New York ISO
Independent System Operator

Manual 12

Transmission and Dispatch Operations Manual

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*v7.0 reflects v6.0 changes that were approved at the 9/14/2023 BIC and 9/15/2023 OC. Please see Revision History for further details.

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Revision History

Version	Effective Date	Revisions
1.0	09/01/1999	Initial Release
2.0	11/21/2007	Complete manual rewrite.
2.1	09/04/2008	Updated Table B-1 to reflect Exceptions to the NYSRC Reliability Rules

2.2	02/01/2012	Global
		➤ Reformatted per new template to standardize presentation.
		➤ Implemented minor stylistic changes.
		➤ Standardized labeling and numbering of tabular material.
		➤ Revised external-document links to explicitly cite URLs from which documents may be accessed.
		Table of Tables
		➤ Expanded to include tables in attachments.
		Revision History Table
		➤ Changed column headings as follows:
		  • "Revision" changed to "Version"
		  • "Changes" changed to "Revisions"
		Section 2.1.5 and 2.1.6
		➤ Switched the order of 2.1.5 and 2.1.6 to better depict the hierarchical relationship between all of the NYS Reliability Rules and the subset of Reliability Rules known as Local Reliability Rules.
		➤ Added material on the evolution and implementation of reliability rules and the NYISO's responsibilities with regard to reliability rules (incorporated Technical Bulletin #159).
		➤ Clarified via a new heading that the process outlined for defining new applications of reliability rules or modifying existing applications of the reliability rules applied to changing the TO application of such rules.
		Section 2.2.5
		➤ Added material detailing the conditions under which LESRs will participate in reserve pickups.
		Section 2.4
		➤ Modified the Real-time market timelines to reflect 15-minute scheduling and the elimination of pre-scheduling.
		Section 4.1.3
		➤ Clarified treatment of Firm Transmission Service for Imports and Exports.
		Section 4.2.7
		➤ Clarified that any of the steps outlines may be taken in to relieve the security violation.

		Section 4.2.12 ➤ Added new subsection on Status of Transmission and Generation Protection Systems-incorporated TB 167 Section 5.1.1 ➤ Clarified that RTC15 schedules hourly transactions and that all RTC runs establish schedules for 15-minute transactions. ➤ Added new material on initialization status, startup time, minimum run time, and minimum down time with regard to the Real-Time Commitment process. ➤ Clarified the timeframe during which customers may submit Real-Time Bids into RTC for real-time evaluation. ➤ Added new material detailing the need for internal bilateral transactions involving trading hubs to be balanced and defining the meaning of *balanced* in this context. Incorporated TBs 18, 51,145 Section 5.1.2 ➤ Removed reference to second impact test. Section 5.2.3 ➤ Clarified treatment of Firm Bilaterals to align with strategic tariff review updates. Section 5.2.4 ➤ Incorporated TB #40 Section 6.2 ➤ Added material specifying LESR response in relation to corrective action during Real-Time Dispatch. Section 6.3 ➤ Added real-time telemetry of energy storage levels for LESRs to the list of the initial conditions that RTC/RTD determines in beginning the commitment and dispatch process. Section 6.3.6 ➤ Added a footnote to Table 6.1 stating that If the Regulation Demand Curve is active, RTD will not set basepoints for LESR energy management. Attachment A ➤ Table A.1, A.2, and A.3 - replaced with links to the external locations where each table is maintained. Attachment B ➤ Table B.1, B.2, B.3, B.4, and B.5 - replaced with links to the external locations where each table is maintained.
2.3	10/23/2012	Section 2.1 ➤ Updated link to NYISO Agreement, NYISO/TO Agreement, and NYSRC Agreement Section 3.1.4 ➤ Updated link to NYISO Ancillary Services Manual ➤ Added link to NYCA regulation requirements

		Section 3.1.11
		➤ Updated link to Accounting and Billing Manual
		Section 5.1.1
		➤ Updated link to Ancillary Services Manual
		Section 5.1.3
		➤ Revised to reflect posting of both a Regulation Capacity and a Regulation Movement price
		➤ Clarify that RTC prices are posted separately from RTD prices
		Section 5.2.4
		➤ Corrected formatting error
		Section 6.1.1
		➤ Clarified that Real-Time Market Prices are calculated for Regulation Service to maintain consistency with Tariff
		Section 6.1.2
		➤ Revised to reflect posting of both a Regulation Capacity and a Regulation Movement price
		➤ Remove reference to RTD 15-minute look ahead price postings
		Section 6.2.1/6.2.2
		➤ Clarified that Regulation schedules are set to zero during Reserve Pickup and Max Gen Pickups
		Section 6.3.5
		➤ Revised interchange modeling assumptions to match revisions to TB 152
		Section 6.3.10
		➤ Revised reference to NPCC document describing SAR procedure
2.4	12/01/2014	Global
		➤ Updated links from individual manuals to the NYISO Manuals webpage
		Section 5.1.1
		➤ Incorporated CTS bids into types of external transaction bids
		➤ Revisions to reflect scheduling 15-minute external transactions from the first timestep of RTC
		➤ Revisions to external proxy bus pricing used for settlement
		Figure 5.1
		➤ Revisions to reflect scheduling 15-minute external transactions from the first timestep of RTC
		Section 5.1.3
		➤ Updated to remove information no longer posted by RTC
		Table 5.1
		➤ Revised terms to be inclusive of CTS bids as necessary
		Section 5.2.4

		➢ Clarifications to distinguish CTS bids from other types of external transaction bids
		➢ Added description of process for creating CTS bid from accepted DAM transactions
		Section 6.3.5
		➢ Update the reference to the 5018 transmission line from "BranchburgRamapo Interconnection" to "Hopatcong-Ramapo Interconnection"
2.5	10/30/2015	Global
		➢ Removal of "Non-firm transaction" language
		Section 3.3
		➢ New section detailing Fuel Availability Self Reporting (FASR) requirements
		Section 4.2.8
		➢ Removed. 'Procedure for Relief of Potential Overloads on Non-Secured Facilities' section currently located in the Emergency Operations Manual section 4.1.3.
		Section 5.7.5
		➢ New section. Incorporated sections of TB-029 which details generator DMNC test scheduling requirements
		Attachment B
		➢ Link to Table B1 and B4 updated
		Attachment C Removed.
2.6	12/29/2015	Global
		➢ Removal of "Non-firm transaction" language throughout
		Section 5.1.1
		➢ "External Transaction Scheduling" for posting of External Interface Interchange Ramp Capacity Limits
		➢ "External Transaction Settlements" – added a new bullet to include reference to the Coordination Agreement between NYISO and ISO-NE
		Section 5.1.3
		➢ Ministerial update for ATC and TTC postings
		Section 5.5
		➢ Updates to the process for events when energy from NYISO ICAP resources outside of the NYISO are called upon
		➢ Incorporated TB-096 contents
2.7	02/01/2016	Section 6.1.2
		➢ Include reference to Southeastern New York reserve clearing prices
		Section 6.2.2
		➢ Include reference to Southeastern New York as a region that may be included as part of a maximum generation pickup event
		Section 6.3.6

		➢ Removed table providing parameters of demand curves implemented by the NYISO and inserted a cross-reference to the Ancillary Services Manual where this information is provided ➢ Relocated footnote from demand curve table regarding the implications of the regulation demand curve on the setting of basepoints in RTD for LESR energy management to main body of text Section 6.3.7 ➢ Include reference to Southeastern New York reserve requirements
3.0	02/11/2016	Version delayed until 2/11/16 to correspond with NYISO deployment and activation of the Graduated Transmission Demand Curve software Section 4.1.3 ➢ Removed reference to NYISO non-firm transactions Section 4.2.2 ➢ Incorporated detail on ISO and transmission owner target voltage level program (TB-195) Section 4.2.7 ➢ Removed reference to NYISO non-firm transactions Table 5.1 ➢ Removed reference to NYISO non-firm transactions Section 5.2.2 ➢ Incorporated detail on how Interchange Scheduler Plus (IS+) is used for Real-Time Transaction Curtailments (TB-061) Section 5.2.3 ➢ Removed reference to NYISO non-firm transactions ➢ Incorporated detail on NYISO actions during neighboring control area TLR events (TB-183) ➢ Incorporated detail on external transaction scheduling messages and curtailment notification (TB-058) ➢ Incorporated detail on IESO/ NYISO transaction scheduling guidelines (TB-092) Section 5.2.4 ➢ Incorporated detail on import transactions (TB-151) Table 5.3 ➢ Removed reference to NYISO non-firm transactions Section 5.7.1 ➢ Removed reference to NYISO non-firm transactions Table 6.1 ➢ Updated the demand curve values to reflect the graduated Transmission Demand Curve Section 6.3.2 Incorporated detail on schedule changes and ramping of dispatch units (TB-023)

3.1	04/28/2016	Global
		➤ Replaced references to "NYISO Secured Transmission System" with "NYISO Controlled Transmission System"
		Section 2.1.6
		➤ Updated references to the updated version of the Reliability Rules & Compliance Manual
		Section 2.2.1
		➤ Deleted language regarding certain Transmission Facilities that are not part of the NYISO Controlled Transmission System
		Section 2.2.3
		➤ Added new section to incorporate Technical Bulletin #165 regarding communications through the Transmission Owner
		➤ Renumbering of subsequent sections to account for new Section 2.2.3
		Section 2.2.5
		➤ Add language regarding the establishment of System Operating Limits
		Section 2.2.6
		➤ Added new subsection 2.2.6.1 that contains the previously-existing language of Section 2.2.6
		➤ Added new subsection 2.2.6.2 to incorporate Technical Bulletin #229 regarding default generator voltage schedules
		Section 2.3.2
		➤ Clarifying revisions to existing language
		Section 2.6.1
		➤ Replaced existing language regarding NYISO Hotline communications with reference to the Emergency Operations Manual
		Section 3.1.2
		➤ Revised timing of periodic security assessment to every 60 seconds
		➤ Removed reference to "Active RTD constraints"
		Section 3.1.6
		➤ Corrected reference to "National Weather Bureau" to reflect "National Weather Service"
		Section 3.1.9
		➤ Remove duplicative section addressing Automatic Voltage Regulator (AVR) and Power System Stabilizer (PSS) outages because already covered by the Outage Scheduling Manual
		Section 5.1.1
		➤ Deleted redundant and outdated language
		Section 6.3.6
		➤ Updated middle pricing point value of Transmission Shortage Cost
		Attachment C
		➤ Removed this previously-unused Attachment

		Attachment D
		Remove duplicative Attachment regarding status reporting for Automatic Voltage Regulator (AVR) and Power System Stabilizer (PSS) because already covered by the Outage Scheduling Manual
3.2	10/28/2016	Section 6.1.2
		➢ Updated to reflect zonal clearing prices as a result of the changes related to Comprehensive Scarcity Pricing
		Section 6.3.6
		➢ Updated Demand Curve table to reflect the changes related to Comprehensive Scarcity Pricing
3.3	06/29/2017	Section 2.3.2
		➢ Noted that the NYSRC Exceptions Process has also been utilized to permit, under limited identified circumstances, post-contingency loading of transmission elements that may exceed STE rating
		Section 2.5.5
		➢ Refer the reader to the Emergency Operations Manual for more information on Backup Operations
		Section 4.1.1
		➢ Remove mention of time duration at the discussion of NYISO Controlled Transmission System Operating Limits
		Section 4.2.5
		➢ Modify the description of Phase Angle Regulators at the NYISO/PJM Interconnection
		Section 4.2.10
		➢ Modify the description of solar magnetic disturbance data sources and alerts
		Section 5.5
		➢ Included clarifying language in this section
		Section 5.7.4
		➢ Clarify the treatment of Out-of-Merit Generation
		Section 6.3.1
		➢ Minor edit to refer to additional information on Out-of-Merit treatment
		Section 6.3.5
		➢ Revisions to the description of interchange percentages
3.4	10/09/2017	Section 6.3.6
		➢ Renamed section to Ancillary Service Demand Curves
		➢ Removed transmission demand curve from section description and table
		Section 6.3.7
		➢ Included new section 6.3.7 which describes the NYISO's transmission constraint pricing logic

4.0	08/29/2018	Section 2.2.3
		➢ Incorporated TB-235
		Section 4.2.4
		➢ Incorporated TB234
		Section 5
		➢ Process for Determining Facilities Secured in the Market Models
		Section 6.7.6
		➢ Incorporated TB-155
4.1	12/04/2018	Section 6.2.4
		➢ If the Market Participant does not provide a "RTM Bid Price" when submitting its DAM bid, a default economic scheduling priority of +$2000.00 (changed from +$1000) will be used when the DAM bid is converted to a bid for the Real-Time Market.
		➢ For Real-Time Export transactions, not using a CTS Interface Bid, Market Participants supply a "Sink Price Cap" amount up to $2000.00 (changed from +$1000).
4.2	07/17/2019	Section 7.3.6
		➢ Updated Ancillary Service Demand Curve table to reflect New York City reserve requirements.
		Section 7.3.7.1
		➢ Updated to reflect the ability to assign non-zero constraint reliability margin values less than 20 MW.
		Section 7.3.8
		➢ Updated to reflect New York City reserve requirements.
4.3	08/26/2019	Section 4.2.3
		➢ Updated guidelines for the operation of the Leeds and Fraser SVCs to control high voltage
		Section 6.5
		➢ Added web location of SRE notice
		Section 6.7.4
		➢ Updated Figure 18 Section 6.7.11
		➢ Added documentation of the normal SRE operating practice
4.4	09/27/2019	Section 2.1.6
		➢ Updated Transmission Owner and NYISO LRR Responsibilities
		Section 2.2.6
		➢ Updated Transmission Owner Responsibilities and Authorities
4.5	05/04/2020	Section 2.1.2
		➢ Added language to include Dual Participation
		Section 2.2.5
		➢ Added dual participation language to NYISO Responsibilities and Authorities
		Section 4.2.2
		➢ Added dual participation language to Voltage Control
		Section 4.2.11

		➢ Removed language from Solar Magnetic Disturbances regarding TO notification of Generators Section 4.2.12 ➢ Added dual participation language to Status of Transmission and Generation Protection Systems Section 6.1.1 ➢ Added dual participation language to Real-Time Commitment Process Section 6.7.4 ➢ Added dual participation language to Out-of-Merit Generation Section 6.7.9 ➢ Added dual participation language to Supplemental Commitment Process Operations ➢ Added language regarding TO actions Branding ➢ Updated logo and formatting
4.6	08/28/2020	Section 6.1.1 ➢ Added ESR Storage Limits language to Real-Time-Commitment Section 6.7.4 ➢ Added language for ESR MWh Out-of-Merit Generation
4.7	9/14/2020	Section 6.1.1 ➢ Added language for Fast Start Resources Appendix C ➢ Added example adjusted offer curve calculations for Fast Start Resources ➢ Clarified units for the total production cost calculations in examples for Fast Start Resources
4.8	03/01/2021	Section 3.3 ➢ Added language to issue weekly and as requested surveys based on Fuel type.
4.9	10/04/2021	Section 2.2.7.1 ➢ Modification to the language of LESR's participation in reserve pickups Section 2.6.1 ➢ Deletion of Interregional Communication Network discussion Modification to the language of LESR's participation in reserve pickups Section 7.3.6 ➢ Updated the Operating Reserve Demand Curve values
5.0	12/15/2021	Section 6.1.1 ➢ Added language referencing CSR Scheduling Limits ➢ Added discussion of the CSR Wind or Solar Output Limit

		Section 6.7.4
		  ➤ NYISO can use OOM to reduce CSR Scheduling Limits
		Section 7.3
		  ➤ MW telemetry for CSR generators should reflect their output at POI
		Section 7.3.1
		  ➤ NYISO can use OOM to reduce CSR Scheduling Limits

5.1	05/05/2022	Section 3.3 ➤ Sharing GFER data with TOPs
5.2	02/09/2023	Recertified Global ➤ Updated broken hyperlinks
6.0	11/14/2023	NOTE: The below changes were approved at the 9/14/2023 BIC & 9/15/2023 OC without incorporating changes that were subsequently made effective in v7.0. Section 7.3.7 ➤ Updated the description of the transmission constraint pricing logic and Transmission Shortage Cost values.

7.0	04/16/2024	NOTE: The below changes were approved at the 7/12/2023 BIC & 7/20/2023 OC.
		
		Section 1
		  ➤ Added a statement to indicate that the term "Resource" is used throughout the document to refer to Generators and Aggregators.
		
		  ➤ Added Aggregation Manual Reference
		
		Global
		  ➤ Replaced Generator with Resource throughout the document.
		
		  ➤ Added Aggregator when applicable.
		
		  ➤ Replace unit with Resource when applicable.
		
		  ➤ Replace generating units with resource when applicable.
		
		Section 2.1.2
		  ➤ Modified TO/DSO, NYISO coordination language.
		
		Section 2.2.7
		  ➤ Added language about Aggregations containing withdrawal generating facilities providing Regulation Service
		
		Section 2.5.4
		  ➤ Added description of the GOCP.
		
		Section 3.3

			➤ Added statement to indicate that fuel and environmental restriction data will be shared with Transmission Operators. Section 6.7.17 ➤ Added this section to describe SRAs.

X.X	MM/DD/YYYY	Global
		
		    ➤ Updated figure numbers
		
		Section 7.3.7
		
		    ➤ Provided further details and examples regarding the enhancements to the operation of transmission demand curves in assisting to resolve certain redundant transmission constraints and multiple active transmission constraints	

1. Introduction

The *NYISO Transmission & Dispatching Operations Manual* is one of a series of manuals within the Operations Manuals. This Manual focuses on describing each of the Transmission & Dispatching Operations with respect to the New York Independent System Operator (NYISO) facilitates and/or controls.

This Manual consists of five sections as follows:

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

Throughout this Transmission and Dispatch Operations Manual, the term "Resource" is used to refer to both Generators and Aggregations. Additional information on Aggregations can be found in Market Administration and Control Area Services Tariff Section 4.1.10 and in the Aggregation Manual (https://www.nyiso.com/manuals-tech-bulletins-user-guides). Throughout this Transmission and Dispatch Manual, any explicit reference to an existing NYISO participation model is also applicable to Aggregations classified under the same participation model. For example, ESR, LESR, Wind, and Solar Aggregations shall follow the same rules as set forth for single resources of those types.

1.1. 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 and Billing Manual

- NYISO Day-Ahead Scheduling Manual

- NYISO Ancillary Services Manual

- NYISO Aggregation Manual

- NYISO Tariffs

- New York State Reliability Council (NYSRC) Agreement

- NYSRC – Reliability Rules Manual

- Market Participant User's Guide

2. Overview

This section presents an overview of the following:

- 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 authority granted by the Federal Energy Regulatory Commission and the terms of the NYISO Agreement, the NYISO/Transmission Owner Agreement, and the NYSRC Agreement (all of which are available from the NYISO Web site at (https://www.nyiso.com/regulatory-resources), the NYISO has the authority to direct the operation of the New York State Power System (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 respond quickly to actual problems when they occur.

To meet its obligations under the Reliability Rules with respect to maintaining the security of the NYS Power System, the NYISO shall maintain a list of transmission facilities included within the NYS Transmission System, defined as the NYISO Controlled Transmission System. The NYISO is responsible for the following:

- The coordination of the operation of those facilities under its Operational Control with the responsible Transmission Owners (TO)
- The commitment and/or dispatch of supply and demand resources connected to the NYS Transmission system, and/or
- The control and/or coordination of facilities used to provide ancillary services

Transmission facilities that are under NYISO operational control and require NYISO notification are listed in Attachment A.1 of this Manual.

Transmission facilities that require NYISO notification are listed in Attachment A.1 of this Manual.

Bus Voltage Limits for buses included as part of the NYISO Controlled Transmission System are listed in [Attachment A.2](#) and [Attachment A.3](#) of 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 Controlled Transmission System by comparing system conditions against certain monitoring criteria. The NYISO Shift Supervisor shall also monitor weather conditions and forecasts.

1. When the NYISO Shift Supervisor determines the state of the NYISO Controlled Transmission System is Normal or Warning, the NYISO shall operate the NYS Power System according to the procedures described in this Manual.
2. When the NYISO Shift Supervisor determines the state of the NYISO Controlled Transmission System is Alert, Major Emergency, or Restoration, the NYISO shall operate the NYS Power System according to procedures in the *NYISO Emergency Operations Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides).

2.1.2. NYISO Objective

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

1. Capacity deficiencies
2. Energy deficiencies
3. Loss of generation or transmission facilities
4. High voltage
5. Low voltage
6. Environmental episodes
7. Transmission overloads
8. Abnormal power system frequency

When the NYISO Controlled Transmission System enters a condition other than the Normal State, the NYISO shall act to return the NYISO Controlled 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, the NYISO shall minimize its extent and duration.

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. The ISO and Transmission Owners shall coordinate scheduling and dispatch for all Resources engaged in Dual Participation giving priority to: 1) minimizing the magnitude of reliability impacts, 2) resolving actual impacts over predicted impacts. An individual Aggregator and /or DER that have a point(s) of interconnection with a distribution system located in the NYCA, and that participate through an Aggregation, shall comply with all Distribution System Operator and/or Transmission Operator instructions to maintain distribution system reliability and safety. Each Aggregator shall report all full or partial Aggregation derates caused by Distribution System Operator and/or Transmission Operator instructions in the GOCP (see the Aggregation Manual). An Aggregator must also modify its Bids, as necessary, to comply with the Distribution System Operator and/or Transmission System Operator instructions. The ISO will issue final schedules for all Resources, including Aggregations, engaged in Dual Participation.

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 TOs.

For a detailed description of the procedures to be followed under these conditions, refer to the *NYISO Emergency Operations Manual* (available from the NYISO Web site at https://www.nyiso.com/manuals-tech-bulletins-user-guides).

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

2.1.4. General Reliability Rules

The New York State Reliability Council (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

relies upon the reliability standards, regulations, criteria, procedures, and rules established or imposed by:

- North American Electric Reliability Corporation (NERC),

- Northeast Power Coordinating Council (NPCC),

- Federal Energy Regulatory Commission (FERC),

- New York State Public Service Commission (PSC),

- Nuclear Regulatory Commission (NRC), and/or

- Any other government agency with jurisdiction over the reliability of the NYS Power System.

The NYISO, a Market Participant, or a member of the NYSRC Executive Committee 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 incorporate all new mandatory compliance rules of NERC and NPCC, unless existing Reliability Rules are more stringent.

2.1.5. Applications of the Reliability Rules

Prior to the NYISO startup, the Applications of the Reliability Rules (Applications) were existing operating procedures and local rules implemented by the Transmission Owners in New York. The Applications of the NYSRC Reliability Rules were assembled from these procedures and acknowledged by the NYSRC. The Applications are implemented through procedures that apply to very specific system locations or conditions in New York.

As a threshold matter, please note that the NYISO's Tariffs implement certain Reliability Rules directly. The implementation of the Applications of the Reliability Rules will continue to require close coordination between the transmission owners and the NYISO in order to maintain the reliability of the NYS Power System. The Transmission Owners (TO) must continue to coordinate with the NYISO on the implementation of Applications of the Reliability Rules for those portions of the New York State Transmission System ("NYS Transmission System") not included in the NYISO Controlled Transmission System.

The NYISO oversees compliance with the Reliability Rules for the New York State Power System. The NYISO performs periodic compliance reviews to determine whether the TOs are continuing to apply the Applications to a specific local area. The Annual NYSRC Compliance Program determines the frequency and schedule for the compliance reviews.

Transmission Owner Responsibilities

The TOs are responsible for implementing the Applications of the Reliability Rules for those portions of the NYS Power System that are not included in the NYISO Controlled Transmission System. Implementation of certain Applications of the Reliability Rules must be coordinated with the NYISO where the NYISO lacks the necessary analysis and/or monitoring capabilities.

