	~~345~~138
~~63~~28243	~~RAINEY~~ASTORIA W	~~345~~138	~~FARRAGUT~~QUEENS BRDG	~~345~~138
~~BK 8W~~28244	~~RAINEY~~ASTORIA W	~~345~~138	~~RAINEY 1~~QUEENS BRDG	138
~~BK 8E~~PAR	~~RAINEY~~BARRETT 1	~~345~~138	~~RAINEY 2~~BARRETT 2	138
~~BK S6~~459	~~SPRAINBROOK~~BARRETT 1	~~345~~138	~~DUNWOODIE N2~~FREEPORT	138
~~BK N7~~864	~~SPRAINBROOK~~BROOKHAVEN	~~345~~138	~~DUNWOODIE S3~~RIVERHEAD	138
~~B3402~~95891	~~HUDSON A~~BUCHANAN GT	~~345~~138	~~FARRAGUT 1~~BUCHANAN TA5	~~345~~138
~~C3403~~96951	~~HUDSON B~~BUCHANAN GT	~~345~~138	~~FARRAGUT 2~~MILLWOOD	~~345~~138

~~Appendix~~ A~~-2: Listing of Transmission Facilities Requiring NYISO Notification~~

~~X28~~96952	~~SPRAINBROOK~~BUCHANAN GT	~~345~~138	~~TREMONT~~MILLWOOD	~~345~~138
~~M51~~18001	~~SPRAINBROOK~~CORONA PAR1	~~345~~138	~~W 49TH ST.~~JAMAICA	~~345~~138
~~M52~~18002	~~SPRAINBROOK~~CORONA PAR2	~~345~~138	~~W 49TH ST.~~JAMAICA	~~345~~138
~~M54~~BK N1	~~W 49TH ST.~~DUNWOODIE N1	~~345~~138	~~E 13TH ST. A~~DUNWOODIE N3	~~345~~138
~~M55~~BK N2	~~W49TH ST.~~DUNWOODIE N1	~~345~~138	~~E 13TH ST. B~~DUNWOODIE N4	~~345~~138
~~A2253~~ 99997 TIE	~~LINDEN~~ DUNWOODIE N1	~~230~~138	~~GOETHALS~~ DUNWOODIE S1	~~230~~138
~~BK 31~~99941	~~DUNKIRK~~DUNWOODIE N2	~~230~~138	~~DUNKIRK~~DUNWOODIE N1	~~115~~138
~~BK 41~~99031	~~DUNKIRK~~DUNWOODIE N3	~~230~~138	~~DUNKIRK~~SHERMAN CRK	~~115~~138
~~BK 2~~99032	~~GARDENVILLE~~ DUNWOODIE N4	~~230~~138	~~GARDENVILLE~~ SHERMAN CRK	~~115~~138
BK ~~3~~S1	~~GARDENVILLE~~ DUNWOODIE S1	~~230~~138	~~GARDENVILLE~~ DUNWOODIE S2	~~115~~138
BK ~~4~~S2	~~GARDENVILLE~~ DUNWOODIE S1	~~230~~138	~~GARDENVILLE~~ DUNWOODIE S2	~~115~~138
~~BK 130~~99153	~~HUNTLEY~~DUNWOODIE S2	~~230~~138	~~HUNTLEY~~E. 179TH ST	~~23~~138
~~BK 140~~99942	~~HUNTLEY~~DUNWOODIE S3	~~230~~138	~~HUNTLEY~~DUNWOODIE S1	~~23~~138
~~BK 3~~15054	~~PACKARD~~E.179TH ST	~~230~~138	~~PACKARD~~ HELLGATE 1	~~115~~138
~~BK 2~~15053	~~PACKARD~~E.179TH ST	~~230~~138	~~PACKARD~~ HELLGATE 4	~~115~~138
~~BK 4~~15055	~~PACKARD~~E.179TH ST	~~230~~138	~~PACKARD~~ HELLGATE 6	~~115~~138
~~BK 1~~38X01	~~PORTER~~E.179TH ST	~~230~~138	~~PORTER~~PARKCHESTR1	~~115~~138
~~BK 2~~38X02	~~PORTER~~E.179TH ST	~~230~~138	~~PORTER~~PARKCHESTR2	~~115~~138
~~BK 6~~38X04	~~ROTTERDAM~~E.179TH ST	~~230~~138	~~ROTTERDAM~~PARKCHESTR3	~~115~~138
~~BK 7~~38X03	~~ROTTERDAM~~E.179TH ST	~~230~~138	~~ROTTERDAM~~PARKCHESTR4	~~115~~138
~~BK 8~~361	~~ROTTERDAM~~E. GARDEN CTY	~~230~~138	~~ROTTERDAM~~CARLE PLACE	~~115~~138
~~BK N1~~462	~~DUNWOODIE N1~~ E. GARDEN CTY	138	~~DUNWOODIE N3~~ NEWBRIDGE RD	138

~~Appendix~~ A~~-2: Listing of Transmission Facilities Requiring NYISO Notification~~

~~BK S1~~ 463	~~DUNWOODIE S1~~ E. GARDEN CTY	138	~~DUNWOODIE S2~~ NEWBRIDGE RD	138
~~PSR 1~~ 465	~~FRESHKILS AK~~ E. GARDEN CTY	138	~~FRESHKILLS R~~ NEWBRIDGE RD	138
~~PSR 2~~ 362	~~FRESHKILS AK~~ E. GARDEN CTY	138	~~FRESHKILLS R~~ ROSLYN	138
~~34181~~32078	~~ASTORIA E~~FARRAGUT HUD	138	~~CORONA~~HUDSON AVE D	138
~~34182~~29211-1	~~ASTORIA E~~FOXHILLS 1	138	~~CORONA~~WILLOWBROOK	138
~~34183~~29212-1	~~ASTORIA E~~FOXHILLS 2	138	~~CORONA~~WILLOWBROOK	138
~~34184~~461	~~ASTORIA E~~FREEPORT	138	~~CORONA~~NEWBRIDGE RD	138
~~34185~~PSR 1	~~ASTORIA E~~FRESHKILS AK	138	~~CORONA~~FRESHKILLS R	138
~~34186~~PSR 2	~~ASTORIA E~~FRESHKILS AK	138	~~CORONA~~FRESHKILLS R	138
~~28241~~366-1	~~ASTORIA W~~GLENWOOD GT	138	~~QUEENS BRDG~~GLENWOOD N	138
~~28242~~364	~~ASTORIA W~~GLENWOOD GT	138	~~QUEENS BRDG~~ROSLYN	138
~~28243~~363	~~ASTORIA W~~GLENWOOD S	138	~~QUEENS BRDG~~CARLE PLACE	138
~~28244~~42231	~~ASTORIA W~~GOWANUS A	138	~~QUEENS BRDG~~GREENWOOD	138
~~96951~~42232	~~BUCHANAN GT~~GOWANUS C	138	~~MILLWOOD~~GREENWOOD	138
~~96952~~674	~~BUCHANAN GT~~GREENLAWN	138	~~MILLWOOD~~ELWOOD E	138
~~18001~~29231	~~CORONA PAR1~~GREENWOOD	138	~~JAMAICA~~FOXHILLS 1	138
~~18002~~29232	~~CORONA PAR2~~GREENWOOD	138	~~JAMAICA~~FOXHILLS 2	138
~~BK N2~~889	~~DUNWOODIE N1~~HAUPPAUG	138	~~DUNWOODIE N4~~CENTRAL ISLIP	138
~~99997 TIE~~34052	~~DUNWOODIE N1~~HELLGATE 1	138	~~DUNWOODIE S1~~ASTORIA E	138
~~99941~~24054	~~DUNWOODIE N2~~HELLGATE 2	138	~~DUNWOODIE N1~~ASTORIA W	138
~~99031~~24053	~~DUNWOODIE N3~~HELLGATE 3	138	~~SHERMAN CRK~~ASTORIA W	138
~~36312~~34051	~~RAINEY 1~~HELLGATE 4	138	~~VERNON~~ASTORIA E	138

~~Appendix A-2: Listing of Transmission Facilities Requiring NYISO Notification~~

~~36311~~24051	~~RAINEY 2~~HELLGATE 5	138	~~VERNON~~ASTORIA W	138
24052	HELLGATE 6	138	ASTORIA W	138
~~BK11~~887	~~TREMONT 11E~~HOLBROOK	138	~~TREMONT 11W~~BROOKHAVEN	138
~~BK12~~888	~~TREMONT 12E~~HOLBROOK	138	~~TREMONT 12W~~HOLTSVILLE	138
~~99032~~874	~~DUNWOODIE N4~~HOLTSVILLE	138	~~SHERMAN CRK~~BROOKHAVEN	138
~~BK S2~~818	~~DUNWOODIE S1~~HOLTSVILLE	138	~~DUNWOODIE S2~~UNION AVE	138
~~99153~~32711	~~DUNWOODIE S2~~HUDSON AVE A	138	~~E.179TH ST~~HUDSON AVE D	138
~~99942~~32077	~~DUNWOODIE S3~~HUDSON AVE B	138	~~DUNWOODIE S1~~HUDSON AVE D	138
~~15054~~701	~~E.179TH ST~~HUDSON AVE D	138	~~HELLGATE 1~~JAMAICA	138
~~15053~~702	~~E.179TH ST~~HUDSON AVE D	138	~~HELLGATE 4~~JAMAICA	138
~~15055~~903	~~E.179TH ST~~JAMAICA	138	~~HELLGATE 6~~LK SUCCESS W	138
~~38X01~~901 L&M	~~E.179TH ST~~JAMAICA	138	~~PARKCHESTR1~~VALLEY STR 1	138
~~38X02~~PAR	~~E.179TH ST~~LK SUCCESS E	138	~~PARKCHESTR2~~LK SUCCESS W	138
~~38X04~~563	~~E.179TH ST~~NEWBRIDGE RD	138	~~PARKCHESTR3~~PILGRIM 1	138
~~38X03~~561	~~E.179TH ST~~NEWBRIDGE RD	138	~~PARKCHESTR4~~RULAND	138
~~32078~~562	~~FARRAGUT HUD~~NEWBRIDGE RD	138	~~HUDSON AVE D~~RULAND	138
~~29211-~~1672	~~FOXHILLS 1~~NORTHPORT E	138	~~WILLOWBROOK~~PILGRIM 1	138
~~29212-~~1677	~~FOXHILLS 2~~NORTHPORT E	138	~~WILLOWBROOK~~PILGRIM 1	138
~~42231~~679	~~GOWANUS A~~NORTHPORT E	138	~~GREENWOOD~~PILGRIM 2	138
~~42232~~PAR 1	~~GOWANUS C~~NORTHPORT NE	138	~~GREENWOOD~~NORTHPORT E	138
~~29231~~681	~~GREENWOOD~~NORTHPORT W	138	~~FOXHILLS 1~~ELWOOD E	138
~~29232~~678	~~GREENWOOD~~NORTHPORT W	138	~~FOXHILLS 2~~ELWOOD W	138

~~**Appendix A-2: Listing of Transmission Facilities Requiring NYISO Notification**~~

~~34052~~PS2	~~HELLGATE 1~~NORTHPORT W	138	~~ASTORIA E~~NORTHPORT E	138
~~24054~~1385	~~HELLGATE 2~~NORWALK HARB	138	~~ASTORIA W~~NORTHPORT NE	138
~~24053~~673	~~HELLGATE 3~~OAKWOOD	138	~~ASTORIA W~~ELWOOD W	138
~~34051~~675	~~HELLGATE 4~~OAKWOOD	138	~~ASTORIA E~~SYOSSET	138
~~24051~~871	~~HELLGATE 5~~PILGRIM 1	138	~~ASTORIA W~~HAUPPAUG	138
~~24052~~881	~~HELLGATE 6~~PILGRIM 2	138	~~ASTORIA W~~HOLTSVILLE	138
~~32711~~PAR	~~HUDSON AVE A~~PILGRIM 2	138	~~HUDSON AVE D~~PILGRIM 1	138
~~32077~~883	~~HUDSON AVE B~~PILGRIM 2	138	~~HUDSON AVE D~~RONKOKOMA	138
~~701~~862	~~HUDSON AVE D~~PORT JEFF	138	~~JAMAICA~~HOLBROOK	138
~~702~~886	~~HUDSON AVE D~~PORT JEFF	138	~~JAMAICA~~HOLBROOK	138
31281	QUEENS BRDG	138	VERNON	138
31282	QUEENS BRDG	138	VERNON	138
~~15031~~36312	~~SHERMAN CRK~~RAINEY 1	138	~~E.179TH ST~~VERNON	138
~~15032~~36311	~~SHERMAN CRK~~RAINEY 2	138	~~E.179TH ST~~VERNON	138
26 / BK 7108	~~SUGARLOAF~~RAMAPO	138	~~RAMAPO~~SUGARLOAF	~~138~~69
~~BK 7108~~875	~~SUGARLOAF~~RONKONKOMA	138	~~SUGARLOAF~~HOLBROOK	~~69~~138
~~38X01~~882	~~TREMONT 11E~~RULAND	138	~~PARKCHESTR1~~HOLBROOK	138
~~38X02~~661	~~TREMONT 11E~~RULAND	138	~~PARKCHESTR2~~PILGRIM 1	138
~~38X04~~662	~~TREMONT 12E~~RULAND	138	~~PARKCHESTR3~~PILGRIM 2	138
~~38X03~~15031	~~TREMONT 12E~~SHERMAN CRK	138	~~PARKCHESTR4~~E.179TH ST	138
~~31231~~15032	~~VERNON~~SHERMAN CRK	138	~~GREENWOOD~~E.179TH ST	138
~~31232~~366-2	~~VERNON~~SHORE RD	138	~~GREENWOOD~~GLENWOOD N	138
~~29211-~~2365	~~WILLOWBROOK~~SHORE RD	138	~~FRESHKILS AK~~LK SUCCESS E	138
~~29212-~~2367	~~WILLOWBROOK~~SHORE RD	138	~~FRESHKILS AK~~LK SUCCESS E	138
~~18~~368	~~BETHLEHEM~~SHORE RD	~~115~~138	~~ALBANY~~LK SUCCESS E	~~115~~138

~~**Appendix A-2: Listing of Transmission Facilities Requiring NYISO Notification**~~

~~1~~861	~~ALBANY~~SHOREHAM	~~115~~138	~~GREENBUSH~~BROOKHAVEN	~~115~~138
2885	~~ALBANY~~SHOREHAM	~~115~~138	~~GREENBUSH~~HOLBROOK	~~115~~138
~~12~~863	~~ALCOA~~SHOREHAM	~~115~~138	~~DENNISON~~WILDWOOD	~~115~~138
~~13~~676	~~ALCOA~~SYOSSET	~~115~~138	~~N.OGDENSBURG~~GREENLAWN	~~115~~138
~~R8105~~558	~~ALCOA N.~~SYOSSET	~~115~~138	~~ALCOA~~ LOCUST GROVE	~~115~~138
~~182~~559	~~PACKARD~~SYOSSET	~~115~~138	~~GARDENVILLE~~LOCUST GROVE	~~115~~138
~~10~~38X01	~~MECO~~TREMONT 11E	~~115~~138	~~ROTTERDAM~~PARKCHESTR1	~~115~~138
~~93~~238X02	~~ANDOVER~~TREMONT 11E	~~115~~138	~~PALMITER RD~~PARKCHESTR2	~~115~~138
~~K26~~BK11	~~ASCUTNEY A~~TREMONT 11E	~~115~~138	~~GRANITE~~TREMONT 11W	~~115~~138
~~22700~~38X04	~~ASHLEY RD~~TREMONT 12E	~~115~~138	~~PLATTSBURGH~~ PARKCHESTR3	~~115~~138
~~117~~38X03	~~BATAVIA~~TREMONT 12E	~~115~~138	~~SE.BATAVIA~~PARKCHESTR4	~~115~~138
~~953~~BK12	~~BATH~~TREMONT 12E	~~115~~138	~~BENNETT A~~TREMONT 12W	~~115~~138
~~104~~291	~~BECK~~VALLEY STR 1	~~115~~138	~~LOCKPORT~~BARRETT 1	~~115~~138
~~932~~PAR	~~BENNETT A~~VALLEY STR 1	~~115~~138	~~PALMITER~~VALLEY STR 2	~~115~~138
~~142~~292	~~GARDENVILLE~~VALLEY STR 2	~~115~~138	~~DUNKIRK~~BARRETT 2	~~115~~138
~~6~~262	~~HOOSICK~~VALLEY STR 2	~~115~~138	~~BENNINGTON~~E. GARDEN CTY	~~115~~138
~~3~~31231	~~COFFEEN~~VERNON	~~115~~138	~~BLACK RIVER~~GREENWOOD	~~115~~138
~~1~~31232	~~BLACK RIVER~~VERNON	~~115~~138	~~TAYLORVILLE~~GREENWOOD	~~115~~138
~~6~~884	~~BLACK RIVER~~WADING RIV	~~115~~138	~~LIGHTHOUSE HILL~~HOLBROOK	~~115~~138
~~2~~891	~~BLACK RIVER~~WADING RIV	~~115~~138	~~TAYLORVILLE~~SHOREHAM	~~115~~138
~~K37~~890	~~BLISSVILLE~~WILDWOOD	~~115~~138	~~W.RUTLAND~~RIVERHEAD	~~115~~138
~~13~~29211-2	~~PLEASANT VALLEY~~WILLOWBROOK	~~115~~138	~~BLU STORES A~~FRESHKILS AK	~~115~~138
~~5~~29212-2	~~TAYLORVILLE~~WILLOWBROOK	~~115~~138	~~BOONVILLE~~FRESHKILS AK	~~115~~138
1	~~BOONVILLE~~ALBANY	115	~~PORTER~~GREENBUSH	115

~~Appendix~~ A~~-2: Listing of Transmission Facilities Requiring NYISO Notification~~

2	~~BOONVILLE~~ALBANY	115	~~PORTER~~GREENBUSH	115
~~6~~12	~~TAYLORVILLE~~ALCOA	115	~~BOONEVILLE~~DENNISON	115
~~969~~13	~~BORDER CITY~~ALCOA	115	~~GREENIDGE~~N.OGDENSBURG	115
~~1-BK~~R8105	~~BRAINARDSVLE~~ALCOA N.	115	~~KENTS FLS~~ALCOA	115
~~1-WB~~20	~~BRAINARDSVLE~~ALTAMONT	115	~~WILLIS~~NEW SCOTLAND	115
~~161-1~~157 (932)	~~DUNKIRK~~ANDOVER	115	~~FALCONER~~PALMITER RD	115
~~7~~700	~~OSWEGO~~ASHLEY RD	115	~~FULTON~~PLATTSBURGH	115
~~1~~5 (972)	~~ROTTERDAM~~AUBURN (STATE ST)	115	~~SPIER~~ ELBRIDGE	115
~~2~~117	~~ROTTERDAM~~BATAVIA	115	~~SPIER~~ SE.BATAVIA	115
~~3~~953	~~BROWNS FALLS~~BATH	115	~~TAYLORVILLE~~BENNETT A	115
~~4~~965	~~BROWNS FALLS~~BATH	115	~~TAYLORVILLE~~MONTOUR FLS	115
~~1~~BL 104	~~CEDARS~~BECK	115	~~DENNISON~~LOCKPORT	115
~~2~~932	~~CEDARS~~BENNETT A	115	~~DENNISON~~PALMITER	115
~~DW-1~~18	~~CHADWICK~~BETHLEHEM	115	~~DANSKAMMER~~ALBANY	115
~~DW-2~~6	~~CHADWICK~~BLACK RIVER	115	~~E.WALDEN~~LIGHTHOUSE HILL	115
~~DW-3~~1	~~CHADWICK~~BLACK RIVER	115	~~W.BALMVILLE~~TAYLORVILLE	115
~~14~~2	~~SCHODACK~~BLACK RIVER	115	~~CHURCHTOWN~~TAYLORVILLE	115
~~3~~8	~~CLAY~~BLUE CIRCLE CEMENT	115	~~DEWITT~~PLEASANT VALLEY	115
~~5~~1	~~CLAY~~BOONVILLE	115	~~DEWITT~~PORTER	115
~~4~~2	~~ELBRIDGE~~BOONVILLE	115	~~WOODWARD~~PORTER	115
~~13~~969	~~GREENBUSH~~BORDER CITY	115	~~SCHODACK~~GREENIDGE	115
~~17~~1	~~CLAY~~BRAINARDSVILLE	115	~~WOODARD~~KENTS FLS	115
~~11~~3	~~CLAY~~BROWNS FALLS	115	~~HOPKINS~~TAYLORVILLE	115
~~14~~4	~~CLAY~~BROWNS FALLS	115	~~GE~~TAYLORVILLE	115

~~**Appendix A-2: Listing of Transmission Facilities Requiring NYISO Notification**~~

~~10~~15	~~CLAY~~CARR ST	115	~~TEALL AVE~~DEWITT	115
~~3(971)~~6	~~SLEIGHT RD~~CEDAR	115	~~AUBURN (STATE ST)~~ WHITEHALL	115
~~15~~1/11	~~CLINTON~~CEDARS	115	~~ING-MECOTAP~~DENNISON	115
~~15~~22/22	~~GARDENVILLE~~CEDARS	115	~~HOMER HILL~~DENNISON	115
~~5~~DW-1	~~COFFEEN~~CHADWICK	115	~~LIGHTHOUSE HILL~~DANSKAMMER	115
~~929~~DW-2	~~COLLIERS~~CHADWICK	115	~~RICHFIELD~~E.WALDEN	115
~~2~~DW-3	~~COLTON~~CHADWICK	115	~~BROWNS FALLS~~W.BALMVILLE	115
~~1~~13	~~COLTON~~CHURCHTOWN	115	~~BROWNS FALLS~~PLEASANT VALLEY	115
~~7~~3	~~COLTON~~CLAY	115	~~BATTLE HILL~~DEWITT	115
5	~~DENNISON~~CLAY	115	~~COLTON~~DEWITT	115
~~4~~14	~~DENNISON~~CLAY	115	~~COLTON~~GE	115
~~950~~10	~~COOPERS CRNS~~CLAY	115	~~FERNDALE~~TEALL AVE	115
~~957~~11	~~COOPERS CRNS~~CLAY	115	~~W.WOODBOURNE~~TEALL AVE	115
~~3-~~17	~~ONEIDA~~CLAY	115	~~CORTLAND~~WOODARD	115
~~18~~15	~~TILDEN~~CLINTON	115	~~CORTLAND~~ING-MECOTAP	115
~~1(947)~~981-1	~~CORTLAND~~CODDINGTN RD	115	~~ETNA~~E. ITHACA	115
~~991/995~~3	~~CROTON FLS~~COFFEEN	115	~~AMAWALK~~BLACK RIVER	115
~~994/990~~5	~~CROTON FLS~~COFFEEN	115	~~SYLVAN LK~~LIGHTHOUSE HILL	115
~~991/992~~929	~~CROTON FLS~~COLLIERS	115	~~WOOD ST~~RICHFIELD SPRINGS	115
~~AC~~7	~~DANSKAMMER~~COLTON	115	~~N.CHELSEA~~BATTLE HILL	115
~~DC~~1	~~DANSKAMMER~~COLTON	115	~~N.CHELSEA~~BROWNS FALLS	115
~~DR~~2	~~DANSKAMMER~~COLTON	115	~~REYNOLDS HL~~BROWNS FALLS	115
~~DB~~3	~~DANSKAMMER~~COLTON	115	~~W.BALMVILLE~~MALONE	115

~~**Appendix A-2: Listing of Transmission Facilities Requiring NYISO Notification**~~

~~903~~950	~~DAVIS RD~~COOPERS CRNS	115	~~GARDENVILE A~~FERNDALE	115
~~927~~957	~~DAVIS RD~~COOPERS CRNS	115	~~STOLLE RD~~W.WOODBOURNE	115
~~951-2~~1 (947)	~~DELHI TAP~~CORTLAND	115	~~COLLIERS~~ETNA	115
~~15~~991/995	~~CARR ST~~CROTON FLS	115	~~DEWITT~~AMAWALK	115
~~4~~994/990	~~TEALL AVE~~CROTON FLS	115	~~DEWITT~~SYLVAN LK	115
~~19~~991/992	~~DEWITT~~CROTON FLS	115	~~TILDEN~~WOOD ST	115
~~16~~013	~~DUNKIRK~~CURTIS ST.	115	~~FALCONER~~TEALL AVE.	115
~~162~~AC	~~DUNKIRK~~DANSKAMMER	115	~~FALCONER~~N.CHELSEA	115
~~EF~~DC	~~E.FISHKIL CH~~DANSKAMMER	115	~~SHENANDOAH~~N.CHELSEA	115
~~LR-1~~DR	~~E.KINGSTON~~DANSKAMMER	115	~~LINCOLN PARK~~REYNOLDS HL	115
~~LR-2~~DB	~~E.KINGSTON~~DANSKAMMER	115	~~RHINEBECK~~W.BALMVILLE	115
~~PX-1~~903	~~E.WALDEN~~DAVIS RD	115	~~MODENA~~GARDENVILLE	115
~~D~~927	~~E.WALDEN~~DAVIS RD	115	~~ROCK TAVERN~~STOLLE RD	115
~~J~~951-1	~~E.WALDEN~~DELHI	115	~~ROCK TAVERN~~DELHI TAP	115
~~19~~949	~~ELBRIDGE~~DELHI	115	~~GERES LOCK~~JENNISON	115
~~3~~919	~~ELBRIDGE~~DELHI	115	~~GERES LOCK~~OAKDALE	115
~~5~~951-2	~~ELBRIDGE~~DELHI TAP	115	~~STATE ST.~~COLLIERS	115
~~5/972~~4	~~ELBRIDGE~~DENNISON	115	~~STATE ST.~~COLTON	115
~~926~~5	~~ERIE ST~~DENNISON	115	~~STOLLE RD~~COLTON	115
~~153~~19	~~FALCONER~~DEWITT	115	~~HOMER HILL~~TILDEN	115
~~154~~160	~~FALCONER~~DUNKIRK	115	~~HOMER HILL~~FALCONER	115
~~954/955~~161	~~FERNDALE~~DUNKIRK	115	~~HAZEL~~FALCONER	115
~~959~~162	~~FERNDALE~~DUNKIRK	115	~~W.WOODBOURNE~~FALCONER	115
~~2~~J	~~FEURA BUSH~~E.WALDEN	115	~~N.CATSKILL~~ROCK TAVERN	115
~~HF~~981-2	~~FISHKILL PLN~~E.ITHACA	115	~~E.FISHKIL CH~~ETNA	115

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~~NF~~LR-2	~~FISHKILL PLN~~E.KINGSTON	115	~~N.CHELSEA~~RHINEBECK	115
~~A/990~~946	~~FISHKILL PLN~~E. NORWICH	115	~~SYLVAN LK~~JENNISON	115
3956	~~FITZPATRICK~~E.SAYRE	115	~~LIGHTHOUSE HILL~~N. WAVERLY	115
~~951-T~~PX-1	~~FRASER~~E.WALDEN	115	~~DELHI TAP~~MODENA	115
4D	~~FULTON~~E.WALDEN	115	~~CLAY~~ROCK TAVERN	115
~~925~~18	~~GARDENVILLE~~ ELBRIDGE	115	~~STOLLE RD~~GERES LOCK	115
~~141~~19	~~GARDENVILLE~~ELBRIDGE	115	~~DUNKIRK~~GERES LOCK	115
~~54(921)~~3	~~GARDENVILLE~~ ELBRIDGE	115	~~ERIE ST~~GERES LOCK	115
~~151~~4	~~GARDENVILLE~~ELBRIDGE	115	~~HOMER HILL~~WOODWARD	115
9926	~~S. OSWEGO~~ERIE ST	115	~~GERES LOCK~~STOLLE RD	115
8945-2	~~GE~~ETNA	115	~~GERES LOCK~~WILLET	115
~~16~~153	~~GERES LOCK~~FALCONER	115	~~TILDEN~~HOMER HILL	115
~~911-1~~154	~~GINNA~~FALCONER	115	~~STA 204A~~HOMER HILL	115
~~913~~171	~~GINNA~~FALCONER	115	~~STA 42~~WARREN	115
~~110~~959	~~MORTIMER~~FERNDALE	115	~~GOLAH~~W.WOODBOURNE	115
~~PV20-1~~2	~~GRAND IS~~FEURA BUSH	115	~~S.HERO~~N.CATSKILL	115
~~15~~HF	~~GREENBUSH~~FISHKILL PLN	115	~~HUDSON~~E.FISHKIL CH	115
9A/990	~~REYNOLDS RD~~FISHKILL PLN	115	~~GREENBUSH~~SYLVAN LK	115
9553	~~HANCOCK~~FITZPATRICK	115	~~HAZEL~~LIGHTHOUSE HILL	115
~~908~~951-T	~~HARRISON RAD~~FRASER	115	~~HINMAN~~DELHI TAP	115
~~962-1~~4	~~HILLSIDE~~FULTON	115	~~N.WAVERLY~~CLAY	115
~~157~~141	~~HOMER HILL~~GARDENVILLE	115	~~ANDOVER~~DUNKIRK	115
5142	~~N. TROY~~GARDENVILLE	115	~~HOOSICK~~DUNKIRK	115
~~38~~54(921)	~~HUNTLEY~~GARDENVILLE	115	~~GARDENVILLE~~ERIE ST	115

~~Appendix~~ A~~-2: Listing of Transmission Facilities Requiring NYISO Notification~~

~~36~~151	~~HUNTLEY~~GARDENVILLE	115	~~LOCKPORT~~HOMER HILL	115
~~37~~152	~~HUNTLEY~~GARDENVILLE	115	~~LOCKPORT~~HOMER HILL	115
~~39~~925	~~HUNTLEY~~GARDENVILLE	115	~~GARDENVILLE~~STOLLE RD	115
~~130~~8	~~PACKARD~~GE	115	~~HUNTLEY~~GERES LOCK	115
~~13~~315 (979)	~~WALCK RD~~GENEVA (BORDER CITY)	115	~~HUNTLEY~~ELBRIDGE	115
~~HP~~16	~~HURLEY AVE~~GERES LOCK	115	~~LINCOLN PARK~~TILDEN	115
~~OR-1~~908	~~HURLEY AVE~~GINNA	115	~~OHIOVILLE~~PANNELL RD	115
~~15(979)~~912	~~GENEVA(BORDER CITY)~~GINNA	115	~~ELBRIDGE~~PANNELL RD	115
~~2~~911-1	~~INDECK~~GINNA	115	~~LIGHTHOUSE HILL~~STA 204A	115
~~15~~913	~~INGHAMS~~GINNA	115	~~MECO~~STATION 42	115
~~PAR-2~~15	~~INGHAMS CD~~GREENBUSH	115	~~INGHAMS ED~~HUDSON	115
~~R81-~~13	~~INGHAMS CD~~GREENBUSH	115	~~INGHAMS ED~~SCHODACK	115
~~39~~67	~~VALLEY~~GREENIDGE	115	~~INGHAMS CD~~MONTOUR FLS	115
~~7(942)~~970	~~INGHAMS ED~~GREENIDGE	115	~~RICHFIELD SPRINGS~~MONTOUR FLS	115
~~1-KS~~908	~~KENTS FLS~~HARRISON RAD	115	~~SARANAC~~HINMAN	115
~~MC~~960/958	~~KNAPPS CRN~~HICKLING	115	~~MANCHESTER A~~HILLSIDE	115
~~952~~962-1	~~LAUREL LK~~HILLSIDE	115	~~GOUDEY~~N.WAVERLY	115
~~7~~157	~~LIGHTHOUSE H~~HOMER HILL	115	~~CLAY~~ANDOVER	115
~~100~~6	~~LOCKPORT~~HOOSICK	115	~~HINMAN~~BENNINGTON	115
~~107~~12	~~LOCKPORT~~HUDSON	115	~~BATAVIA~~PLEASANT VALLEY	115
~~108~~38	~~LOCKPORT~~HUNTLEY	115	~~BATAVIA~~GARDENVILLE	115
~~112~~39	~~LOCKPORT~~HUNTLEY	115	~~BATAVIA~~GARDENVILLE	115
~~102~~36	~~LOCKPORT~~HUNTLEY	115	~~NIAGARA~~LOCKPORT	115

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~~111~~37	~~LOCKPORT~~HUNTLEY	115	~~MORTIMER~~LOCKPORT	115
~~113~~HP	~~LOCKPORT~~HURLEY AVE	115	~~MORTIMER~~LINCOLN PARK	115
~~114~~OR-1	~~LOCKPORT~~HURLEY AVE	115	~~MORTIMER~~OHIOVILLE	115
~~3~~2	~~COLTON~~INDECK	115	~~MALONE~~LIGHTHOUSE HILL	115
~~1~~15	~~WILLIS~~INGHAMS	115	~~MALONE~~MECO	115
~~6~~7(942)	~~MCINTYRE~~INGHAMS ED	115	~~BATTLE HILL~~RICHFIELD SPRINGS	115
~~T7~~9	~~N. CATSKILL~~INGHAMS	115	~~MILAN~~STONER	115
~~MR~~PAR 2	~~MILAN~~INGHAMS CD	115	~~RHINEBECK~~INGHAMS ED	115
~~PX-2~~R81	~~MODENA~~INGHAMS CD	115	~~OHIOVILLE~~INGHAMS ED	115
~~139~~54	~~WHITEHALL~~JENNISON	115	~~MOHICAN~~HANCOCK	115
1-KS	~~MORTIMER~~KENTS FLS	115	~~ELBRIDGE~~SARANAC	115
~~2~~MC	~~MORTIMER~~KNAPPS CRN	115	~~ELBRIDGE~~MANCHESTER A	115
~~24~~952	~~MORTIMER~~LAUREL LK	115	~~PANNELL RD~~GOUDEY	115
~~25~~7	~~MORTIMER~~LIGHTHOUSE H	115	~~PANNELL RD~~CLAY	115
~~904~~LR-1	~~MORTIMER~~LINCOLN PARK	115	~~ROCHESTER (STA 80)~~E. KINGSTON	115
~~103~~107	~~MOUNTAIN~~LOCKPORT	115	~~LOCKPORT~~BATAVIA	115
~~702~~108	~~NORTHEND~~LOCKPORT	115	~~ASHLEY RD~~BATAVIA	115
~~9~~112	~~N.OGDENSBURG~~LOCKPORT	115	~~MCINTYRE~~BATAVIA	115
~~16~~100	~~N.TROY~~LOCKPORT	115	~~REYNOLDS RD~~HINMAN	115
~~14~~111	~~N.TROY~~LOCKPORT	115	~~WYNANTSKILL~~MORTIMER	115
~~8~~113	~~NEW SCOTLAND~~LOCKPORT	115	~~ALBANY~~MORTIMER	115
~~20~~114	~~ALTAMONT~~LOCKPORT	115	~~NEW SCOTLAND~~MORTIMER	115
~~4~~6	~~NEW SCOTLAND~~MCINTYRE	115	~~BETHLEHEM~~BATTLE HILL	115
~~3~~10	~~NEW SCOTLAND~~MECO	115	~~FEURA BUSH~~ROTTERDAM	115

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~~9~~10	~~NEW SCOTLAND~~MILAN	115	~~FEURA BUSH~~PLEASANT VALLEY	115
~~7~~MR	~~NEW SCOTLAND~~MILAN	115	~~LONG LANE~~RHINEBECK	115
~~13~~PX-2	~~ROTTERDAM~~MODENA	115	~~NEW SCOTLAND~~OHIOVILLE	115
~~181(922)~~963-2	~~PACKARD~~MONTOUR FLS	115	~~ERIE ST.~~RIDGE RD	115
~~180~~978-2	~~NIAGARA~~ MONTOUR FLS	115	~~GARDENVILLE~~ RIDGE RD	115
~~101~~1	~~NIAGARA~~ MORTIMER	115	~~LOCKPORT~~ELBRIDGE	115
~~120~~2	~~MOUNTAIN~~MORTIMER	115	~~NIAGARA~~ELBRIDGE	115
~~191~~110	~~NIAGARA~~ MORTIMER	115	~~PACKARD~~ GOLAH	115
~~192~~24	~~NIAGARA~~ MORTIMER	115	~~PACKARD~~ PANNELL RD	115
~~193~~25	~~NIAGARA~~ MORTIMER	115	~~PACKARD~~ PANNELL RD	115
~~194~~904	~~NIAGARA~~ MORTIMER	115	~~PACKARD~~ ROCHESTER (STA 80)	115
~~195~~901	~~NIAGARA~~ MORTIMER	115	~~PACKARD~~ STA 33	115
~~102~~7X8272	~~NIAGARA~~MORTIMER	115	~~LOCKPORT~~ STA 82	115
MAL 4	~~NINE MILE PT 1~~MOSES	115	~~FITZPATRICK~~ALCOA N.	115
~~OR-2~~MAL 6	~~OHIOVILLE~~MOSES	115	~~REYNOLDS HL~~ALCOA N.	115
~~6~~MAL 5	~~ONEIDA~~MOSES	115	~~YAHNUNDASIS~~ALCOA S.	115
~~2~~103	~~TEALL AVE~~MOUNTAIN	115	~~ONEIDA~~LOCKPORT	115
~~5~~120	~~TEALL AVE~~MOUNTAIN	115	~~ONEIDA~~NIAGARA	115
~~3~~5	~~OSWEGO~~N. TROY	115	~~S.OSWEGO~~HOOSICK	115
~~5~~T7	~~OSWEGO~~ N. CATSKILL	115	~~S.OSWEGO~~MILAN	115
~~8~~NF	~~OSWEGO~~ N. CHELSEA	115	~~S.OSWEGO~~FISHKILL PLN	115
~~12~~99	~~PACKARD~~ N.OGDENSBURG	115	~~WALCK RD~~MCINTYRE	115
~~23~~16	~~STA 82~~N.TROY	115	~~QUAKER~~REYNOLDS RD	115

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~~PS1~~14	~~PLATTSBURGH~~ N.TROY	115	~~SARANAC~~WYNANTSKILL	115
8	~~E. CIRCLE CEMENT~~NEW SCOTLAND	115	~~PLEASANT VALLEY~~ALBANY	115
~~C/A~~4	~~PLEASANT VALLEY~~NEW SCOTLAND	115	~~FISHKILL PLN~~BETHLEHEM	115
~~1~~23	~~HUDSON~~NEW SCOTLAND	115	~~PLEASANT VALLEY~~FEURA BUSH	115
~~X-1~~9	~~PLEASANT VLY~~NEW SCOTLAND	115	~~INWOOD~~FEURA BUSH	115
~~M~~7	~~PLEASANT VLY~~NEW SCOTLAND	115	~~MANCHESTER A~~LONG LANE	115
~~10~~180	~~MILAN~~NIAGARA	115	~~PLEASANT VALLEY~~GARDENVILLE	115
~~13~~101	~~CHURCHTOWN~~NIAGARA	115	~~PLEASANT VALLEY~~LOCKPORT	115
~~7~~102	~~ONEIDA~~NIAGARA	115	~~PORTER~~LOCKPORT	115
~~4~~191	~~PORTER~~NIAGARA	115	~~VALLEY~~PACKARD	115
~~5~~192	~~PORTER~~NIAGARA	115	~~WATKINS RD~~PACKARD	115
~~930~~193	~~QUAKER RD~~NIAGARA	115	~~MACEDON~~PACKARD	115
~~914~~194	~~QUAKER RD~~NIAGARA	115	~~PANNELL RD~~PACKARD	115
~~13~~195	~~QUAKER RD~~NIAGARA	115	~~SLEIGHT RD~~PACKARD	115
~~3~~4	~~YAHNUNDASIS~~NINE MILE PT 1	115	~~PORTER~~FITZPATRICK	115
~~7X8272~~702	~~MORTIMER~~NORTHEND	115	~~STA 82~~ASHLEY RD	115
~~X-~~OR-2	~~REYNOLDS HL~~OHIOVILLE	115	~~INWOOD~~REYNOLDS HL	115
~~SL~~3	~~ROCK TAVERN~~ONEIDA	115	~~SUGARLOAF~~CORTLAND	115
~~1~~7	~~ROTTERDAM~~ONEIDA	115	~~ALTAMONT~~PORTER	115
~~1~~6	~~ROTTERDAM~~ONEIDA	115	~~NEW SCOTLAND~~YAHNUNDASIS	115
~~6~~3	~~S.~~OSWEGO	115	~~INDECK~~S. OSWEGO	115

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~~1~~5	~~S.~~OSWEGO	115	~~NINE MILE PT 1~~S. OSWEGO	115
~~10~~8	~~S.~~OSWEGO	115	~~CURTIS ST~~S. OSWEGO	115
~~961~~181 (922)	~~S.OWEGO~~PACKARD	115	~~GOUDEY~~ERIE ST.	115
~~962-2~~182	~~S.OWEGO~~PACKARD	115	~~N.WAVERLY~~GARDENVILLE	115
~~REA BYPSS~~ 130	~~SANDBAR~~PACKARD	115	~~SANDBAR OMS~~HUNTLEY	115
~~SERIES REA~~129	~~SANDBAR~~PACKARD	115	~~SANDBAR OMS~~WALCK RD	115
~~PV20-2~~4 (977)	~~SANDBAR OMS~~PANNELL RD	115	~~S.HERO~~GENEVA (BORDER CITY)	115
~~119~~PS1	~~SE.BATAVIA~~PLATTSBURGH	115	~~GOLAH~~SARANAC	115
~~906~~C/A	~~STA 162~~PLEASANT VLY	115	~~STA 82~~FISHKILL PLN	115
~~911-2~~X-1	~~STA 204A~~PLEASANT VLY	115	~~STA 42~~INWOOD	115
~~901~~M	~~MORTIMER~~PLEASANT VLY	115	~~STA 33~~MANCHESTER A	115
~~922~~4	~~STA 67~~PORTER	115	~~STA 80B~~VALLEY	115
~~903~~5	~~STA 67~~PORTER	115	~~STA 82~~WATKINS RD	115
~~902~~930	~~STA 82~~QUAKER RD	115	~~STA 33B~~MACEDON	~~34~~115
~~905~~914	~~STA 82~~QUAKER RD	115	~~STA 80A~~PANNELL RD	115
~~BK 6108~~13 (980)	~~SUGARLOAF~~QUAKER RD	115	~~SUGARLOAF~~SLEIGHT RD	~~69~~115
~~17~~16	~~FALCONER~~QUEENSBURY	115	~~WARREN~~CEDAR	115
~~WH1-1~~X-2	~~HONK FLS~~REYNOLDS HL	~~69~~115	~~NEVERSINK B~~INWOOD	~~69~~115
~~WH2~~SL	~~HONK FLS~~ROCK TAVERN	~~69~~115	~~W.WOODBOURNE~~SUGARLOAF	~~69~~115
~~WH1-2~~17	~~NEVERSINK A~~ROTTERDAM	~~69~~115	~~NEVERSINK B~~ALTAMONT	~~69~~115
13	~~CURTIS ST~~ROTTERDAM	115	~~TEALL AVE~~NEW SCOTLAND	115
~~WH1-3~~19	~~NEVERSINK B~~ROTTERDAM	~~69~~115	~~W.WOODBOURNE~~NEW SCOTLAND	~~69~~115