The TOs shall maintain procedures to implement the Applications. Any new or revised procedure developed or modified by the TO shall be provided to the NYISO Staff for review and approval.

A Transmission Owner may define new or modified Applications of the Reliability Rules. New or modified Applications of the NYSRC Reliability Rules, proposed by a Transmission Owner are subject to review and approval by the NYISO Staff.

NYISO Responsibilities

The NYISO shall maintain the Applications of NYSRC Reliability Rules and make them in a table posted on the NYISO's website. The NYISO will review these Applications with the TOs periodically and update the table of Applications as necessary.

The NYISO Staff shall review and approve any modified or newly proposed Applications of the Reliability Rules. Following approval, the NYISO shall notify the NYSRC and revise the table of TO Applications.

The NYISO may also propose revisions to or additional Applications of the Reliability Rules. The NYISO will work closely with the Transmission Owner to develop and implement these Applications.

The NYISO shall also review and approve any new or revised procedures developed by the TO associated with an Application.

Changes to the TO Application of Reliability Rules

The following process will be used to define new Applications of Reliability Rules or modification of existing Applications of the Reliability Rules:

1. The following entities can define new Applications of the Reliability Rules or modify existing Applications of the Reliability Rules:
   NYISO
   NY Transmission Owners
2. Applications of the Reliability Rules proposed by the TOs shall be referred to the NYISO for approval.
3. Once the NYISO concurs, it shall take two actions:
   Include them in the next version of the NYISO Transmission and Dispatching Operations Manual, and Advise the NYSRC.
4. The NYSRC shall post the updated Applications of the Reliability Rules on its web site.

Any incremental uplift costs incurred to meet Applications of the Reliability Rules shall be recovered by the NYISO through a statewide uplift charge if the Application secures a facility within the NYISO Controlled Transmission System. Applications of the Reliability Rules may apply to facilities that are not included in the NYISO Controlled Transmission System, but are implemented by the NYISO at the TO's request. Incremental uplift costs associated with such Applications shall generally be borne by the Load Serving Entities in the Zone or Zones of the TO(s) making the request.

The Application of the Reliability Rules and the associated cost allocations are listed in Table B.5 of this Manual.

2.1.6. NYSRC Local Reliability Rules

Local Reliability Rules (LRR) are a specific set of five rules defined in the New York State Reliability Rules and are maintained by the New York State Reliability Council (NYSRC). They apply to New York City (G.1 and G.2), and Long Island (G.3).

G.1 New York City System Operations

G.2 Loss of Gas Supply – New York City

G.3 Loss of Gas Supply – Long Island

Transmission Owner LRR Responsibilities

The Transmission Owners are required to maintain procedures to comply with each NYSRC LRR. These procedures shall contain operational parameters that are developed based on studies performed by the TO. The NYSRC Reliability Rules require the NYISO to review and approve any updates to procedures or studies associated with the NYSRC LRRs.

The TO will notify the NYISO when actions are taken in accordance with these procedures.

The TO will provide the date, time and description of actions implemented by the TO in accordance with these procedures to the NYISO when requested.

At times, TOs may propose modifications to the NYSRC LRRs or other Reliability Rules. Any proposed change to a Reliability Rule is required to be presented to the NYSRC for consideration by the NYSRC through the Reliability Rules development process. (See the appropriate NYSRC Policy at http://nysrc.org/policies.html)

NYISO LRR Responsibilities

The NYISO Staff will review any new or revised procedures developed by the TO associated with the NYSRC LRRs. The NYISO will submit the date, time and description of the actions implemented by the TO in

accordance with these procedures, as provided by the TO, to NYSRC upon request.

The NYISO Operating Committee (OC) is responsible for review and approval of any operational parameters necessary to implement the Application associated with NYSRC LRRs.

The OC may require review and approval of any study or analysis that was completed to justify new or modifications of existing operational parameters.

The NYISO will post the Applications associated with all Local Reliability Rules in the table of Applications of the Reliability Rules on the NYISO's website (see Table B.5).

The LRRs of the New York TOs are listed in Table B.4 of this Manual.

2.2. NYISO, Transmission Owner, Generator Owner, and Aggregator Responsibilities and Authorities

The following defines the responsibilities and authorities assigned to the NYISO, TOs, Distribution Providers, Generator Owners, and Aggregators.

2.2.1. Background Definitions

New York State Transmission System (NYSTS)

The New York State Transmission System (NYS Transmission System) 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.

Local Area Transmission System Facilities are the Transmission Facilities and the subtransmission facilities that are not included in Table A.1 of this Manual

New York State Power System (NYSPS)

The New York State Power System includes all facilities of the NYS 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 NYISO.

Thus,

NYSPS = NYSTS + Internal/External Generators Subject to NYISO Operational Control

Reliability Rules

Those rules, standards, procedures, and protocols developed and promulgated by the NYSRC (in accordance with NERC, NPCC, FERC, PSC, and Nuclear Regulatory Commission (NRC) standards, criteria, rules and regulations, and other criteria) and the LRRs pursuant to the NYSRC Agreement.

NYISO Secured Transmission System

Certain transmission facilities in the NYS Transmission System that the NYISO will be responsible to secure through: (1) the coordination of the operation of those facilities under its Operational Control with the responsible TOs, (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 [Table A.1](#) of this Manual. Bus Voltage Limits for buses included as part of the NYISO Controlled Transmission System are listed in [Table A.2](#) of this Manual.

Therefore:

1. 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.

2. 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 Controlled Transmission System Facilities designated on the Bus Voltage Limit list will be secured by the NYISO in terms of voltages at those buses.

3. 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 Controlled Transmission System only.

Terms Defined in NERC Glossary

Capitalized terms not defined herein or in the NYISO Tariffs may have the meaning specified in the NERC Glossary of Terms Used in Reliability Standards.

2.2.2. General Relationships between NYISO and Transmission Owners

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

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

The NYISO enforces the Reliability Rules for the NYISO Controlled Transmission System. Certain applications of the Reliability Rules, previously implemented by the TOs, will continue to require close coordination between the TOs and the NYISO to maintain the reliability of the NYS Power System.

2.2.3. NERC Distribution Provider (DP) Standards Compliance

A number of NERC compliance standards require a Distribution Provider to maintain communication capabilities and convey critical information directly to its Reliability Coordinator, Balancing Authority, or Transmission Operator. The NYISO is registered with NERC as the Reliability Coordinator and Balancing Authority for New York.   Both the NYISO and all New York State Transmission Owners except NYPA are registered as Transmission Operators.

2.2.3.1. Operations Communications

Operational communication between the NYISO and each Distribution Provider is conducted through each Distribution Provider's interconnected Transmission Owner, in order to timely provide pertinent information to both the NYISO and the Transmission Owner, who is managing local transmission and transmission security.

2.2.3.2. Compliance to NERC Standards

Distribution Providers will maintain communication capabilities and communicate conditions and status as required by the NERC Standards through their interconnected Transmission Owner. The NYISO Transmission Owners are obligated to provide that Distribution Provider information to the NYISO.

2.2.4. NERC Generator Operator (GOP) Standards Compliance

A number of NERC compliance standards require a Generator Operator and Aggregator to convey critical status information and "changes to capabilities and characteristics" directly to its Transmission

Operator without any intentional time delay. The NYISO is registered with NERC as the Transmission Operator for New York as well as the Reliability Coordinator and Balancing Authority.

Operations Communications

Operational communications between the NYISO and each Generator Operator and Aggregator is through each Generator's and Aggregator's interconnected Transmission Owner. This means of communication has been used exclusively and consistently since the inception of NYISO operations and, prior to that, during New York Power Pool operations. For practical purposes, it serves as an efficient mechanism to apprise both the Transmission Owner, who is managing local transmission and local security, as well as the NYISO, of important generator parameters and statuses. A Resource can arrange to establish a communications pathway for electronic basepoints and metering directly with the NYISO pursuant to the *NYISO Direct Communications Manual,* available at the following URL:

https://www.nyiso.com/documents/20142/2923301/dir_comm_mnl.pdf/cc35a5dd-6c08-0e13-048e-968e47d4edd1

Voice communications regarding status and changes to capability would still continue through the Transmission Owner.

Compliance to NERC Standards

Generator Operators and Aggregators will communicate conditions and statuses as required by the NERC Standards through their interconnected Transmission Owner. The NYISO Transmission Owners are obligated to provide that Resource information to the NYISO as the Transmission Operator.

Related Documents

The NYISO receives Resource information required for real time operations, Day Ahead and long-term planning either through the interconnected Transmission Owner or directly from Generation Operators or Aggregators by means of various scheduling systems and voice communications. These processes are further outlined elsewhere, including but not limited to in the following documents:

- Sections 2.2.1, 2.2.2 and 5.7.4 of this manual

- Sections 3.2.1, 3.2.4, 3.2.5, 5.3, and Attachment B of the *NYISO Outage Scheduling Manual* available at the following URL: https://www.nyiso.com/documents/20142/2923301/outage_sched_mnl.pdf/1c2cc085-0fce-6540-fded-c95d0c662568

- Sections 7.3 and 7.4 of the *Market Participant User's Guide* available at the following URL: https://www.nyiso.com/documents/20142/3625950/mpug.pdf/c6ca83ca-ee6b-e507-4580-0bf76cd1da1b

- Section 3 of the *Control Center Requirements Manual* available at the following URL: https://www.nyiso.com/documents/20142/2923231/M-21-CCRM-v4.3-Final.pdf/6a89d4db-55e6-de2d-73fb-1eb36866fe13

- *System Protection Manual* available at the following URL: https://www.nyiso.com/documents/20142/2923301/System_Protection_Manual.pdf/e55deef5-ae32-8324-60b8-a70bbfb33c50

- Generator Fuel and Emissions Report User's Guide available at the following URL: https://www.nyiso.com/documents/20142/3625950/GFER_UG.pdf/7729b367-b2ffhttps://www.nyiso.com/documents/20142/3625950/GFER_UG.pdf/7729b367-b2ff-d257-19ba-835c4e102e25d257-19ba-835c4e102e25

- *Wind Plant Operator Data Guide* available at the following URL: https://www.nyiso.com/documents/20142/3625950/Wind-and-Solar-Planthttps://www.nyiso.com/documents/20142/3625950/Wind-and-Solar-Plant-UG.pdf/964e9927-bb40-86f1-ea5e-471dabe11a1dUG.pdf/964e9927-bb40-86f1-ea5e-471dabe11a1d

- Sections 3.1 and 9.1 of the *Outage Scheduler User's Guide* available at the following URL: https://www.nyiso.com/documents/20142/3625950/OS_UG.pdf/02c47c12https://www.nyiso.com/documents/20142/3625950/OS_UG.pdf/02c47c12-4ad7-386e-d8bf-4a60e0f2f2004ad7-386e-d8bf-4a60e0f2f200

- *Aggregation Manual* available at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides

2.2.5. NYISO Responsibilities and Authorities

The primary responsibilities and authorities of the NYISO are:

1. Control Area operations of the NYS Power System.
2. Perform balancing of generation and load while maintaining 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 Controlled Transmission System in Normal State based upon reliability criteria, and declare Warning, Alert, Major Emergency, and Restorative States for the NYISO Controlled 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 Controlled Transmission System, maintain appropriate flows and voltage levels during normal operations and order adjustments to be made under emergency conditions.
6. In the event of, or 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 Resource output levels in certain areas of the 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.
8. Maintain the safety and short-term reliability of the NYS Power System.
9. Coordinate NYS Power System equipment outages and maintenance.
10. Approve maintenance schedules for Transmission Facilities under NYISO Operational Control based on approved criteria.
11. Coordinate the scheduling and dispatch of dual participating resources with TOs

2.2.6. Transmission Owner Responsibilities and Authorities

The primary responsibilities and authorities of each TO are as follows:

1. Implement the Reliability Rules for those portions of the NYS Transmission System not included in the NYISO Controlled Transmission System.

2. Coordinate with the NYISO to implement certain applications to the Reliability Rules where the NYISO lacks the necessary expertise and/or monitoring capabilities.

3. Physically maintain and operate Table A.1 facilities under direction and control of the NYISO to assure secure operation of the NYISO Controlled Transmission System.

4. Comply with maintenance schedules coordinated by the NYISO for Table A.1 facilities.

5. Recommend activation of applicable procedures for adverse conditions associated with a Local Reliability Rule to the NYISO. The TO and the NYISO shall coordinate implementation of the procedures that impact Table A.1 facilities.

6. Notify NYISO prior to any planned outage and notify the NYISO of any change in status of Table A.1 facilities requiring NYISO notification.

7. Physically maintain and operate Table A.1 facilities requiring NYISO notification.

8. Operate Local Area Transmission System Facilities, provided 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.

10. Take action with respect to the operation of its facilities, as it deems necessary to maintain Safe Operations. Promptly conduct investigations of equipment malfunctions and failures, significant forced transmission outages, and provide a report of such investigations to the System Protection Advisory Subcommittee.

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

12. Each TO shall continue to receive telemetry from existing Resources in its control center and provide for the receipt of such information from new Resources.

13. Establish System Operating Limits (SOL), consistent with NYISO SOL methodology, as required by NERC FAC-011,for those portions of the NYS Transmission System not included in the NYISO Controlled Transmission System in accordance with the Transmission Owner SOL methodology set forth in Attachment A.7 of the *Emergency Operations Manual* (available from the NYISO Web site at https://www.nyiso.com/manuals-tech-bulletins-userhttps://www.nyiso.com/manuals-tech-bulletins-user-guidesguides).

14. Develop, maintain, and review annually with the NYISO operating plans to mitigate emergencies, including GMD events, within local Transmission Owner area.

2.2.7. Generator Owner and Aggregator Responsibilities

2.2.7.1. Resource Response during Reserve Activation

Dispatchable Resources Not Providing Regulation Service

All non-Intermittent Power Resource (IPR) units that are NOT "self-committed fixed" or "ISO-committed 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 Real-Time Dispatch (RTD) basepoint, which will be consistent with the LBMP, within three (3) RTD intervals (approximately 15 minutes) following termination of the reserve pickup. The unit will also be paid for overgeneration during that grace period.

Resources Providing Regulation Service

A Resource providing regulation service is expected to respond to a reserve pickup 10-minute basepoint at its stated response rates as bid. If the Resource exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However, the Resource must return to its RTD/Automatic Generation Control (AGC) basepoint, within three (3) RTD intervals following termination of the reserve pickup. The Resource will be paid for overgeneration during the three (3) RTD interval grace period. Withdrawal-Eligible Generators and Aggregations containing at least one Withdrawal-Eligible Generator may receive a basepoint to withdraw during a reserve pickup. Withdrawal-Eligible Generators and Aggregations containing at least one Withdrawal-Eligible Generator that withdraw less than basepoint are charged for actual withdrawals only, during the three (3) RTD interval grace period. Limited Energy Storage Resources (LESRs) do not participate in reserve pickups. AGC will move the LESR to zero MW.

2.2.7.2. Default Generator Voltage Schedule

Generators operating in the New York Control Area, connected at 100kV and higher, are provided a default Generator voltage schedule and allowable bandwidth, in the event they have not received a more specific schedule from the NYISO or the interconnecting TO.

The below default Generator voltage schedule is to be followed only in the event the generator has not received a more specific schedule from either the NYISO or the interconnecting TO.

Figure 1: Default Generator Voltage Schedule

Voltage Level (kV)	345	230	138	115
Schedule (kV)	355	233.5	140	117.5
Bandwidth (+/- kV)	7	8.5	5	2.5

General Operating Procedures

1. Interconnecting TOs or the NYISO generally provide specific voltage schedules and a low and high bandwidth to interconnecting generators. Generators are required to

follow their specified voltage schedules with their AVR in service and controlling voltage. Generators that have not been provided specific voltage schedules are required to follow the default Generator voltage schedule specified above.

2. TOs coordinate adjustments to voltage schedules with the NYISO in accordance with the requirements specified in this manual.

3. The NYISO and interconnecting TOs may direct Generators to deviate from specified voltage schedules or the default Generator voltage schedule as required by system conditions.

4. Generation Owners shall communicate concerns regarding voltage schedule/bandwidth with the entity that issued the schedule.

5. Generator communications with the NYISO will be through the interconnecting TO in accordance with Section 2.2.3.

2.3. Normal and Warning Operating States

This section of the manual 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 after 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 NYCA 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 does not exceed their associated Normal ratings.

2. Post Contingency Flow Criteria:

   Single Circuit and Two adjacent circuits on same structure Criteria:

Normal Transfer Criteria: Loss of any single Resource, 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 overhead Transmission System to exceed its Long Term Emergency (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 Short Term Emergency (STE) rating, provided 10-minute reserve and/or phase angle control is available to return the loading below its LTE rating within 15 minutes, without causing another facility to become loaded above its LTE rating.

With prior approval of the NYISO and NYSRC, the post-contingency loading of any portion of the NYS Transmission System may exceed its LTE rating, but not its STE rating, provided sufficient operating measures are available to return the loading on the facility to below its LTE rating within 15 minutes, without causing another facility to exceed its LTE rating. The NYSRC Exceptions Process has also been utilized to permit, under limited identified circumstances, post-contingency loading of transmission elements that may exceed STE 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 Table B.2 of this Manual.)

Actual voltages on all buses listed in Table A.2 and Table A.3, of this Manual are within pre-contingency limits.

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

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 Controlled Transmission System unless they remain unchecked. Operator action may be required to return the system to the Normal state.

2.3.4. Warning State Criteria

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

1. Pre Contingency (Actual) Flow Criteria:

    Normal Transfer Criteria: The actual loading on any portion of NYISO Controlled Transmission System is 105% or more of its associated Normal Rating, but is less than the LTE rating for not more than 30 minutes or exceeds its Normal Rating by less than 5% and corrective actions are not effective within 10 minutes.

Emergency Transfer Criteria are invoked: The actual loading of any NYISO Controlled Transmission System facility does not exceed its associated Normal rating.

2. Post Contingency Flow Criteria:

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

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

3. Sufficient Operating Reserve exists to meet the requirements specified by the NYSRC, but only using Emergency Transfer Criteria.

4. Area Control Error is greater than +/- 100 MW, but not more than +/- 500 MW for more than 10 minutes.

5. A neighboring Control Area is not operating under Normal State conditions, but has not implemented voltage or load reduction.

6. An Operating Reserve deficiency is predicted for the NYCA peak load forecast and reserve purchases are not available.

2.4. Market Operations Time Line

Operation of the NYCA and the Locational Based Marginal Pricing (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.

Figure 2 summarizes the important events that characterize the day-to-day operation of the NYISO LBMP market. Although this Manual focuses mainly on dispatch day activities, it is important to understand how day-ahead activities can impact real-time operation.

Figure 2: Energy Market Operations Timeline
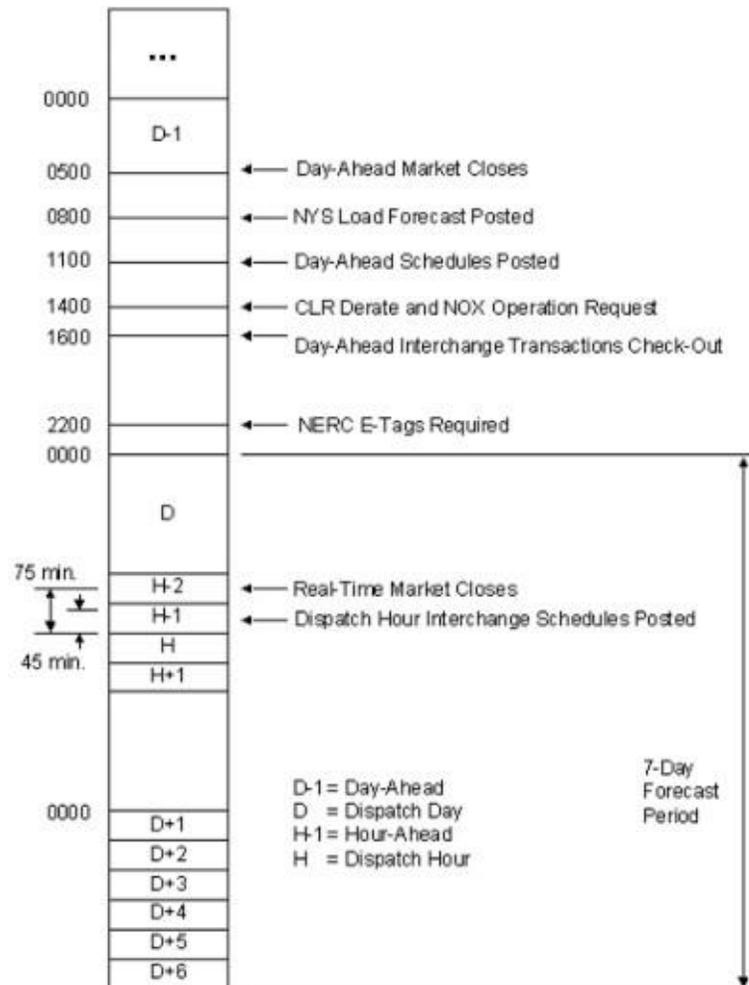
For more information, see the *NYISO Day Ahead Scheduling Manual*, available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides

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

1. ***0500 (D-1):*** Closing time of the day-ahead energy market.
2. ***0800 (D-1):*** The load forecast for the State of New York is posted.
3. ***1100 (D-1):*** The results of the day-ahead security constrained unit commitment (SCUC) are posted.
4. ***1400 (D-1):*** Deadline for Capacity Limited Resources (CLRs) to submit requests for derates and for NOX impacted entities to submit requests for steam unit operation.

5. ***1600 (D-1):*** Day-ahead external interchange transaction checkout has been completed.

6. ***2200 (D-1):*** Deadline for NERC E-Tags to be submitted for external interchange transactions.

7. ***xx45 (H-2):*** Closing time of the real-time energy market.

8. ***Starting with xx15 (H-1):*** The Real-Time Commitment (RTC) application, that executes periodically every 15 minutes. The execution at xx15 posts the upcoming "Dispatch Hour" external interchange transaction schedules for hourly transactions, while every execution posts the interchange transaction schedules for intra-hour transactions according to the scheduling frequency supported at each external proxy.

9. ***xxxx (H):*** The dispatch hour with locked offers/bids and interchange transactions.

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

The following applications are said to execute in "real-time":

- ***Real-Time Commitment (RTC)*** – executes every 15 minutes as described in this Manual.

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

- ***Real-Time Dispatch (RTD)*** – executes every 5 minutes as described in this Manual.

- Real-Time Dispatch/Corrective Action Mode (RTD-CAM) – executes on demand as described in this Manual

- ***Automatic Generation Control (AGC)*** – executes every 6 seconds as described in the *NYISO Ancillary Services Manual* (available from the NYISO Web site at https://www.nyiso.com/manuals-tech-bulletins-user-guides).

2.5. Operations Functions

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

- NYISO Controlled Transmission System Monitoring

- Transmission System Operation

- Energy Market Overview

- Energy Market Functions

- Backup Operations

2.5.1. NYISO Controlled Transmission System Monitoring

The NYISO Controlled Transmission System is monitored on a continuous basis to evaluate its current operating state. The first step in this process is to determine which of the five States the

NYISO Controlled Transmission System is in. This Manual covers the Normal and Warning States.

The monitored conditions of critical concern include:

- System Load and Operating Reserves

- Regulation capability

- NYISO Controlled Transmission System flows and voltages

- NYCA Control Error

- This section discusses the power system monitoring requirements and procedures in further detail.

2.5.2. Transmission System Operation

The operation of the NYISO Controlled 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 NYISO Controlled 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.

2.5.3. Energy Market Overview

A review of market mechanics is presented in Figure 3 as an introduction to the dispatch day functions. Sections 5 and 6 of this Manual provide further detail.