~~Appendix A-2: Listing of Transmission Facilities Requiring NYISO Notification~~

~~908~~1	~~GINNA~~ROTTERDAM	115	~~PANNELL~~ SPIER	115
~~912~~2	~~GINNA~~ROTTERDAM	115	~~PANNELL~~SPIER	115
~~913~~7	~~GINNA~~S. OSWEGO	115	~~STATION 42~~FULTON	115
~~903~~ 10	~~JAMAICA~~ S. OSWEGO	~~138~~115	~~LK SUCCESS W~~ CURTIS ST	~~138~~115
~~901 L&M~~ 9	~~JAMAICA~~ S. OSWEGO	~~138~~115	~~VALLEY STR 1~~ GERES LOCK	~~138~~115
~~PAR~~ 6	~~LK SUCCESS E~~ S.OSWEGO	~~138~~115	~~LK SUCCESS W~~ INDECK	~~138~~115
~~PAR~~ 1	~~VALLEY STR 1~~ S.OSWEGO	~~138~~115	~~VALLEY STR 2~~ NINE MILE PT 1	~~138~~115

~~**Appendix A-3**~~
~~**Bus Voltage Limits**~~
~~for ISO Secured System~~

~~Bus Name~~	~~Pre Low~~	~~Pre High~~	~~Post Low~~	~~Post High~~	~~Set By~~
~~Bowline 345~~	~~338~~	~~362~~	~~328~~	~~362~~	~~OR~~
~~Buchanan 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~Clay 345~~	~~345~~	~~362~~	~~328~~	~~362~~	~~NM~~
~~Coopers Corners 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~NY~~
~~Dunwoodie 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~(1) Edic 345~~	~~347~~	~~362~~	~~328~~	~~362~~	~~NM~~
~~Farragut 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~Fraser 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~NY~~
~~Gardenville 230~~	~~217~~	~~242~~	~~207~~	~~242~~	~~NY~~
~~Gilboa 345~~	~~348~~	~~362~~	~~328~~	~~362~~	~~PA~~
~~Goethals 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~Gowanus 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~Hurley Ave 345~~	~~338~~	~~362~~	~~328~~	~~362~~	~~CH~~
~~Ladentown 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~Leeds 345~~	~~345~~	~~362~~	~~328~~	~~372~~	~~NM~~
~~(1) Marcy 345~~	~~348~~	~~362~~	~~328~~	~~380~~	~~PA~~
~~Millwood 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~NewScotland 345~~	~~348~~	~~362~~	~~328~~	~~362~~	~~NM~~
~~Niagara 230~~	~~225~~	~~242~~	~~219~~	~~242~~	~~PA~~
~~Niagara 345~~	~~338~~	~~362~~	~~328~~	~~362~~	~~PA~~
~~Northport 138~~	~~135~~	~~145~~	~~131~~	~~145~~	~~LI~~
~~(2) Oakdale 345~~	~~335~~	~~-362~~	~~320~~	~~380~~	~~NY~~
~~(2) Pannell Road 345~~	~~see pg 2~~	~~359~~	~~328~~	~~362~~	~~RG~~
~~Pleasant Valley 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~Rainey 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~(3) Ramapo 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~Ramapo 500~~	~~500~~	~~550~~	~~500~~	~~575~~	~~CE~~
~~Roseton 345~~	~~338~~	~~362~~	~~328~~	~~362~~	~~CH~~
~~Somerset 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~NY~~
~~Sprainbrook 345~~	~~338~~	~~362~~	~~328~~	~~380~~	~~CE~~
~~(2) Station 80 345~~	~~see pg 2~~	~~359~~	~~328~~	~~362~~	~~RG~~
~~St Lawrence 230~~	~~225~~	~~242~~	~~219~~	~~242~~	~~PA~~
~~(2) Watercure 230~~	~~215~~	~~242~~	~~207~~	~~242~~	~~NY~~

~~**Notes**~~

~~(1): Marcy 345 kV bus voltage is reduced to 345 kV prior to energizing the Massena-Marcy 765 kV MSU-1 line. By exception, Marcy and Edic voltages are allowed below their pre-contingency low limits for this condition.~~

~~(2): Pre-contingency low limits for various HQ to NYISO transfers are listed in Exhibit A-4~~

~~(3): Voltage below 327 kV at Ramapo may cause the loss of the Bowline Units~~

~~Appendix B – Operating Criteria~~

~~Appendix B-1 summarizes the system conditions defining the Operating States.~~

~~Appendix B-2 lists exceptions to operating criteria for pre-contingency and post-contingency transmission facility flows and voltages.~~

~~Appendix B-3 lists pre-contingency low limits for various HQ to NYISO transfers.~~

~~Appendix B-4 lists multiple circuit tower lines in the NY Control Area [MP 29-1, A].~~

~~Appendix B-5 lists the~~ 961	S.OWEGO	115	GOUDEY	115
962-2	S.OWEGO	115	N.WAVERLY	115
933	S. PERRY	115	MEYER	115
14	SCHODACK	115	CHURCHTOWN	115
119	SE. BATAVIA	115	GOLAH	115
EF	SHENANDOAH	115	E. FISHKIL CH	115
3 (971)	SLEIGHT RD	115	AUBURN (STATE ST)	115
906	STA 162	115	STA 82	115
911-2	STA 204A	115	STA 42	115
922	STA 67	115	STA 80	115
903	STA 67	115	STA 82	115
902	STA 82	115	STA 33	34
905	STA 82	115	STA 80	115
12	STONER	115	ROTTERDAM	115
BK 6108	SUGARLOAF	115	SUGARLOAF	69
5	TAYLORVILLE	115	BOONVILLE	115
6	TAYLORVILLE	115	BOONVILLE	115
4	TEALL AVE	115	DEWITT	115
2	TEALL AVE	115	ONEIDA	115
5	TEALL AVE	115	ONEIDA	115
18	TILDEN	115	CORTLAND	115
3	VALLEY	115	INGHAMS	115
133	WALCK RD	115	HUNTLEY	115
2	WATKINS RD	115	INGHAMS	115
7	WHITEHALL	115	BLISSVILLE	115
13	WHITEHALL	115	MOHICAN	115
945-1	WILLET	115	E. NORWICH	115
1	WILLIS	115	BRAINARDSVILLE	115

1 (910)	WILLIS	115	MALONE	115
996	WOOD ST	115	AMAWALK	115
13	WYANTSKILL	115	REYNOLDS RD	115
3	YAHUNDASIS	115	PORTER	115
WH1-1	HONK FLS	69	NEVERSINK B	69
WH 2	HONK FLS	69	W. WOODBOURNE	69
WH 1-2	NEVERSINK A	69	NEVERSINK B	69
WH 1-3	NEVERSINK B	69	W. WOODBOURNE	69
690	SMITHFIELD	69	FALLS VILLGE	69
R1	DUNWOODIE	345		
SR #1 REAC	E. GARDEN CTY	345		
SR #2 REAC	E. GARDEN CTY	345		
R25	GOETHALS	345		
R26	GOETHALS	345		
REA #1	GOETHALS S.	345		
R18	GOWANUS	345		
R6	GOWANUS	345		
CAP #1	LEEDS	345		
CAP #2	LEEDS	345		
SVC	LEEDS	345		
CAP #1	NEW SCOTLAND	345		
CAP #2	NEW SCOTLAND	345		
CAP #3	NEW SCOTLAND	345		
RSR61	POLETTI	345		
RSR62	POLETTI	345		
R1	SHORE RD	345		
2N1 REACT	SPRAINBROOK	345		
2N2 REACT	SPRAINBROOK	345		
4S1 REACT	SPRAINBROOK	345		
4S2 REACT	SPRAINBROOK	345		
5S1 REACT	SPRAINBROOK	345		
5S2 REACT	SPRAINBROOK	345		
R49 S. REACT	SPRAINBROOK	345		
S6A REACT	SPRAINBROOK	345		

A.3 - Bus Voltage Limits for NYISO Secured Transmission System

	Bus Name	Pre Low	Pre High	Post Low	Post High	Set By
	Bowline 345	345	362	328	362	OR
	Buchanan 345	346	362	328	380	CE
	Clay 345	345	362	328	362	NM
	Coopers Corners 345	338	362	328	380	NY
	Dunwoodie 345	346	362	328	380	CE
(1)	Edic 345	347	362	328	362	NM
	Farragut 345	338	362	328	380	CE
	Fraser 345	338	362	328	380	NY
	Gardenville 230	217	242	207	242	NY
	Gilboa 345	348	362	328	362	PA
	Goethals 345	338	362	328	380	CE
	Gowanus 345	338	362	328	380	CE
	Ladentown 345	346	362	328	380	CE
	Leeds 345	345	362	328	372	NM
(1)	Marcy 345	348	362	328	380	PA
	Millwood 345	338	362	328	380	CE
	New Scotland 345	348	362	328	362	NM
	Niagara 230	225	242	219	242	PA
	Niagara 345	338	362	328	362	PA
	Northport 138	135	145	131	145	LI
	Oakdale 345	336	362	320	380	NY
	Pannell Road 345	see A.4	359	328	362	RG
	Pleasant Valley 345	343	362	328	380	CE
	Rainey 345	338	362	328	380	CE
	Ramapo 345	346	362	328	380	CE
	Ramapo 500	500	550	500	575	CE
	Rock Tavern 345	348	362	328	362	CH
	Roseton 345	345	362	328	362	CH
	Somerset 345	338	362	328	380	NY
	Sprainbrook 345	346	362	328	380	CE
	Station 80 345	see A.4	359	328	362	RG
	St Lawrence 230	225	242	219	242	PA
	Watercure 230	215	242	207	242	NY

Notes:

(1) Marcy 345 kV bus voltage is reduced to 345 kV prior to energizing the Massena-Marcy 765 kV MSU-1 line. By exception, Marcy and Edic voltages are allowed below their pre-contingency low limits for this condition.

A.4 - Bus Voltage Limits for HQ-NYISO Transfers

NYS Power System Status	Pre-contingency Low Bus Voltage Limits		
	Pannell Rd 345 kV	**Station 80 345 kV**	**Oakdale 345 kV**
HQ-NYCA transfer on 7040 is:			
-1000 to +1000 MW	341 kV	343 kV	--
+1000 to +1350 MW	341 kV	343 kV	--
+1351 to +1850 MW	344 kV	344 kV	--
+1851 to +2000 MW	345 kV	345 kV	--
+2001 to +2350 MW	346 kV	346 kV	--
Ginna station out of service and:			
3, 4, or 5 Oswego units in service	--	344 kV	--
2 Oswego units in service	--	345 kV	--
1 Oswego unit in service	--	346 kV	--
0 Oswego units in service	--	347 kV	--
Fraser SVC out of service or 'not normal'	--	--	339 kV

B. Operating Criteria

- B.1 summarizes the system conditions defining the Operating States.
- B.2 lists exceptions to operating criteria for pre-contingency and post-contingency transmission facility flows and voltages.
- B.3 lists multiple circuit tower lines in the NY Control Area [MP 29-1, A].
- B.4 lists the NYISO thunderstorm multiple contingencies [MP 29-1, B].

~~Appendix B-1~~
~~System Conditions For Operating States~~

~~MONITORED CRITERIA~~	~~NORMAL~~	~~WARNING~~	~~ALERT~~	~~MAJOR EMERGENCY~~	~~RESTORATION~~
~~Transmission Facility Pre-Contingency Flow (see Exhibit A-2)~~	~~Flow is less than or equal to Normal rating~~	~~Flow is greater than Normal rating but less than or equal to LTE rating for not more than 30 minutes~~ ~~OR~~ ~~Emergency Transfer Criteria have been invoked but flow is less than or equal to Normal rating~~	~~Emergency Transfer Criteria have been invoked~~ ~~AND~~ ~~Flow is greater than Normal rating but less than or equal to LTE for not more than 4 hours~~	~~Flow is greater than LTE rating~~ ~~OR~~ ~~Flow is greater than Normal rating but less than or equal to LTE rating for 4 hours.~~	
~~Transmission Facility Post-contingency Flow for loss of generation or single facility (see Exhibit A-2)~~	~~Predicted flow is less than or equal to LTE rating~~	~~Predicted flow is greater than LTE rating but less than or equal to STE rating~~	~~Predicted flow is greater than STE rating and there is sufficient time to take corrective action following contingency~~ ~~AND~~ ~~Emergency Transfer Criteria have not been exceeded for more than 30 minutes.~~	~~Predicted flow is greater than STE rating and there is not sufficient time to take corrective action following contingency~~ ~~OR~~ ~~Emergency Transfer Criteria have been invoked and criteria have been exceeded for more than 30 minutes.~~	
~~Transmission Facility Post-contingency Flow for loss of two adjacent circuits on the same structure (see Exhibit A-2)~~	~~Predicted flow is less than or equal to LTE rating~~	~~Emergency Transfer Criteria have been invoked.~~ ~~Post-contingency flow may exceed STE rating.~~	~~Emergency Transfer Criteria have been invoked.~~ ~~Post-contingency flow may exceed STE rating.~~	~~Emergency Transfer Criteria have been invoked.~~ ~~Post-contingency flow may exceed STE rating.~~	
~~Actual Voltage (see Exhibit A-3)~~	~~Voltage is within pre-contingency limits~~	~~Not Applicable~~	~~Voltage is less than its pre-contingency low limit or greater than its pre-contingency high limit for less than 15 minutes.~~ ~~OR~~ ~~Voltage is greater than its post-contingency high limit for less than 10 minutes and is indicative of a system problem.~~	~~Voltage is less than its pre-contingency low limit or greater than its pre-contingency high limit for 15 minutes and is indicative of a system problem.~~ ~~OR~~ ~~Voltage is less than its pre-contingency low limit, is indicative of a system problem, and appropriate voltage control measures have already been taken.~~ ~~OR~~ ~~Voltage is less than its post-contingency low limit and is indicative of a system problem.~~ ~~OR~~ ~~Voltage is greater than its post-~~	

~~Appendix B-1~~
~~System Conditions For Operating States~~

~~MONITORED CRITERIA~~	~~NORMAL~~	~~WARNING~~	~~ALERT~~	~~MAJOR EMERGENCY~~	~~RESTORATION~~
				~~contingency high limit for 10 minutes.~~	
~~Post-contingency voltage (see Exhibit A-2)~~	~~Post-contingency transmission facility flow is less than or equal to voltage collapse limit~~	~~Not Applicable~~	~~Post-contingency transmission facility flow is greater than voltage collapse limit by less than 5% for less than 15 minutes~~	~~Post-contingency transmission facility flow is greater than voltage collapse limits by less than or equal to 5% for 15 minutes, or by more than 5%~~	
~~Reserve~~ ~~10 minute Reserve~~	~~No 10-Minute Reserve deficiency~~	~~No 10-Minute Reserve deficiency, but only if using Emergency Transfer Criteria.~~	~~No 10-Minute Reserve deficiency, but only including quick response Voltage Reduction.~~	~~10 Minute Reserve deficiency exists after taking all actions defined in the *NYISO Manual for Emergency Operations* including purchase of operating capability.~~	
~~Reserve~~ ~~Operating Reserve~~	~~No Operating Reserve deficiency~~	~~No Operating Reserve deficiency, but only if using Emergency Transfer Criteria.~~	~~No Operating Reserve deficiency, but only using Emergency Transfer Criteria.~~	~~Operating Reserve deficiency exists after taking all actions defined in the *NYISO Manual for Emergency Operations* including purchase of operating capability.~~	
~~Stability Limits~~	~~Transmission facility flow is less than or equal to stability limit~~	~~Not Applicable~~	~~Transmission facility flow is greater than stability limit by less than 5% for less than 15 minutes.~~	~~Transmission facility flow is greater than stability limit by less than or equal to 5% for 15 minutes, or by more than 5%~~	
~~Pool Control Error (PCE)~~	~~PCE is less than " 100 MW~~ ~~OR~~ ~~PCE is less than " 500 MW for less than 10 minutes~~	~~PCE is greater than " 100 MW but less than " 500MW for more than 10 minutes.~~	~~PCE is greater than or equal to " 500 MW for less than 10 minutes.~~	~~PCE is greater than or equal to " 500 MW for more than 10 minutes.~~	
~~Frequency~~	~~Frequency is greater than or equal to 59.95 Hz and less than or equal to 60.05 Hz~~	~~Not Applicable~~	~~Frequency is greater than 60.05 Hz and less than 60.10 Hz~~ ~~OR~~ ~~Frequency is greater than 59.90 Hz and less than 59.95 Hz~~	~~Frequency is greater than or equal to 60.10 Hz and is sustained at that level or continues to increase~~ ~~OR~~ ~~Frequency is less than or equal to 59.90 Hz and is sustained at that level or continues to decline.~~	
~~Communication, Computer,~~	~~Sufficient facilities to~~	~~Not Applicable~~	~~Partial failures impairing the~~	~~Insufficient communication facilities to~~	

~~Appendix B-1~~
~~System Conditions For Operating States~~

~~MONITORED CRITERIA~~	~~NORMAL~~	~~WARNING~~	~~ALERT~~	~~MAJOR EMERGENCY~~	~~RESTORATION~~
~~Control, & Indication Facilities~~	~~monitor system status~~		~~capability of monitoring system status and the NYISO Shift Supervisor determines the power system is in jeopardy.~~	~~monitor system status and the NYISO Shift Supervisor determines the power system is in serious jeopardy.~~	
~~Neighboring Systems~~	~~All neighboring systems operating under normal conditions~~	~~One or more neighboring systems not operating under normal conditions~~	~~One or more neighboring systems in Voltage Reduction.~~	~~One or more neighboring systems in Voltage Reduction and requesting NYISO assistance via Voltage Reduction~~	
~~Separation within the New York Control Area~~	~~NO~~	~~NO~~	~~NO~~	~~YES~~	~~An Area within the NY Control Area is islanded, customer load is interrupted, or both, following a system disturbance affecting the NYS Power System.~~
~~Overgeneration~~	–	–	–	~~NY Control Area is overgenerating and corrective measures are not sufficient to reduce PCE to zero.~~	
~~Other~~	————	————	~~A situation involving impending severe weather exists~~ ~~OR~~ ~~A situation involving severe Solar Magnetic Disturbances exists.~~	————	

~~Appendix B-2~~

~~Exceptions to Operating Criteria for Pre-contingency & Post-contingency Transmission Facility Flows & Voltages~~

14. ~~The post-contingency flow on the Marcy-New Scotland 18 line is allowed to exceed its LTE rating for the loss of the Edic-New Scotland 14 line by the amount of relief that can be obtained by tripping the Gilboa pumping load as a single corrective action. Also, the post-contingency flow on the Edic-New Scotland 14 line is allowed to exceed its LTE rating for either the loss of the Marcy-New Scotland 18 line alone, or the double-circuit loss of the Marcy-New Scotland 18 and Adirondack-Porter 12 lines, by the amount of relief that can be obtained by tripping the Gilboa pumping load as a single corrective action.~~   ~~Operating Committee – January 27, 1988~~
15. ~~The post-contingency flow on the Volney-Clay #6 line and the 9 Mile-Clay #8 line is allowed to reach its STE rating for "normal" transfers.~~   ~~Operating Committee – October 25, 1979~~
16. ~~The post-contingency flow on the NS-Leeds line is allowed to reach its STE rating for transfers to NE & SENY, with sufficient generation at Gilboa.~~   ~~Operating Committee – October 25, 1979~~
17. ~~NMPC is fully responsible for monitoring all NMPC 345/115 kV, 345/230 kV, and 230/115 kV transformer overloads and contingency overloads. The NYISO notifies NMPC of any overloads and contingency overloads it detects, but does not invoke these limits unless requested to do so by NMPC.~~   ~~Operating Committee – October 25, 1979~~
18. ~~The post-contingency flow on the Gilboa-Leeds (GL-3) line is allowed to reach its STE rating with four generators on at Gilboa.~~   ~~Operating Committee – December 7, 1983~~
19. ~~The post-contingency flows on the L33P line and the L34P line are allowed to reach their STE ratings, provided there is sufficient generation rejection selected at the Saunders generating station in Ontario, or sufficient control remaining on the phase angle regulators to return the flows to LTE within 15 minutes.~~   ~~Operating Committee – December 14, 1994~~
20. ~~The post-contingency flow on Con Edison feeder 21192 is allowed to exceed its STE rating for the simultaneous loss of circuits 21 and 22 (Goethals-Fresh Kills) or selected breaker failures in Fresh Kills during maintenance outages.~~   ~~Operating Committee – December 6, 1984~~
21. ~~The post-contingency flow on line W97 for the loss of W98 may exceed its LTE rating up to its STE rating if the contingency loss of lines W98 and Y88 does not cause resultant flows on any other feeder to exceed Normal Transfer Criteria.~~

~~Appendix B-2~~

~~**Exceptions to Operating Criteria for Pre-contingency & Post-contingency Transmission Facility Flows & Voltages**~~

~~The post-contingency flow on line W98 for the loss of W97 may exceed its LTE rating up to its STE rating if the contingency loss of lines W97 and Y88 does not cause resultant flows on any other feeder to exceed Normal Transfer Criteria.~~ ~~This exception does not apply if either W97, W98, Y88, Indian Point 3, or the overload relay system is out of service.~~ ~~Operating Committee – May 30, 1985~~
~~22. The post-contingency flow on the Oswego-Volney #12 line is allowed to exceed its STE rating for the simultaneous loss of the Oswego-Elbridge-Lafayette #17 line and the Oswego-Volney #11 line.~~ ~~Operating Committee – May 26, 1988~~
~~23. The post-contingency flow on the Marcy AT-1 bank is allowed to exceed its STE rating for the loss of the Marcy AT-2 bank, provided that the overload relay protection on the AT-1 bank is in-service.~~ ~~Operating Committee – November 20, 1986~~
~~24. The post-contingency flow on the Plattsburgh-Vermont PV20 tie-line is allowed to reach its STE rating so long as NYPA can ensure that the Overload Mitigation system is available on a manual or automatic basis to reduce the flow to below the LTE rating immediately following the actual occurrence of the contingency.~~ ~~Operating Committee – February 15, 1995~~
~~25. The post-contingency flow on the Marcy Transformer T2 is allowed to exceed its LTE rating up to its STE rating following the loss of Marcy Transformer T1.~~ ~~Operating Committee – July 23, 1987~~
~~26. For the following Niagara Project facilities, the post-contingency flows are allowed to reach their STE ratings, if NYPA can ensure that sufficient generation can be reduced at Niagara to return the flows to less than their STE ratings within 5 minutes and to less than their LTE ratings within 10 minutes from the initial overload:~~ • ~~Niagara Project transformers~~ • ~~Lines connected directly to the Niagara Project~~ • ~~The Niagara-Robinson Road 230 kV Line #64 when Niagara 230 kV bus-ties (breakers 2332 and 2342) are open~~ ~~Operating Committee – August 19, 1993~~
~~27. The post-contingency flow on feeder 42232, Gowanus-Greenwood 138kV, is allowed to exceed its STE rating following the simultaneous loss of feeders 21 and 22, Gowanus-Freshkills 345kV, which run on common towers. In the event that this contingency occurs, the Con Edison System~~

~~Operator will immediately reduce the generation of the Linden Cogeneration Facility to alleviate the overload to less than its STE rating within 5 minutes and to less than its LTE rating within 10 minutes from the initial overload.~~

~~Operating Committee - January 29, 1997~~

28. ~~The post-contingency voltages at the Oakdale 345 kV bus, the Oakdale 230 kV bus, and Watercure 230 kV bus are allowed to fall below their respective post-contingency low voltage limits for either the simultaneous loss of the Oakdale-Lafayette 4-36 line and the Oakdale-Fraser 32 line, or the loss of one of these lines when the other line is already out of service.~~

~~Operating Committee - May 16, 1991~~

29. ~~Con Edison is responsible for operating for contingencies resulting from the loss of any East 13th Street 345/138 kV transformer, or the 345/69 kV transformer. These facilities provide radial support to the East 13th Street and East River load pocket and are not part of the bulk power system.~~

~~Operating Committee - August 27, 1997~~

30. ~~During times when the Y94 Ramapo to Buchanan 345 kV Feeder is out of service, allow post-contingency loading for loss of 345 kV Feeder W93 to exceed STE ratings on transformer TA-5 and 138 kV Feeder 95891. If this event occurs, there is automatic overload protection installed to trip Buchanan 138 kV breaker F7.~~

~~Operating Committee - August 27, 1997~~

31. ~~During times when the W79 Eastview to Sprainbrook 349 kV Feeder is out of service, allow post-contingency loadings for loss of Feeder Y94/95891 to exceed STE ratings on Transformer TR-2N. This exception will only be applied under conditions where Indian Point #2 generation can and will run back following the contingency in order to reduce flows through TR-2N within applicable limits, i.e., less than its STE rating within 5 minutes and to less than its LTE rating within 10 minutes from the initial overload.~~

~~Operating Committee - August 27, 1997~~

32. ~~Allow post-contingency loading on Q35L and Q35M to exceed STE loading for loss of one of these circuits on each other. If the contingency occurs, NYPA is responsible for immediately reducing Poletti generation in order to clear the overload.~~

~~Operating Committee - November 20, 1997~~

33. ~~Con Edison operates to post-contingency STE ratings on underground circuits based on the ability to reduce the loading to LTE ratings within 15 minutes and not exceed LTE ratings on any other facilities.~~

~~The following PSE&G tie feeders are operated to post-contingency LTE ratings:~~

- ~~A2253 Linden-Goethals 230 kV~~
- ~~B3402Hudson-Farragut 345 kV~~

~~Appendix B-2~~
~~Exceptions to Operating Criteria for Pre-contingency & Post-contingency Transmission Facility Flows & Voltages~~

- ~~C3403Hudson-Farragut 345 kV~~

34. ~~The following feeders on the Consolidated Edison System have STE ratings which are limited by disconnect or wavetrap restrictions and not by conductor sagging limitations. These feeders will be operated above Normal ratings and up to LTE ratings (for 4 hours) without changing their STE ratings:~~

- ~~F30 Pleasant Valley-Wood St.~~
- ~~F31 Pleasant Valley-Wood St.~~
- ~~F36 Pleasant Valley-East Fishkill~~
- ~~F37 Pleasant Valley-East Fishkill~~
- ~~W64 Eastview-SprainBrook~~
- ~~W65 Eastview-SprainBrook~~
- ~~69 Ramapo-South Mahwah~~
- ~~70 Ramapo-South Mahwah~~
- ~~W72 Ramapo-Ladentown~~
- ~~W75 SprainBrook-Dunwoodie (Winter Rating Period Only)~~
- ~~W79 Eastview-SprainBrook~~
- ~~W80 Wood St.-Millwood West~~
- ~~W81 Wood St.-Millwood West~~
- ~~W82 Millwood West-Eastview~~
- ~~W85 Millwood West-SprainBrook~~
- ~~Y86 Wood St.-Pleasantville~~
- ~~Y87 Wood St.-Pleasantville~~
- ~~Y88 Ladentown-Buchanan South~~
- ~~W89 Pleasantville-Dunwoodie~~
- ~~W90 Pleasantville-Dunwoodie~~
- ~~W93 Buchanan North-Eastview~~
- ~~Y94 Ramapo-Buchanan North~~
- ~~W99 Millwood West-Eastview~~

35. ~~The following feeders on the Consolidated Edison System have overload relay protection. These feeders will be operated above Normal rating and up to LTE rating (for 4 hours) without changing their STE ratings:~~

- ~~W97 Buchanan South-Millwood West~~
- ~~W98 Buchanan South-Millwood West~~

~~Appendix B-3~~
~~Bus Voltage Limits for HQ-NYISO Transfers~~

~~NYS Power System Status~~	~~Pre-contingency Low Bus Voltage Limits~~		
	~~Pannell Rd 345 kV~~	~~Station 80 345 kV~~	~~Oakdale 345 kV~~
~~HQ-NYCA transfer on 7040 is:~~			
~~-1000 to +1000 MW~~	~~341 kV~~	~~343 kV~~	~~--~~
~~+1000 to +1350 MW~~	~~341 kV~~	~~343 kV~~	~~--~~
~~+1351 to +1850 MW~~	~~344 kV~~	~~344 kV~~	~~--~~
~~+1851 to +2000 MW~~	~~345 kV~~	~~345 kV~~	~~--~~
~~+2001 to +2350 MW~~	~~346 kV~~	~~346 kV~~	~~--~~
~~Ginna station out of service and:~~			
~~3, 4, or 5 Oswego units in service~~	~~--~~	~~344 kV~~	~~--~~
~~2 Oswego units in service~~	~~--~~	~~345 kV~~	~~--~~
~~1 Oswego unit in service~~	~~--~~	~~346 kV~~	~~--~~
~~0 Oswego units in service~~	~~--~~	~~347 kV~~	~~--~~
~~Fraser SVC out of service or 'not normal'~~	~~--~~	~~--~~	~~339 kV~~

- B.5 lists the local reliability rules of the New York Transmission Owners.
- B.6 shows the applications of reliability rules and cost allocation responsibility.

B.1 - System Conditions for Operating States

MONITORED CRITERIA	NORMAL	WARNING	ALERT	MAJOR EMERGENCY	RESTORATION
Transmission Facility Pre-Contingency Flow (see Attachment B.2)	Flow is less than or equal to Normal rating	Flow is greater than Normal rating but less than or equal to LTE rating for not more than 30 minutes **OR** Emergency Transfer Criteria have been invoked but flow is less than or equal to Normal rating	Emergency Transfer Criteria have been invoked **AND** Flow is greater than Normal rating but less than or equal to LTE for not more than 4 hours	Flow is greater than LTE rating OR Flow is greater than Normal rating but less than or equal to LTE rating for 4 hours.	
Transmission Facility Post-contingency Flow for loss of generation or single facility (see Attachment B.2)	Predicted flow is less than or equal to LTE rating	Predicted flow is greater than LTE rating but less than or equal to STE rating	Predicted flow is greater than STE rating and there is sufficient time to take corrective action following contingency **AND** Emergency Transfer Criteria have not been exceeded for more than 30 minutes.	Predicted flow is greater than STE rating and there is not sufficient time to take corrective action following contingency **OR** Emergency Transfer Criteria have been invoked and criteria have been exceeded for more than 30 minutes.	
Transmission Facility Post-contingency Flow for loss of two adjacent circuits on the same structure (see Attachment B.2)	Predicted flow is less than or equal to LTE rating	Emergency Transfer Criteria have been invoked. Post-contingency flow may exceed STE rating.	Emergency Transfer Criteria have been invoked. Post-contingency flow may exceed STE rating.	Emergency Transfer Criteria have been invoked. Post-contingency flow may exceed STE rating.	
Actual Voltage (see Attachment A.3)	Voltage is within pre-contingency limits	Not Applicable	Voltage is less than its pre-contingency low limit or greater than its pre-contingency high	Voltage is less than its pre-contingency low limit or greater than its pre-contingency high	

MONITORED CRITERIA	NORMAL	WARNING	ALERT	MAJOR EMERGENCY	RESTORATION
			limit for less than 15 minutes. **OR** Voltage is greater than its post-contingency high limit for less than 10 minutes and is indicative of a system problem.	limit for 15 minutes and is indicative of a system problem. **OR** Voltage is less than its pre-contingency low limit~~,~~; is indicative of a system problem, and appropriate voltage control measures have already been taken. **OR** Voltage is less than its post-contingency low limit and is indicative of a system problem. **OR** Voltage is greater than its post-contingency high limit for 10 minutes.	
Post-contingency voltage (see Attachment B.2)	Post-contingency transmission facility flow is less than or equal to voltage collapse limit	Not Applicable	Post-contingency transmission facility flow is greater than voltage collapse limit by less than 5% for less than 15 minutes	Post-contingency transmission facility flow is greater than voltage collapse limits by less than or equal to 5% for 15 minutes, or by more than 5%	
Reserve 10 minute Reserve	No 10-Minute Reserve deficiency	No 10-Minute Reserve deficiency, but only if using Emergency Transfer Criteria.	No 10-Minute Reserve deficiency, but only including quick response Voltage Reduction.	10~~-~~-Minute Reserve deficiency exists after taking all actions defined in the ***NYISO Emergency Operations Manual*** including purchase of operating capability.	

MONITORED CRITERIA	NORMAL	WARNING	ALERT	MAJOR EMERGENCY	RESTORATION
Reserve Operating Reserve	No Operating Reserve deficiency	No Operating Reserve deficiency, but only if using Emergency Transfer Criteria.	No Operating Reserve deficiency, but only using Emergency Transfer Criteria.	Operating Reserve deficiency exists after taking all actions defined in the ***NYISO Emergency Operations Manual*** including purchase of operating capability.	
Stability Limits	Transmission facility flow is less than or equal to stability limit	Not Applicable	Transmission facility flow is greater than stability limit by less than 5% for less than 15 minutes.	Transmission facility flow is greater than stability limit by less than or equal to 5% for 15 minutes, or by more than 5%	
Area Control Error (ACE)	ACE is less than ±100 MW OR ACE is less than ±500 MW for less than 10 minutes	ACE is greater than ±100 MW but less than ± 500MW for more than 10 minutes.	ACE is greater than or equal to ± 500 MW for less than 10 minutes.	ACE is greater than or equal to ± 500 MW for more than 10 minutes.	
Frequency	Frequency is greater than or equal to 59.95 Hz and less than or equal to 60.05 Hz	Not Applicable	Frequency is greater than 60.05 Hz and less than 60.10 Hz **OR** Frequency is greater than 59.90 Hz and less than 59.95 Hz	Frequency is greater than or equal to 60.10 Hz and is sustained at that level or continues to increase **OR** Frequency is less than or equal to 59.90 Hz and is sustained at that level or continues to decline.	
Communication, Computer, Control, & Indication Facilities	Sufficient facilities to monitor system status	Not Applicable	Partial failures impairing the capability of monitoring system status and the NYISO Shift Supervisor determines the power	Insufficient communication facilities to monitor system status and the NYISO Shift Supervisor determines the power	

MONITORED CRITERIA	NORMAL	WARNING	ALERT	MAJOR EMERGENCY	RESTORATION
			system is in jeopardy.	system is in serious jeopardy.	
Neighboring Systems	All neighboring systems operating under normal conditions	One or more neighboring systems not operating under normal conditions	One or more neighboring systems in Voltage Reduction.	One or more neighboring systems in Voltage Reduction and requesting NYISO assistance via Voltage Reduction	
Separation within the New York Control Area	NO	NO	NO	YES	An Area within the NY Control Area is islanded, customer load is interrupted, or both, following a system disturbance affecting the NYS Power System.
Overgeneration	--	--	--	NY Control Area is over-generating and corrective measures are not sufficient to reduce ACE to zero.	
Other	--	--	A situation involving impending severe weather exists **OR** A situation involving severe Solar Magnetic Disturbances exists.		

B.2 - Exceptions to Operating Criteria for Pre-contingency & Post-contingency Transmission Facility Flows & Voltages

The post-contingency flow on the Marcy-New Scotland 18 line is allowed to exceed its LTE rating for the loss of the Edic-New Scotland 14 line by the amount of relief that can be obtained by tripping the Gilboa pumping load as a single corrective action. Also, the post-contingency flow on the Edic-New Scotland 14 line is allowed to exceed its LTE rating for either the loss of the Marcy-New Scotland 18 line alone, or the double-circuit loss of the Marcy-New Scotland 18 and Adirondack-Porter 12 lines, by the amount of relief that can be obtained by tripping the Gilboa pumping load as a single corrective action. Operating Committee - January 27, 1988
The post-contingency flow on the Volney-Clay #6 line and the 9 Mile-Clay #8 line is allowed to reach its STE rating for "normal" transfers. Operating Committee - October 25, 1979
The post-contingency flow on the NS-Leeds line is allowed to reach its STE rating for transfers to NE & SENY, with sufficient generation at Gilboa. Operating Committee - October 25, 1979
NMPC is fully responsible for monitoring all NMPC 345/115 kV, 345/230 kV, and 230/115 kV transformer overloads and contingency overloads. The NYISO notifies NMPC of any overloads and contingency overloads it detects, but does not invoke these limits unless requested to do so by NMPC. Operating Committee - October 25, 1979
The post-contingency flow on the Gilboa-Leeds (GL-3) line is allowed to reach its STE rating with four generators on at Gilboa. Operating Committee - December 7, 1983
The post-contingency flows on the L33P line and the L34P line are allowed to reach their STE ratings, provided there is sufficient generation rejection selected at the Saunders generating station in Ontario, or sufficient control remaining on the phase angle regulators to return the flows to LTE within 15 minutes. Operating Committee - December 14, 1994
The post-contingency flow on Con Edison feeder 21192 is allowed to exceed its STE rating for the simultaneous loss of circuits 21 and 22 (Goethals-Fresh Kills) or selected breaker failures in Fresh Kills during maintenance outages. Operating Committee - December 6, 1984
The post-contingency flow on line W97 for the loss of W98 may exceed its LTE rating up to its STE rating if the contingency loss of lines W98 and Y88 does not cause resultant flows on any other feeder to exceed Normal Transfer Criteria. The post-contingency flow on line W98 for the loss of W97 may exceed its LTE rating up to its STE rating if the contingency loss of lines W97 and Y88 does not cause resultant flows on any other feeder to exceed Normal Transfer Criteria. This exception does not apply if either W97, W98, Y88, Indian Point 3, or the overload relay system is out of service. Operating Committee - May 30, 1985
The post-contingency flow on the Oswego-Volney #12 line is allowed to exceed its STE rating for the simultaneous loss of the Oswego-Elbridge-Lafayette #17 line and the Oswego-Volney #11 line. Operating Committee - May 26, 1988

The post-contingency flow on the Marcy AT-1 bank is allowed to exceed its STE rating for the loss of the Marcy AT-2 bank, provided that the overload relay protection on the AT-1 bank is in-service. Operating Committee - November 20, 1986
The post-contingency flow on the Plattsburgh-Vermont PV20 tie-line is allowed to reach its STE rating so long as NYPA can ensure that the Overload Mitigation system is available on a manual or automatic basis to reduce the flow to below the LTE rating immediately following the actual occurrence of the contingency. Operating Committee - February 15, 1995
The post-contingency flow on the Marcy Transformer T2 is allowed to exceed its LTE rating up to its STE rating following the loss of Marcy Transformer T1. Operating Committee - July 23, 1987
For the following Niagara Project facilities, the post-contingency flows are allowed to reach their STE ratings, if NYPA can ensure that sufficient generation can be reduced at Niagara to return the flows to less than their STE ratings within 5 minutes and to less than their LTE ratings within 10 minutes from the initial overload: • Niagara Project transformers • Lines connected directly to the Niagara Project • The Niagara-Robinson Road 230 kV Line #64 when Niagara 230 kV bus-ties (breakers 2332 and 2342) are open Operating Committee - August 19, 1993
The post-contingency flow on feeder 42232, Gowanus-Greenwood 138kV, is allowed to exceed its STE rating following the simultaneous loss of feeders 21 and 22, Gowanus-Freshkills 345kV, which run on common towers. In the event that this contingency occurs, the Con Edison System Operator will immediately reduce the generation of the Linden Cogeneration Facility to alleviate the overload to less than its STE rating within 5 minutes and to less than its LTE rating within 10 minutes from the initial overload. Operating Committee - January 29, 1997
The post-contingency voltages at the Oakdale 345 kV bus, the Oakdale 230 kV bus, and Watercure 230 kV bus are allowed to fall below their respective post-contingency low voltage limits for either the simultaneous loss of the Oakdale-Lafayette 4-36 line and the Oakdale-Fraser 32 line, or the loss of one of these lines when the other line is already out of service. Operating Committee - May 16, 1991
Con Edison is responsible for operating for contingencies resulting from the loss of any East 13th Street 345/138 kV transformer, or the 345/69 kV transformer. These facilities provide radial support to the East 13th Street and East River load pocket and are not part of the bulk power system. Operating Committee - August 27, 1997
During times when the Y94 Ramapo to Buchanan 345 kV Feeder is out of service, allow post-contingency loading for loss of 345 kV Feeder W93 to exceed STE ratings on transformer TA-5 and 138 kV Feeder 95891. If this event occurs, there is automatic overload protection installed to trip Buchanan 138 kV breaker F7. Operating Committee - August 27, 1997
During times when the W79 Eastview to Sprainbrook 349 kV Feeder is out of service, allow post-contingency loadings for loss of Feeder Y94/95891 to exceed STE ratings on Transformer TR-2N. This exception will only be applied under conditions where Indian Point #2 generation can and will run back following the contingency in order to reduce flows through TR-2N within applicable limits, i.e., less than its STE rating within 5 minutes and to less than its LTE rating within 10 minutes from the initial overload. Operating Committee - August 27, 1997

Allow post-contingency loading on Q35L and Q35M to exceed STE loading for loss of one of these circuits on each other. If the contingency occurs, NYPA is responsible for immediately reducing Poletti generation in order to clear the overload. Operating Committee - November 20, 1997
Con Edison operates to post-contingency STE ratings on underground circuits based on the ability to reduce the loading to LTE ratings within 15 minutes and not exceed LTE ratings on any other facilities. The following PSE&G tie feeders are operated to post-contingency LTE ratings: • A2253 Linden-Goethals 230 kV • B3402 Hudson-Farragut 345 kV • C3403 Hudson-Farragut 345 kV
The following feeders on the Consolidated Edison System have STE ratings which are limited by disconnect or wavetrap restrictions and not by conductor sagging limitations. These feeders will be operated above Normal ratings and up to LTE ratings (for 4 hours) without changing their STE ratings: • F30 Pleasant Valley-Wood St. • F31 Pleasant Valley-Wood St. • F36 Pleasant Valley-East Fishkill • F37 Pleasant Valley-East Fishkill • W64 Eastview-SprainBrook • W65 Eastview-SprainBrook • 69 Ramapo-South Mahwah • 70 Ramapo-South Mahwah • W72 Ramapo-Ladentown • W75 SprainBrook-Dunwoodie (Winter Rating Period Only) • W79 Eastview-SprainBrook • W80 Wood St.-Millwood West • W81 Wood St.-Millwood West • W82 Millwood West-Eastview • W85 Millwood West-SprainBrook • Y86 Wood St.-Pleasantville • Y87 Wood St.-Pleasantville • Y88 Ladentown-Buchanan South • W89 Pleasantville-Dunwoodie • W90 Pleasantville-Dunwoodie • W93 Buchanan North-Eastview • Y94 Ramapo-Buchanan North • W99 Millwood West-Eastview
The following feeders on the Consolidated Edison System have overload relay protection. These feeders will be operated above Normal rating and up to LTE rating (for 4 hours) without changing their STE ratings: • W97 Buchanan South-Millwood West • W98 Buchanan South-Millwood West