Figure 3: Market Overview

Figure 3: Market Overview
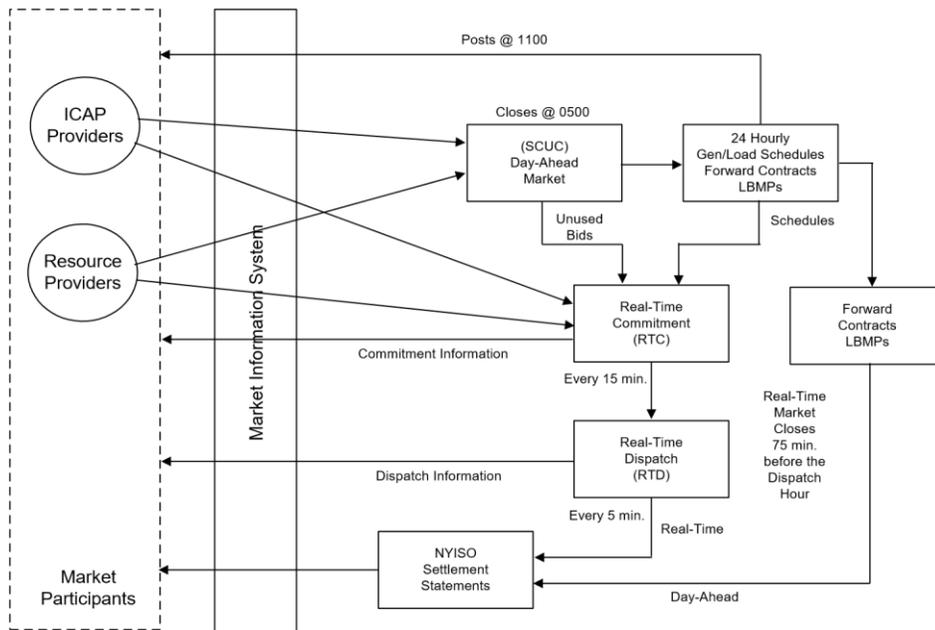
2.5.4. Energy Market Functions

Figure 4: Day-Ahead and Dispatch Day Functions
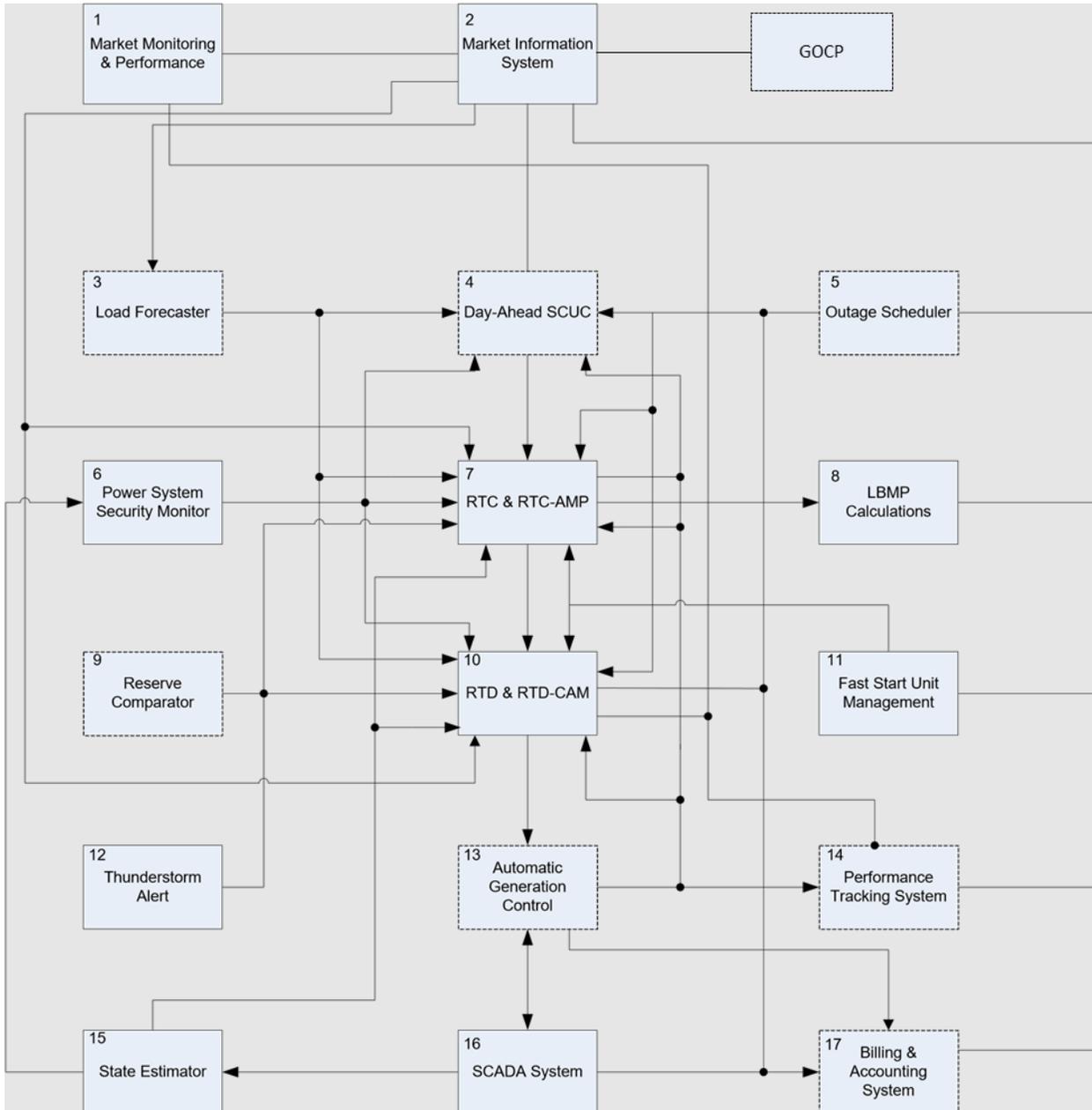
The following is a brief summary of each function block in

Figure 4. The dotted boxes are described in more detail in other NYISO Manuals:

1. ***Market Mitigation & Analysis Department (MMA):*** The MMA Department is charged with analyzing market participant bids and their impact on energy market

prices. MMA 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. **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.

4. **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 Dayhttps://www.nyiso.com/documents/20142/2923301/dayahd_schd_mnl.pdf/0024bc71-4dd9-fa80-a816-f9f3e26ea53aAhead Scheduling Manual for details. The SCUC model serves as the basis for deriving the Day-Ahead Market transmission loss and congestion sensitivity coefficients.

5. **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.

6. **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 the operating limits of which must be observed by the market applications.

7. **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).

8. **LBMP Calculations:** The RTC and RTD programs produce LBMPs for market advisory and settlement purposes.

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

10. **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 RTDCAM functions override the normal RTD executions, as determined by the NYISO Operators, to deal with "off-normal" power system conditions. The RTD model serves as the basis for deriving the Real-Time Market transmission loss and congestion sensitivity coefficients.

11. **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.

12. ***Thunderstorm Alert (TSA):*** TSA is declared by NYISO Operators when severe operating conditions are detected. A predetermined set of pre- and postcontingency constraints are passed to the RTC and RTD programs while TSA is in effect.

13. ***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.

14. ***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.

15. ***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 data values that are not metered.

16. ***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.

17. ***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 Accounting and Billing Manual at the following link for details: https://www.nyiso.com/documents/20142/2923231/acctbillmnl.pdf

18. ***Grid Operations Coordination Portal (GOCP):*** The Grid Operations Coordination Portal is used by Aggregators, TOs and the NYISO operators to enter full or partial outages and SRAs for Aggregations. See the NYISO Grid Operations Coordination Portal User Guide (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for details.

2.5.5. Backup Operations

For details, refer to the *NYISO Emergency Operations Manual* (available from the NYISO Web site at https://www.nyiso.com/manuals-tech-bulletins-user-guides).

2.6. Communications

This subsection describes the NYISO hotline communications systems.

2.6.1. Hotline Communications

For details, refer to the NYISO Emergency Operations Manual (available from the NYISO Web site at https://www.nyiso.com/manuals-tech-bulletins-user-guides

3. Operations Monitoring

This section describes the NYS Power System operations monitoring requirements and procedures.

3.1. Operations Monitoring Requirements

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

- Current Operating State

- System Load

- Operating Reserve

- Regulation

- NYISO Controlled Transmission System

- Ancillary Services

- Communications

- Weather Conditions

- Telemetered Data

Reliability Assessment

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

- Real-Time Data Monitoring and Alarming

- Security Analysis

- Reserve Calculation

- Regulation Requirement

3.1.1. Real-Time Data Monitoring and Alarming

This function is executed, nominally every six (6) seconds for SCADA data and thirty (30) seconds for state estimated values.

NYISO Actions

The following are performed:

1. Determines whether to use: (1) metered values (2) state estimated values or (3) NYISO override/substitution values for:
    a. Switch status data
    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:
    a. User analog data
    b. Audible alarms, text alarms, mimic board outputs
    c. Confirmed switch status
    d. Updated outage schedules

3.1.2. Security Assessment

The security assessment is triggered to execute on:

- Network configuration status change

- Periodic, nominally every 60 seconds

- Operator demand

NYISO Actions

The following are performed:

1. Executes the network configurator and state estimator functions based on confirmed switch status
2. Performs a contingency analysis based on the state estimator solution of the NYS Transmission System, using:
    a) Pre-defined single and multiple contingencies
    b) Facility Line ratings and interface transfer limits
3. Produces a list of potential transmission system violations for NYISO Operations review based on actual SCADA (actual violations only) or state-estimated values (contingency violations only).

3.1.3. Reserve Calculation

The NYISO monitors NYCA reserve through the use of the Reserve Monitor Program using actual

generation). These reserve calculations indicate the reserve available for the NYCA.

Corrective action is taken by the NYISO only if the NYCA is deficient in reserve. Reserve calculations and constraints are also performed by RTC and RTD.

Minimum Operating Reserve Requirement

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

1. 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 multiplied by the contingency reserve adjustment factor.

2. 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 multiplied by the contingency reserve adjustment factor.

3. 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. Sufficient Reserve in 10 minutes to return the system to a Normal State following the most severe transmission contingency multiplied by the contingency reserve adjustment factor.

At all times sufficient 10 Minute Reserve shall be maintained to cover 1) the energy loss due to the most severe Normal Transfer Criteria contingency within NYCA or 2) the energy loss associated with recallable import transactions from another control area, whichever is greater.

3.1.4. Regulation Requirement

The NYCA Regulation requirements, in MW/minute, are established by analyzing NYCA daily load patterns and actual operating conditions. The NYISO establishes the regulation and frequency response requirements consistent with criteria established by NERC, which may vary by hour and season.

This Manual describes the process by which the NYCA regulation requirement is allocated to the generating units.

The NYISO will determine the amount of regulation required for different time periods and load conditions in accordance with procedures defined in the *NYISO Ancillary Services Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletinshttps://www.nyiso.com/manuals-tech-bulletins-user-guidesuser-guides).

The amount of Regulation Service required varies on an hourly and seasonal basis. The NYCA regulation requirements are posted on the NYISO website at the following URL:

https://www.nyiso.com/regulatory-resources

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, followed by specific procedures to be carried out under Normal and Warning State conditions.

Specific procedures cover the following:

- Response to Normal State Conditions

- Response to Warning State Conditions

- Reliability Assessment Support

- Automatic Voltage Regulators / Power System Stabilizer Outages

- Communication of NYCA Operating Conditions

- Hourly Inadvertent Accounting

- Local Reliability Rules

- Applications of the NYSRC Reliability Rules

- Daily Operation for Monitoring Operating Reserve

3.1.6. Response to Normal State Conditions

NYISO Actions

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

1. Coordinate actions with TOs and other Control Areas.
2. Initiate one or more of the following actions:
   a. Adjust phase angle regulators.
   b. Shift or start generation by NYISO request to obtain additional reactive power (MVAr) control.
   c. Activate reserves.
   d. Adjust reactive sources and transformer taps.
   e. Perform Generation shifts.
   f. Modify 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.

    k. Take actions to maintain operating reserve, in accordance with the procedures described in this Manual.

Transmission Owner Actions

NYISO operational contact is generally with the TO. The TOs are responsible for controlling or coordinating the operation of Resources connected to their systems, as follows:

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 NYCA is operating in the Normal State and Normal State Criteria are not met:

    a. Notify the NYISO Shift Supervisor.

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

    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 the Normal State 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 in the Normal State. Transmission Owners are responsible for providing appropriate advance notice of such switching.

3. During periods when adverse conditions such as tornadoes or hurricanes exist, or 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.

4. It is the responsibility of the NYISO to monitor weather conditions and forecasts issued by the National Weather Service. Should local adverse conditions occur or if they are predicted to occur, it is the responsibility of the TO to inform the NYISO. If a situation involving impending severe weather exists, the NYISO shall notify all TOs and consider declaration of the Alert State.

5. The actual voltage on all busses listed in Table A.2 and Table A.3 shall be monitored by the NYISO and TOs. It shall be the TO responsibility to maintain voltage levels within limits specified in Table A.2 and Table A.3 and to coordinate actions, which would affect voltage levels on busses of other TOs or Neighboring Systems.

6. If the NYISO anticipates conditions, which would cause the voltage at any bus listed in Table A.2 and Table A.3 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.

7. It may be necessary to schedule energy transactions from neighboring control areas for reliability reasons in accordance with Interconnection Agreements.

3.1.7. Response to Warning State Conditions

NYISO Actions

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

1. Coordinate actions with TOs and other Control Areas.
2. Initiate one or more of the following actions:
   a. Adjust phase angle regulators.
   b. Shift or start generation by NYISO request to obtain additional reactive power (MVAr) control.
   c. Activate reserves.
   d. Adjust reactive sources and transformer taps.
   e. Perform Generation shifts.
   f. Modify 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 (ACE) exceeds 100 MW.
   k. Take actions to maintain operating reserve, in accordance with the procedures described in this Manual.
   l. Curtail non-essential TO and Generation Owner load.
   m. Order Generation to full operating capability.
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 TOs, via the Hotline communications system, that Emergency Transfer Criteria are in effect for the facility (ies) involved.
   b. Take actions, as required, to stay within Emergency Transfer Criteria.
   c. Confer with TOs 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:

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

    b. Monitor conditions with respect to their own systems.

    c. Perform the following actions when the NYCA is operating in the Warning State and Warning State Criteria are not met:

    d. Notify the NYISO.

    e. Request assistance from the NYISO, as required.

    f. Initiate unilateral corrective action, if the violation is severe enough to require immediate action.

Other Considerations

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

2. If the NYISO foresees an extended period of operation in the Warning State, a canvass of the TO 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 TOs and consider declaration of the Alert State.

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.

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 potential transmission system violations produced by the state estimator and Security Analysis functions.

3.1.9. Communication of New York Control Area Operating Conditions

NYISO Actions

The NYISO shall perform the following actions:

1. Obtain the following data for the NYCA Report, prior to 0530 hours:

> Resource anticipated operating capability for the NYCA peak hour, including all purchases and sales.
>
> Forecast NYCA load requirements.

2. Determine the following information for the NY Control Capacity Report display, using the acquired data:

> NYCA forecast peak hour load
>
> NYCA reserve requirements
>
> NYCA generation available capability
>
> Interchange summary and peak hour Desired Net Interchange (DNI)
>
> Total anticipated reserve for the NYCA peak hour
>
> Previous day's peak load and hour

3. Post the NYCA Capacity Report.

4. Immediately report any critical change in the status of the NYCA, either via the emergency telephone system or the NYCA Status Report.

5. Report all NYCA disturbances, e.g., loss of a major Resource, when appropriate.

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

3.1.10. Hourly Inadvertent Accounting

The following procedures apply only to the NYISO. The *NYISO Accounting and Billing Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-techhttps://www.nyiso.com/manuals-tech-bulletins-user-guidesbulletins-user-guides) describes the Inadvertent Interchange accounting procedure in further detail.

NYISO Actions

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

1. *Prior to each hour* – The sum of External transaction schedules should be equal to the NYCA DNI schedule.

2. *After each hour* – The sum of the interconnection readings should be equal to the NYCA Actual Net Interchange (ANI).

3. *After each hour* – The NYCA Inadvertent Interchange should be equal to the 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.

3.2. Daily Operation for Monitoring Operating Reserve

The NYISO Shift Supervisor will monitor the Operating Reserve both as forecast for the expected system peak each day and under actual conditions as the day progresses.

Peak Load Forecast

The NYISO Shift Supervisor (or designee) shall prepare the NYISO daily status report twice daily, in anticipation of the morning peak and evening peak as indicated in this Manual.

If a shortage of energy, reserves, or other Ancillary Services is projected, the NYISO will take actions as directed in the *NYISO Emergency Operations Manual*, available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides.

3.3. Periodic Monitoring of Fuel and Resource Availability

Installed Capacity (ICAP) Suppliers shall submit Fuel and Environmental Restriction Data to the NYISO on weekly and yearly intervals and as requested by the NYISO. This data will be shared with the Transmission Operators (TOPs) to ensure all operating limitations are incorporated to perform Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. For weekly and other as-needed surveys, the NYISO may only solicit responses from generators that use fossil fuels to produce electricity. All ICAP Suppliers shall complete the Fuel Availability Self Reporting Surveys as follows:

1. Yearly Fuel Surveys must be completed within 30 days of NYISO notification of its availability.
2. Weekly Surveys must be completed by 1:00 p.m. of the first business day of each week.
3. As Requested Surveys must be completed by 1:00 p.m. of the day prior to the operating day the survey is requested for.

4. Transmission Operations

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

4.1. Transmission Operations Requirements

This section addresses the operation of the NYISO Controlled Transmission System when it is in the Normal State or Warning State. The following requirements and guidelines are discussed:

- NYISO Controlled Transmission System Operating Limits
- Corrective Control Strategies
- Transmission Service Reduction & Curtailment
- Solar Magnetic Disturbances

The Transmission Facilities Under NYISO Operational Control and subject to *Orders* from the NYISO are identified in Table A.1 of this Manual. The Transmission Facilities Requiring NYISO Notification are also identified in Table A.1.

4.1.1. NYISO Controlled Transmission System Operating Limits

Limits that are used in the operation of the NYCA are classified as follows:

1. ***Thermal (Summer/Winter):*** MW
   Normal
   Long Term Emergency (LTE)
   Short term Emergency (STE)
2. ***Voltage:*** kV
   Pre-contingency High/Low
   Post-contingency High/Low
3. ***Frequency:*** Hz
   Normal High
   Normal Low
4. ***Interface Transfer:*** MW
   Stability
   Voltage Collapse

4.1.2. Corrective Control Strategies

The major electrical network problems that can occur in the NYCA and the primary (or most effective) means of overcoming these problems are identified in Figure 6. The major problems are:

- Facility overloads and excessive transfers

- NYISO Controlled Transmission System low voltage conditions

- NYISO Controlled Transmission System high voltage conditions

- System low frequency conditions

- System high frequency conditions

Figure 5: Corrective Control Strategies

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

Load Shed	✔	✔		✔	

Some of the controls listed in [Figure 6](#) are automatically applied by local closed-loop control while other controls are acted on by the TOs upon NYISO request. The NYISO has no direct means (via SCADA) of controlling the generation, transmission, and distribution systems.

4.1.3. Transmission Service Reduction and Curtailment

Firm Transmission Service

If a Transmission Customer's Firm Transmission Service is supporting a Bilateral Transaction supplied by an Internal Resource and that Resource 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 provided however, the NYISO shall reduce Transmission Service supporting an Export bilateral if the amount of Energy scheduled to be exported is reduced. The NYISO shall not reduce Transmission Service scheduled to support an Import with a non-reference bus sink even if the amount of Energy scheduled to be imported is reduced.

4.2. Transmission Operations Procedures

These procedures apply mainly to the operation of the NYISO Controlled Transmission System network facilities. Procedures for the following are covered:

- Developing & Approving Operating Limits

- Voltage Control

- Guidelines for Leeds and Fraser SVCs to Control Voltage

- Phase Angle Regulators – ConEd/PSE&G

- Phase Angle Regulators Operations

- Implementing Special Multiple Contingencies

- Exceptions to the NYSRC Reliability Rules

- Security Violation Relief

- Operating Under Adverse Conditions

- Solar Magnetic Disturbances

4.2.1. Developing & Approving Operating Limits

Procedures have been established for the following:

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

2. The collection of operating data required to determine voltage limits for selected buses in the NYCA.

NYISO Actions

The NYISO shall perform the following actions:

1. Prepare Seasonal studies of thermal transfer limits for the "all-lines in" condition.

2. Prepare stability transfer limits for the "all-lines in" condition. These limits will be used for the secure operation of the NYISO Controlled Transmission System.

3. 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 Controlled Transmission System.

4. 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 for 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.

4.2.2. Voltage Control

These procedures are for coordinating and controlling the voltage of the NYISO Controlled Transmission System and define the respective actions to be taken by the NYISO and the TOs. 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 NYCA 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 TOs and adjacent Control Areas that can assist in adjusting voltage on the buses being corrected.

4. Inform the affected TOs of anticipated changes in 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 Controlled Transmission System voltages within limits.

6. NYISO and applicable TO shall coordinate to ensure dual participating resources are available to provide emergency services if applicable.

Transmission Owner Actions – General

The TO 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-Control 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, but shall inform them as soon as possible.

5. Request Generators to adjust machine excitation as required to maintain desired voltages within limits.

NYISO Actions – High-Voltage Conditions

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

1. Switch out shunt capacitors
2. Switch in shunt inductors
3. Request that machine excitation be decreased to decrease the reactive power output
4. Adjust load tap changing (LTC) transformer tap positions
5. Reschedule pumped hydro units to pump
6. Adjust SVC output
7. Start fast response units with reactive power absorption capability
8. Switch out lines, as a last resort, without dropping load or generation

NYISO Actions – Low-Voltage Conditions

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

1. Switch in shunt capacitors
2. Switch out shunt inductors
3. Request that machine excitation be increased to increase the reactive power output
4. Adjust load tap changing (LTC) transformer tap positions

5. Reschedule pumped hydro units to generate

6. Motor pumped hydro units to produce reactive power

7. Adjust SVC output

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

9. Switch in lines where available

Transmission 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 TO 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 TOs.

ISO and Transmission Owner Target Voltage Level Program

The ISO, in agreement with the Transmission Owners, develops, reviews and maintains a set of agreed-upon target voltages for the NYS transmission system stations listed in Appendix A2 of this manual.

- These target voltages represent the expected voltage level that the ISO and Transmission Owners will reasonably attempt to maintain in order to reduce system losses.

- These target voltage levels do not replace the existing reliability based limits defined in Appendix A2 of this manual.

Communication between the ISO and the Transmission Owners to determine control actions will occur as necessary to maintain actual NYS transmission system station voltages within an expected range of the target voltage levels.

- It is recognized that target voltages may not be achievable at all times; however the ISO and Transmission Owners will work to maintain actual station voltages as close to the target levels as possible.

4.2.3. Guidelines for Marcy STATCOM 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:

- Central – East and Total – East transfers are at or below transfer limits that assume the SVCs are unavailable.

- As appropriate, switchable shunt capacitors have been taken out-of-service. As appropriate, switchable inductors have been placed in-service.

- 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.

- The SVCs must be able to automatically respond to contingencies.

4.2.4. Process for Determining the Status of Series Reactors that are under ISO Operational Control

When determining the operating status of series reactors required for fault current mitigation, the Transmission Owners of the equipment that the series reactors protect will develop operating guidelines that will be included in the seasonal NYISO Fault Current Assessment report. The NYISO will follow the operating recommendations of the Transmission Owner, including when, pursuant to the ISO-TO Agreement, the NYISO has Operational Control over the series reactors or the elements protected by the series reactors. The NYISO will coordinate with the applicable Transmission Owners regarding the switching of the series reactors for managing power flow and/or voltage control. In addition, the NYISO will give due consideration to series reactor bypass requests from the Transmission Owner as a last resort to mitigate conditions that require emergency voltage support.