B.3 - Multiple Circuit Tower Lines in NY Control Area

Circuit Designations	Terminals	Included in On-line MCE	Exemption and Reason
	345 kV		
11 17	Oswego-Volney Oswego-Lafayette	Yes	--
32 36	Oakdale-Fraser Oakdale-Lafayette	Yes	Note 3
91 92	Leeds-Pleasant Valley (2 Parallel Circuits)	No	Note 1
GNS1 GL3	Gilboa-New Scotland Gilboa-Leeds	No	Note 1
F30/W80 F31/W78	Pleasant Valley-Wood St-Millwood W. (2 Parallel Circuits)	Yes	--
W82/W65 W85/W78	Millwood W.-Eastview-SprainBrook (2 Parallel Circuits)	Yes	--
F36 F37	Pleasant Valley-E. Fishkill (2 Parallel Circuits)	Yes	--
F38/Y86 F39/Y87	E. Fishkill-Wood St-Pleasantville (2 Parallel Circuits)	Yes	--
W89 W90	Pleasantville-Dunwoodie (2 Parallel Circuits)	Yes	--
W93/W79- W99/W64	Buchanan-Eastview-SprainBrook & Millwood W.-Eastview-SprainBrook	Yes	--
W97 W98	Buchanan S.-Millwood W. (2 Parallel Circuits)	No	Note 2
W72 Y94	Ramapo-Ladentown & Ramapo-Buchanan N.	Yes	--
Y88 Y94	Ladentown-Buchanan S. & Ramapo-Buchanan N.	Yes	--
67 68	Bowline Pt.-W. Haverstraw- Ladentown & Bowline Pt.-Ladentown	Yes	--
21 22	Goethals-Fresh Kills (2 Parallel Circuits)	Yes	--
69/J3410- 70/K3411	Ramapo-Waldwick (2 Parallel Circuits)	Yes	--

Circuit Designations	Terminals	Included in On-line MCE	Exemption and Reason
EF24-40 UCC2-41	Edic-Fraser Marcy-Coopers Corners	Yes	--
33 UCC2-41	Fraser-Coopers Corners Marcy-Coopers Corners	Yes	--
CCRT-34 CCRT-42	Coopers Corners-Rock Tavern Coopers Corners-Rock Tavern	Yes	--
4-36 22	Lafayette-Oakdale Dewitt-Lafayette	No	Note 1
11 12	Oswego-Volney (2 Parallel Circuits)	No	Note 1
230 kV & 345 kV			
11 UCC2-41	Adirondack-Porter (230kV) Marcy-Coopers Corners (345kV)	Yes	--
12 18	Adirondack-Porter (230 kV) Marcy-New Scotland (345 kV)	Yes	--
67 37	Stolle Road-Meyer (230 kV) Stolle Road-Homer City (345 kV)	Yes	--
31 UCC2-41	Porter-Rotterdam (230 kV) Marcy-Coopers Corners (345 kV)	Yes	--
30 EF24-40	Porter-Rotterdam (230 kV) Edic-Fraser (345 kV)	Yes	--
230 kV			
61 64	Niagara-Packard Niagara-Robinson Road	Yes	--
62 PA27	Niagara-Packard Niagara-Beck	Yes	--
62 BP76	Niagara-Packard Packard-Beck	Yes	--
68 69	Hillside-Meyer Hillside-Watercure Road	Yes	--
73 74	Gardenville-Dunkirk (2 Parallel Circuits)	Yes	--
77 78	Packard-Huntley (2 Parallel Circuits)	Yes	--

Circuit Designations	Terminals	Included in On-line MCE	Exemption and Reason
77 80	Packard-Huntley Huntley-Gardenville	Yes	--
78 79	Packard-Huntley Huntley-Gardenville	Yes	--
79 80	Huntley-Gardenville (2 Parallel Circuits)	Yes	--
PA27 BP76	Niagara-Beck Packard-Beck	Yes	--
L33P L34P	St. Lawrence T.S.-Moses (2 Parallel Circuits)	Yes	--
MA-1/11 MA-2/12	Moses-Adirondack-Porter (2 Parallel Circuits)	Yes	--
MW1/WP1 MW2/WP2	Moses-Willis-Plattsburgh (2 Parallel Circuits)	Yes	--
MMS1 MMS2	Moses-Massena (2 Parallel Circuits)	Yes	--
61 62	Niagara-Packard (2 Parallel Circuits)	No	Note 1

Note 1: Exempt because of 5 tower criteria.
Note 2: Exempt because they are not adjacent.
Note 3: Exempt by NYISO for development of Voltage limits only.

B.4 - Thunderstorm Multiple Contingencies Cases

1. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 311
2. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 77
3. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, Y94, TA5, Bank (95891)
4. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, Y88
5. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, F31, W81
6. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, W82, Eastview Bank 2S, W65
7. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, W93, Eastview Bank 2N, W79
8. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, A2253
9. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, W75
10. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 301
11. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 303
12. W89, W73, W90, W74, Y50, Pleasantville Bank 2, 311
13. W89, W73, W90, W74, Y50, Pleasantville Bank 2, 77
14. W89, W73, W90, W74, Y50, Pleasantville Bank 2, Y94, TA5 Bank (95891)
15. W89, W73, W90, W74, Y50, Pleasantville Bank 2, Y88
16. W89, W73, W90, W74, Y50, Pleasantville Bank 2, F31, W81
17. W89, W73, W90, W74, Y50, Pleasantville Bank 2, W82 Eastview Bank 2S, W65
18. W89, W73, W90, W74, Y50, Pleasantville Bank 2, W93, Eastview Bank 2N, W79
19. W89, W73, W90, W74, Y50, Pleasantville Bank 2, A2253
20. W89, W73, W90, W74, Y50, Pleasantville Bank 2, W75, 72, 71
21. W89, W73, W90, W74, Y50, Pleasantville Bank 2, 301
22. W89, W73, W90, W74, Y50, Pleasantville Bank 2, 303
23. F36, F37, 301
24. F36, F37, 303
25. F36, F37, 311
26. F36, F37, 77
27. F36, F37, Y94, TA5 Bank (95891)
28. F36, F37, Y88
29. F36, F37, F31, W81
30. F36, F37, W82, Eastview Bank 2S, W65
31. F36, F37, W75
32. F36, F37, W93, Eastview Bank 2N, W79
33. F36, F37, A2253
34. F36, F37, F38, RFK305

35. F31, W81, F30, W80, Wood St. Bank 1, 311
36. F31, W81, F30, W80, Wood St. Bank 1, 77
37. F31, W81, F30, W80, Wood St. Bank 1, Y94, TA5 Bank (95891)
38. F31, W81, F30, W80, Wood St. Bank 1, Y88
39. F31, W81, F30, W80, Wood St. Bank 1, W75
40. F31, W81, F30, W80, Wood St. Bank 1, F38, Y86, Pleasantville Bank 1
41. F31, W81, F30, W80, Wood St. Bank 1, W93, Eastview Bank 2N, W79
42. F31, W81, F30, W80, Wood St. Bank 1, A2253
43. F31, W81, F30, W80, Wood St. Bank 1, 301
44. F31, W81, F30, W80, Wood St. Bank 1, 303
45. F31, W81, F30, W80, Wood St. Bank 1, 305
46. W85, W82, W65, Eastview Bank 2S, Eastview Bank 1S, W99, Eastview Bank 1N, W64, W78
47. W85, W82, W65, Eastview Bank 2S, Eastview Bank 1S, W93, Eastview Bank 2N, W79, W78
48. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, Y94, TA5 Bank (95891), IP2
49. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, Y88
50. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, F38, Y86, Pleasantville Bank 1
51. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, Eastview Bank 1S, W85, W78
52. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, W82 Eastview Bank 2S, W65
53. Y88, Y94, TA5 Bank (95891), 91
54. Y88, Y94, TA5 Bank (95891), 92
55. Y88, Y94, TA5 Bank (95891), F38, Y86, Pleasantville Bank 1
56. Y88, Y94, TA5 Bank (95891), F39, Y87, Pleasantville Bank 2, Wood St. Bank 2
57. Y88, Y94, TA5 Bank (95891), F31, W81
58. Y88, Y94, TA5 Bank (95891), F30, Wood St. Bank 1, W80
59. Y88, Y94, TA5 Bank (95891), W93, Eastview Bank 2N, W79, IP2
60. Y88, Y94, TA5 Bank (95891), A2253
61. Y88, Y94, TA5 Bank (95891), 301
62. Y88, Y94, TA5 Bank (95891), 303
63. Y88, Y94, TA5 Bank (95891), RFK305
64. W97, W98, Y88, IP3
65. W97, W98, Y88, IP3, 91
66. W97, W98, Y88, IP3, 92

67. W97, W98, Y88, IP3, F38, Y86, Pleasantville Bank 1
68. W97, W98, Y88, IP3, F39, Y87, Wood St. Bank 2
69. W97, W98, Y88, IP3, F31, W81
70. W97, W98, Y88, IP3, F30, Wood St. Bank 1, W80
71. W97, W98, Y88, IP3, W93, Eastview Bank 2N, W79
72. W97, W98, Y88, IP3, 301
73. W97, W98, Y88, IP3, 303
74. W97, W98, Y88, IP3, RFK305
75. 91, 92
76. 91, 311
77. 91, 77
78. 92, 311
79. 92, 77
80. 91, 301
81. 91, 303
82. 91, RFK305
83. 301, RFK305
84. 69, South Mahwah Bank, J3410, Waldwick Bank 2, 70, K3411, Waldwick Bank 3, Y88
85. Y88, Y94, TA5 (95891), 69, South Mahwah Bank, J3410, Waldwick Bank 2
86. Y88, Y94, TA5 (95891), 70, K3411, Waldwick Bank 3

B.5 - Local Reliability Rules of the New York Transmission Owners

Local Rule No.	Company	Specific Local Reliability Rule	Justification
1	CON EDISON	OPERATING RESERVES/UNIT COMMITMENT Certain areas of the Con Edison system are designed and operated for the occurrence of a second contingency. Unit Commitment is based on second contingency operation as well as consideration of the Storm Watch Procedure, Loss of Six Lines South of Millwood and the locational requirements for its operating reserves.	PSC Directive July 17, 1961
2	CON EDISON	LOCATIONAL RESERVES Con Edison must maintain its 10 Minute Operating Reserve on in-City steam units and on Fast Start Gas Turbines.	PSC Order No.27302
3	CON EDISON	GAS BURNING PROCEDURE A sudden loss of gas pressure in the gas transmission facilities that supply Con Edison's in-City generators could result in the units tripping off line. This rule requires certain in-City units to burn oil at a minimum level, based on the forecasted system load as follows: 1. Above 8000 MW - two of the three Astoria generators must be switched to minimum oil burn. 2. Above 9000 MW - all of the generators at Astoria, Ravenswood and East River should be switched to minimum oil burn.	Exceeds Minimum Criteria
4	CON EDISON	Con Edison will operate its system as if the first contingency has already occurred on its northern transmission system when thunderstorms are within one hour of the system or are actually being experienced.	PSC Order No.27302
5	LIPA	LOSS OF GENERATOR SUPPLY Considering the loss of gas supply as a single contingency that will impact the electric power system, the number of gas fired generators must be limited above critical system load levels. Above 3200 MW, 2 North Port units can be gas fired. At peak loads, Port Jefferson 3-4 gas operation must be restricted.	Exceeds Minimum Criteria

B.6 - Applications of Reliability Rules and Cost Allocation Responsibility

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
OPERATION DURING IMPENDING SEVERE WEATHER Section 4.2.7.	ADVERSE WEATHER Icing Conditions	NYPA	The 765 kV high voltage limit may be reduced during ice formation or other conditions. This may impact the permissible transformer tap ranges and settings of other voltage regulating equipment. This may impact Bulk Power System interface transfer capability.	STATEWIDE A'
AS ABOVE	ADVERSE WEATHER Storm Watch	NYPA	NYPA may limit the imports on the 765kV tie line with Hydro Quebec to a maximum of 1300MW when thunderstorms are reported to be in the vicinity of the 765kV transmission corridor. This may impact Bulk Power System interface transfer capability.	STATEWIDE A'
VOLTAGE ASSESSMENT Section 4.2.3 – Reactive power reserves should be available to maintain voltages within applicable pre-disturbance and post-disturbance limits VOLTAGE LIMITS Section 2.1 – Voltage ratings of each BPS facility shall be determined by its owner	REACTIVE POWER SUPPORT Function of Power Flow	NYPA	765 kV OPERATING VOLTAGE LIMITS In operation of the 765 kV transmission system, permissible voltage and MVAR ranges are coordinated with levels of power flow. Coordinated switching of shunt reactors, capacitor banks, and transformer taps is done to maintain voltage within permissible ranges. This may impact Bulk Power System interface transfer capability.	STATEWIDE A'
SPS GENERAL REQUIREMENTS Section 4.2.1 STABILITY ASSESSMENT Section 4.2.4	BULK POWER SYSTEM Generation Rejection	NYPA	L33P AND L34P OUT OF SERVICE When the L33P and L34P circuits are out of service, NYPA monitors a special Moses South stability indicator (MSC7040 SOUTH MINUS 250 MW) to be within certain limits to maintain the security of the North Country power system. Curtailment of Hydro Quebec import and/or local generation may be required to respect the limits. Moreover, NYPA may enable the Moses 230 kV generation rejection scheme. This may impact Bulk Power System interface transfer capability.	STATEWIDE A'
SPS GENERAL REQUIREMENTS Section 4.2.1 THERMAL ASSESSMENT Section 4.2.2 STABILITY ASSESSMENT Section 4.2.4 SYSTEM PROTECTION	BULK POWER SYSTEM Generation Rejection	NYPA	MMS-1 AND MMS-2 OUT OF SERVICE When the MMS-1 and MMS-2 circuits are out of service restrictions are placed on the permissible equipment configurations and number of Beauharnois units in the Chateauguay complex, as well as the MSV-7040 flow limits. NYPA monitors a special stability indicator (MS-MSU-OH) to be within certain limits to maintain the security of the North Country power system. Curtailment of Hydro Quebec import and/or local generation may be required to respect the limits. Moreover, NYPA may enable the Moses 230 kV generation rejection scheme. This may impact Bulk Power System interface transfer capability.	STATEWIDE A'

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
Section 4.17				
GENERAL REQUIREMENTS OF SPSs Section 4.2.1 THERMAN ASSESSMENT Section 4.2.2 STABILITY ASSESSMENT Section 4.2.4	BULK POWER SYSTEM Generation Rejection	NYPA	MSU-1 OUT OF SERVICE When the MSU-1 765 kV circuit is out of service, NYPA monitors the Moses South minus Ontario Hydro South flows to be within certain limits to maintain the security of the North Country power system. Curtailment of Hydro Quebec import and/or local generation may be required to respect the limits. Moreover, NYPA may enable the Moses 230 kV generation rejection scheme. This may impact Bulk Power System interface transfer capability.	STATEWIDE A'
AS ABOVE	BULK POWER SYSTEM Generation Rejection	NYPA	MSU-1 AND L33P OR L34P OUT OF SERVICE When the MSU-1 circuit and L33P or L34P are out of service, NYPA monitors the Moses South minus Ontario South flows to be within certain limits to maintain the security of the North Country power system. Curtailment of Hydro Quebec import and/or local generation may be required to respect the limits. Moreover, NYPA may enable the Moses 230 kV generation rejection scheme. Also, operation of Chateauguay HVDC is not permitted. This may impact Bulk Power System interface transfer capability.	STATEWIDE A'
AS ABOVE	BULK POWER SYSTEM Generation Rejection	NYPA	ST. LAWRENCE BUSES 1A OR 2A OUT OF SERVICE When St. Lawrence bus 1A or 2A are out of service, NYPA monitors a special stability indicator (MS-MSC7040-OH+PV20) to be within certain limits to maintain the security of the North Country power system. Curtailment of Hydro Quebec import and/or local generation may be required to respect the limits. Moreover, NYPA may enable the Moses 230 kV generation rejection scheme. Several other restrictions are placed on operation of the Chateauguay complex. This may impact Bulk Power System interface transfer capability.	STATEWIDE A'
SPS GENERAL REQUIREMENTS Section 4.2.1 STABILITY ASSESSMENT Section 4.2.4	BULK POWER SYSTEM Generation Rejection	NYPA	OUTAGES OF PA301 AND PA302 To increase Western NY export limit for a simultaneous outage of PA301 and PA302 345 kV circuits, NYPA may enable the OCB 2114 Breaker Failure Timer Bypass and arm the Generation Drop Scheme at the Robert Moses Niagara Power Project. This may impact Bulk Power System interface transfer capability.	STATEWIDE A'
SPS GENERAL REQUIREMENTS Section 4.2.1 THERMAL ASSESSMENT	BULK POWER SYSTEM Generation Rejection	NYPA	NIAGARA 230 kV SWITCHYARD For certain line/breaker outage conditions in the Niagara 230 kV East yard, post-contingency loading up to STE rating is permitted on certain equipment and NYPA may place Niagara generators on the generation rejection scheme.	STATEWIDE A'

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
Section 4.2.2			This may impact Bulk Power System interface transfer capability.	
AS ABOVE	BULK POWER SYSTEM Generation Rejection	NYPA	NIAGARA 230 kV GENERATOR DROP SCHEME NYPA may enable the Niagara 230 kV generation rejection scheme to relieve thermal overloads in the area. This may impact Bulk Power System interface transfer capability.	STATEWIDE A’
SPS GENERAL REQUIREMENTS Section 4.2.1 THERMAL ASSESSMENT Section 4.2.2 STABILITY ASSESSMENT Section 4.2.4	BULK POWER SYSTEM Generation Rejection	NYPA	ST. LAWRENCE /FDR 230 kV GENERATION DROP SCHEME To increase the export capability from the Northern NY area and the Central East limit for various line and equipment maintenance conditions, NYPA may enable the Moses 230 kV generation rejection scheme. This may impact Bulk Power System interface transfer capability	STATEWIDE A’
SPS GENERAL REQUIREMENTS Section 4.2.1 THERMAL ASSESSMENT Section 4.2.2 STABILITY ASSESSMENT Section 4.2.4 SYSTEM PROTECTION Section 4.17	BULK POWER SYSTEM	NYPA	NYPA-HYDRO-QUEBEC MSC-7040 765 kV INTERCONNECTION This rule contains the extensive operating instructions for the Hydro Quebec Chateauguay complex that is interconnected with NYPA via the MSC-7040 765 kV line. The instructions provide for the reliable operation of the bulk power system by delineating permissible equipment configurations, permissible number of Beauharnois machines and MSC-7040 import/export flow limits among other things. This may impact Bulk Power System interface transfer capability.	STATEWIDE A’
OUTAGE COORDINATION Section 4.2.6 provides that appropriate adjustments shall be made to the NY Control Area operations to accommodate the impact of protection group outages.	BULK POWER SYSTEM Relay Protection	NYPA	765 kV SYSTEM PROTECTION OUTAGES For certain relay equipment outages on the 765 kV system, NYPA may impose restrictions on the Moses South and MSC-7040 transfer limits. Under more severe relay equipment outage conditions, NYPA may remove the MSU-1 and or the MSC-7040 from service. This may impact Bulk Power System interface transfer capability.	STATEWIDE A’
AS ABOVE	BULK POWER SYSTEM Relay Protection	NYPA	IN-SERVICE RELAY WORK AT MASSENA SUBSTATION. To prevent unnecessary trips of the 765 kV tie line to Hydro Quebec at high import levels, NYPA may remove the 765 kV system from service or limit the import level to a maximum of 1300 MW for certain relay maintenance procedures at Massena substation. This may impact Bulk Power System interface transfer capability.	STATEWIDE A’

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
STABILITY ASSESSMENT Section 4.2.4	BULK POWER SYSTEM Local Actions	NYPA	OUTAGE OF MARCY-EDIC 345KV LINE NYPA has procedures that include modifications of the Fitzpatrick terminal voltage requirements for stability and possible operating restrictions on the Chateauguay Complex. This may impact Bulk Power System interface transfer capability.	STATEWIDE A’
THERMAL ASSESSMENT Section 4.2.2	BULK POWER SYSTEM Local Actions	NYPA	AUTOBANK OUTAGE AT NIAGARA During an outage of autobank #3 at Niagara, NYPA may open bus tie breakers 2332 and 2342 to prevent greater than STE post-contingency overloading of bank #5 for the loss of bank #4. This will allow normal MW output of the Niagara plant.	STATEWIDE A’
STABILITY ASSESSMENT Section 4.2.4	BULK POWER SYSTEM Local Actions	NYPA	FITZPATRICK PLANT TERMINAL VOLTAGE REQUIREMENTS To maintain the stability of the James A Fitzpatrick (JAF). NPP generator for certain severe contingencies on the 345 kV grid, NYPA requires the JAF NPP to keep its terminal voltage and in some cases its reactive power output above certain minimum levels.	STATEWIDE A’
AS ABOVE	BULK POWER SYSTEM Local Actions	NYPA	ISOLATION OF MSU-1 LINE ON A SINGLE MARCY 345 kV LINE NYPA may impose operating restrictions on the Chateauguay Complex and limit the maximum MSC-7040 flow for maintenance outage conditions where a contingency may isolate the MSU-1 line onto a single Marcy 345 kV exit. This may impact Bulk Power System interface transfer capability.	STATEWIDE A’
SPS GENERAL REQUIREMENTS Section 4.2.1 THERMAL ASSESSMENT Section 4.2.2 VOLTAGE ASSESSMENT Section 4.2.3 STABILITY ASSESSMENT Section 4.2.4	LOCAL AND BULK POWER SYSTEM Generator Dispatch Restrictions	NYPA/NYSEG	Certain line outages will require a pre-contingency re-dispatch of the Saranac generation. Saranac Energy must be notified of planned or emergency outages involving these facilities. A. 700 Line outage will require Saranac to reduce its output to 170 or 180 MW or less depending on load conditions. B. 701 Line outage will require Saranac to reduce to 170 MW or less. C. 702 Line outage: A subsequent forced outage of the 701 Line will cause the Saranac units to trip. D. MW P#1 Line outage: With the PV-20 "cross-trip" enabled, Saranac must reduce its output to as low as 175MW. E. Whenever the PV-20 cross trip is enabled: Saranac may be reduced to as low as 180 MW. F. MWP #2 Line Outage: With the PV –20 cross trip enabled Saranac must reduce its output to as low as 175 MW.	STATEWIDE A’ FOR ALL