4.2.5. Phase Angle Regulators Operations

Normal Operating Conditions

Under normal operating conditions, TOs shall determine power flows on PAR controlled lines and normally will implement PAR adjustments to avoid the need for generation redispatch if NYISO secured transmission constraints can be mitigated by such adjustments. 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 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 postcontingency 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.

Power flows on PAR controlled lines that are within a TO's system shall be monitored and controlled by that TO. Power flows on other PAR controlled lines shall be monitored by the NYISO and appropriate

action shall be coordinated with the TOs.

The following PAR actions apply to normal conditions.

NYISO Actions

The NYISO shall perform the following actions:

1. Coordinate the operation of the PARs that affect the transfer of power between the NYCA and adjacent Control Areas.
2. Request the TOs and adjacent Control Areas to adjust PAR taps.

Transmission Owner Actions

Transmission Owners shall perform the following actions:

1. Set the PAR taps and normally implement PAR adjustments to avoid the need for generation redispatch if NYISO secured transmission constraints can be mitigated by such PAR adjustments.

4.2.6. Phase Angle Regulators – NYISO/ PJM Interconnection

The NYISO and PJM Control Areas are interconnected at several locations with the following Phase

Angle Regulators (PARs) to control the transfer of power over the circuits connecting the two regions:

1. Two 345 kV phase angle regulating transformers, Hopatcong-Ramapo 500 kV ("5018"), installed at the Con Edison Ramapo substation
2. A 230 kV phase angle regulating transformer, Linden - Goethals 230 kV ("A"), installed at the Con Edison Goethals substation
3. A 345 kV phase angle regulating transformer, Hudson - Farragut 345 kV ("B"), installed at the Con Edison Farragut substation
4. A 345 kV phase angle regulating transformer, Marion - Farragut 345 kV ("C"), installed at the Con Edison Farragut substation
5. A 230 kV phase angle regulating transformer, Waldwick-Hawthorne 230 kV ("E"), located at the PSE&G Waldwick Switching Station.
6. A 230 kV phase angle regulating transformer, Waldwick-Hillsdale-New Milford 230 kV ("F"), located at the PSE&G Waldwick Switching Station.
7. A 230 kV phase angle regulating transformer, Waldwick-Fair Lawn 230 kV ("O"), located at the PSE&G Waldwick Switching Station.

A FERC approved Joint Operating Agreement between NYISO and PJM (NYISO Open Access

Transmission Tariff (OATT) Attachment CC) describes the real-time flow of energy over the Hopatcong-

Ramapo, ABC, and JK interconnections.

4.2.7. Implementing Special Multiple Contingencies

The SCUC and RTC/RTD programs 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 due to certain maintenance outage conditions.

NYISO Actions

The NYISO shall perform the following actions:

1. Validate the need for special multiple contingencies and request the TOs to submit the required information as defined.
2. Following notification by the TO to the NYISO Outage Scheduling Department and Transmission System Operator, the NYISO will implement the special multiple contingency for the Day-Ahead and Real-Time Market operation.

Transmission Owner Actions

The TO shall perform the following actions:

1. Notify the NYISO and request the need for monitoring of special contingencies.
2. Supply a description of the special operating maintenance 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 to implement such a contingency:

    The necessary data must be provided to the NYISO Outage Scheduling Department at least by the morning of the previous working day, prior to the closing of the Day-Ahead Market.

    Notification must be provided to the Transmission System Operator at least one hour in advance of the special operating condition.
4. Provide special contingency data when required and requested by the NYISO.

4.2.8. Security Violation Relief

When a security violation occurs or is anticipated to occur on the NYISO Controlled Transmission System, the NYISO shall attempt to relieve the violation by using any one or more of the following procedures, typically in this order:

1. Re-dispatch internal Resources, based on Incremental and Decremental Bids.
2. Adjust the NYCA's 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 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.
3. Request Internal Generators to voluntarily operate in manual mode below minimum dispatchable levels.
4. Decommit Internal Generators based on their minimum generation Bid rate in descending order.

5. Attempt to purchase emergency energy from other control areas that will provide relief to the security violation.

4.2.9. Operating Under Adverse Conditions

The NYISO shall operate the NYISO secured transmission system during adverse conditions, including but not limited to peak load system conditions, thunderstorms alerts, hurricanes, tornadoes, solar magnetic flares and threat of terrorist activities, in accordance with the Reliability Rules, inclusive of LRRs and related PSC orders. Consistent with such Rules, the NYISO shall maintain reliability of the NYISO Controlled Transmission System by directing the adjustment of the Resource 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 Controlled Transmission System in response to those conditions. Activation of a procedure in compliance with a LRR shall involve a two step process. The TO, directly involved with such LRR, 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 LRR, the NYISO shall declare the activation of the appropriate procedures. The TO 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 DayAhead 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.

4.2.10. Adverse Operating Conditions

NYISO Actions

The NYISO may perform the following actions under adverse operating conditions:

1. Notify all TOs and NPCC Control Areas.
2. Reduce RTC/RTD Stability Transfer Limits and RTC/RTD Central East Voltage Transfer Limits to 90% of the Stability Transfer Limit and Central East Voltage Transfer Limits where appropriate.

3. Reduce flows on inter-area and internal NYISO secured transmission lines to a maximum of 90% of the Normal Rating.

4. Cancel in-service relay and hot line work on A-1 transmission facilities. Recommend TO cancel in-service relay and hot line work on A-2 transmission facilities.

5. Restore out-of-service A-1 transmission facilities where possible. Recommend TO restore of out-of-service A-2 transmission facilities where possible.

6. Request TOs to implement appropriate emergency procedures when a contingency occurs.

Transmission Owner Actions

1. Implement NYISO requests to cancel in-service relay and hot line work on A-1 transmission facilities. Evaluate cancellation in-service relay and hot line work on A-2 transmission facilities.

2. Implement NYISO requests to restore out-of-service A-1 transmission facilities. Evaluate restoration of out-of-service A-2 transmission facilities.

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

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

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 two agencies:

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

2. Space Environment Services Center (SESC) in Boulder, Colorado

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. 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 STD GSMS. As described in NPCC Procedure C-15 or its replacement, Solar Terrestrial Dispatch (STD) using the Geomagnetic Storm Mitigation System (GSMS) is the primary mechanism for notification of SMD information to all NPCC Areas. STD will issue a Warning for forecasted Kp levels, and issue an Alert for observed Kp levels. Warnings and Alerts are issued using a Kp index based on activity. The Kp Index quantifies disturbances in the horizontal component of earth's magnetic field with an integer in the range 0-9 with 1 being calm and 5 or more indicating a geomagnetic storm. The Kp Index is derived from the maximum fluctuations of horizontal components observed on a magnetometer during a three-hour interval.

SMD Forecasts and Alerts

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 Alert is issued. They are issued depending on the activity seen by

their satellite in regards to predicted and actual SMD activity.

The STD GSMS software classifies GIC activity at three levels:

Weak: observed GIC of 15 amps or less

Moderate: observed GIC of between 15 and 30 amps

Strong: observed GIC of greater than 30 amps

Voltage fluctuations at a transmission or generator substation can also be an indication of GIC activity.

SESC (Boulder) issues forecasts in the form of 3-Day Geomagnetic Forecast and issues alerts in the form of a 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 "K" index of K5 or above to the NYISO.

All time references in SMD Forecasts and SMD Alerts received from SESC (Boulder) 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 (Standard Time or Daylight Saving Time) as shown in Figure 7.

Figure 6: Conversion from Universal Time

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

NYISO Actions

Notification to NYISO Transmission Owners will include a start time and end time (or duration) for the Warning or Alert.

These procedures will be terminated when the Warning or Alert is no longer active.

Levels up to K5, no NYISO action is required.

Level K6 Warning or Alert:

1. Notify all New York TOs

Level K7 or above Warning or Alert:

1. Notify all New York TOs

2. If significant GIC is observed or reported to NYISO by TO or NPCC Area:

   (a) Declare the Alert State

   (b) Notify TOs 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, to maintain the NYISO Controlled 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.

   (e) Reduce flows on inter-area and internal NYISO secured transmission lines to a maximum of 90% of the Normal Rating.

Level K9 Warning or Alert:

1. Complete all actions above for Level K7 or greater Warning or Alert
2. Activate Thunder Storm Alert Cases in BMS
3. Cancel scheduled transmission outages and request TOs restore out of service transmission
4. Review in-service work and cancel where appropriate

Transmission Owner Actions

TOs shall perform the following actions upon notification of an SMD Alert of a Major Storm Condition (K7-K9) or prior to the forecasted arrival of the storm upon notification of an SMD Forecast of a Major Storm Condition (K7-K9):

1. Notify generators within their areas that have a high-side wye grounded winding with terminal voltage greater than 200kV.

2. Restore out-of-service transmission facilities, where possible, and avoid taking long transmission lines out of service.

3. Review 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.

4. Monitor the MVAr and voltage displays on their SCADA systems for unusual voltage and/or MVAr variations.

5. Keep area substation capacitor banks in service, where possible, and evaluate the impact of the loss of transmission shunt capacitor banks.

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

7. Implement emergency procedures as requested by NYISO

4.2.12. Status of Transmission and Generation Protection Systems

Background

NERC reliability standards require the NYISO to be cognizant of the status of transmission and generation special protection systems affecting the New York bulk power system.

Details

In order to assist the NYISO in performing its responsibilities as a Reliability Coordinator, Transmission and Generation Owners and Operators in the NYISO Reliability Coordination Area are required to perform the following:

1. *Coordination.* Coordinate protection systems and changes in generation, transmission, load, or operating conditions that could require changes in the protection systems of others. This coordination shall take place between the affected facility owners, including dual participating resources.

2. *Operational Status.* Notify the NYISO of changes in the operational status of all Special Protection Systems. This reporting will be to the NYISO Grid Operations Shift Supervisor via the affected Transmission Owner's control center. NYISO will notify neighboring Balancing Authorities as noted in the New York Protection Memos.

3. *Failures.* Notify the NYISO of relay or protective system operational failures which reduce system reliability. Failures should be reported immediately to the NYISO Grid Operations Shift Supervisor via the affected Transmission Owner's control center. NYISO will notify neighboring Balancing Authorities as noted in the New York Protection Memos.

References for this Section 4.2.12:

NPCC Directory D1, "Design and Operation of the BPS," December 15,2009, or latest issue.

NERC Reliability Standard PRC-001-1, "System Protection Coordination," effective January 1, 2007, or latest issue.

5. Process for Determining Facilities Secured in the Market Models

Consistent with the NYISO's responsibility to ensure reliable operation and efficient market outcomes, the following process is utilized to identify and evaluate facilities that should be secured in the Business Management System (BMS) Day-Ahead and real time market models. The NYISO is the Transmission Operator (TOP) responsible for operating and securing the transmission system 230kV and above, which is typically done in the market models. The NYISO has worked with Con Ed and LIPA to include their respective 138 kV facilities in the BMS market models to facilitate congestion management improvements in those franchise areas. The NYISO expects there may be additional congestion management opportunities to modeling other 100+ kV facilities throughout the state for those facilities that often require manual action to secure.

5.1. Identify candidate transmission facilities to be secured including expected contingencies

5.1.1. The NYISO shall evaluate all transmission facility thermal constraints that require out of market actions to operate reliably including, but not limited to, DARU/SRE/Out of Merit operation of a NYCA generating resource, Applications of Reliability Rules (ARRs), modification of external TTC limits, Phase Angle Regulator (PAR) adjustments, or interchange transaction contract curtailments.

5.1.2. The NYISO shall review with the local Transmission Operator (TOP) the facility constraints to be secured in the BMS market models. The NYISO and local TOP will determine whether additional operating actions are used to secure the facility (e.g. load switching, station bus sectionalizing, phase angle regulator action, etc.).

5.1.2.1. If the actions that the local TOP will take to secure the facility cannot be adequately represented in the BMS market models, then the facility under consideration shall not be secured in the BMS market models until such actions can be adequately represented

5.1.3. Before considering a facility to be modeled as secured in the market models, the NYISO shall verify that facility constraint flow development in the BMS market models is consistent with expected EMS actual constraint power flows. This step shall ensure that the market models accurately reflect expected power flows over the transmission facilities to be secured (e.g. market model flows are expected to be within 5% of EMS flows).

5.1.3.1. If constraint flow development in the BMS market models is not consistent with EMS actual constraint power flows, then the facility under consideration shall not be secured in the BMS market models until such constraint flows can be adequately represented

5.2. Confirm efficient solution options are expected to be available to the BMS market models to secure the thermal constraints in the market model.

    5.2.1. The NYISO shall verify that NYCA resources are available with a greater than or equal to 5% Resource shift factor on the constraint in either direction (i.e., dispatch generation up or dispatch generation down), and that those resources are capable of establishing an appropriate shadow price in the BMS market models.

        5.2.1.1. A generation shift factor of 5% is consistent with the North American Electric Reliability Corporation (NERC) Transmission Loading Relief (TLR) procedure that is used for interchange transaction contract curtailments and is considered by the NYISO to provide effective relief of a constraint

    5.2.2. The NYISO shall evaluate whether any NYCA resources necessary to solve the facility constraint could result in an exercise of market power if the facility is implemented in the BMS market models. If so, the NYISO shall determine if there are existing mitigation rules in place to effectively address the market power issues. If the existing mitigation rules are insufficient to address the market power concerns, the facility will continue to be secured using local TOP operating actions and be subject to the NYISO's existing market power mitigation rules (e.g. Rest-of-State Reliability Mitigation Rules).

        5.2.2.1. If existing mitigation rules are insufficient to address the market power concerns, then the facility under consideration shall not be secured in the BMS market models until further mitigation rules are developed

5.3. Identify system changes that could trigger the removal of a facility as secured in the market models

    5.3.1. The NYISO shall consider topology changes that make it no longer necessary to secure a given facility within the market models. No longer securing a facility in the market models in these instances ensures that solve times are kept within acceptable limits while ensuring that the most important facilities are included.

        5.3.1.1. For example, the frequent OOMs that originally triggered securing of the facility in the market models could be resolved by transmission facility or Resource upgrades.

5.4. Communicate to stakeholders that the transmission facility thermal constraints are now being secured, or is no longer secured, within the BMS market models.

    5.4.1. The NYISO shall include an additional column within Attachment A of the Outage Scheduling Manual to indicate that a given facility is secured within the market models

6. Scheduling Operations

This section describes the Dispatch Day scheduling process, covering the following:

- Real-Time Commitment
- Scheduling Operations Requirements
- Scheduling Operations Procedures
- Supplemental Resource Evaluation Procedures

6.1. 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 for hourly transactions. Figure 8 presents the timeline for RTC$_{15}$.

Figure 7: RTC15 Time Line
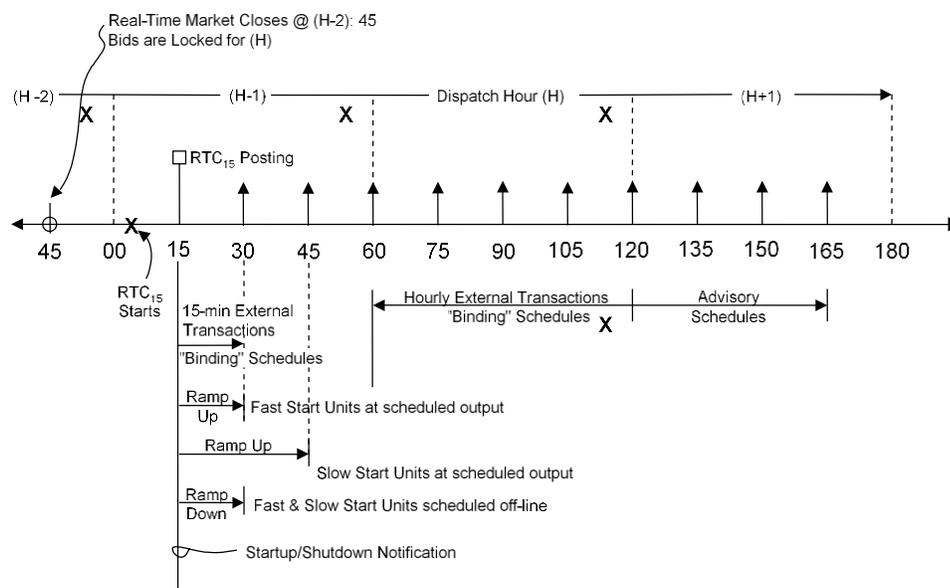
6.1.1. Real-Time Commitment Process

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 quarter 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.

Initialization Status

RTC honors all day-ahead commitments of internal generation resulting from SCUC, except for 10 and 30 minute start gas turbines. The unit statuses at the time of initialization are based on the current operating mode at the time of initialization, modified to include projected changes from the previous quarter hour's evaluation.

Startup Time

 RTC can commit units with a startup time of 30 minutes or less. For instance, units that submit a 30-minute startup time will receive a binding startup notification from the RTC that posts its results 30 minutes before the scheduled start of the unit. Units that submit a 10 to 15-minute startup time will receive a binding startup notification from the RTC that posts its results 15 minutes before the scheduled start of the unit.

Minimum Down Time

The minimum down time is honored by RTC unless a unit has a Day-Ahead Market commitment included as part of the 2 ½ hour RTC evaluation window. In this situation, RTC will automatically reset the bid minimum down time parameter at the start of its evaluation to honor the Day-Ahead commitment.

Minimum Run Time

The minimum run time values allowed in RTC can be as little as 15 minutes. The longest Minimum Run Time allowed for generators that are economically committed by RTC in the Real-Time Market shall be one hour, unless the generator is a Real-Time Minimum Run Qualified Gas Turbine. For Real-Time Minimum Run Qualified Gas Turbines, the Minimum Run Time assigned by RTC for economic commitment shall be

two hours.

Qualification for a Real-Time Minimum Run Qualified Gas Turbine

Market Participant must first qualify its unit(s) with the NYISO by submitting a completed Real-Time Minimum Run Qualified registration form. This form can be found on the NYISO web-site under Services/NYISO Registration.

The Real-Time Minimum Run qualification is intended to more appropriately represent the physical operating characteristics of a combined cycle unit. Characteristics that qualify combined cycle units for this treatment include using waste heat from the gas turbine exhaust to make steam for the generation of additional electricity via a steam turbine.

All bidding points of a Generator must qualify if that Generator is to qualify for Real-Time Minimum Run treatment. See the definition of Generator in the Market Services Tariff.

If the unit is approved, the Real-Time Minimum Run Qualified parameter will be applied by NYISO Customer Relations in the NYISO Market Information System (MIS).

Real-Time Bids to Supply Energy and Ancillary Services

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. 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. Incremental Energy Bids may be submitted by Suppliers bidding Resources using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, if not otherwise prohibited. Minimum Generation Bids and Start-Up Bids for any hour in which such Resources received a Day-Ahead Energy schedule may not exceed the Minimum Generation Bids and Start-up Bids submitted for those Resources in the Day-Ahead Market.   Provided however, a Fast-Start Resource that receives a Day-Ahead schedule may submit Minimum Generation Bids using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the dollar component of the Bids submitted in the Day-Ahead Market, or the dollar component of the mitigated Day-Ahead Bids where appropriate, if not otherwise prohibited pursuant to other provisions of the tariff. Additionally, Real-Time Minimum Run Qualified Gas Turbine Customers shall not increase their previously submitted Real-Time Incremental Energy Bids, Minimum Generation Bids, or Start-Up Bids within 135 minutes of the dispatch hour. Bids to supply Energy or Ancillary Services shall be subject to the rules set forth in the *NYISO*

Ancillary Services Manual (available from the NYISO Web site at the following URL:
https://www.nyiso.com/manuals-tech-bulletins-userhttps://www.nyiso.com/manuals-tech-bulletins-user-guidesguides.

Resources engaged in Dual Participation that are operating to meet an obligation outside the NYISO-administered markets must bid in the Real-Time market in a manner that ensures they will be dispatched by the NYISO for the market intervals consistent with the manner in which the resources operate to meet non-wholesale commitments. Resources engaged in Dual Participation must abide by all NYISO market rules. For the purposes of compliance with proposed Services Tariff Section 4.1.11, "an obligation outside the ISO-Administered Markets" is a direction from a New York Control Area ("NYCA") Transmission Owner or distribution system operator to operate a facility in a particular manner to meet a distribution system need, and/or provision of a service for which a facility is compensated by the Transmission Owner or distribution system operator. Obligations outside the ISO-Administered Markets can include providing products or services that roughly correspond to Installed Capacity obligations, directions to inject Energy or reduce demand, or to provide Ancillary Services such as Operating Reserves or frequency response, as those services are commonly understood in the markets that the NYISO administers.

An Aggregation comprising one or more Demand Side Resource and Demand Side Resources engaged in Dual Participation will not be required to submit Bids to the NYISO when the Load of that Resource modulates as a result of normal day-to-day activity (e.g., Load changes resulting from routine changes in electricity consumption due to the end of the work day or weekends), or when an Aggregation comprising one or more Demand Side Resource or Demand Side Resource reduces its Load for its own business purposes (e.g., when reducing its Load for the purposes of its own demand charge management).

Resources 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 or ISO Committed Fixed (with ISO approval). Resources 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 except for ISO-Committed Fixed which requires ISO approval. Resources 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. Resources 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. Resources 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. Resources that were scheduled Day-Ahead in NYISO-Committed Fixed mode must be in Self-Committed Fixed mode in real-time unless ISO approves a request to operate in ISO-Committed Fixed mode in real-time.

4. Resources that were scheduled Day-Ahead in Self-Committed Fixed mode may not switch to a different bidding mode in real-time except that they can switch to ISO-Committed Fixed mode in real-time with ISO approval.

Resources 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 Services Tariff, available from the NYISO Web site at the following URL: https://www.nyiso.com/regulatory-viewer .

Dispatch Options for 10-Minute Start and 30-Minute Start Generators

For all eligible Fast-Start Resources that can respond to instructions to start, synchronize to the grid, inject energy within 30 minutes, and have a minimum run time of one hour or less, modeling in the ideal pass will treat these units as dispatchable between zero and their upper operating limit except for Energy Limited Resources that are withdrawing Energy (which shall be treated as dispatchable between their lower operating limit and zero), and will relax the economic minimum operating limits of all eligible Fast-Start Resources by 100 percent for the purpose of determining LBMPs in the DAM and Real-Time Market , when marginal, and included in the idealized dispatch by RTC and RTD/RTD-CAM if the unit can pass the qualifications. See Attachment C of this Manual for examples.

Units that desire to operate in this fashion will have their bid options limited to a model that SCUC, RTC, and RTD/RTD-CAM can support.

Any unit that qualifies as a 10-Minute Start Generator can then participate in the idealized dispatch performed in real time by RTC and RTD-CAM. These units will receive forward commitments from SCUC and may be committed by RTC. These units may also be committed by RTD-CAM when needed in real time. When started, they will be ramped to their upper operating limit or lower operating limit (when applicable)and will be used in setting the LBMP when they are the marginal unit in the idealized dispatch.

Any unit that can be started within 30 minutes has the option of being qualified as a 30-Minute Start Generator. These units may receive forward commitments from SCUC and may be committed by RTC in real time.. These units may also be committed by RTD-CAM operating in maximum gen pickup mode. These

units will be used in setting the LBMP when they are the marginal unit in the idealized dispatch.

10-Minute Start Generators

Units utilizing this flexibility to participate in the markets need to be aware of the bidding requirements placed on them when deciding to qualify a unit in this fashion. Because of the special modeling requirements in Real-Time Commitment (RTC) and Real-Time Dispatch (RTD)/Real-Time Dispatch-Corrective Action Mode (RTD-CAM) for 10-minute start units, units that are qualified for this option will need to coordinate with the NYISO if they wish to be treated as a 10-minute start generator.

A unit that is designated as a 10-minute start unit will be considered Flexible in real time, but Off-Line until either RTC or RTD-CAM dispatches the unit. When RTC/RTD-CAM decides the unit should be started, the unit will be turned on and ramped over a nominal 10-minute interval to the upper operating limit or lower operating limit (when applicable). The unit will remain on for as long as needed or for a minimum period. Because RTD-CAM is making an instantaneous decision on starting the unit versus looking at the need for the unit over some longer time period, the NYISO has set and will guarantee the minimum run time for one hour. 10-minute start units will also be allowed to bid a start-up, minimum generation and energy price in the Day-Ahead Market or Real-Time Market.

Requirements:

- Pre-qualified as 10-Minute Generator

- Check ISO-Committed Flexible in Real Time

- Start-up time = 0 minutes

- Start-up cost = per bidder in DAM or Real Time

- Minimum Generation level = per bidder in DAM or Real Time (subject to other bidding rules as described in MPUG 7.4.1)

- Minimum Generation cost = per bidder in DAM or Real Time

- Minimum Run Time <= 1 hour

Units have the flexibility to bid start-up costs on an hourly basis, for each hour of the day, or by a curve that relates the start-up cost to the elapsed time since shutdown. Hourly startup costs, if bid, take precedence over the startup cost curve related to hours off-line.

All programs determine if the unit is a marginal unit, where the desired operating point would be between zero and the upper limit or between their lower limit and zero (when applicable), and allow the unit to set the LBMP. All bids are passed to RTC and RTD/RTD-CAM regardless of whether they are

actually scheduled by SCUC.

In addition to energy, 10-minute start generators can bid only 10-minute non-synchronous reserve. 10-minute start units may not bid the other types of reserve or regulation.

30-Minute Generators

Generators utilizing this flexibility to participate in the markets need to be aware of the bidding requirements placed on them when deciding to qualify a unit in this fashion. Because of the special modeling requirements in RTC/RTD-CAM for 30-Minute Generators, units that may qualify for this option will need to coordinate with the NYISO on how they would like to be treated.

A unit that is designated as a 30-Minute Generator will only be scheduled by RTD or RTD-CAM if it has been selected by RTC or RTD-CAM (operating in the max gen pickup mode). The difference between a normal fixed unit bid and a 30-minute generator is the 30-minute generator provides a dispatch bid for RTD or RTD-CAM to determine if the unit is marginal in an idealized dispatch and thus set the LBMP. The unit will remain on for as long as RTC or RTD-CAM (operating in the max gen pickup mode) has committed the unit.

Requirements:

- Pre-qualified as 30-Minute Generator

- Check ISO-Committed Flexible in Real Time

- Start-up time <= 30 minutes

- Start-up cost = per bidder

- Minimum Generation level = per bidder in DAM or Real Time (subject to other bidding rules as described in MPUG 7.4.1)

- Minimum Generation cost = per bidder in DAM or Real Time

As with 10-minute start units, these units will be evaluated based on the bid curve between zero and upper operating limit, except for Energy Limited Resources that are withdrawing Energy (which shall be treated as dispatchable between their lower operating limit and zero). SCUC, RTC, RTD and RTD-CAM determine if the unit is a marginal unit in the idealized dispatch, where its operating point would be between zero and the upper limit or between their lower limit and zero (when applicable), and, if so, allow the unit to set the LBMP. Only RTC-scheduled units are passed to RTD.

ESR (Energy Storage Resources)

Real-Time Dispatch will review each Energy Storage Resource's Beginning Energy Level in each interval. Real-Time Dispatch will attempt to prevent dispatching a Self-Managed Energy Storage Resource in a manner that would be infeasible based on its Beginning Energy Level.

Instead, Real-Time dispatch will consider an Energy Storage Resource's Beginning Energy Level in developing a schedule for the binding interval.

An Energy Storage Resource's Beginning Energy Level will be used to ensure that Operating Reserves scheduled from the Resource can be sustained for one hour if the Operating Reserves are converted to Energy.

CSR (Co-located Storage Resources)

Schedules awarded to CSR Generators represent the desired output from these units at the Point of Injection (POI). The Market Participant will be responsible for determining the dispatch level for each generator to achieve the schedule awarded at the POI by incorporating appropriate conversion losses between the POI and each Generator. The MW telemetry from CSR Generators shall represent their equivalent output at the POI. Aggregations comprised of ESRs, Wind, or Solar only are not permitted to participate in a CSR.

The sum of (a) the Energy injection schedule(s) minus the Energy withdrawal schedule, (b) the Operating Reserve schedule, and (c) the Regulation Capacity schedule(s) for a set of CSR Generators will ordinarily be less than or equal to the applicable CSR injection Scheduling Limit. The sum of (a) the Energy withdrawal schedule minus the Energy injection schedule(s), and (b) the Regulation Capacity schedule(s) for a set of CSR Generators will ordinarily be less than or equal to the applicable CSR withdrawal Scheduling Limit.

The NYISO may relax a CSR Scheduling Limit when it is in direct conflict with other limits. Conflicting limits are expected to be a response rate, upper storage limit (USL), lower storage limit (LSL), upper operating limit or lower operating limit of a CSR Generator. In all cases, the NYISO will relax the CSR Scheduling Limit by the minimum amount and for the shortest time period necessary to resolve the conflict.

When total CSR schedules approach the CSR injection Scheduling Limit, the solar or wind IPR unit will be instructed not to exceed its economic basepoint. This instruction will be communicated via a Wind and Solar Output Limit flag. A Wind and Solar Output Limit on the IPR unit will be set when the following conditions are met:

- Condition 1: ESR unit either has a non-zero ancillary services award or a positive energy

schedule; and

- Condition 2: The sum of the CSR Generators' Energy, Operating Reserves , and Regulation Service schedules is greater than or equal to a threshold (X %) times the CSR Injection Limit

Additional information on Wind and Solar Output Limits can be found in NYISO Technical Bulletin 154.

15 Minute Scheduling of Internal Generation

NYISO qualified non-flexible generators have an option in the Real-Time Market to bid economically using the *ISO-Committed Fixed* mode. Market Participants using this option must convert to *ISO-Committed Fixed* their Day-Ahead Market bids (if any), that have rolled into the Real time Market in the default *Self-Committed Fixed* mode. These bids will be evaluated by RTC so its schedule will better follow Real-Time energy prices. If these bids are accepted they will receive a market-based schedule that is fixed for each 15-minute segment of the hour and will be honored in RTD.

Resource Qualification

A Market Participant must first qualify its unit(s) with the NYISO via its Customer Representative.

15-minute scheduling is intended to provide economic scheduling opportunities for units that are currently operating at pre-specified fixed output schedules. Qualification for 15-minute scheduling includes, but is not limited to, having submitted 100% of available bid opportunities as either Self-Committed-Fixed, or ISO Committed-Fixed, in the Day-Ahead Market (which converts to Self-Committed Fixed in real-time) for a period of at least six (6) contiguous months.

Resources that do not have the communications systems, operational control mechanisms or hardware to be able to respond to five-minute dispatch basepoints may also be eligible for 15 minute scheduling.

Temporary equipment problems affecting Resources that do not meet the above standards do not make them eligible for 15-minute scheduling.

If the unit is approved, its 15-minute scheduling parameter, also known as a "qualified-to-bid" flag, will be set to Y (Yes) by the Customer Representative in the NYISO Market Information System (MIS). The term used for such approved and flagged units are "15-minute Resources/units."

Bidding and Scheduling Rules

It follows from the qualification constraints mentioned above that for **both** the Day-Ahead (DAM) and

Real-Time (RT) Markets, 15-minute Resources must submit **either** *ISO-Committed Fixed* or *Self-Committed Fixed* bids. In the RT Market these units may still self-schedule in 15-minute blocks using the *Self-Committed Fixed* mode, but to be scheduled economically by the NYISO they must bid in, and be accepted, as *ISO-Committed Fixed*. Again, *ISO-Committed Flexible* and *Self-Committed Flexible* bids will **not** pass MIS bid validation in either market for 15-minute units. No DAM schedule is necessary to bid in the RT Market for 15-minute Resources. The table below summarizes the allowed combinations of DAM and subsequent RT bids:

Day-Ahead Mkt 15m gens.	Real-Time Market - 15-minute Resources			
	ISO-Committed Flexible	Self-Committed Flexible	Self-Committed Fixed	ISO-Committed Fixed (15 minute qualified)
ISO-Committed Fixed	No	No	Yes	Yes - see Note below
Self-Committed Fixed	No	No	Yes	Yes - see Note below
15m units with No Day-Ahead Schedule	No	No	Yes	Yes
Note: Upon posting of the Day-Ahead market, the Day-Ahead schedule for each 15-minute Resources (like other fixed Resources) is used to pre-populate (initialize) its Real-Time bids in the *Self-Committed Fixed* mode, no matter which of the two *fixed* modes is used in the DAM. **Therefore:** If a 15-minute generator with a DAM schedule intends to bid in RT as *ISO-Committed Fixed*, it **must**, for each hour desired, convert its *Self-Committed Fixed* RT bids in the MIS using the radio buttons in the "Unit Operations" box on the Generator Bid screen. Initial bids and bid modifications may be entered in the MIS through the upload process.				

Consistent with all RT bidding rules, this may be done from when the DAM schedule has posted until 75 minutes before the operating hour.

This conversion option is available only to 15-minute Resources and will be subject to the standard RT Market validation rules for adjusting DAM bids that have rolled into the RT market:

1. The Minimum Generation MW must be equal to bid Min Gen MW from the accepted DAM bid.

2. The Upper Operating Limit-Normal (UOLn) must be greater than or equal to the UOLn from the accepted DAM bid.

3. The UOLn must be greater than or equal to the sum of DAM accepted energy, reserves, and regulation schedules.

4. The Upper Operating Limit-Emergency (UOLe) must be greater than or equal to the sum of the DAM accepted energy, reserves, and regulation schedules.

5. Incremental Energy Bids may exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, if not otherwise prohibited.

6. The RT Startup Cost must be less than or equal to the accepted DAM bid startup cost.

7. The RT bid Minimum Generation Dollars must be less than or equal to the accepted DAM bid minimum generation cost.

8. RT bids must not have any dollar value, including $0, in the reserve or regulation fields. Only null dollar amounts are acceptable. In other words, no reserve or regulation will be awarded to 15-minute scheduled units.

> **Note:** Please see the Market Participant User's Guide, Section 6, for bid rules on generator operating modes for those units **not** qualified to bid 15-minute scheduling.

Bids Associated with Internal and External Transactions

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

Sink Price Cap Bids, Decremental Bids and CTS Interface Bids to schedule 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 cover a one-hour period and must start and stop on the hour. Intra-hour modifications to External Transaction Bids will not be accommodated. Schedules associated with External Transactions will be established based on the schedule type indicated on the submitted bid (Hourly vs Intra-hour), as well as on the scheduling frequency supported by the associated Proxy Generator Buses, as outlined in the tariff.

Internal Bilateral Transactions involving Trading Hubs must be part of a balanced set for the Trading Hub Energy Owner by the time the respective market closes. In order for a Trading Hub Energy Owner to have a balanced set, that Trading Hub Energy Owner must source the same amount of megawatts as it sinks at that zonal Trading Hub in a given market and hour. If an Internal Bilateral Transaction involving a Trading Hub is not part of a balanced set, it will not be scheduled.

Self-Commitment Requests

Self-Committed Flexible Resources, including Resources engaged in Dual Participation, 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 will schedule External Transactions based on the schedule type indicated on the submitted bid (Hourly vs Intra-hour), as well as on the scheduling frequency supported by the associated Proxy Generator Buses, as outlined in the tariff. RTC_{15} will establish binding schedules for hourly transactions for the next hour and each RTC run will establish binding schedules for intra-hour transactions for the period beginning fifteen minutes after the scheduled posting time of each RTC run as part of its development of a co-optimized least-bid cost real-time commitment. The RTC evaluation includes limitations for both quarter-hour and top-of-the-hour scheduling changes. External Interface Interchange Ramp Capacity Limits are available from the NYISO website at the following URL:

https://www.nyiso.com/documents/20142/3694424/External_Interface_Interchange_Ramp_Limits.pdf/00782f62-bcfc-703e-bf00-15904977647d

Posting Commitment/De-Commitment and External Transaction Scheduling 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 economic hourly External Transactions to run during the entirety of the next hour.

6. Schedule economic 15-minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus.

7. Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and

8. Issue real-time schedules for resources in ISO-Committed Fixed mode.

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 hourly External Transactions scheduled by RTC_{15} to flow in the next hour should flow, or inform the NYISO that hourly External Transactions may need to be reduced.

6. Schedule economic 15-minute External Transactions , for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus.

7. Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at CTS Enabled Proxy Generator Buses; and

8. Issue real-time schedules for resources in ISO-Committed Fixed mode.

External Transaction Settlements

RTC will calculate the External Interface Congestion component of the Real-Time LBMP for all External Transactions if constraints at the interface associated with that External Transaction are binding. In addition, RTC will calculate the External Interface Congestion component of the 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 will also calculate the External Interface Congestion component of the Real-Time LBMPs at certain times at Non-Competitive Proxy Generator Buses.

1. Any External Interface Congestion calculated by RTC will be added to the Marginal Cost of Internal Congestion calculated by RTD to determine the total Marginal Cost of Congestion that will be reflected in the RTD LBMP at a Proxy Generator Bus that is not a Non-Competitive Proxy Generator Bus or a Proxy Generator Buses associated with a designated Scheduled Line. Additional detail regarding the calculation of real-time prices at Proxy Generator Buses appears in:

a. Section 17.1.6 of the Services Tariff.

b. The Coordination Agreement Between ISO New England Inc. and New York Independent System Operator, Inc, Section 37 of (Attachment EE to) the NYISO OATT, Schedule D

6.1.2. 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 an amount specified by the Market Mitigation Measures (defined in Attachment H of the NYISO Services Tariff, available from the NYISO Web site at the following URL:

https://www.nyiso.com/regulatory-viewer), the conduct test is said to have "tripped."

The AMP LBMP impact test examines the change in prices that would prevail if conduct-failing offer prices were mitigated. This test "trips" if mitigation of conduct-failing offers would change prices by an amount specified by the Market Mitigation Measures (defined in Attachment H of the NYISO Services Tariff. A variation of the first impact test applies to designated "Constrained Areas" when the transmission system is congested and "trips" if the change in LBMP exceeds an amount specified by the Market Mitigation Measures (defined in Attachment H of the NYISO Services Tariff.

This first impact test will be performed following a full recommitment and dispatch.

There are many rules, parameters, limits, and thresholds that have been defined associated with the automated mitigation 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 the automated mitigation process.
4. Portfolio exclusion that may be applied to super-zones and load pockets.
5. Definition of the specific units subject to the automated mitigation process.

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 is executed as a separate process so they can be run in parallel as shown in Figure 9. The advantage is that a full RTC cycle (15 minutes) can be used to evaluate impact; hence, timing concerns are minimized. The possibility of mitigation is tested for the next RTC cycle (15 minutes) in the future. RTC_{15} and $RT\text{-}AMP_{15}$ perform unit commitment evaluations simultaneously. Results of RTC_{15} and RT-AMP15 are then evaluated for impact and, if mitigation is necessary, mitigated offers are sent to RTC_{30}. Mitigation of offers for RTC15 (if any) was determined previously by $RT\text{-}AMP_{00}$.

Figure 8: RTC_{15} Time Line
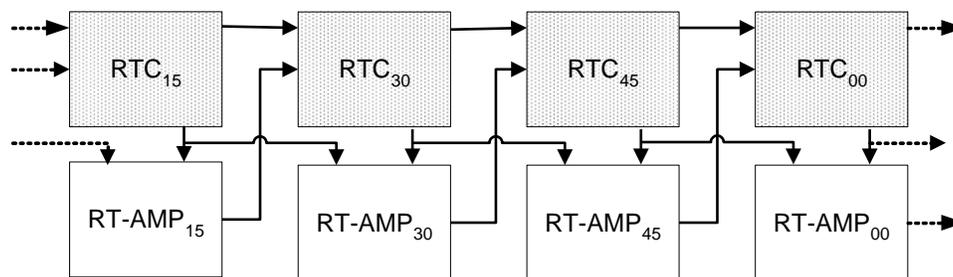
A third unit commitment is required to assure that prices and schedules are consistent with the final set of offers, some of which may be mitigated. Because the test is conducted in parallel, only one, instead of two, additional unit commitment is required in each RTC cycle. As shown in Figure 10, for the time period 15 to 30, Base-Set and Mit-Set are identical. RTC_{15} provides the base case unit commitment. Simultaneously $RT\text{-}AMP_{15}$ calculates the reference unit commitment, conducts the impact test, and determines the actual set of resources whose offers are to be mitigated (MitSet). Finally, RTC_{30} ensures that the commitment is

consistent with the set of mitigated offers. Subsequently the Mit-Set is used as the Base-Set and RTC_{30} would provide the base case for RTAMP30.

Figure 9: Parallel Impact Test 15 to 30 Minutes
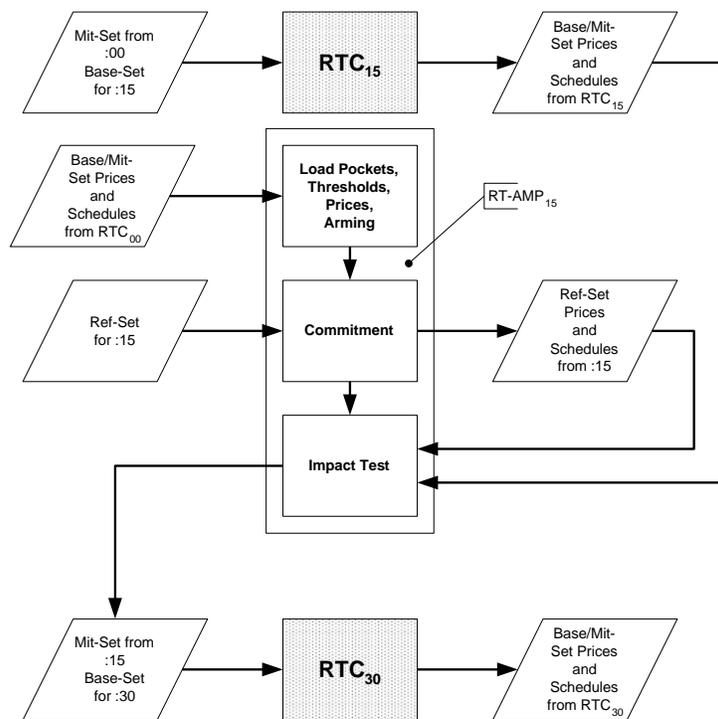
Conduct Test

The conduct tests compare offers of suppliers for start-up, minimum generation, and incremental energy with reference levels for each of those bids. Differences are compared to the thresholds set forth in Attachment H of the NYISO Services Tariff to determine whether conduct suggests the possible economic withholding of resources or a possible attempt to exercise market power. A subsequent impact test determines if conduct-failing bids (or bid components) had the requisite market impact, and should be mitigated.

An energy resource may be associated with several load pockets, each of which has a threshold value. In such a case, conduct is tested using the threshold value(s) for all load pockets in which the resource is located. The arming test later selects the appropriate conduct test results to use to determine if mitigation is appropriate.

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.

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) exceeds an amount specified by the Market Mitigation Measures (defined in Attachment H of the NYISO Services Tariff.

Mitigation Duration

For purposes of settlement, Mitigation is applied for whole hours, when impact is determined for any interval of that hour. For dispatch purposes, mitigation is applied for the remainder of the current hour and/or all of the next hour, following a determination of impact. For dispatch purposes both RT-AMP$_{15}$ and RT-AMP$_{30}$ are able to mitigate offers for all or part of 2 hours. RTAMP$_{45}$ is able to mitigate offers for the "next" hour. RT-AMP$_{00}$ is able to mitigate offers for part of an hour. Mitigated offers are used by both RTC and RTD.

6.1.3. Real-Time Commitment Information Posting

The public information and secure Market Participant data 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. Updated ATCs and TTCs for each RTC execution.
2. Advisory prices for Zones and Generators.

Secure Data to Market Participant

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 interval.
2. Advisory MW commitment schedules for generators for each RTC 15-minute increment beyond the time frame covered by RTD.

6.2. 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

- Interchange Scheduling

- 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.

6.2.1. 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. 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 RTC or SRE or day ahead for potential commitment by SCUC.

The NYISO may augment, as necessary, the Day-Ahead commitment schedules to achieve a reliable next-day schedule by performing a Supplemental Resource Evaluation (SRE). The NYISO may use the following resources:

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
2. New Bids from all Suppliers, including those in neighboring systems
3. Cancellation of/or rescheduling of transmission facility maintenance outages where 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. The procedures for supplemental resource evaluation for energy and ancillary services are covered in this Manual.

6.2.2. 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 RTC

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

1. ***Desired Net Interchange (DNI):*** This calculation provides the net interchange schedule between the NYCA and each of the External Control Areas.
2. ***Instantaneous ANI:*** This is the metered control area interchange between the NYCA and each of the External Control Areas.

DNIs that 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.

How IS+ is Used for Real-Time Transaction Curtailments

IS+ allows NYISO Dispatchers to review and confirm the transaction schedules with the neighboring control areas. In addition IS+ is used to monitor ongoing energy transactions and to adjust transactions in real time to address security problems.

The IS+ curtailment process includes consideration of:

- Curtailment Types

- Sorting Order of Transactions

- Curtailment Options

6.2.2.1. Description of Curtailment Types

Interface Curtailment

This curtailment is used for NYISO security to relieve an overloaded transmission interface.

Only transactions whose curtailment would reduce overloads on an interface in an amount equal to 5 percent or more of the flow scheduled in conjunction with the transaction will appear on the list of transactions that may be curtailed for this reason.

Locational Curtailment

This curtailment is used to relieve an overloaded boundary interface between the NYCA and an adjoining Control Area. All transactions that meet the locational selection criteria will be included on the list

ICAP Curtailment

This curtailment is used to curtail transactions for NYISO reserve or capacity deficiencies. ICAP curtailment will display any export transaction that has a source generator within the NYCA with ICAP

obligations in the NYISO's ICAP market, as well as any LBMP export transactions.

Ramp Constrained Curtailment (In or Out)

The typical scenario that requires a ramp curtailment is due to transaction mismatches identified during the checkout process with the External Control areas. The mismatches subsequently result in a DNI change that would violate the NYISO ramping ability for the next hour's schedule. Ramp-In or Ramp-Out (depending on the direction needed) will display all transactions either coming from or going to all of the External Control areas.

Externally Initiated

This type of curtailment occurs when a neighboring control area initiates the curtailment. All transactions active with that control area are displayed and curtailments are made manually as dictated by the initiating external control area.

6.2.2.2. IS+ Sorting Order for Transaction Curtailments

The order in which transactions are displayed in IS+, and subsequently curtailed under the Ranked or NERC Curtailment Option, is as follows:

1. NERC Priority (Lowest to Highest)
2. Federal Contracts (Y/N with Non-Federals First)
3. Economic Ranking Criteria For each transaction type the Economic Ranking Criteria is defined as:
   Imports: Decremental Bid cost value associated with latest schedule (Highest to Lowest).
   Exports: Sink Price Cap Bid cost value associated with latest schedule (Lowest to Highest).
   Wheels: Decremental Bid cost value associated with latest schedule (Lowest to Highest).
4. Date and Time that the bid was submitted (Last one in to First one in)

6.2.2.3. Description of Curtailment Options

The NERC prorating option will normally be used when making transaction curtailments, as time permits. The Ranked option, which does no prorating, may be used in situations where it is necessary to implement a curtailment within a time constraint. The Manual option is normally used when an external control area initiates a curtailment and the NYISO is curtailing transactions based on that external control area's selection.