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
			G. MSU #1 Line Outage: Outages of this line will reduce the capacity on the Moses-South Interface. Saranac will need to reduce its output to somewhere between 0 and 240 MW, depending on system conditions during the outage. H. MMS #1 or MMS #2 Line Outages: Maintenance outages involving either of these two Moses to Massena 230 kV lines will result in restricted capacity on the Moses South Interface. It will be necessary for Saranac to reduce its output to somewhere between 0 and 240 MW, depending on system conditions during the outage. I. PV-20 Line Outage: Outages of this line will require Saranac to be reduced to 175 MW to avoid stability problems for loss of both Moses-Willis-Plattsburgh (MWP) circuits. J. NYPA Plattsburgh Bus #1: To maintain stability for the loss of Moses-Willis-Plattsburgh (MWP) and stuck breaker 202, Saranac must be limited to 110 MW. K. NYPA Plattsburgh Bus #2: To maintain stability during this outage for the loss of both MWP 1 and MWP 2, Saranac must be limited to 140 MW. L. WM #1 line and Moses to Willis to Plattsburgh: During this multiple circuit outage, Saranac must be limited to 200 MW to maintain stability for the loss of the remaining MWP line. Willis to Saranac WS #1 line and one MWP line: During this multiple circuit outage, Saranac must be limited to 210 MW to maintain stability for the loss of the remaining MWP line.	
OPERATION DURING IMPENDING SEVERE WEATHER Section 4.2.7. Corrective actions to protect for one contingency greater than normal criteria shall be carried out, and generation may be ordered to full capability	ADVERSE WEATHER Storm Watch	CENTRAL HUDSON	STORMWATCH CONDITIONS Requires two units at Danskammer to be committed for service under storm watch conditions when Central Hudson's system loads are greater than 450 MW.	LOCAL C
VOLTAGE ASSESSMENT Section 3.2.3 and 4.2.3. Reactive power reserves should be available to maintain voltages within applicable pre-disturbance and post-	REACTIVE POWER SUPPORT Unit Commitment	LIPA	UNIT COMMITMENT FOR VOLTAGE SUPPORT LIPA operates in accordance with local reliability rules to insure the safe and reliable operation of the transmission system. The following table is a summary of local generation or unit commitment requirements to meet voltage control and thermal loading ~~criteria.Voltage~~criteria. Voltage support in LIPA system:	LOCAL

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
disturbance limits			A. During peak load conditions commitment of any two (of four) Northport units are required to prevent voltage collapse of the 138 kV system. B. During light load conditions commitment of any two (of four) Northport units are required to prevent over-voltage on the 138 kV system. C. During peak load conditions commitment of up to two Port Jefferson units are required to prevent voltage collapse of the 138 kV system east of Holbrook.	C C C
AS ABOVE	REACTIVE POWER SUPPORT Function of System Load	NIAGARA MOHAWK	VOLTAGE SUPPORT IN SOUTHWEST REGION ~~Indeck~~ Indeck -Olean Unit to support 115 kV area during peak loads.	LOCAL C
VOLTAGE ASSESSMENT Section 3.2.3 and 4.2.3. Reactive power reserves should be available to maintain voltages within applicable pre-disturbance and post-disturbance limits	REACTIVE POWER SUPPORT For Outages	NIAGARA MOHAWK	VOLTAGE SUPPORT IN CENTRAL REGION (ROME) A. During outages of lines 3. 4, or 5, the Oneida Sterling unit must be available to maintain 115 kV bus voltages in the Rome area. B. During maintenance outages of the Oneida Cap bank, the Oneida Sterling unit must be available to support 115 kV voltages in the Oneida - Rome area. C. During maintenance outages of the Porter-Yahundasia 3 line, the Oneida Sterling unit must be available to support 115 kV buses in the Westmoreland / Clinton/ Chadwick areas. D. During outages of the Rome Cap bank, the Oneida -Sterling unit must be available to support 115 kV voltages in the Rome area. E. During maintenance outages of the Tilden-Cortland 18 line, the Oneida Sterling unit must be available to support 115 kV voltages in the Nedrow/Cortland area.	LOCAL C FOR ALL
AS ABOVE	REACTIVE POWER SUPPORT For Outages	NIAGARA MOHAWK	VOLTAGE SUPPORT IN CENTRAL REGION A. During maintenance outages of the Cortland-Etna 1 (947) line, the OCRRA unit must be available to support 115 kV voltages in the Nedrow/Cortland area. B. During maintenance outages of the Oneida-	LOCAL C FOR ALL

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
			Cortland 3 line out of service, the OCRRA unit must be available to maintain 115 kV voltages in the Nedrow/Cortland area. C. During maintenance outages of the Cortland 115 kV Cap bank, the OCRRA unit must be available to maintain voltages in the Nedrow/Cortland area.	
AS ABOVE	REACTIVE POWER SUPPORT Voltage Specification	CON EDISON	TRANSMISSION LEVEL VOLTAGES This procedure uses existing operating guidelines to maintain adequate voltage levels and reactive reserve for its portion of the NYS power system. For normal and peak load conditions, the 345 kV and 138 kV voltages shall be maintained within these limits: 345 kV Voltage 350 kV +9 kV to 350 - 4 kV 138 kV Voltage 138 kV +5 kV to 138 - 2 kV	LOCAL B
AS ABOVE	REACTIVE POWER SUPPORT	LIPA	REACTIVE RESERVESLIPA must maintain sufficient reactive reserves on Long Island to sustain the loss of the two largest reactive sources.	LOCAL C
VOLTAGE ASSESSMENT Section 3.2.3 and 4.2.3. Reactive power reserves should be available to maintain voltages within applicable pre-disturbance and post-disturbance limits	REACTIVE POWER SUPPORT Unit Commitment	LIPA	UNIT COMMITMENT REQUIREMENTS FOR VOLTAGE CONTROL LIPA operates in accordance with local reliability rules to insure the safe and reliable operation of the transmission system. The following table is a summary of local generation or unit commitment requirements to meet voltage control and thermal loading ~~criteria.Voltage~~criteria. Voltage support in LIPA system: A. During peak load conditions commitment of any two (of four) Northport units are required to prevent voltage collapse of the 138 kV system. B. During light load conditions commitment of any two (of four) Northport units are required to prevent ~~overvoltage~~over-voltage on the 138 kV system. C. During peak load conditions commitment of up to two Port Jefferson units are required to prevent voltage collapse of the 138 kV system east of Holbrook.	LOCAL C FOR ALL

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
			D. During light load conditions commitment of one Barrett unit is required to prevent ~~overvoltage~~over-voltage on the 138 kV system. E. At or above average system load conditions commitment of the Far Rockaway unit is required to prevent voltage collapse of the 69 kV Rockaway Peninsula. F. At peak load conditions commitment of the Montauk Diesel unit is required to prevent voltage collapse of the 69 kV system on the South Fork of Long Island. G. At or above average system load conditions commitment of the East Hampton Gas Turbine unit is required to prevent voltage collapse of the 69 kV system on the South Fork of Long Island. H. At or above average system load conditions commitment of the South Hampton Gas Turbine is required to prevent voltage collapse of the 69 kV system on the South Fork of Long Island. I. At or above average system load conditions commitment of the East Hampton Diesel unit is required to prevent voltage collapse of the 69 kV system on the South Fork of Long Island. J. At peak load conditions commitment of the Southold Gas Turbine unit is required to prevent voltage collapse of the 69 kV system on the South Fork of Long Island. Major LIPA facilities out of service may ~~required~~require increased generation in load pockets to reduce line flows or maintain voltage. Further, prudent utility practice warrants a review of the impact of loss of the Northport Substation and that possible over-trips of Y49 and Y50 be considered for unit commitment.	
VOLTAGE ASSESSMENT Section 3.2.3 and 4.2.3. Reactive power reserves should be available to maintain voltages within applicable pre-disturbance and post-disturbance limits	REACTIVE POWER SUPPORT Function of System Load	NYSEG	During summer and winter heavy load periods at least one unit at Miliken must be in service to provide adequate voltage to the customers in NYSEG's Ithaca Division.	LOCAL C
AS ABOVE	REACTIVE POWER SUPPORT Function of System Load	NIAGARA MOHAWK	VOLTAGE SUPPORT IN SOUTHWEST REGION During peak loads requires sufficient commitment of Dunkirk generating units to support 115 and 230 kV voltages.	LOCAL C

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
AS ABOVE	REACTIVE POWER SUPPORT Function of System Load	NIAGARA MOHAWK	VOLTAGE SUPPORT IN SOUTHWEST REGION During peak loads requires sufficient commitment of Dunkirk generating units to support 115 and 230 kV voltages.	LOCAL C
AS ABOVE	REACTIVE POWER SUPPORT Function of System Load	NIAGARA MOHAWK	OFF-PEAK AND LIGHT LOAD CONDITIONS During off-peak and light load periods, the availability of various system generation resources over a wide area must be committed for voltage control to protect equipment from damage and avoid equipment malfunction due to high voltages.	LOCAL C
AS ABOVE	REACTIVE POWER SUPPORT Voltage Specification	CENTRAL HUDSON	ALLOWABLE VOLTAGE RANGE Voltages on the 115 and 69kV transmission system will be maintained within =/- 2.5% of nominal under normal conditions.	LOCAL C
AS ABOVE	REACTIVE POWER SUPPORT Voltage Specification	CENTRAL HUDSON	ALLOWABLE VOLTAGE RANGE Voltages on the 115 and 69kV transmission system will be maintained within =/- 2.5% of nominal under normal conditions.	LOCAL C
AS ABOVE	REACTIVE POWER SUPPORT Voltage Specification	CENTRAL HUDSON	ALLOWABLE VOLTAGE RANGE Voltages on the 115 and 69kV transmission system will be maintained within =/- 2.5% of nominal under normal conditions.	LOCAL C
AS ABOVE	REACTIVE POWER SUPPORT Function of System Load	CENTRAL HUDSON	HEAVY LOAD PERIODS During heavy load periods one or more units at	LOCAL C

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
			Danskammer may be required to provide adequate voltage support.	
AS ABOVE	REACTIVE POWER SUPPORT For Outages	NIAGARA MOHAWK	VOLTAGE SUPPORT IN SOUTHWEST REGION ~~Indeck~~ Indeck --Olean unit must support 115 kV voltages when more than one Dunkirk unit is out of service.	LOCAL C
VOLTAGE ASSESSMENT Section 3.2.3 and 4.2.3. Reactive power reserves should be available to maintain voltages within applicable pre-disturbance and post-disturbance limits	REACTIVE POWER SUPPORT For Outages	NIAGARA MOHAWK	VOLTAGE SUPPORT IN SOUTHWEST REGION Reactive support needed from Dunkirk units 1&2 when one Dunkirk 230/115 kV transformer is out of service.	LOCAL C
AS ABOVE	REACTIVE POWER SUPPORT For Outages	NIAGARA MOHAWK	VOLTAGE SUPPORT IN CENTRAL REGION (OSWEGO) During outages of Oswego 345/115 kV or Oswego 115 kV Cap bank, ~~Indeck~~ Indeck -Hammermill generator is required to support voltage on 115 kV buses at Nine Mile and Fitzpatrick.	LOCAL C
PRE-CONTINGENCY AND POST-CONTINGENCY THERMAL CRITERIA Section 4.2.2.1 and 4.2.2.2~~:No~~: No facility shall be loaded pre-contingency beyond its normal rating, and no facility shall be loaded post-contingency beyond its LTE rating (STE rating for underground cables).	BULK POWER SYSTEM Rapid Response to Manage Cable System Loading	CON EDISON	MAXIMUM GEN AND FAST LOAD PICK UP ALARMS SYSTEM The use of phase angle regulators and rapid increases in in-City generation permits Con Edison to use Short Term Emergency (STE) ratings rather than Long Term Emergency (LTE) ratings for operating the cable system. If contingency analysis shows that the post contingency loading on the cable system will exceed STE ratings, then immediate action is taken, including Fast Load Pick-up/Maximum Generation, to mitigate the post contingency overloads.	LOCAL C

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
AS ABOVE	LOCAL POWER SYSTEM Transfer Limits	NIAGARA MOHAWK	ALCOA BUS TIE OUTAGES During outages of the Alcoa Bus Tie, R8105, the Northern Region area north of Dennison station must have limited import capability from Cedars (HQ). The import form Cedars under this condition is 150 MW as metered at Cornwall Electric and 95 MW as metered at Dennison.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Transfer Limits	NIAGARA MOHAWK	During outages of either the Cedars-Dennison 1 or 2 lines, the Northern Region area north of Dennison must have limited import capability form Cedars (HQ). The import from Cedars under this condition is 150 MW as metered at Cornwall Electric.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Transfer Limits	NIAGARA MOHAWK	DENNISON BUS TIE OUTAGES During outages of the Dennison Bus Tie, R8105, the Northern Region area north of Dennison must have limited import capability from Cedars (HQ). The import from Cedars under this condition is 115 MW as metered at Cornwall Electric.	LOCAL C
PRE-CONTINGENCY AND POST-CONTINGENCY THERMAL CRITERIA. Section 4.2.2.1 and 4.2.2.2~~:No~~: No facility shall be loaded pre-contingency beyond its normal rating, and no facility shall be loaded post-contingency beyond its LTE rating (STE rating for underground cables).	LOCAL POWER SYSTEM Transfer Limits	NIAGARA MOHAWK	DENNISON-COLTON, ALCOA-DENNISON LINE OUTAGES During outages of either Dennison-Colton 4 or 5 lines or Alcoa-Dennison 12 line, the Northern Region area north of Dennison must have limited import capability from Cedars (HQ). The import from Cedars under this condition is 200 MW as metered at Cornwall Electric.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Dispatch	CENTRAL HUDSON	GENERATION CONSTRAINTS / DANSKAMMER	LOCAL C

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
	Restrictions		Under certain circumstances including, but not limited to, planned and/or forced outages of critical transmission facilities, the level of generation at Danskammer must be constrained in order to ensure system security.	
AS ABOVE	LOCAL POWER SYSTEM Generator Dispatch Restrictions	CENTRAL HUDSON	GENERATION CONSTRAINTS / WEST SIDE 69 kV SYSTEM Under certain circumstances, including but not limited to, planned and/or forced outages of critical transmission facilities, the level of generation within the West Side 69 kV System must be constrained in order to insure system security.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Dispatch Restrictions	NYSEG	ITHACA 115 kV TRANSMISSION SYSTEM During maintenance outages of any one of the three 115 kV lines that exit Miliken, the Miliken unit output will need to be reduced so that the loss of either remaining line will not cause the single remaining line to exceed its STE rating and that the emergency response rates of both units can reduce the line loading to normal within 15 minutes. The three lines involved are~~:~~Miliken to Etna 975L, Miliken to Etna 974L, and Miliken to Wright 973L.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Dispatch Restrictions	RG&E	GINNA GENERATION TRANSMISSION LIMITATIONS Subsequent to a permanent outage of selected 115 kV circuits, reductions in Ginna output are required. Maintenance outages on circuits 908 and 912 are restricted to periods when Ginna generation is on line.	LOCAL C
PRE-CONTINGENCY AND POST-CONTINGENCY THERMAL CRITERIA Section 4.2.2.1 and 4.2.2.2: No facility shall be loaded	LOCAL POWER SYSTEM Generator Dispatch	RG&E	KAMINE GENERATION TRANSMISSION LIMITATIONS	LOCAL C

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
pre-contingency beyond its normal rating, and no facility shall be loaded post-contingency beyond its LTE rating (STE rating for underground cables).	Restrictions		The loss of RG&E's 906 circuit between Station 162 and Station 158 will require an immediate reduction in the output of the KAMINE generator, which is connected to Station 162 (South Perry).	
	LOCAL POWER SYSTEM Generator Dispatch Restrictions	O&R	GENERATION CONSTRAINTS IN EASTERN LOAD POCKET During planned or forced outages of one of the two Lovett to West Haverstraw 138 kV lines, the maximum generation of the Lovett plant must be constrained to protect the underlying transmission system from overloads due to the loss of the second Lovett-West Haverstraw line.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Dispatch Restrictions	NYSEG	NYSEG has various IPPs located on the sub transmission and distribution system, which require curtailment for sub transmission and distribution line switching and maintenance conditions. This is required to avoid ferro-resonance on the NYSEG sub transmission during maintenance conditions, or because the maintenance involves opening the IPP connection to the rest of the system, or because the switching procedure may cause the unit to unexpectedly trip off line.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Requirement	CENTRAL HUDSON	GENERATION SUPPORT/SYSTEM IMPORT CAPABILITY Under certain circumstances including, but not limited to, planned and/or forced outages of critical transmission facilities, minimum levels of generation must be committed and dispatched at Danskammer in order to ensure system security.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Requirement	CENTRAL HUDSON	GENERATION SUPPORT / WEST SIDE 69 kV SYSTEM Under certain circumstances including, but not	LOCAL C

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
			limited to, planned and or forced outages of critical transmission facilities, minimum levels of generation must be committed and dispatched within the West Side 69 kV System in order to ensure system security.	
PRE-CONTINGENCY AND POST-CONTINGENCY THERMAL CRITERIA Section 4.2.2.1 and 4.2.2.2: No facility shall be loaded pre-contingency beyond its normal rating, and no facility shall be loaded post-contingency beyond its LTE rating (STE rating for underground cables).	LOCAL POWER SYSTEM Generator Requirement	NIAGARA MOHAWK	SYSTEM SECURITY IN SOUTHWEST REGION Requires dispatching of ~~Indeck~~ Indeck -Olean unit during outages of either of the Dunkirk-Falconer 160, 161, or 162 lines.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Requirement	NIAGARA MOHAWK	SYSTEM SECURITY IN NORTHEAST REGION DURING LOW HYDROELECTRIC GENERATION During peak load conditions with low Northeast Region hydro generation, the non-hydro units in the Northeast Region must be committed to operate to avoid exceeding STE ratings on certain 115 kV lines following a contingency.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Requirement	NIAGARA MOHAWK	SYSTEM SECURITY IN CAPITAL REGION DURING EHV BANK OUTAGE During maintenance outages of the Capital Region's 345/115 kV or 230/115 kV transformers, sufficient Albany generation must be available to ensure adequate (acceptable?) post-contingency loading on the remaining Capital Region autotransformers.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Requirement	NIAGARA MOHAWK	GENERATION SUPPORT/SYSTEM IMPORT CAPABILITY During peak load conditions with low Northern Region (Watertown area) hydro generation, the non-hydro units in the Watertown area must be	LOCAL C

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
			committed to operate to avoid exceeding STE ratings on certain 115 kV lines Following a contingency.	
AS ABOVE	LOCAL POWER SYSTEM Generation Requirement	O&R	GENERATION SUPPORT REQUIRED IN EASTERN LOAD POCKET During peak load periods, sufficient Lovett generation is required to maintain system reliability so that voltage reduction or load shedding is not required for the loss of a transmission circuit or transformer.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Requirement	O&R	GENERATION SUPPORT REQUIRED IN WESTERN LOAD POCKET During times of thunderstorm alert, peak loads or planned or forced transmission outages in the vicinity of the Western load pocket, sufficient Hydro and Gas Turbine reserve capacity must be available so that voltage reduction or load shedding is not required following a contingency.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generation Requirement	RG&E	RUSSELL DISPATCH For system conditions when the load is less than 650MW and Ginna generation is above 450MW, additional generation within RG&E is required at Russell to relieve 34.5kV overloads.	LOCAL C
AS ABOVE	LOCAL POWER SYSTEM Generator Requirement	RG&E	MUST RUN GENERATION During peak load condition all RG&E fossil generation becomes “must run” to maintain system reliability. This avoids the need for voltage reduction or load shedding in the event of loss of	LOCAL C

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
			Ginna or a transmission facility.	
SYSTEM RESTORATION AND BLACKSTART Restoration, Section 4.16,and NYPP Operating Procedure OP 13-4, "Restoration Policy", September 1, 1986: Guide for The Restoration of the Bulk Power System Following a Major Disturbance, Islanding, or System Interruption, requires Member Systems to have a restoration procedure.	LOCAL POWER SYSTEM System Restoration Plans and Blackstart Capability	ALL NYPP MEMBER SYSTEMS	IMPLEMENTATION OF MEMBER SYSTEMS RESTORATION PLANS The NYPP maintains a system restoration plan for the bulk power system under its control. In addition, the Member Systems of NYPP each have their own company Restoration Plans and Blackstart Procedures that are more specific to their systems and must be coordinated with the NYPP (NYISO). The NYISO authorizes each Transmission Owner and its operators to take the appropriate steps under normal and extreme emergency conditions to restore equipment as quickly as possible in accordance with each TO's operating practices.	LOCAL C
"Reliability Rules for Planning and Operating the New York Bulk Power System" May 2, 1997 Filing. NYPP principal document on planning and operating criteria	PLANNING CRITERIA	CENTRAL HUDSON	DANSKAMMER EXPORTS Used in determining system import and Danskammer export capabilities.	LOCAL C
SPS GENERAL REQUIREMENTS Section 4.2.1VOLTAGE ASSESSMENT Section 4.2.3	BULK POWER SYSTEM Reliability (SPS)	NYPA	PV-20 CROSS-TRIP SCHEMEF or certain system conditions, NYPA or VELCO may require the PV-20 cross-trip scheme to be enabled to maintain reliability.	STATEWIDE A'
STABILITY ASSESSMENT Section 4.2.4	BULK POWER SYSTEM Transfer Limits	NIAGARA MOHAWK	OSWEGO COMPLEX STABILITY LIMITS During "all lines in service" operation of the Oswego complex, the transient stability limit of the complex must be observed to insure the security of the Bulk Power System. The export out of the Oswego Complex must be within the appropriate transient stability limit assuming this limit is lower than the thermal limit of the complex.	LOCAL D
AS ABOVE	BULK POWER SYSTEM Transfer	NIAGARA MOHAWK	OSWEGO COMPLEX –345KV LINE OUTAGES	LOCAL

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation
	Limits		During outages of the 345kV transmission lines in the Oswego Complex, the transient stability limit of the complex must be observed to insure the security of the bulk power system. The export limit Out of the Oswego Complex must be within the appropriate transient stability limit, assuming this limit is lower than the thermal limit of the complex.	D
PRE-CONTINGENCY AND POST-CONTINGENCY THERMAL CRITERIA Section 4.2.2.1 and 4.2.2.2: No facility shall be loaded pre-contingency beyond its normal rating, and no facility shall be loaded post-contingency beyond its LTE rating (STE rating for underground cables).	BULK POWER SYSTEM Local Actions	NIAGARA MOHAWK	OSWEGO GENERATION COMPLEX – THERMAL LIMITS During operation of the Oswego Complex, the thermal limits of the complex must be observed and solved for to insure the security of the bulk power system. The export out of the Oswego Complex must be within the appropriate thermal limit by re-dispatching Oswego Complex Generation, should no units be “On Dispatch” in NYPP SCD.	LOCAL D
STABILITY ASSESSMENT Section 4.2.4	BULK POWER SYSTEM Local Actions	NYPA	OPERATION WITH HVDC ISOLATED. NYPA may remove the MSC- 040 line from service if the Chateauguay HVDC is isolated onto a single 765/120 kV transformer at Chateauguay and the condition is not corrected within 15 minutes.	STATEWIDE A’

Basic Reliability Rule	Category	Company	Definition of The Application	Cost Allocation/Implementation

IMPLEMENTATION RULES

A – The reliability criteria is monitored and implemented by the NYISO, and any uplift costs due to the application over & above the LBMP market are recovered through a statewide uplift

A' – The reliability criteria is monitored by the TP. The NYISO implements the restriction in SCUC and RTD. Any uplift costs due to the application are recovered through a statewide uplift.