Ranked

When the Ranked Option is used, the ISO will sequentially proceed through in the list of transactions that may be curtailed, using the sorting order described above. The ISO will reduce the amount of

transmission service scheduled in conjunction with each transaction to the greater of zero or the amount necessary to obtain the desired amount of relief.

NERC

When the NERC Option is used, the ISO will sequentially proceed through the list of transactions that may be curtailed, using the sorting order described above, except that the timestamp criterion is not used to determine the sorting order. As a result, multiple transactions may be tied in the sorting order. The ISO will reduce the total amount of transmission service scheduled in conjunction with each transaction (or group of transactions, if they are tied in the sorting order) to the greater of zero or the amount necessary to obtain the desired amount of relief. In the event that transmission service for a group of transactions that is tied in the sorting order is reduced to some level that is greater than zero, the reductions in transmission service will be prorated among all transactions in that group in proportion to the amount of transmission service scheduled in conjunction with each transaction

Manual

The Manual option allows for the manual selection of individual transactions for curtailment as well as the manual entry of a new MW amount for each transaction to be curtailed.

6.2.2.4. Curtailment Types and Inputs in IS+

The basic inputs to any curtailment performed by the NYISO Dispatchers are as follows:

1. Select the Curtailment Type (Interface, Locational, ICAP, Ramp Constrained In, Ramp Constrained Out or Externally Initiated by a Neighboring Control Area).
2. Enter the time that the curtailment will take effect.
3. Enter the amount of curtailment (Either the desired amount of Interface Relief or the Total Transaction MW curtailment amount).
4. Select the Interface to be unloaded or the Control Area(s) to curtail with.
5. Enter the curtailment option (Ranked, NERC, or Manual).

IS+ then displays all transactions that meet the input criteria and are presorted in the correct order. The order is NERC priority, Federal Contract Status, Economic Ranking Criteria and Time Stamp. From the entire list of transactions that are displayed, the program will automatically select for curtailment, only as many transactions as is needed to obtain the desired curtailment amount.

Some inputs described above will be dependent on the curtailment type that is selected in the first step. For example, Interface Curtailment requires the Dispatcher to select a specific NYISO Interface to unload whereas Locational Curtailment requires the selection of a Control Area or Control Areas with whom to perform the curtailment. Externally Initiated curtailments require that the Dispatcher select the initiating control area and the manual curtailment option since the transactions to be curtailed will be

selected by the other control area.

Curtailment Notifications from IS+

When a curtailment is made, IS+ will send a transaction specific email notification to the owner of each affected transaction. In addition, a generic curtailment message will be posted in real-time to the Market Data-Reports/Info-NYISO Operational Announcements page of the NYISO website at:

https://www.nyiso.com/reports-information The following is a complete list of sample messages that may be posted on the NYISO website when a curtailment is performed with IS+:

NYISO Initiated Curtailment Messages

- NYISO Locational based curtailment cut 100 MWs

- NYISO Emergency Transaction added 10 MWs

- NYISO ICAP curtailment cut 5 MWs

- NYISO Ramp-In curtailment cut 50 MWs

- NYISO Ramp-Out curtailment cut 25 MWs

- NYISO Interface based curtailment cut 50 MWs, Impact on selected interface DYSINGER EAST is: 25 MWs

- NYISO Reinstatement added 5 MWs

External Control Area Initiated Curtailment Messages

- HQ initiated curtailment cut 28 MWs

- NPX initiated curtailment cut 28 MWs

- OH initiated curtailment cut 1 MWs

- PJM initiated curtailment cut 50 MWs

6.2.3. Scheduling and Curtailment of Bilateral Transactions

Firm transactions into or out of the NYCA will be scheduled based on economics and Available Transmission Capacity. A load being supplied by a Firm Import transaction or from an internal generator will have a financial schedule equal to the amount of transmission service scheduled. If the Import is curtailed, or the internal Generator is dispatched below the amount of the transaction, the Load will be supplied with Energy from the LBMP Market. A generator supplying a Firm bilateral transaction, either internally or for export, will have an operational physical schedule based upon its Energy offer. 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 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. Financial schedules that differ in real-time from those scheduled DayAhead will balance the differences in the real-time LBMP Market (*i.e.* the balancing 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 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:

- Figure 11: Scheduling and Physically Curtailing Firm Bilateral Transactions

- Figure 12: NYISO Curtailment Steps

- Figure 13: Re-Instatement of Curtailed Bilateral Transactions

- Figure 14: Transaction Conversion and Curtailment Notifications Required by NYISO

- Figure 15: Scheduling and Dispatching LBMP Suppliers and Loads

Figure 10: Scheduling and Physically Curtailing Firm Bilateral Transactions

	Internal Source				External Source			
Summary Table — Scheduling and Physically Curtailing Firm Bilateral Transactions	**Internal Load**		**External Load (Export)**		**Internal Load (Import)**		**External Load (Wheel-Through)**	
	(1) Transmission Service: **Financial Transaction Schedule**	**(2)** Transaction Source: **Operational Physical Schedule**	**(3)** Transmission Service: **Financial Transaction Schedule**	**(4)** Transaction Source: **Operational Physical Schedule**	**(5)** Transmission Service: **Financial Transaction Schedule**	**(6)** Transaction Source: **Operational Physical Schedule**	**(7)** Transmission Service: **Financial Transaction Schedule**	**(8)** Transaction Source: **Operational Physical Schedule**
A. DayAhead	Set to full Requested MW Amount submitted in transaction bid	Source Scheduled economically based on submitted energy offer Supplier buys in LBMP market for shortfall	Up to Full Requested Amount Based on Day-Ahead transaction bids Limited to Applicable ATC*. *	Source Scheduled economically based on submitted energy offer Supplier buys in LBMP market for shortfall Total Exports Limited to ATC	Full Requested MW Amount submitted on transaction bid	Up to Day-Ahead Financial Schedule based on the economics of the transaction bid. Total Imports Limited to ATC un-economic Suppliers not scheduled; Transmission Customer buys LBMP	Up to Full Requested MW based upon Source's Day-Ahead WheelThrough Dec. Bid with Total Imports and Exports Limited to Applicable ATC*.	Same as Financial Transaction Schedule
B. HourAhead	Same as above for comparable Day-Ahead case *except* using Hour-Ahead bilateral schedule requests *and* no Forward Commitment is issued*.							
C. DayAhead or HourAhead Schedule Supplier is Uneconomic in RealTime	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed	Supplier Dispatched Down in Real-Time. Supplier buys in LBMP market for shortfall	Day-Ahead Schedule and TUC are Fixed; Real-Time Schedule is Fixed	Supplier Dispatched Down in Real-Time. No change in DNI takes place. Supplier buys in LBMP market for shortfall	Day-Ahead Schedule and TUC are Fixed; Real-Time Schedule is Fixed.	External Suppliers reevaluated in Real-Time; change in DNI may take place. Real-Time uneconomic Suppliers not scheduled; Transmission Customer buys LBMP market for shortfall	Day-Ahead Schedule and TUC are Fixed; Real-Time Schedule and TUC are also Fixed.	No Re-Dispatch of Supplier and no change in DNI takes place Real-Time, un-economic Suppliers not scheduled; Transmission Customer balances any day-ahead TUC charges at real-time LBMP prices

D. Security Violation Occurs in Real-Time	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed	Supplier 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 Down and/or decommitted in Real-Time if Needed. No Change 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 ReScheduled Down ("Curtailed") in Real-Time if Needed; DNI also changed. No Change in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures	Day-Ahead TUC balanced at RT TUC prices if curtailed	Supplier ReScheduled Down ("Curtailed") and Energy Transaction is curtailed in Real-Time if Needed; DNI changed to reflect both curtailments.
E. A scheduled DayAhead Transaction is Self Canceled (Withdrawn) by Supplier (Source) or LSE (Sink) Prior to HAM evaluation	Day-Ahead Schedule and TUC are Fixed; transaction cannot be withdrawn	Economic bid of source may be modified and the source will be scheduled based on the economics of the revised bid	Day-Ahead Schedule and Price are Fixed; Real-Time Schedule is set to 0 .	Source and Sink update schedule in RTC. DNI is changed (in Real-Time).	Day-Ahead Schedule and Price are Fixed; Real-Time Schedule is set = 0.	Source and Sink update schedule in RTC. DNI is changed.	Day-Ahead Schedule and Price are Fixed; Real-Time Schedule is set = 0	Source and Sink update schedule in RTC. DNI is changed. to reflect both curtailments

* 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.

In general, 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.

Figure 11: NYISO Curtailment Steps

Corresponding TLR Level	Minimum NERC Required Action
TLR 1	Notify Reliability Coordinators of potential SOL or IROL Violations
TLR 2	Hold transfers at present level to prevent SOL or IROL Violations
TLR 3a	Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service
TLR 3b	Curtail Interchange Transactions using Non-firm Transmission Service Arrangements to mitigate a SOL or IROL Violation
TLR 4	Reconfigure Transmission
TLR 5a	Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-toPoint Transmission Service
TLR 5b	Curtail Interchange Transactions using Firm Point-toPoint Transmission Service to mitigate an SOL or IROL violation
TLR 6	Emergency Procedures
TLR 0	TLR concluded

Figure 12: Re-Instatement of Curtailed Bilateral Transactions

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

Figure 13: Transaction Conversion Curtailment Notifications Used by NYISO

Transaction Conversion and Curtailment Notifications Used by NYISO	
Action	**Notification**
Physical curtailment (through DNI schedule change) of Inter-Control Area Non-Firm transactions (TLR 2c)	Automatic E-Mail to financially responsible party; 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)
Physical curtailment (through DNI schedule change) of Firm External Source to Internal Sink Transaction (Import)	Automatic E-Mail to financially responsible party. 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)	Automatic E-Mail to financially responsible party. 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)	Automatic E-Mail to financially responsible party. 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)	

Figure 14: 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. DayAhead	Based on Day-Ahead Bids	Same as Day-Ahead Financial Schedule	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	Full Requested Amount or Based on Day-Ahead Bids for Price Capped Loads*. Total Exports Limited to ATC.	Same as Day-Ahead Financial Schedule

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
B. HourAhead	Based on Hour-Ahead Incremental Bids	Dispatched in Real-Time	Not Available		Based on Hour-Ahead Incremental Bids with Total Imports Limited to ATC	Same as Financial Schedule	Full Requested Amount Based on Hour-Ahead Bids for Price Capped Loads* with Total Exports Limited to ATC	Same as Financial Schedule
C. DayAhead or HourAhead Supplier is Uneconomic in RealTime	Day-Ahead Schedule and Price are Fixed; differences settled in real-time	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; HourAhead DNI schedule are Fixed for hourly transactions.	
D. Security Violation Occurs in Real-Time	Day-Ahead Schedule and Price are Fixed	Supplier Dispatched Down and/or decommitted 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 and Intrahour Schedule is Fixed.	Supplier ReScheduled Down ("Curtailed") in Real-Time if Needed; Also DNI is changed	Day-Ahead Schedule and Price are Fixed; Hour-Ahead and Intrahour 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. DayAhead or HourAhead Schedule is Self	Day-Ahead Schedule and Price are Fixed	Supplier updates schedule in RTC; NYISO updates RTD or	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	Day-Ahead Schedule and Price are Fixed	LSE updates schedule in RTC; NYISO updates DNI

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
Canceled by Supplier or LSE		Outage Scheduler				Outage Scheduler		

* 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.

NYISO Actions during Neighboring Control Area Transmission Loading Relief (TLR) Events

When TLRs are declared by neighboring control areas, specific transactions are curtailed to provide transmission relief in real-time using Interchange Scheduler (see section 5.2.2 in this manual, How IS+ is used for Real-Time Transaction Curtailment). If the TLR is still in effect for subsequent RTC runs, then the NYISO will take the following actions:

- Real-Time Market (RTM)[1] transactions that negatively impact the TLR flowgate are not evaluated for scheduling by RTC.

- All remaining RTM transactions continue to be evaluated normally.

- DAM transactions previously curtailed by the TLR will no longer be evaluated.

- The normal RTC evaluation protocol for scheduling for all RTM transactions resumes after the TLR is terminated.

The NYISO's procedures take advantage of RTM scheduling capabilities; i.e., RTM transactions associated with a TLR flowgate are proactively removed from consideration by RTC. This, in turn:

- Promotes a reliable dispatch, as in-hour TLR curtailments could be larger than NYISO operating reserve requirements.

- Minimizes potential for disruptive market operations due to in-hour transaction curtailments.

- Minimizes the need for curtailing additional DAM transactions as a result of a continued TLR event that could result from additional transaction curtailments.

- Reduces the likelihood that RTC will schedule transactions that are uneconomic in real time.

For the purposes of this procedure, DAM transactions include all transactions that were scheduled and clear DAM Checkout regardless if the real-time bid for that transaction has been modified prior to the RTC evaluation.

External Transaction Scheduling Messages and Curtailment Notification

RTC Evaluation:

External firm transaction bids in the Real-Time are evaluated by RTC according to the economics of their decremental bids for imports or their sink price cap bids for exports. The quantity of transactions accepted is subject to NYISO transfer capabilities and the ramp rates within the system.

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[1] The Real-Time Market (RTM) includes all transactions other than Day Ahead Market (DAM) transactions

The RTC process begins with an initial unconstrained unit commitment. The RTC program will then iterate between the Security Analysis (SA) module and the Unit Commitment (UC) module to solve all constraints. Once a solution has been reached, the results will be a final security constrained dispatch.

The RTC evaluation will produce one or more of the following messages for each external transaction in the Market Information System (MIS).

Firm Transactions:

Z	Not Evaluated
E	Evaluation fully accepted transaction
U	Evaluation fully rejected uneconomical transaction
M	Evaluation partially accepted marginal cost transaction
S+	Evaluation partially to fully accepted transaction due to security
S-	Evaluation partially to fully rejected transaction due to security
D	Evaluation partially to fully rejected transaction due to DNI ramp constraint

The transaction messages are determined by RTC in a simplistic method, by comparing the initial unconstrained schedule with the final security constrained schedule. Neither LBMPs nor the bid prices are reviewed when determining the flags.

"Z" - If the transaction was not available for RTC to evaluate, then the transaction is flagged as unavailable "Z". A valid transaction will typically be unavailable for an RTC evaluation in one of two cases: a) if the transaction has zero MWs to evaluate due to a de-rate by the MP, NYISO, or the external control area prior to the evaluation, or; b) if the transaction would be undeliverable due to a transmission outage that prevents interchange schedules from flowing across the path specified by the transaction. In both of these cases, the transaction will not be included in the RTC evaluation, and as a result, will not receive a schedule in real-time.

"E" - If the transaction was fully scheduled (schedule energy = bid energy) during both the unconstrained and secure dispatches, then the transaction is flagged as economic "E".

"U" - If the transaction was not scheduled (schedule energy = 0) during both the unconstrained and secure dispatches, then the transaction is flagged as uneconomical "U".

"M" - If the transaction is not fully scheduled (0 < schedule energy < bid energy) but has the same dispatch for both the unconstrained and secure dispatches, then the transaction is flagged as marginal "M". Typically, transactions will only be flagged as marginal when there are no constraints developed. Otherwise, the transaction will be at different schedules for the unconstrained and secure dispatches.

"S-/+" - If the transaction schedules are different for the unconstrained and secure dispatches, then the transaction is flagged as moved for security "S". If in response to solving for constraints the transaction schedule was increased, the transaction is flagged as "S+". If in response to solving for constraints the transaction schedule was decreased, the transaction is flagged as "S-". Typically most constraints are developed for a generation deficient area of the network. With this type of constraint, generation will be increased in the deficient area to solve the constraint. To satisfy the load/generation balance some other resource (generator or transaction) will have to be decreased. The flag will be marked as security for transactions that are moved to solve the constraint directly. The flag will also be marked as security for transactions that are moved economically to offset the movement of other resources solving the constraint (i.e., a NYC generator is increased to solve a NYC constraint and a transaction that was near the margin is decreased to balance the load).

"D" -   If the transaction is not fully scheduled (schedule energy < bid energy) and the DNI ramp is binding, then the transaction is flagged with the DNI limitation "D". The DNI ramp limit can be constraining between any pair of adjacent quarter-hours in the RTC study period. RTC will move resources in either or both quarter hours that the DNI ramp constraint is active based on the economics of the study period. Since RTC is simultaneously solving for all constraints, including DNI limits, the logic required would be extremely complex to determine the exact transaction(s) that were moved to solve the DNI limit. Therefore, the DNI flag is appended to other flags such as security (DS-) or uneconomic (DU). Additionally, since the DNI ramp limit is a constraint that UC develops, it is the only constraint that can be active during the unconstrained dispatch.

Real-Time Operation

When curtailment of external transactions is necessary within the hour for system security, the NYISO interchange operator implements the curtailment via the scheduling software, IS+. Curtailment priority is determined according to the relative economic priorities of the decremental bids and NERC transaction priorities. Curtailments are coordinated with neighboring Control Areas, and the parties who arranged the transactions are notified via e-mail.

Transaction reinstatement

An inter-control area transaction into, out of, or through the NYCA that is curtailed in hour for a reliability violation may be reinstated in the same dispatch hour at the discretion of the NYISO Shift Supervisor. Upon determination by the NYISO Shift Supervisor that the reliability violation is resolved, and that reinstatement of the curtailed transaction will not adversely impact system reliability the NYISO will:

- Contact other affected control areas and attempt to arrange for a mutually agreed upon reinstatement schedule.

- Reinstate the transaction using IS+, upon approval by all affected control areas, and make an appropriate entry in the IS+ log.

- Provide email notification to the Market Participant scheduling entity that the transaction has been reinstated.

IESO/ NYISO Transaction Scheduling Guidelines

In an effort to ensure fair and efficient use of the IESO/NYISO interface, the two organizations have agreed to follow a scheduling protocol for the exchange of transaction scheduling information. This scheduling protocol establishes a timeline that defines when certain scheduling activities occur, both within and between the two organizations. This timeline is illustrated below.
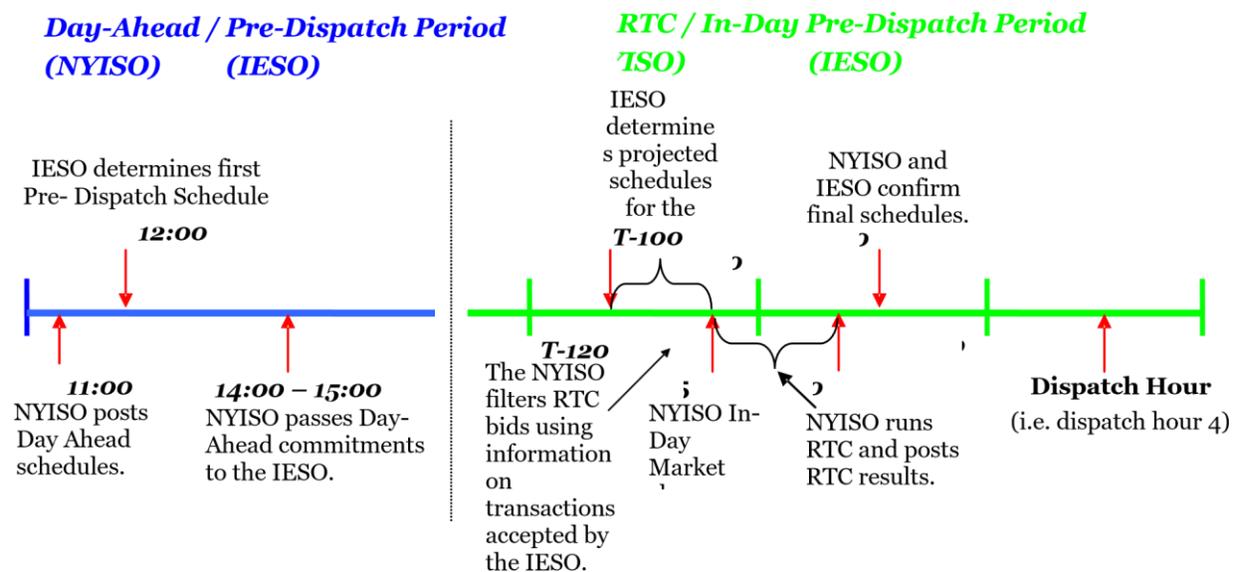
The IESO restricts revisions and/or additions to offers and bids within the four hours prior to the dispatch hour. The IESO may, however, accept revisions and/or additions that benefit reliability. At the request of the NYISO, the IESO may allow revisions and/or additions during this timeframe if the changes facilitate a solution to NYISO reliability concerns.

NYISO/ IESO intertie schedule implementation is consistent with the NERC transactions ramping default of 10 minutes with the ramp straddling the top of the hour.

DAM transactions

DAM transactions (transactions that originated as DAM transaction bids) will be considered by the IESO to be "advisory" and are subject to the availability of ramping and transmission capacity on the interface.

Curtailed and failed transactions

A transaction that has been curtailed during the dispatch hour for reliability reasons may be reinstated within that hour if the reliability condition causing the curtailment is resolved, and the curtailed transaction is scheduled in the next dispatch hour

Failed transactions will be monitored by the IESO and the NYISO, and the reasons for the failures will be identified and shared between the two organizations within the confidentiality provisions of their respective tariffs. Transactions that fail for reasons under the control of the

Market Participant are subject to investigation by the IESO and NYISO market monitoring units.

6.2.4. Dispatch Day Scheduling Priority for Day-Ahead External Transactions

For Real-Time Import and Wheel-Through transactions, not using a CTS Interface Bid, a "Decremental Bid" (Dec Bid) amount is used in the RTC. The highest economic scheduling priority that can be supplied by Market Participants is -$1000.00 for RT Dec Bids. A Dec Bid reflects the minimum the MP is willing to accept to import energy into the NYCA.

For Real-Time Export transactions, not using a CTS Interface Bid, Market Participants supply a "Sink Price Cap" amount up to $2000.00. A Sink Price Cap Bid reflects the maximum the MP is willing to pay to get its energy export scheduled.

For Import or Export transactions using a CTS Interface Bid, Market Participants supply a Bid

Price which indicates the bidder's willingness to be scheduled so long as the forecasted CTS Sink

Price minus the forecasted CTS Source Price is greater than or equal to the dollar value specified in the Bid. The highest economic scheduling priority than can be supplied by Market Participant using a CTS Interface Bid is -$1000.00.

NYISO's scheduling systems do not differentiate between an Import Transaction for which the source Control Area (CA) has committed resources and one for which it has not. That is, the NYISO's scheduling systems consider all external supply offers as backed by resources committed to support the transaction by the source CA. This allows SCUC and RTS to efficiently schedule energy and ensure that the NYISO commits adequate resources to meet reliability requirements. Similarly, absent emergency situations that are communicated to the receiving CA, the NYISO considers its scheduled Export Transactions as backed by resources committed to the Export.

If an Import offer is scheduled by the NYISO because it is economic but the source CA has not committed resources in support of that transaction, the NYISO will fail that transaction at checkout or

otherwise curtail it. Simply because such Import Transactions get scheduled does not mean they will be capable of flowing in Real-Time if the source CA has not committed resources in support of such Imports sinking in the NYISO.

If the NYISO has reason to believe the Transmission Customer scheduling the Import knew or had reason to know that the source CA had not committed resources in support of that transaction, the checkout failure or curtailment will be labeled as occurring for reasons within the Transmission Customer's control. Under such circumstances, the Transmission Customer scheduling that transaction will be liable for all balancing obligations and other charges otherwise imposed under the NYISO's Tariffs.

This prohibition does not affect the ability of the NYISO, or an external Reliability Coordinator, to convert an Export Transaction for which resources have been committed to one that can be immediately recalled, on notice, due to unforeseen circumstances pursuant to NPCC provisions for such conversion in emergencies.

Decremental Bids (Imports)

An accepted, Day-Ahead Import that is not designated as a CTS Interface Bid for the Real-Time Market will be converted to a Real-Time Market bid using the "RTM Bid Price" provided in the Market Participant's DAM bid. If the Market Participant does not provide a "RTM Bid Price" when submitting its DAM bid, a default economic scheduling priority of - $0.01 will be used when the DAM bid is converted to a bid for the Real-Time Market.