B – The application is implemented by the NYISO. Any uplift costs incurred as a result of the application are recovered through a localized uplift calculated by the NYISO.

C – The application is implemented by the TP. Any uplift costs incurred as a result of the application are recovered by the TP outside of the NYISO billing process.

D – The application is monitored and implemented by the TP. Any uplift costs incurred as a result of the application are recovered through a statewide uplift calculated by the NYISO.

C. Solar Magnetic Disturbance Form

This form is used to record Solar Magnetic Disturbance (SMD) Forecasts and Alerts from the Space Environment Services Center (SESC) in Boulder, Colorado and from Energy, Mines, and Resources (EMR) in Ottawa, Ontario.

SESC	Intensity	Date/Time: ____ Alert Received By: ____ Duration of Forecast or Alert From: ____ To: ____
Forecasts	____ ("A" Index of 30 or Above)	Valid Period (Date, Time, Duration) From: ____ To: ____
Alerts	____ ("K" Index of 5 Above)	Valid Period (Date, Time, Duration) From: ____ To: ____
Other Comments	____ ____	

EMR	Intensity	Date/Time: ____ Alert Received By: ____ Duration of Forecast or Alert From: ____ To: ____
Forecasts	____ (Active or Major Storm Conditions)	Valid Period (Date, Time, Duration) From: ____ To: ____
Alerts	____ (Active or Major Storm Conditions)	Valid Period (Date, Time, Duration) From: ____ To: ____
Other Comments	____ ____	

D. Automatic Voltage Regulator Log

This form is used by the NYISO to record the status of Automatic Voltage Regulators in the New York Control Area.

Unit Name & Identification	Out-of-Service		Return-to-Service	
	Date	Time	Date	Time

E. Locational Based Marginal Pricing

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

Real-Time LBMP

For each RTD interval, the NYISO shall calculate Real-Time LBMPs, the Marginal Losses Component, and the Congestion Component at each Load Zone and Generator bus. In addition, when certain conditions exist, as defined in Exhibit E-1 below, the NYISO shall employ the special scarcity pricing rules described in Attachment E.6.

Exhibit 7-1: Real-Time LBMP Procedures

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

SCR/EDRP NYCA, Called and Needed

Is “YES” if the NYISO has called SCR/EDRP resources and determined that, but for the Expected Load Reduction, the Available Reserves would have been less than the NYCA requirement for total 30-Minute Reserves; or is “NO” otherwise.

SCR/EDRP East, Called and Needed

Is "YES" if the NYISO has called SCR/EDRP from resources located East of Central-East and determined that, but for the Expected Load Reduction, the Available Reserves located East of Central-East would have been less than the requirement for 10-Minute Reserves located East of Central-East; or is "NO" otherwise.

Scarcity Pricing Rule to be Used in the West

Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Zones located West of Central-East, including the Reference Bus.

Scarcity Pricing Rule to be Used in the East

Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Zones located East of Central-East.

The Real-Time Commitment

Real-Time Commitment (RTC) and automated market power mitigation measures may affect the calculation of Real-Time LBMPs. This process is carried out in two steps:

1. The first evaluation, referred to as the RTC evaluation, will determine the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied.
2. The second evaluation, referred to as the RT-AMP evaluation, will determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures.

In situations where real-time automated mitigation measures may be utilized, the NYISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, RTC15 and RT-AMP15 will perform Resource commitment evaluations simultaneously. RT-AMP15 will then apply the mitigation "impact" test, account for reference bid levels as appropriate and determine which Resources are actually to be mitigated. This information will then be conveyed to RTC30, which will make Resource commitments consistent with the application of the mitigation measures (and will thus indirectly be incorporated into future RTD runs).

E.1 Bus LBMP Calculation Method

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

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma^L_i + \gamma^C_i$$

Where:

γ_i = LBMP at bus i in $/MWh

λ^R = System marginal price at the Reference Bus

γ^L_i = Marginal Losses Component of the LBMP at bus i which is the marginal cost of losses at bus i relative to the Reference Bus

γ^C_i = Congestion Component of the LBMP at bus I which is the marginal cost of Congestion at bus I relative to the Reference Bus

Marginal Losses Component

~~Appendix B-4~~
~~Multiple Circuit Tower Lines in NY Control Area~~

The Marginal Losses Component of the LBMP at any bus i within the NYCA is calculated using the equation:

$$\gamma^L_i = (DF_i - 1)\lambda^R$$

~~Circuit Designations~~	~~Terminals~~	~~Included in On-line MCE~~	~~Exemption and Reason~~

Where:

DF_i = Delivery factor for bus i to the system Reference Bus and:

$$DF_i = \left(1 - \frac{\partial L}{\partial P_i}\right)$$

Where:

L = NYCA losses

P_i = Generation injection at bus i

Congestion Component

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

$$\gamma^c_i = -\left(\sum_{k \in K}^{n} GF_{ik}\mu_k\right)$$

Where:

K = The set of thermal or Interface Constraints

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

μ_k = The reduction in system cost that results from an incremental relaxation of Constraint k expressed in $/MWh.

Substituting the equations for γ^L_i and γ^C_i into the first equation yields:

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

Day-Ahead and Real-Time

~~345 kV~~LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the Day-Ahead Market, the three components of the LBMP at each location will be calculated from the SCUC results and posted for each of the twenty-four hours of the next day. The Real-Time LBMPs will be calculated and posted for each execution of RTD.

~~11~~ ~~17~~	~~Oswego-Volney~~ ~~Oswego-Lafayette~~	~~Yes~~	~~--~~
~~32~~ ~~36~~	~~Oakdale-Fraser~~ ~~Oakdale-Lafayette~~	~~Yes~~	~~Note 3~~
~~91~~ ~~92~~	~~Leeds-Pleasant Valley~~ ~~(2 Parallel Circuits)~~	~~No~~	~~Note 1~~
~~GNS1~~ ~~GL3~~	~~Gilboa-New Scotland~~ ~~Gilboa-Leeds~~	~~No~~	~~Note 1~~
~~F30/W80~~ ~~F31/W78~~	~~Pleasant Valley-Wood St-Millwood W.~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~W82/W65~~ ~~W85/W78~~	~~Millwood W.-Eastview-SprainBrook~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~F36~~ ~~F37~~	~~Pleasant Valley-E. Fishkill~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~F38/Y86~~ ~~F39/Y87~~	~~E. Fishkill-Wood St-Pleasnatville~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~W89~~ ~~W90~~	~~Pleasantville-Dunwoodie~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~W93/W79-~~ ~~W99/W64~~	~~Buchana-Eastview-SprainBrook &~~ ~~-Millwood W.-Eastview-SprainBrook~~	~~Yes~~	~~--~~
~~W97~~	~~Buchanan S.-Millwood W.~~	~~No~~	~~Note 2~~

~~W98~~	~~(2 Parallel Circuits)~~		
~~W72~~ ~~Y94~~	~~Ramapao-Ladentown &~~ ~~Ramapo-Buchanan N.~~	~~Yes~~	~~--~~
~~Y88~~ ~~Y94~~	~~Ladentown-Buchanan S. &~~ ~~Ramapo-Buchanan N.~~	~~Yes~~	~~--~~
~~67~~ ~~68~~	~~Bowline Pt.-W. Haverstraw-~~ ~~Ladentown & Bowline Pt.-Ladentown~~	~~Yes~~	~~--~~
~~21~~ ~~22~~	~~Goethals-Fresh Kills~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~69/J3410-~~ ~~70/K3411~~	~~Ramapo-Waldwick~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~EF24-40~~ ~~UCC2-41~~	~~Edic-Fraser~~ ~~Marcy-Coopers Corners~~	~~Yes~~	~~--~~
~~33~~ ~~UCC2-41~~	~~Fraser-Coopers Corners~~ ~~Marcy-Coopers Corners~~	~~Yes~~	~~--~~
~~CCRT-34~~ ~~CCRT-42~~	~~Coopers Corners-Rock Tavern~~ ~~Coopers Corners-Rock Tavern~~	~~Yes~~	~~--~~
~~4-36~~ ~~22~~	~~Lafayette-Oakdale~~ ~~Dewitt-Lafayette~~	~~No~~	~~Note 1~~
~~11~~ ~~12~~	~~Oswego-Volney~~ ~~(2 Parallel Circuits)~~	~~No~~	~~Note 1~~
~~230 kV & 345 kV~~			
~~11~~ ~~UCC2-41~~	~~Adirondack-Porter (230kV)~~ ~~Marcy-Coopers Corners (345kV)~~	~~Yes~~	~~--~~
~~12~~ ~~18~~	~~Adirondack-Porter (230 kV)~~ ~~Marcy-New Scotland (345 kV)~~	~~Yes~~	~~--~~
~~67~~ ~~37~~	~~Stolle Road-Meyer (230 kV)~~ ~~Stolle Road-Homer City (345 kV)~~	~~Yes~~	~~--~~
~~31~~ ~~UCC2-41~~	~~Porter-Rotterdam (230 kV)~~ ~~Marcy-Coopers Corners (345 kV)~~	~~Yes~~	~~--~~
~~30~~ ~~EF24-40~~	~~Porter-Rotterdam (230 kV)~~ ~~Edic-Fraser (345 kV)~~	~~Yes~~	~~--~~
~~230 kV~~			
~~61~~ ~~64~~	~~Niagara-Packard~~ ~~Niagara-Robinson Road~~	~~Yes~~	~~--~~

~~62~~ ~~PA27~~	~~Niagara-Packard~~ ~~Niagara-Beck~~	~~Yes~~	~~--~~
~~62~~ ~~BP76~~	~~Niagara-Packard~~ ~~Packard-Beck~~	~~Yes~~	~~--~~
~~68~~ ~~69~~	~~Hillside-Meyer~~ ~~Hillside-Watercure Road~~	~~Yes~~	~~--~~
~~73~~ ~~74~~	~~Gardenville-Dunkirk~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~77~~ ~~78~~	~~Packard-Huntley~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~77~~ ~~80~~	~~Packard-Huntley~~ ~~Huntley-Gardenville~~	~~Yes~~	~~--~~
~~78~~ ~~79~~	~~Packard-Huntley~~ ~~Huntley-Gardenville~~	~~Yes~~	~~--~~
~~79~~ ~~80~~	~~Huntley-Gardenville~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~PA27~~ ~~BP76~~	~~Niagara-Beck~~ ~~Packard-Beck~~	~~Yes~~	~~--~~
~~L33P~~ ~~L34P~~	~~St. Lawrence T.S.-Moses~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~MA-1/11~~ ~~MA-2/12~~	~~Moses-Adirondack-Porter~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~MW1/WP1~~ ~~MW2/WP2~~	~~Moses-Willis-Plattsburgh~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~MMS1~~ ~~MMS2~~	~~Moses-Massena~~ ~~(2 Parallel Circuits)~~	~~Yes~~	~~--~~
~~61~~ ~~62~~	~~Niagara-Packard~~ ~~(2 Parallel Circuits)~~	~~No~~	~~Note 1~~

~~Note 1: Exempt because of 5 tower criteria.~~
~~Note 2: Exempt because they are not adjacent.~~
~~Note 3: Exempt by NYISO for development of Voltage limits only.~~

~~Appendix B-5~~
~~Thunderstorm Multiple Contingencies Cases~~

~~36. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 311~~

~~37. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 77~~

38. ~~F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, Y94, TA5, Bank (95891)~~

39. ~~F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, Y88~~

40. ~~F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, F31, W81~~

41. ~~F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, W82, Eastview Bank 2S, W65~~

42. ~~F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, W93, Eastview Bank 2N, W79~~

43. ~~F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, A2253~~

44. ~~F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, W75~~

45. ~~F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 301~~

46. ~~F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 303~~

47. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, 311~~

48. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, 77~~

49. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, Y94, TA5 Bank (95891)~~

50. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, Y88~~

51. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, F31, W81~~

52. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, W82 Eastview Bank 2S, W65~~

53. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, W93, Eastview Bank 2N, W79~~

54. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, A2253~~

55. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, W75, 72, 71~~

56. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, 301~~

57. ~~W89, W73, W90, W74, Y50, Pleasantville Bank 2, 303~~

58. ~~F36, F37, 301~~

59. ~~F36, F37, 303~~

60. ~~F36, F37, 311~~

61. ~~F36, F37, 77~~

62. ~~F36, F37, Y94, TA5 Bank (95891)~~

63. ~~F36, F37, Y88~~

64. ~~F36, F37, F31, W81~~

65. ~~F36, F37, W82, Eastview Bank 2S, W65~~

66. ~~F36, F37, W75~~

67. ~~F36, F37, W93, Eastview Bank 2N, W79~~

68. ~~F36, F37, A2253~~

69. ~~F36, F37, F38, RFK305~~

70. ~~F31, W81, F30, W80, Wood St. Bank 1, 311~~

71. ~~F31, W81, F30, W80, Wood St. Bank 1, 77~~

72. ~~F31, W81, F30, W80, Wood St. Bank 1, Y94, TA5 Bank (95891)~~

73. ~~F31, W81, F30, W80, Wood St. Bank 1, Y882. F31, W81, F30, W80, Wood St. Bank 1, W75~~

74. ~~F31, W81, F30, W80, Wood St. Bank 1, F38, Y86, Pleasantville Bank 1~~

75. ~~F31, W81, F30, W80, Wood St. Bank 1, W93, Eastview Bank 2N, W79~~

76. ~~F31, W81, F30, W80, Wood St. Bank 1, A2253~~

77. ~~F31, W81, F30, W80, Wood St. Bank 1, 301~~

78. ~~F31, W81, F30, W80, Wood St. Bank 1, 303~~

79. ~~F31, W81, F30, W80, Wood St. Bank 1, 305~~

80. ~~W85, W82, W65, Eastview Bank 2S, Eastview Bank 1S, W99, Eastview Bank 1N, W64, W78~~

81. ~~W85, W82, W65, Eastview Bank 2S, Eastview Bank 1S, W93, Eastview Bank 2N, W79, W78~~

82. ~~W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, Y94, TA5 Bank (95891), IP2~~

83. ~~W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, Y88~~

84. ~~W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, F38, Y86, Pleasantville Bank 1~~

85. ~~W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, Eastview Bank 1S, W85, W78~~

86. ~~W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, W82 Eastview Bank 2S, W65~~

87. ~~Y88, Y94, TA5 Bank (95891), 91~~

88. ~~Y88, Y94, TA5 Bank (95891), 92~~

89. ~~Y88, Y94, TA5 Bank (95891), F38, Y86, Pleasantville Bank 1~~

90. ~~Y88, Y94, TA5 Bank (95891), F39, Y87, Pleasantville Bank 2, Wood St. Bank 2~~

91. ~~Y88, Y94, TA5 Bank (95891), F31, W81~~

92. ~~Y88, Y94, TA5 Bank (95891), F30, Wood St. Bank 1, W80~~

93. ~~Y88, Y94, TA5 Bank (95891), W93, Eastview Bank 2N, W79, IP2~~

94. ~~Y88, Y94, TA5 Bank (95891), A2253~~

95. ~~Y88, Y94, TA5 Bank (95891), 301~~

96. ~~Y88, Y94, TA5 Bank (95891), 303~~

97. ~~Y88, Y94, TA5 Bank (95891), RFK305~~

98. ~~W97, W98, Y88, IP3~~

99. ~~W97, W98, Y88, IP3, 91~~

100. ~~W97, W98, Y88, IP3, 92~~

~~101. W97, W98, Y88, IP3, F38, Y86, Pleasantville Bank 1~~

~~102. W97, W98, Y88, IP3, F39, Y87, Wood St. Bank 2~~

~~103. W97, W98, Y88, IP3, F31, W81~~

~~104. W97, W98, Y88, IP3, F30, Wood St. Bank 1, W80~~

~~105. W97, W98, Y88, IP3, W93, Eastview Bank 2N, W79~~

~~106. W97, W98, Y88, IP3, 301~~

~~107. W97, W98, Y88, IP3, 303~~

~~108. W97, W98, Y88, IP3, RFK305~~

~~109. 91, 92~~

~~110. 91, 3113. 91, 77~~

~~111. 92, 311~~

~~112. 92, 77~~

~~113. 91, 301~~

~~114. 91, 303~~

~~115. 91, RFK305~~

~~116. 301, RFK305~~

~~117. 69, South Mahwah Bank, J3410, Waldwick Bank 2, 70, K3411, Waldwick Bank 3, Y88~~

~~118. Y88, Y94, TA5 (95891), 69, South Mahwah Bank, J3410, Waldwick Bank 2~~

~~119. Y88, Y94, TA5 (95891), 70, K3411, Waldwick Bank 3~~

~~Appendix C – Solar Magnetic Disturbance Form~~

~~This form is used to record SMD Forecasts and Alerts from the Space Environment Services Center (SESC) in Boulder, Colorado and from Energy, Mines, and Resources (EMR) in Ottawa, Ontario.~~

~~**SESC**~~	~~Intensity~~	~~Date/Time:~~ ~~Alert Received By:~~ ~~Duration of Forecast or Alert~~ ~~From:~~ ~~To:~~
~~*Forecasts*~~	~~("A" Index of 30 or Above)~~	~~Valid Period~~ ~~(Date, Time, Duration)~~ ~~From:~~ ~~To:~~

~~*Alerts*~~	~~("K" Index of 5 Above)~~	~~Valid Period~~ ~~(Date, Time, Duration)~~ ~~From:~~ ~~To:~~
~~*Other Comments*~~		

~~**EMR**~~	~~Intensity~~	~~Duration of Forecast or Alert~~ ~~From:~~ ~~To:~~
~~*Forecasts*~~	~~(Active or Major Storm Conditions)~~	~~Valid Period~~ ~~(Date, Time, Duration)~~ ~~From:~~ ~~To:~~
~~*Alerts*~~	~~(Active or Major Storm Conditions)~~	~~Valid Period~~ ~~(Date, Time, Duration)~~ ~~From:~~ ~~To:~~
~~*Other Comments*~~		

~~Appendix D – Automatic Voltage Regulator Log~~

~~This form is used by the NYISO to record the status of Automatic Voltage Regulators in the New York Control Area.~~

~~**Unit Name & Identification**~~	~~**Out-of-Service**~~		~~**Return-to-Service**~~	
	~~**Date**~~	~~**Time**~~	~~**Date**~~	~~**Time**~~

~~Appendix E – LBMP Example~~

~~This attachment illustrates the LBMP calculation method, using a two-bus example. The example is sufficient to demonstrate the concepts and calculations involved. The settlement and billing processes are not covered in this example.~~

~~Exhibit E.~~

E.2 - Zonal LBMP Calculation Method

The computation described above is at the bus level. An ~~11 zone~~11-zone model will be used for the LBMP billing related to Loads. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the zone. The Load weights, which will sum to unity will be predetermined by the NYISO. Each component of the LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone *j* can be written as:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

Where:

γ_j^Z = LBMP for zone *j*

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

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

n = Number of Load buses in zone j for which LBMPs are calculated

W_i = Load weighting factor for bus i.

The zonal LBMPs will be a weighted average of the Load bus LBMPs in the zone. The weightings will be predetermined by the NYISO as given in Technical Bulletin #28.

E.3 - External LBMP Calculation Method

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

General

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of buses External to the NYCA. LBMPs will be calculated for each bus within this limited set. The three components of LBMP will be calculated from the results of RTD, or, in the case of a Proxy Generator Bus, from the results of RTC15 during periods in which:

1. Proposed economic transactions over the Interface between the NYCA and the Control Area with which that Proxy Generator Bus is associated would exceed the Available Transfer Capability for that Interface,
2. Proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole, or
3. Proposed interchange schedule changes pertaining to the Interface between the NYCA and the Control Area with which that Proxy Generator Bus is associated would exceed any Ramp.

Non-Competitive Proxy Generator Buses

Real-Time LBMPs for a Non-Competitive Proxy Generator Bus shall be determined as follows:

When (i) the proposed Real-Time Market economic net Import transactions into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located, or (ii) the proposed interchange schedule changes pertaining to increases in Real-Time Market net imports into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the NYISO for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located.

Then the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the higher of (i) the RTC-determined price at that Non-Competitive Proxy Generator Bus or (ii) the lower of the LBMP determined by RTD for that Non-Competitive Proxy Generator Bus or zero.

When (i) the proposed Real-Time Market economic net export transactions from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located, or (ii) the proposed interchange schedule changes pertaining to increases in Real-Time Market net Exports from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the NYISO for the Interface between the NYCA and the Control Area in which that Non-Competitive Proxy Generator Bus is located.

Then the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the lower of (i) the RTC-determined price at the Non-Competitive Proxy Generator Bus or (ii) the higher of the LBMP determined by RTD for the Non-Competitive Proxy Generator Bus or the Day-Ahead LBMP determined by SCUC for the Non-Competitive Proxy Generator Bus.

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

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

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

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

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

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

Where:

Energy $_{\text{RTC REF BUS}}$	=	Marginal Bid cost of providing Energy at the reference Bus, as calculated by RTC15 for the hour;
Losses $_{\text{RTC PROXY GENERATOR BUS}}$	=	Marginal Losses Component of the LBMP as calculated by RTC15 at the Non-Competitive Proxy Generator Bus for the hour;
Day-Ahead LBMP $_{\text{PROXY GENERATOR BUS}}$	=	Day-Ahead LBMP as calculated by SCUC for the Non-Competitive Proxy Generator Bus for the hour.

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

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

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

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

Where:

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

E.4 - Suppliers Setting LBMP

All NYISO and Self-Committed Flexible resources, including GTs dispatched in both ideal dispatches of the ~~hybrid pricing~~hybrid-pricing module are eligible to set prices in the ex-ante pricing module.

Ex-ant pricing determines an estimate of prices made before the time period being priced. Ex-ante prices assume that projected conditions (load, system configuration, etc.) materialize, and that providers perfectly follow schedules determined by the optimization processes.

Exhibit 3-2: Suppliers that can Set LBMP

Suppliers that can Set LBMP		
Supplier	**Internal Suppliers**	**External Suppliers**
NYISO-Committed Flexible and Self-Committed Flexible suppliers that are not pinned to an upper or lower operating unit	Yes	N/A
10 Minute Non-Synch Operating Reserve supplier**** whose reserves have been converted to energy which is shown to be economical in an ideal dispatch	Yes	Yes*
30 Minute Non-Synch Operating Reserve supplier**** whose reserves have been converted to energy which is shown to be economical in an ideal dispatch	Yes	Yes**
Minimum Generation Segment of a supplier whose Minimum Operating Level is less than its Maximum Operating Level	No***	N/A
NYISO-Committed Fixed and Self-Committed Fixed suppliers whose Maximum Operating Level is equal to its Maximum Operating Level (not dispatchable in real-time, and not continuously schedulable Day-Ahead and by RTC)	No	No
NYISO-Committed Flexible and Self-Committed Flexible suppliers**** whose Minimum Operating Level is equal to its Maximum Operating Level (not dispatchable in real-time, and not continuously pre-schedulable Day-Ahead with a range Day-Ahead and by RTC)	Yes	Yes

Notes:

* External 10 Min. Non-Synch Operating Reserves will need to be sanctioned through Inter-Control Area agreements.

** External 30 Min. Non-Synch Operating Reserves will need to be sanctioned through Inter-Control Area agreements.

*** The minimum generation segment of a committed generator that can be dispatched higher will not set LBMP unless the minimum is equal to its upper operating limit.

**** Maximum honored run times for Non-Synch Reserve suppliers and NYISO or Self-Committed Flexible suppliers must be 1 hour for RTC or RTD-CAM committed resources, and the remainder of the Dispatch for SRE committed resources.

E.5 - Reserve Shortage Pricing

Whenever NYISO System Operations declares a NYCA-wide 10-minute total reserve shortage event, Real-time LBMPs throughout the NYCA will be calculated, for each bus, such that the zonal LBMP in New York City (Zone J) is set to $1,000.00. These calculated LBMP values are then compared to the RTD dispatch LBMP values, or the calculated SCR/EDRP activation LBMP values if a SCR/EDRP activation applies, and the posted LBMP, at each bus, will be the higher of the two values for that bus.

In the event that a 10-minute total reserve shortage condition exists only in the eastern region, then the reserve shortage cost pricing rule will apply only in the eastern region zones and the prices in the west will be unaffected.

This 10-minute total reserve shortage ~~cost pricing~~cost-pricing rule does not apply for transitional reserve shortage conditions that include, but are not limited to:

- A transitional reserve shortage condition that immediately follows the end of a reserve pick-up,
- Periods when emergency sales to other control areas are in effect,
- Transitional reserve shortage conditions attributed to top-of-the-hour schedule changes.

Lost Opportunity Cost

During intervals when these reserve shortage pricing rules are in effect, all units that are instructed, by the NYISO, to operate below the point where their bid equals the LBMP, and are following their basepoint (within a 3% tolerance), are eligible to receive lost opportunity cost payments. The lost opportunity cost payments will be consistent with the posted energy prices.

E.6 - Scarcity Pricing

The NYISO shall implement the following price calculation procedures for intervals when scarcity pricing rules are applicable:

Rule A

1. The LBMP at the Reference Bus shall be determined by dividing the lowest offer price at which the quantity of Special Case Resources offered is equal to $RREQ_{NYCA} - (RACT_{NYCA} - ELR_{NYCA})$, or \$500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{NYCA} - (RACT_{NYCA} - ELR_{NYCA})$, by the weighted average of the delivery factors produced by RTD that the NYISO uses in its calculation of prices for Load Zone J in that RTD interval,

Where:

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

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

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

5 However, the NYISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus.

Rule A4 Violation

In cases in which the procedures described above would cause this Rule A4 to be violated:

1. The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location, or the LBMP calculated for that location using the ~~scarcity pricing~~scarcity-pricing Rule A procedures.
2. The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one.
3. The Congestion Component of the LBMP at each such location shall be calculated as the LBMP at that location, minus the LBMP calculated for the Reference Bus, minus the Marginal Losses Component of the LBMP at that location.

Rule B

The NYISO shall implement the following price calculation procedures in intervals when scarcity pricing rules are applicable.

1. The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one.
2. The Congestion Component of the LBMP at each location shall be equal to the lowest offer price at which the quantity of Special Case Resources offered is equal to $RREQ_{East} - (RACT_{East} - ELR_{East})$, or $500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{East} - (RACT_{East} - ELR_{East})$, minus the LBMP calculated for the Reference Bus, minus the Marginal Losses Component of the LBMP for Load Zone J,

Where:

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

- $RREQ_{East}$ equals the 10-Minute Reserve requirement set by the NYISO for the portion of the NYCA located East of Central-East; and ELR_{East} equals the Expected Load Reduction East of Central-East from the Emergency Demand Response Program and Special Case Resources in that RTD interval.

6 The LBMP at each location shall be the sum of the LBMP calculated for the Reference Bus and the Marginal Loss Component and the Congestion Component for that location.

7 However, the NYISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus.

Rule B4 Violation

In cases in which the procedures described above would cause this Rule B4 to be violated:

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

E.7 - Hourly LBMP Rates for Billing Reconciliation

Each time Real-Time Dispatch (RTD) runs during an hour (nominally every 5 minutes), the NYISO calculates a dollar value and a MW value for each unit. The dollar value is in effect for the interval until the next RTD execution. The MW value is the unit's ramped schedule averaged over the RTD interval. These two values are time weighted by the RTD interval length in seconds.

The monetary values are summed at the end of the hour, and the MW values are summed at the end of the hour. A time-weighted average hourly LBMP rate is then calculated by dividing the summed dollar values by the summed MW values. The same calculation is performed for the zonal loads to produce an hourly zone weighted-average price.

A time-weighted ceiling MW value is also calculated for each generator. It is the base-point schedule that was sent to each generator, and it reflects the maximum hourly MW value that a supplier will be paid for energy scheduled by the NYISO through the billing reconciliation process. The ceiling value may be exceeded in certain cases, such as during reserve pickup periods or when units are running out-of-merit.

Any differences between the hour-by-hour MW values used in RTD calculations and the MW values obtained from actual meter readings from the revenue-quality meters at the generating units are reconciled. The time-weighted average hourly LBMP rates are then applied to the reconciled MW values. This billing reconciliation is normally done three months after the fact.

RTD normally executes for the first time in an hour at about 60 seconds into the hour. The LBMP rate used for this short interval is the last-calculated LBMP rate in the previous hour. The MW value is the average of the unit output measurements each 6 seconds during the interval from the beginning of the hour until the RTD execution.

A detailed description of these calculations is given in the *NYISO Accounting & Billing Manual*.

F. LBMP Example

This attachment illustrates the LBMP calculation method, using a two-bus example. The example is sufficient to demonstrate the concepts and calculations involved. The settlement and billing processes are not covered in this example.

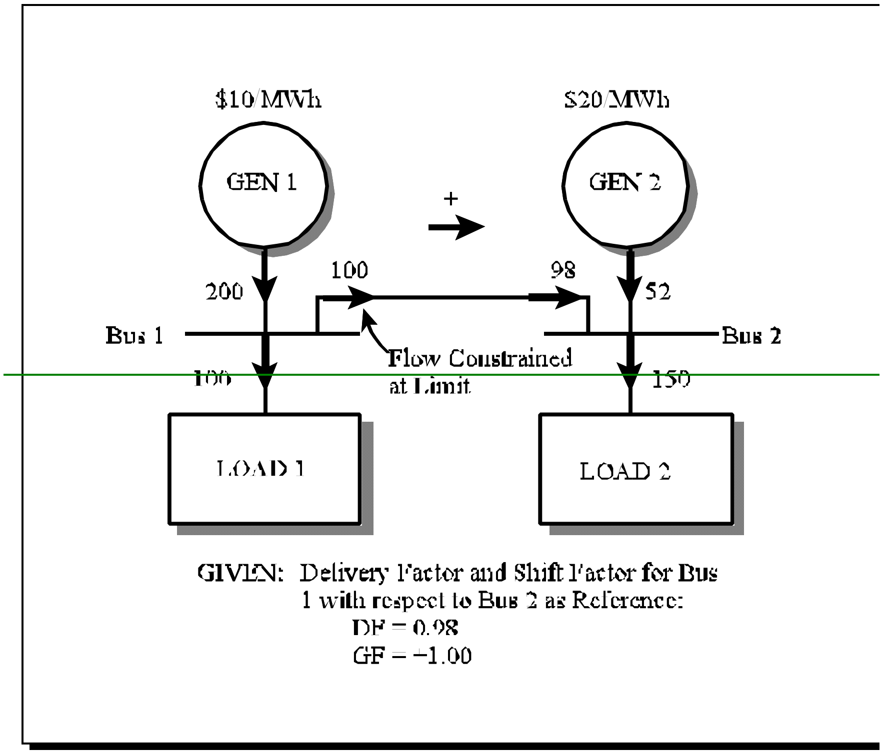
Exhibit F-1 shows the two-bus power system and its initial conditions. The initial conditions show the incremental costs of the generators and the flows in megawatts. A flow constraint of 100 MW has been placed on the Bus 1 end of the transmission line, restricting the amount of power that can be sent to load at Bus 2.

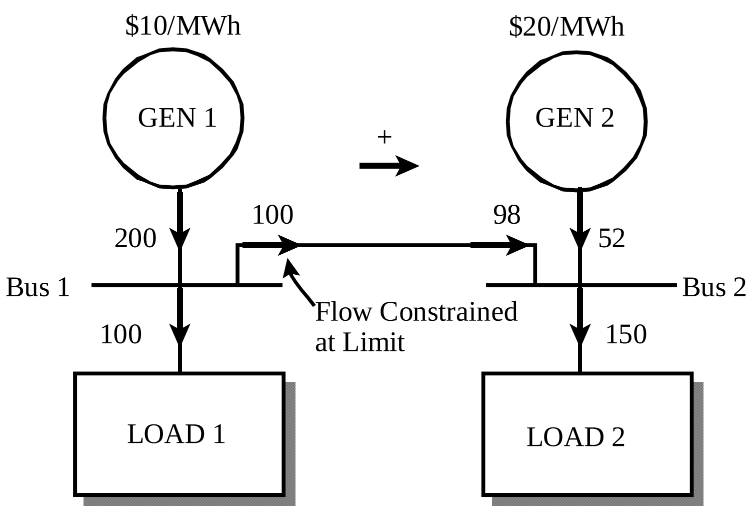
Our objective is to determine the following, either by inspection or calculation. The effect of the choice of reference bus is also examined:

- ~~generator~~Generator shift factor (GF)
- ~~constraint cost (F)~~
- Constraint cost (μ)
- LBMP
- ~~energy~~Energy component of LBMP
- ~~loss~~Loss component of LBMP
- ~~congestion~~Congestion component of LBMP

Exhibit ~~E.~~F-2 shows the results for this example.

Exhibit ~~E.1~~3-3: Two-Bus Example





GIVEN: Delivery Factor and Shift Factor for Bus
1 with respect to Bus 2 as Reference:
DF = 0.98
GF = +1.00

~~Exhibit E.2~~

Exhibit 3-4: Two-Bus Case Results

~~Bus~~	~~Elements~~	~~Bus 1 Reference~~	~~Bus 2 Reference~~
~~Bus 1~~	~~Delivery Factor (DF)~~	~~1.000~~	~~0.9800~~
	~~Generator Shift Factor (GF), ignoring losses~~	~~0~~	~~1.0000~~
	~~Constraint Cost (F) $/MWh~~		~~9.6000~~
	~~LBMP $/MWh~~	~~10~~	~~10~~
	~~Energy Component of LBMP (λ^R)~~	~~10~~	~~20~~
	~~Loss Component of LBMP~~	~~0~~	~~λ^R * (DF-1) = -0.4000~~
	~~Congestion Component of LBMP~~	~~0~~	~~-F* (GF) = -9.6000~~
~~Bus 2~~	~~Delivery Factor (DF)~~	~~1/0.98 = 1.0204~~	~~1.0000~~
	~~Generator Shift Factor (GF), ignoring losses~~	~~-1.0000~~	~~0~~
	~~Constraint Cost (F) $/MWh~~	~~9.7959~~	
	~~LBMP $/MWh~~	~~20~~	~~20~~
	~~Energy Component of LBMP (λ^R)~~	~~10~~	~~20~~
	~~Loss Component of LBMP~~	~~λ^R * (DF – 1) = +0.2041~~	~~0~~
	~~Congestion Component of LBMP~~	~~-F* (GF) = +9.7959~~	~~0~~

Bus	Elements	Bus 1 Reference	Bus 2 Reference
Bus 1	Delivery Factor (DF)	1.000	0.9800
	Generator Shift Factor (GF), ignoring losses	0	1.0000

	Constraint Cost (μ) \$/MWh		9.6000
	LBMP \$/MWh	10	10
	Energy Component of LBMP (λ^R)	10	20
	Loss Component of LBMP	0	λ^R * (DF-1) = -0.4000
	Congestion Component of LBMP	0	-μ* (GF) = -9.6000
Bus 2	Delivery Factor (DF)	1/0.98 = 1.0204	1.0000
	Generator Shift Factor (GF), ignoring losses	-1.0000	0
	Constraint Cost (μ) \$/MWh	9.7959	
	LBMP \$/MWh	20	20
	Energy Component of LBMP (λ^R)	10	20
	Loss Component of LBMP	λ^R * (DF - 1) = +0.2041	0
	Congestion Component of LBMP	-μ* (GF) = +9.7959	0

Delivery Factors~~:~~

The delivery factor for Bus 1 with respect to Bus 2 as a reference has an arbitrarily given value of (DF = 0.98). In this example we are saying that for the next MW that is sent from Generator 1 to Bus 2, only 0.98 MW is received at Bus 2.

Notice that the delivery factor for Bus 2 with respect to Bus 1 as a reference will then be (1/0.98), which is greater than 1.0. This implies a reduction in losses since the “positive” flow on the line is reduced.

The numerical values of the delivery factors can vary with the choice of reference bus.

The delivery factor for a bus with respect to itself as a reference is equal to 1.0 since there will be no change in losses.

Generator Shift Factors~~:~~

In this example, the generator shift factors are with respect to the flow at the constrained end (Bus 1) of the transmission line. Losses are ignored in our calculation of the generator shift factors. The generation shift factor is defined as the ratio of the change in line flow (in the positive direction) to the change in generation of the designated bus. The reference bus compensates for the change in generation.

The generator shift factor for Bus 1 with respect to bus 2 as a reference is given as:

$$\cancel{GF = \frac{+1.0\ (\mathit{Flow}\ \text{change})}{+1.0\ (\text{Generator 1 change})} = 1.0000}$$

$$GF = \frac{+1.0\ (\text{Flow change})}{+1.0\ (\text{Generator 1 change})} = 1.0000$$

The generator shift factor for Bus 2 with respect to Bus 1 as a reference is negative, also with a magnitude of 1.0, since losses are ignored. The calculation is given as:

$$\cancel{GF = \frac{-1.0\ (\text{Flow change})}{+1.0\ (\text{Generator 2 change})} = -1.0000}$$

$$GF = \frac{-1.0\ (\text{Flow change})}{+1.0\ (\text{Generator 2 change})} = -1.0000$$

The generator shift factor for a bus with respect to itself as a reference bus is equal to zero since there will be no change in the constrained transmission line flow.

The numerical values of the generator shift factors can vary with the choice of reference bus.

Constraint Cost~~:~~

The constraint cost ~~(F)~~(μ) is dependent on the choice of reference bus when losses are ignored in the calculation of generator shift factors. It is defined as the reduction in overall cost when the constraint is relaxed by a small amount.

Bus 2 as Reference

In our example, we will allow the transmission line flow to increase from its limit of 100 MW to a new limit of 101 MW. This will allow the low cost Generator 1 to pick up 1 MW and the higher cost Generator 2 to drop 0.98 MW. The constraint cost is calculated as follows:

$$\cancel{\mu = \frac{+0.98 * 20 - 1.00 * 10\ (\text{Overall cost reduction})}{+1.00\ (\text{Flow constraint change})}}$$

$$\cancel{\mu = 9.6000\ \$/MWh}$$

$$\mu = \frac{+0.98*20 - 1.00*10 \text{ (Overall cost reduction)}}{+1.00 \text{ (Flow constraint change)}}$$

$$\mu = 9.6000 \text{ \$/MWh}$$

Bus 1 as Reference

With Bus 1 as the reference we decrease the generation at Bus 2 by one MW, which we assume will increase the flow by one MW (GF = -1). Generator 1 will need to increase its output by (1/0.98) MW to compensate. The constraint is calculated as follows:

$$\cancel{\mu =} \frac{+1.00*20 - (1/0.98)*10 \text{ (Overall cost reduction)}}{+1.00 \text{ (Flow constraint change)}}$$

$$\cancel{\mu = 9.7959 \text{ \$/MWh}}$$

$$\mu = \frac{+1.00*20 - (1/0.98)*10 \text{ (Overall cost reduction)}}{+1.00 \text{ (Flow constraint change)}}$$

$$\mu = 9.7959 \text{ \$/MWh}$$

LBMP~~:~~

The locational bus marginal prices can be determined by inspection in this example. LBMP is the minimum cost of supplying an increment of power at the designated bus, without violating any constraints. LBMP is independent of the choice of reference bus.

The LBMP for Bus 1 is 10 \$/MWh since Generator 1 is cheaper than Generator 2. The LBMP for Bus 2 is 20 \$/MWh since we cannot use the cheaper generator without violating the flow constraint.

The three components of LBMP are dependent on the choice of reference bus and are calculated as described in ~~Section 5.1.5~~Attachment E of ~~this manual~~this Manual.

- ~~energy~~Energy component (λ^R) = reference bus LBMP
- ~~loss~~Loss component = λ^R (DF - 1)
- ~~congestion~~Congestion component = -μGF

These components are related to LBMP as follows:

LBMP = [λ^R] + [λ^R (DF - 1)] + [-μGF]

Bus 1 as Reference

For Bus 1 with Bus 1 as the reference, we get:

10 = [10] + [0] + [0]

For Bus 2 with Bus 1 as the reference, we get:

20 = [10] + [0.2041] + [9.7959]

Bus 2 as Reference

For Bus 1 with Bus 2 as the reference, we get:

10 = [20] + [-0.4000] + [-9.6000]

For Bus 2 with Bus 2 as the reference, we get:

20 = [20] + [0] + [0]

Note ~~1:~~ to Reader

It is not necessary for a bus (including the reference bus) to have a dispatchable generator or a load in order to calculate its LBMP. We can still attach a hypothetical 1 MW load and supply it at minimum cost, without constraint violations, from the dispatchable generators in the power system.