Decremental Bids (Wheels)

A Wheel-Through that is accepted in the DAM will be converted to a bid for the Real-Time Market using the "RTM Bid Price" provided in the Market Participant's DAM bid. If the Market Participant does not provide a "RTM Bid Price" when submitting its DAM bid, a default economic scheduling priority of - $1000.00 will be used when the DAM bid is converted to a bid for the RealTime Market.

Sink Price Cap Bids (Exports)

An accepted, Day-Ahead Export that is not designated as a CTS Interface Bid for the Real-Time Market will be converted to a Real-Time Market bid using the "RTM Bid Price" provided in the Market Participant's DAM bid. If the Market Participant does not provide a "RTM Bid Price" when submitting its DAM bid, a default economic scheduling priority of + $2000.00 will be used when the DAM bid is converted to a bid for the Real-Time Market.

CTS Interface Bids (Imports and Exports)

An accepted, Day-Ahead Import or Export that is designated as a CTS Interface Bid for the RealTime Market will be converted to a bid for the Real-Time Market using the "RTM Bid Price" provided in the

Market Participant's DAM bid. Market Participants must specify a "RTM Bid Price" when submitting an Import or Export designated as a CTS Interface Bid for the Real-Time Market, whereas this field is optional for Decremental bids and Sink Price Cap Bids.

A Market Participant also has the option of modifying its Real-Time Market Bid, regardless of whether the Bid has an MP-specified "RTM Bid Price," or the Bid was adjusted by the MIS to the applicable default economic scheduling priority, as outlined above. After the Day-Ahead checkout process with neighboring Control Areas, the Real-Time Market Bid can be adjusted for megawatts and/or price by the MP before the close of each hourly RT Market. In this instance the entire megawatt amount of the transaction will be evaluated by the RTC with this new price.

6.3. 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 (CLR) or the sub-classification of Energy Limited Resource (ELR) may qualify such generating units for special balancing energy and Installed Capacity (ICAP) consideration while making energy and/or capacity limited MWs available to the Day-Ahead, In-Day, and Real-Time Markets. Additional information on CLR and ELR usage can be found in Attachment M of the *NYISO Installed Capacity Manual (*available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletinshttps://www.nyiso.com/manuals-tech-bulletins-user-guidesuser-guides)

6.4. Normal and Emergency Upper Operating Limits (UOLN and UOLE)

All energy Suppliers are required to specify both a Normal Upper Operating Limit (UOL_N) and an Emergency Upper Operating Limit (UOL_E) in their Day-Ahead ("DA") and Real-Time ("RT") offers. The UOL_N defines the unit's operating limit under normal system conditions; the UOL_E defines the unit's operating limit achievable at the request of the NYISO during extraordinary conditions. Both limits should reflect the unit's achievable capacity. The specified value of UOL_E in the DA and RT offers must be greater than or equal to value specified for UOL_N. Additional information on Upper Operating Limits for CLR and ELR resources can be found in Attachment M of the *NYISO Installed Capacity Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides).

6.5. 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 NYCA. Rules governing the obligations associated with NYISO ICAP contracts are defined in the *NYISO Installed Capacity Manual (*available from the NYISO Web site at the following URL:

https://www.nyiso.com/manuals-tech-bulletins-user-guides).

An ISO has certain additional rights to energy associated with ICAP committed to its Control Area in real time. PJM, ISO-NE, IESO, HQ, 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 the PJM, ISO-NE or IESO Control Area

In the event that energy from a NYISO ICAP resource located in the PJM, ISO-NE or IESO Control Area is required to resolve a capacity deficiency in the NYCA, the NYISO will publish an alert to the

NYISO Market & Operations web page, specifically on the System Conditions page (https://www.nyiso.com/system-conditions), which is also available in the Real Time Events data (http://mis.nyiso.com/public/). This alert serves as NYISO's instruction 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). An email will also be sent to the ICAP resource's designated contact provided in the NYISO Market Information System (MIS). Transaction offers should identify the source as the appropriate external proxy bus and the sink as the NYCA reference bus. The specific ICAP unit should also be identified in the User Reference field of the MIS form.

Suppliers providing ICAP to NYISO at the NE-AC Proxy wishing to bid energy that is above their capacity contract will need to enter two bids into the NYISO's Joint Energy Scheduling System (JESS). The first bid should be for the contracted ICAP amount of energy and the second should be for any energy above the contracted amount.

Resources from Quebec

In the event that NYISO ICAP backed energy is required from Quebec, the NYISO will publish an alert to the NYISO Market & Operations web page, specifically on the System Conditions page (https://www.nyiso.com/system-conditions), which is also available in the Real Time Events data (http://mis.nyiso.com/public/). An email will also be sent to the ICAP resource's designated contact provided in the NYISO Market Information System (MIS). This serves as the NYISO's instruction to 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 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 inday forecasted or actual reserve shortage (e.g. a PJM Maximum Generation Emergency), the affected control area's ICAP resource(s) located within the NYCA are expected to follow the rules and obligations set forth by the affected control area in order to make their ICAP backed energy available. The ICAP resource(s) is also expected to follow the standard NYISO bidding rules required to make their ICAP backed energy available to the affected control area. In addition, in the event the ICAP backed energy transaction is not accepted in RTC due to a NYISO reserve shortage, the NYISO operator may take manual action to facilitate the delivery of ICAP backed energy if such action is requested by the affected control area. Transaction offers need to identify the source as the specific ICAP resource sold and the sink as the appropriate external proxy bus.

Pro-rata reductions in energy delivery will be applied based upon the current capability of the NYCA resource supplying the external ICAP energy. If the resource has less capacity available than its ICAP obligation calls for, and/or it has ICAP obligations in more than one control area, then the ICAP obligation(s), as well as non-ICAP energy contracts, will be pro-rated accordingly. The NYISO is not obligated to supply energy from NYISO-only ICAP resources.

Wheel-through transactions with ICAP implications

In the event that an ICAP transaction between two neighboring control areas must pass through the NYCA, the NYISO will deliver the associated energy, subject to transfer limitations. The entity offering the ICAP transaction must follow the standard NYISO bidding rules to wheel their ICAP backed energy through the NYCA.

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.

MIS Transaction IDs must be submitted for all inter-control area ICAP transactions

In order to manage external ICAP transactions, all NYCA resources with ICAP obligations in external control areas, all external resources with ICAP obligations in the NYCA, and all ICAP transactions that will wheel through the NYCA must submit MIS transaction IDs to the NYISO via email to icap_info@nyiso.com. Additionally, each NYISO ICAP resource located outside the NYCA shall include a 24 X 7 telephone contact number when providing its MIS transaction ID each month. MIS transaction IDs and telephone contact numbers must be received by the NYISO by or before the dates shown in the ICAP Event Calendar at: https://www.nyiso.com/installed-capacity-market

6.6. 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. Forecast reserve shortages may be shortages for the NYCA statewide region, locational shortages within the NYCA region due to transmission constraints, or inter-regional locational shortages between NYCA and neighboring Control Areas due to transmission constraints. A complete description can be found in the *NYISO Emergency Demand Response Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletinshttps://www.nyiso.com/manuals-tech-bulletins-user-guidesuser-guides) .

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

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 (SCR) 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

It is the NYISO's intention to provide CSPs notice no less than two hours in advance of the time specified to reduce load, pursuant to NYISO emergency operations procedures. However, instructions may be issued requesting an immediate start.

Special Case Resources

Special Case Resources are Loads capable of being interrupted upon demand, and distributed generators 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. For details, refer to the *NYISO Installed Capacity Manual*, available from the NYISO Web site at the following URL:

https://www.nyiso.com/manuals-tech-bulletins-user-guides

6.7. 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

6.7.1. 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 power system grid model based on the latest transmission outage schedules, including forced outages.
2. Updates the load forecast based on the latest load information.
3. Accepts any 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 with adjustments made for known schedule changes.
7. Executes the Real-Time Commitment (RTC) using SCUC with a 2½ hour horizon.

Posts the following results:

1. Revised Resources schedules for the next hour.
2. Revised firm transaction schedules for the next hour.
3. Market Participant Actions.
4. Market Participants shall request the NYISO for any changes in generation, load, and transactions schedules.

6.7.2. 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 Figure 16 summarizes the startup characteristics for real-time commitment.

Figure 15: Unit Startup Characteristics

Unit Classification	Startup Characteristics
10-15 minute start*	10-15 minute startup notice starts by RTC on the quarter hour On-Demand starts by RTD-CAM

30 minute start	30-minute startup notice starts by RTC on the quarter hour
* Also known as Quick Start Units	

6.7.3. 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 TOs.

Resource Categories

There are ten Resource Categories as shown by Figure 17.

Figure 16: Resource Categories

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) Simultaneous Active of Reserves and/or External Emergency Purchases	(R8) Unexpired Un-accepted Day-Ahead Bids	(R9) Unexpired Un-accepted Hour-Ahead Bids	(R10) Involuntary Load Curtailment
Regulating resources or Dispatchable or NonDispatchable	Regulating resources	Dispatchable or NonDispatchable	Dispatchable or NonDispatchable and Off-Line but Available	Dispatchable or NonDispatchable and Off-Line but Available	Dispatchable or NonDispatchable and Off-Line but Available	Invoked Manually	Non-Dispatchable or Off-Line but Available	Non-Dispatchable or Off-Line but Available	Invoked Manually
FRED = **F**orecast **R**equired **E**nergy for **D**ispatch; the capacity to supply energy to meet NYISO forecasted load that is in excess of the sum total of DayAhead load bids.									

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

1. AGC moves regulating resources from (R2) to (R1) and from (R1) to (R2) to maintain regulation.

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

3. If RTD can't solve rapidly enough for an energy deficiency, Reserve Pickup is invoked to move some "Dispatchable" and "Non-Dispatchable" 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.

> **Note:** LESRs will not respond to reserve pickups except to either maintain any injection or terminate any consumption of energy.

4. During a Reserve Pickup – RTD-CAM is used to convert 10-Minute Operating Reserve to energy using emergency response rates for some or all suppliers providing operating reserve 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 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 Resource; to return schedules if the ACE exceeds 100 MWs; or if a faster ramp rate is required to solve a transmission security violation.

    During Reserve Pickup, no regulation penalty is invoked for Resources that exceed their RTD basepoint (i.e., over-generation is encouraged and rewarded). Reserve Pickup will be terminated by the Operator when a sufficient level of energy has been replaced. Upon this termination, Resource 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.

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

    Simultaneous 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 energy payback.

6. If steps 2, 3, and/or 4 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 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.

7. If Reserve Pickup is (or is expected to be) insufficient, Max Gen Pickup may be invoked manually through phone notifications to TOs to move "Dispatchable" and "Non-Dispatchable" 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.

    > **Note:** LESRs will not respond to reserve pickups except to either maintain any injection or terminate any consumption of energy.

    A Maximum Generation Pickup is an emergency energy pickup as directed by the NYISO outside a normal RTD run. At the NYISO's 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.

8. If a reliability violation continues to occur, 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* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides). This may also include curtailment of external transactions.

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

10. 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.

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

If the data indicates that the NYCA will be short of Operating Reserve, the NYISO shall perform the actions described for supplemental commitment and scheduling.

6.7.4. Out-of-Merit Generation

From time to time, Resources 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 (OOM) 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.

Out-of-Merit Generation directives for an Energy Storage Resource will account for both the inverter limit (MW) and storage capacity (MWh).

An Out-of-Merit directive can also apply to CSR Scheduling Limits. Such a directive will reduce the CSR injection Scheduling Limit (so less Energy can be injected), reduce the CSR withdrawal Scheduling Limit (so less Energy can be withdrawn), or reduce both CSR Scheduling Limits.

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 not all out-of-merit units are eligible to set LBMPs. The unit will be provided a supplemental payment, if required to recover its bid cost, consistent with the rules for bid production cost guarantees. Note that all OOMs for reliability in NYC (Zone J) are

considered as OOM for ISO reliability, as the NYISO secures the 138 kV system in Zone J. For more information on OOM treatment, see table 5-8 below.

Any supplemental payments will be charged to all NYISO Loads through the Schedule 1 Ancillary Service. The Resource 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 Resource be run out-of-merit, either up or down, for local reliability. The specific Resource and reason for the request must be identified by the TO at the time of the request. The energy provided by the Resource will be paid at the Real-Time Market LBMP, but not all OOM units are eligible to set LBMPs. 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 TO's area. The Resource will remain out-of-merit until the TO requests that the NYISO put it back in merit. A TO may request an OOM for Resources engaged in Dual Participation that are not economically scheduled by the NYISO for a local system need. For more information on OOM treatment, see table 5-8 below.

Generator Operator/ Aggregator Requests for Out-of-Merit Generation

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

A generator operator or Aggregator may request out-of-merit operation to perform a Dependable Maximum Net Capability (DMNC) test. The process for this test is described in Section 6.7.5. During a DMNC test, energy that is 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, and it will not receive an in-day bid production cost guarantee. Not all Out-of-Merit Generation is eligible to set LBMP. For more information on OOM treatment, see table 5-8 below.

Derated generation can also be requested by a generator operator or Aggregator for extenuating circumstances that require reduced operation or shutdown. This includes equipment failure or pollution episodes. The Resource remains responsible for balancing energy.

Figure 17: Out-of-Merit Treatment

Action Type	OOM	Fast-Start Resource Eligible to Set Price?	Public Notice Posted?	

	ISO VOLTAGE SUPPORT	No	Yes	
	OPS INTERVENE/MODIFY MINGEN	Yes	No	
	OPS INTERVENE/MODIFY UOL	Yes	No	
	OPS INTERVENE/MODIFY BOTH	Yes	No	
ISO Action	START-UP/SHUT DOWN	Yes*	No	
	OOM FOR TESTING	Yes*	No	
	NYISO GEN AUDIT	Yes	Yes	
	COMMITTED FOR ISO RELIABILITY	Yes	Yes	
	ISO ENERGY LIMITED RES	Yes	Yes	
	OOM FOR RESERVES	Yes	Yes	
Gen Action	GEN REQUEST/MODIFY MINGEN	Yes	No	
	GEN REQUEST/MODIFY UOL	Yes	No	
	GEN REQUEST/MODIFY BOTH	Yes	No	
TO Action	OOM FOR TO RELIABILITY	No	Yes	
	TO VOLTAGE SUPPORT	No	Yes	

*Note: OOM for Testing and START UP/ SHUT DOWN are two additional OOM types assigned by the NYISO's settlements department after the market software has run

6.7.5. Resource DMNC Test Scheduling Requirements

Please note: The term 'Resource' as used throughout the following Sections 6.7.5; 6.7.6; 6.7.7; and 6.7.8 is not inclusive of Special Case Resources and Demand Side Resources (E.g., DSASP). For the sole purpose of Sections 6.7.5.; 6.7.6; 6.7.7.; and 6.7.8. the term 'Resource' refers to Generators and Aggregations.

Test Scheduling Notification Rules

For Resources 100 MW and greater; the Generator notifies the NYISO Scheduling Department (see immediately above) and the Transmission Owner (TO) at least five (5) business days in advance of the proposed test date that the Generator is requesting a DMNC test.

For Resources 25 to 99 MW, (including multiple units under a single owner totaling more than 25 MW), the Resource notifies the NYISO Scheduling Department and the TO at least two (2) business days in advance of the proposed test date that the Resource is requesting a DMNC test.

Resources under 25 MW testing separately have no notification requirements.

The NYISO will conduct a system reliability review and notify the Resource through the TO if, and only if, the request is denied.

Day-Ahead Bidding

Resource 100 MW and greater must bid into the Day-Ahead energy market such that the Resource is scheduled for the hours requested for the DMNC test. If the Resource is not scheduled, the DMNC test is cancelled and notification must be made to NYISO Scheduling (at the number/email address above in red) and the TO by hour 1400 of the business day prior to when the DMNC test is scheduled.

For Resources 25 to 99 MW, a Day-Ahead bid is not required if the Resource is a unit that can be committed through Real-Time Commitment (RTC). In the event of a test cancellation the Resource must notify NYISO Scheduling and the TO by hour 1400 of the business day prior to when it is requesting a DMNC test.

Test Day Procedures

On the day of the scheduled DMNC test, at least three (3) hours prior to the scheduled test, the Resource, through the Transmission Owner, must request permission from the NYISO to perform the test. Also, the Resource, regardless of size, (i.e., with or without a DAM schedule), must ensure that in the Real-Time Market the unit is scheduled for the hours requested for the DMNC test, including ramping up to the test level. The NYISO will approve or deny the request at least two (2) hours prior to the scheduled test, notifying the Resource through the Transmission Owner, allowing time for Real-Time Market energy market bid adjustments.

On the day of the test, the Resource is required to adjust its (price-taking) Real-Time Market bid to allow Real-Time Dispatch (RTD) to schedule the Resource up to its current DMNC rating.

The Resource must notify the NYISO through the Transmission Owner that the DMNC test has started.

The NYISO will log that the Resource is performing a DMNC test and that the Resource is dispatched out-of-merit.

The Resource must notify the NYISO through the Transmission Owner that the test is complete. The NYISO will log the completion time and the Resource will resume following normal base points.

Accounting for and Submitting DMNC Test Results

During the Resource's DMNC test period, the Resource will not set the LBMP.

For the energy that is not subject to Day Ahead LBMP, the NYISO will pay the Resource the LBMP in the Real-Time Market at its location for the energy it produced during the Resource's DMNC test.

The NYISO will not charge the Resource for any performance and regulation penalties that may apply during the Resource's DMNC test period.

The Resource must submit DMNC test results data online, (including weather-adjusted data), as defined in the ICAP Automated Market User's Guide, Section 11, and section 4.2 of the NYISO Installed Capacity Manual. Requirements applicable to Aggregations can be found in the Aggregation System User's Guide (available from the NYISO Web site at the following URL:

https://www.nyiso.com/manuals-tech-bulletins-user-guides).

6.7.6. Rules for Resources Conducting Certain Scheduled Steady-State Tests

There are special settlement rules for Resources conducting certain scheduled steady-state tests. Please see the Accounting and Billing Manual at the following link for this information:
https://www.nyiso.com/documents/20142/2923231/acctbillmnl.pdf

6.7.6.1. Eligible Units

This eligibility is extended to all Resources that may be conducting ISO-required DMNC or VAr tests, or other necessary tests outlined below. These tests require operation while synchronized to the NYISO power grid. No pre-registration to qualify a Resource is required to use this feature; however, Resources are required to follow the bidding, scheduling and test notification procedures defined in this section in order to qualify for the settlement treatment discussed below. Resources will be subject to audit and the ISO may revoke, for cause, its approval for any Resource's testing coverage under the special settlement provisions.

New units undergoing startup tests will be considered eligible for the special settlement rules as long as the tests conducted are included among the Eligible Tests listed, and the Aggregator or generator operator conforms to the rules outlined below. Questions about eligibility for Special Settlement

Rules for unlisted tests should be directed to your Stakeholder Services representative. New Units are also directed to TB 116 at: https://www.nyiso.com/documents/20142/2931465/tb_116.pdf for additional information on requirements and procedures to be followed for new unit startup testing.

6.7.6.2. Tests that are not Eligible Tests

Tests that are not listed below do not qualify for the treatment provided in this section. Tests otherwise eligible, but for which the Resource operator has failed to follow the prescribed procedures, are also not Eligible Tests. In addition, the following four tests are excluded from the treatment available under this section because they cannot be scheduled in advance or have undefined test processes.

The four tests for which special settlement rules are not available pursuant to the terms of this section are:

- Water outfall tests
- Gas system interruption
- Compliance assurance monitoring
- Turbine overspeed tests

6.7.6.3. Procedures and Rules Governing Eligible Tests

Resources conducting Eligible Tests must follow the bidding, scheduling and test notification procedures listed below. Any failure by the Market Participant to meet the rules governing a specific test or to provide complete and timely information during the execution of a test may result in the disqualification of the request for the penalty exemption.

6.7.7. General Rules

6.7.7.1. Test Notification

To schedule a test period, the requestor must contact the NYISO Scheduling Department and provide the following test information:

Test Notification Contact: NYISO scheduling at 518-356-6050 or genplan@nyiso.com

Resource Name

Eligible Test

Start and End Date/Time Period for the test:

- For Resources 25 MW and greater; the Resource must notify the NYISO Scheduling Department (see immediately above) and the Transmission Owner (TO) at least three (3) business days in advance of the proposed test date.

- Resources less than 25 MW testing separately are not required to make this advanced test period notification.

- The NYISO will notify the Resource through the TO if, and only if, the request is denied.

6.7.7.2. Day-Ahead Bidding

- Resources 100 MW and greater must bid into the Day-Ahead energy market such that the Resource is scheduled appropriately[2] for the hours requested for the test. If the Resource is not scheduled, the Resource must cancel the test and notify NYISO Scheduling (at the number/email address set forth above) and the TO by hour 1400 of the business day prior to the day of the cancelled test.

- For Resource 25 to 99 MW, a Day-Ahead bid is not required. In the event of a test cancellation the Resource must notify NYISO Scheduling (at the number/email address set forth above) and the TO by hour 1400 of the business day prior to the day of the cancelled test.

6.7.7.3. Test Day Procedures

- On the day of the scheduled test, at least three (3) hours prior to the scheduled test, the Resource, through the Transmission Owner, must request permission from the NYISO to perform the test. Also, the Resource, regardless of size, (with or without a DAM schedule), must ensure that in the Real-Time Market the unit is scheduled for the hours requested for the test, including ramping up to and down from the test level (as needed). Test schedules must be appropriate to the Resource's normal ramp rate. The NYISO will approve or deny the request at least two (2) hours prior to the start of the scheduled test, notifying the Resource through the Transmission Owner, allowing time for Real Time Market bid adjustments.

- If conditions occur that could result in a test cancellation, a delay beyond the scheduled start time, an extension beyond the scheduled end time, or if the Resource is projecting that it cannot meet its Day-Ahead schedule, the Resource will notify the Transmission Owner who will notify the NYISO operators. Resources should communicate their expected operating characteristics during these events and make appropriate changes in the unit's Real-Time

energy offers. If the NYISO approves a schedule change, special settlement rules may still apply. However, the test duration limits included in the Test Specific Criteria section below for all Eligible Tests still apply.

- At least 3 hours before the test, the Resource is required to have submitted in the NYISO Real Time market, hourly offers reflecting a good-faith estimate of its energy production. For all tests with the exception of those tests required by the NYISO (DMNC & VAr)

Suppliers must bid the generators in Self-Committed Fixed mode in quarter-hour increments for all hours when the Eligible Test is expected to be conducted. These offers will be used for all NYISO Real-Time schedule forecasts. Rules addressing NYISO required tests are outlined in the documents identified in the Eligible Tests section below.

- The Resource must notify the NYISO through the Transmission Owner that the test has started.

- The NYISO will log the Resource test and will dispatch the Generator consistent with its Real-Time schedule.

- The Resource must notify the NYISO through the Transmission Owner that the test is complete. The NYISO will log the completion time and the Resource will continue to follow its Real-Time schedule.

6.7.7.4. Test Specific Criteria

The NYISO will apply special settlement rules for Eligible Tests pursuant to the following test criteria:

- Special settlement rules will be applied to the shorter of i) the time period listed in the Qualifying Test Duration section of the description of the Eligible Tests provided below or ii) the length of the actual test. In addition, the NYISO will refer to Periodicity as the expected frequency of a test for any given Resource. Periodicity is a guideline for the NYISO to use in assessing the impact of this exemption process and with which the NYISO will monitor the program for possible abuse.

6.7.8. Eligible Tests

1. **DMNC Test**

   (See Section 3.8.5 of this manual for Resource DMNC Test Scheduling Requirements)

   Steam Unit/ Combined Cycle DMNC Test DAM scheduling criteria

Must be scheduled to 90% of Operating Capability

Test Periodicity – 2/year, Bi-Annually (Winter/Summer);

Qualifying test duration – up to 6 hours

GT DMNC (With/Without Power Recovery) Test DAM scheduling criteria

Must be scheduled to 90% of Operating Capability Test Periodicity – 2/year Qualifying test duration – up to 2 hours

2. **VAr Tests**

   (See Section 3.6 of the Ancillary Services Manual for specific VAr testing and reporting   requirements at:
   https://www.nyiso.com/documents/20142/2923301/ancserv.pdf

   Steam Unit /GT VAR (Lead/Lag) Test

   DAM scheduling criteria – As per the Ancillary Services Manual

   Test Periodicity – 1/year

   Qualifying test duration – up to 3 hours

3. **RATA Testing**

   DAM scheduling criteria – as accurate as can be done, NYISO expectation is that unit will be scheduled to at least its minimum operating level

   Test Periodicity – 1/year

   Qualifying test duration – up to 16 hours

4. **Mill fineness checks**

   DAM scheduling criteria – No special operating levels defined. Test Periodicity – 1/year Qualifying test duration – up to 2 hours

5. **Reheat intercept/stop valve leakage test**

   DAM scheduling criteria – could be done at different load points

   Test Periodicity – as needed Qualifying test duration – up to 1 hr

6. **N2 Leakage Test**

   DAM scheduling criteria – as accurate as can be done, minimum schedule 50% of full load

Test Periodicity – 1/year

Qualifying test duration – up to 8 hours

7. **Boiler Efficiency Test**

   DAM scheduling criteria – 90% of full load

   Test Periodicity – 2/year

   Qualifying test duration – up to 4 hours

8. **GT Monthly Operational Test**

   DAM scheduling criteria – 100% of opcap

   Test Periodicity – 1/month

   Qualifying test duration – up to 2 hours

9. **Particulate Testing**

   DAM scheduling criteria – No special operating levels defined

   Test Periodicity – 1/5 years

   Qualifying test duration – up to 16 hours

Residual oil fired units will be required to conduct particulate testing annually for nickel under the EPA's proposed Hazardous Air Pollutant (HAP) Maximum Achievable Control Technology (MACT) requirements. Coal may have similar requirements under the HAP MACT mercury requirements (Generally 12-16 hours per unit).

10. **NOx Testing**

   DAM scheduling criteria – full load.

   Real-Time scheduling criteria – full load.

   Test Periodicity – 1/5 years

   Qualifying test duration – 3 hours on each fuel

Every combustion turbine and diesel generator that is grid connected and is not RATA tested (no CEMS) is subject to NOx testing once every five years. If the unit is capable of operating on multiple fuels, testing must be conducted on each fuel. Regulatory provisions may allow testing of representative units (basically one in three) so practically speaking not every unit will actually be tested. (Generally 3 hours per

unit per fuel). Generators should consult relevant federal and state air emission testing regulations to determine their specific requirements.

11. Full Load Fuel Oil Test

Scheduling criteria – The following process will apply to the scheduling of these tests:

    a. Test schedules will be submitted three days in advance including an estimate of the expected test hours for the selected pseudo-unit per Section A-2 above.

    b. When DAM schedules for the day following the test are received by the CC unit owner/operator (by 11:00 of the test day) the test will either be feasible or not based upon the unit minimum down time and the following day's schedule.

        i. If the test is feasible and will be conducted, the CC unit owner/operator will, as described in Section A-3 above, notify the NYISO through the Transmission Owner that the test is confirmed and the planned actual hours in which it will be conducted. Following the procedures described in Section A-3 the CC unit owner/operator will also bid into the RT market (HAM) in "Self-Scheduled Fixed Mode" their best estimate of unit output in 15 minute increments over the test period and will also follow all other procedures described in section A-3 above.

        ii. If the Day Ahead schedules will not permit sufficient downtime to run the test as scheduled, the CC unit owner/operator will follow the test cancellation procedures described in Section A-3 above and reschedule the test per section A-1 above for a subsequent day.

Test Periodicity – 1/month/Combustion Turbine

Qualifying test duration – 3 hours

12. Control System Performance Testing

DAM scheduling criteria – No special operating levels defined.

Test Periodicity – as needed

Qualifying test duration – up to 16 hours

6.7.9. Supplemental Commitment Process

The NYISO may use the SRE process to commit additional resources outside of the SCUC and

RTC processes to meet NYISO reliability or local reliability requirements. Transmission Owners (TOs) may request the commitment of additional generators to ensure local reliability in accordance with the local reliability rules. The NYISO will use SREs to fill these requests by TOs. In addition, Generator Owners may request the operation of a specific steam unit if certain combustion turbines have an energy or a non-synchronous reserve schedule that necessitates operation of the steam unit due to 24-hour NO_X Averaging Period requirements.

When the NYISO requests that generators submit bids in response to an SRE, ICAP suppliers must offer their available capacity unless an offer is pending in the Real Time market when the SRE request is made or the unit is unable to run due to an outage, operational issues or temperature derates. Special Case Resources are not required to respond to SRE requests by section 5.12.1 of the

Market Services Tariff. However, the NYISO may request SCR and EDRP resources to respond to SRE requests on a voluntary basis.

Since SREs are only performed to address reliability concerns, it is intended that units committed by the SRE process fulfill their obligation by physically operating.

A TO may utilize the SRE process for Resources engaged in Dual Participation that are not economically scheduled by the NYISO for a local system need.

NYISO Requests for SREs

The NYISO may perform SREs in response to the following two conditions:

1. When Day-Ahead reliability criteria violations are forecast after SCUC has begun or completed its Day-Ahead evaluation (i.e.: too late for additional day-ahead commitments).
2. When In-Day reliability criteria violations are anticipated more than 75 minutes ahead (i.e.: too early for RTC commit additional resources).

Transmission Owner Requests for SREs

TOs may request the NYISO to issue an SRE to commit additional resources for reliability purposes in a local area. TO requests for SREs are subject to the same conditions and the same time frame as the NYISO's use of the SRE process – after SCUC has run. Any requests by TOs to commit generators not otherwise committed by the NYISO in the Day-Ahead Market will be posted to the OASIS.

When requesting an SRE, TOs must give the NYISO the reliability reason for the request, the expected duration of the SRE, and the specific facility or constraint affected. NYISO dispatchers will log all such TO requests for SREs. Within 5 business days the TO requesting the SRE commitment shall provide detailed written justification for the SRE to SREinfo@nyiso.com. The NYISO will review all SRE requests to ensure

that practices being followed are consistent with NYISO tariffs and NYS Reliability Rules.

The TOs written justification must detail the system conditions that resulted in the need for the SRE commitment such that the NYISO can independently verify the request. The following system conditions should be identified when applicable: TO local area or regional load levels; identification of thermal transmission facility or substation voltage constraint, identification of whether the constraint represents a predicted actual or post-contingency violation; identification of significant transmission or generating unit outages affecting such constraint; and identification of special local reliability criteria. Other local area system conditions that resulted in the need for the SRE commitment should also be identified.

Generator Owner Requests for SREs

If certain combustion turbines have an energy or a non-synchronous reserve schedule that necessitates the operation of a specific steam unit operated by the turbine owner due to 24-hour NO_X Averaging Period requirements, the NYISO may commit the steam unit if the generator owner takes the following actions:

- The generator owner shall notify the NYISO and the TO of this operational requirement. The generator owner must notify the NYISO via the TO after the DAM posts, but no later than Hour Beginning (HB) 14 of the day prior to the operating day. In addition, throughout the operating day, the generator owner must communicate to the NYISO via the TO any changes in run-time limitations that may result from the combustion turbine's actual energy schedule or availability.

- The generator owner may request of the NYISO and inform the TO that a specific steam unit be operated, as required, to satisfy the NOx averaging requirements for the selected combustion turbine's energy or non-synchronous reserve DAM schedule given the 24-hour NO_X Averaging Period requirements for the operating day. The generator owner request should identify the steam unit, the required additional hours of operation, and the specific generation levels necessary to meet the 24-hour NOx Averaging Period requirement.

If the combustion turbines are not required for either NYISO or local TO reliability, and the associated steam units are not committed in the DAM, then the NYISO will mark the combustion turbines as unavailable in the generation outage scheduler, such that they are not committed in real-time operation. The combustion turbines will be identified as Energy Limited Resources (ELR), since the generator owner will be unable to fulfill the DAM energy or non-synchronous reserve schedule as determined by the NYISO. Combustion turbines subject to the 24-hour NOx Averaging Period requirement must be registered as Energy Limited Resources.

6.7.10. Supplemental Resource Evaluation Procedures

SRE commitment refers to the NYISO scheduling a generator to start-up to run at, or above, its

minimum generation level. SCUC commits resources for the next day, and RTC can commit resources in the Dispatch Day. RTC begins with SCUC Day-Ahead generator and load schedules, non-expired/non-accepted/non-updated (but not SCUC) bids, updated or new bids, updated transaction requests, updated load forecasts, updated outage schedules, and updated status changes. It then evaluates conditions for the next 2 ½ hours, performs a supplemental commitment (if needed) optimized for the next dispatch hour, and schedules newly requested transactions for the next 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 commitments for non-synchronized reserves. However, RTC will consider start-up costs. A generator started by 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 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.

Resource Monitoring Procedures

1. ***Monitor Regulation/Reserve Levels*** – The NYISO shall monitor the level of regulation and reserve resources available to meet anticipated NYCA requirements.
2. ***Monitor Adequacy of Bids*** – The NYISO shall 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 shall post an announcement to market participants to solicit additional bids.

6.7.11. General SRE Commitment

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

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

More detailed steps are subsequently listed below to specifically describe DayAhead and Dispatch Day SRE procedures.

3. ***Define Replacement Required*** – Based on the deficiency, the NYISO will determine:

Type of replacement required (i.e., regulation capability, operating reserve capability, or energy resource). In general, as shown in Figure 19, the replacement to be selected should match the resource lost.

- Location that the replacement is needed
- How soon the replacement is required
- Amount in MW needed by hour
- How long the replacement will be required.

Figure 18: 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).

   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.

5. ***Solve Dispatch Day (First) and Day-Ahead Deficiencies (Second)*** – In the case in which SCUC has begun or already completed its execution, and a combination of Dispatch Day and/or Day-Ahead resource deficiencies are subsequently anticipated, SRE shall be used to solve any Dispatch Day problems independently first. This shall be followed, if necessary, by another re-evaluation and a second SRE to solve any remaining Day-Ahead problems.

6. ***Allow, but Do not 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 an SRE. Alternately, the SRE may select another source for the replacement, presumably, because it is a more economical and/or more effective replacement choice.

The normal operating practice for addressing resource deficiencies, time and circumstances permitting, includes selecting resources for an SRE in the following order:

1) Economic based selection of available internal resources that cost less to supply Energy and/or Operating Reserves than Special Case Resources (SCRs)
2) External capacity
   a. The NYISO ordinarily issues SREs to either none or all of the external capacity that is available for scheduling at a Proxy Generator Bus.
   b. The NYISO chooses the Proxy Generator Bus(es) at which to call upon external capacity based on its evaluation of which Proxy Generator Bus(es) would effectively address the identified reliability need while using the least amount of external capacity, in light of anticipated system conditions.
3) SCR/EDRP
   a. For more information on SCR/EDRP activation, refer to Section 4.4 of the NYISO Emergency Operations Manual.
4) Economic based selection of available internal resources that cost more to supply Energy and/or Operating Reserves than SCRs

Further information on the NYISO's process for addressing reliability needs can be found in the NYISO Emergency Operations Manual.

6.7.12. Two- to Seven-Day Ahead SRE

A two- to seven-day ahead SRE shall 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 shall 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):
   • Determine the amount, location and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.
   • Determine how soon the Supplemental Resource will be needed.

- 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.

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.

6.7.13. Post-SCUC Day-Ahead SRE

A SRE to address a Day-Ahead deficiency would be performed after SCUC has begun its Day-Ahead evaluation.

1. ***Post Announcement*** – If a SRE to address a Day-Ahead deficiency is anticipated, and if time permits, the NYISO shall 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 Non-SRE Resource Adjustment steps 2 through 7:
   - Determine the amount, location and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.
   - Determine how soon the Supplemental Resource will be needed.
   - Determine how long, i.e., the SCP in hours up to the end of the Dispatch Day, the Supplemental Resource is likely to be needed.

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 Non-SRE Resource Adjustments:
   - Determine the amount and location of Supplemental Resource(s) required to eliminate the energy deficiency.
   - Determine how soon the Supplemental Resource(s) will be needed.
   - Determine how long, i.e., the SCP in hours up to the end of the Dispatch Day, the Supplemental Resource(s) are likely to be needed.

Select and schedule the move of Supplemental Resource(s) 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. **RTC Re-Adjustment** – Following steps 2 and/or 3 above, subsequent RTC runs may re-adjust resources.

6.7.14. Dispatch Day SRE

A Dispatch Day SRE would be performed as follows:

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

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

   • Determine the amount, location and type of Supplemental Resource(s) required. Type should be the same kind of resource that is deficient.
   • Determine how soon the Supplemental Resource(s) will be needed.
   • Determine how long, i.e., the SCP in hours up to the end of the Dispatch Day, the Supplemental Resource(s) are likely to be needed.

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

   • Determine the amount and location of Supplemental Resource(s) required to eliminate the energy deficiency.
   • Determine how soon the Supplemental Resource(s) will be needed.
   • Determine how long, i.e., the SCP in hours up to the end of the Dispatch Day the Supplemental Resource(s) are likely to be needed.

Select and schedule the move of Supplemental Resource(s) 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. **RTC Re-Adjustment** – Following steps 2 and/or 3 above, subsequent RTC runs may re-adjust resources.

6.7.15. Real-Time SRE

A Real-Time SRE would be performed as follows:

1. ***Post Announcement*** – If a Real-Time SRE is needed, and time permits, the NYISO shall post, an announcement to market participants that a SRE is being invoked.

2. ***Real-Time Regulation or Reserve Deficiency*** – If any deficiencies in Resources (R2), (R3), (R4), and/or (R6) are expected to exist in Real-Time after Non-SRE Resource adjustments steps 1 through 7 have been invoked:

Determine the amount, location, and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.

Select and move Supplemental Resources from Category (R9) to Categories (R2), (R3), (R4), (R5), and/or (R6) 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 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 Supplemental Resources available in 10 minutes
- 2nd – Least cost Supplemental Resources available in 30 minutes if additional Supplemental Resources are still needed.
- 3rd – Least cost Supplemental Resources 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 RTC Resource Adjustments: Determine the amount and location of Supplemental Resources required.

Select and move Supplemental Resources from category (R9) to (R1) on a least cost basis where start-up costs (if start-up is required) are spread over one hour as follows:

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

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

6.7.16. SRE Pricing and Cost Allocations

Energy Payments

Resources committed by SRE will be paid the real time LBMP for Energy and may be guaranteed recovery of start up and minimum generation bid costs ([2]) pursuant to Sections 4.1.8, 4.6.6, and Attachment

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[2] Bids submitted by generators are subject to conduct and impact testing, and may be mitigated pursuant to the provisions of Attachment H to the Services Tariff. If the Bid has been mitigated, the Bids used to evaluate BPCG eligibility will reflect the mitigation.

C of the Services Tariff. As previously stated, a resource committed by SRE cannot raise (but may lower) its price bid for the duration of time it was committed.

Cost Allocation

Assignment of replacement costs that result from a SRE will be as given as shown in .

Figure 19: Assignment of SRE Replacement Costs

Assignment of SRE Replacement Costs		
Cause for SRE	Impact of Replacing 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

If combustion turbines have an energy or a non-synchronous reserve schedule in the DAM that necessitates the SRE operation of a specific steam unit operated by the turbine owner due to 24hour NO_X Averaging Period requirements, then the following cost allocation applies:

If the combustion turbines are required for NYISO reliability purposes, the NYISO shall operate the selected steam unit as required via the Supplemental Resource Evaluation (SRE) process. Any real-time uplift costs associated with the operation of the steam unit will be allocated on a statewide basis.

If the combustion turbines are required only for local TO reliability purposes, then the TO shall notify the NYISO of this requirement and the NYISO shall operate the required company steam unit via the SRE process for local TO reliability. Any real-time uplift costs associated with the required steam unit will be allocated to the LSEs in the LBMP zone that had the reliability requirement.

6.7.17. Supplemental Resource Availability (SRA)

TOs and the NYISO Operators can submit a SRA to request that a specific Aggregation has a specified

amount of available operating capacity at a specified period. The request can be made by TOs for local reliability requirements or the NYISO Operators for NYISO reliability requirements.

SRA requests are made through the Grid Operations Coordination Portal (GOCP).

7. 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.

7.1. 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. Real-Time Dispatch runs will normally occur every five minutes.

Figure 21 presents the RTD time line for a period of one hour.

Figure 20: Real-Time Dispatch Time Line
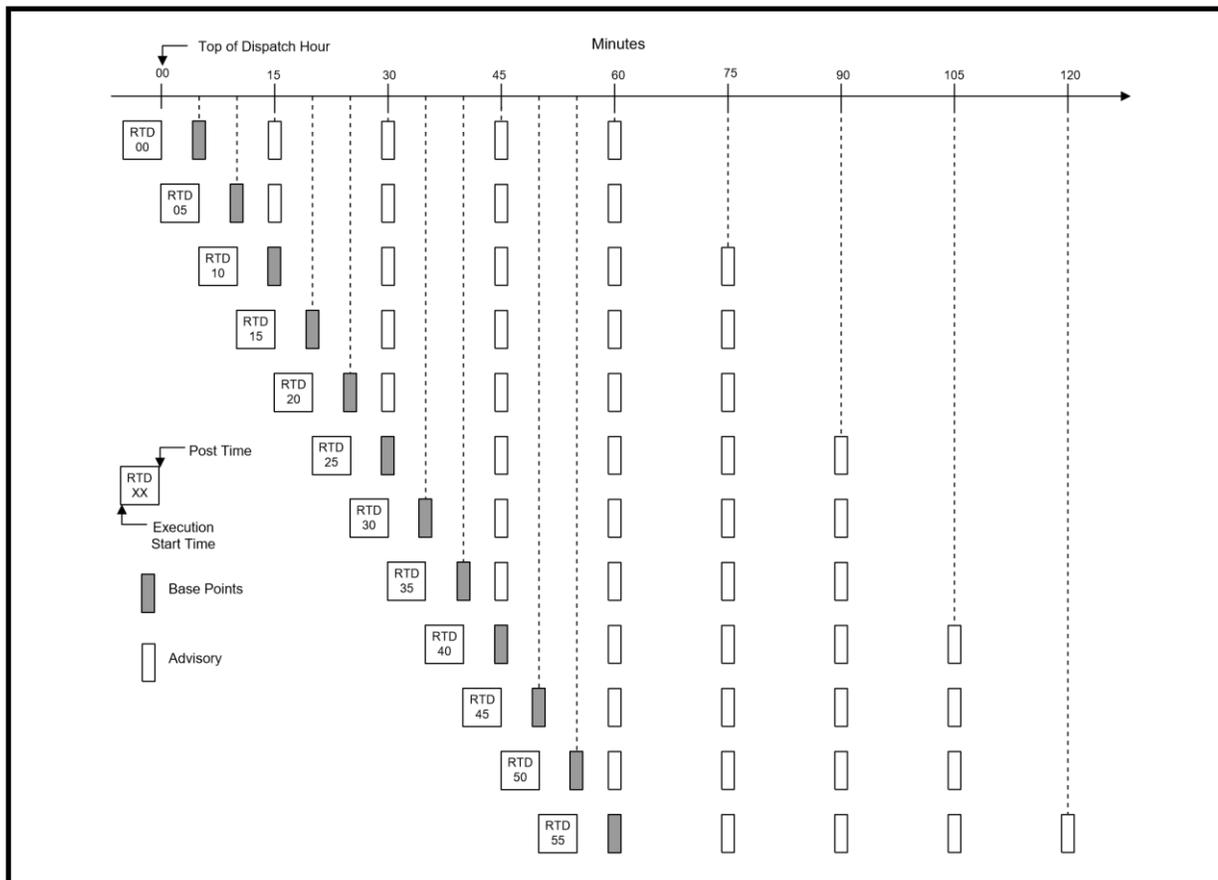
7.1.1. Real-Time Dispatch Process

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Resources 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 Real-Time Market Prices for 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.

7.1.2. Real-Time Dispatch Information Posting

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

Public Information

The following information will be produced by RTD and is posted:

1. 5-minute look ahead zonal and Resource prices from the first increment of RTD.
2. Ancillary Services prices for the 5-min look-ahead interval of RTD. The following incremental prices are posted:
   - 10-min Spinning Reserve by Load Zone
   - 10-min Non-Spinning Reserve by Load Zone
   - 30-min Spin/Non-Spin Reserve by Load Zone
   - Regulation Capacity (NYCA only)
   - Regulation Movement (NYCA only)
3. The following additional information will be posted as required:
   - Phase Angle Regulator (PAR) schedules for all PARs
   - Limiting Constraints on transmission network MW flows (Constraint Type [Base/Contingency] and Shadow Price).
   - Transmission Interface Flows
4. A set of real-time prices produced by RTD and RTC will also be posted periodically at a NYISO specified time. These prices may be corrected and reposted as required.
5. Zonal, Generator and Transmission Node 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 10minutes after top-of-hour.

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.

Market Participants must examine the RTD 15-minute advisory base points 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 Max Gen Pickup and Base Points ASAP- Commit as Necessary.

Startup of quick start units is also communicated via Inter-Control Center Communications Protocol

(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.

7.2. 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 Resource 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.

- LESRs will not respond to either reserve or max gen pickups. If it is in the supply mode they will maintain its current output level subject to available energy. If consuming, AGC will set the LESR to zero. RTD-CAM modes will solve assuming a net zero position for LESRs.

7.2.1. Reserve Pickup Mode

The NYISO may enter this RTD-CAM mode when necessary to re-establish schedules if the ACE is greater than 100 MW. 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, and will recognize locational Operating Reserve requirements, but will set all Regulation Service schedules to zero. 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 to reduce transmission line loadings. In a large event, RTD-CAM will not reduce Base Point Signals.

7.2.2. 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, Southeastern New York, East of Central East, and/or NYCA-wide. RTD-CAM will produce schedules directing all Resources 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 set all its Regulation Service schedules to zero.

7.2.3. 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 Resources that are capable of responding within five minutes. RTD-CAM will not commit or decommit Resources in this mode.

7.2.4. 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.

7.2.5. 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.

7.3. RTC/RTD Solution Process

RTC/RTD calculates a short-term generation schedule, referred to as a "base point," for each of the generating Resources designated as flexible or "on-dispatch." RTC/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 Resources, telemetry data, and other data needed to model each of the constraints.

RTC/RTD determines the initial conditions to begin the commitment and dispatch process.

These initial conditions include:

a. Real-time telemetry values for generation output, which represents the initial generation MW values.

b. Forecasted values of zonal, load, and the last RTD powerflow transmission zonal losses.

c. Real-time telemetry values for phase angle regulator flows, which represent their initial power schedule if optimized; otherwise the real-time telemetry represents their final power schedule.

d. Real-Time telemetry values to model unscheduled transmission system powerflows such as Lake Erie Circulation.

e. Current facility outage schedules, including forced and scheduled outages and any outages that affect system transfer limits.

f. For LESRs real-time telemetry of energy storage levels.

g. For ESRs real-time telemetry of energy storage level

h. For solar or wind IPR and ESR Generators that participate in a CSR, the MW values from real-time telemetry shall represent each Generator's equivalent output at the Point of Injection. Aggregations comprised of ESR, Wind, or Solar only are not eligible to participate in a CSR

RTC/RTD performs a unit commitment and dispatch and a corresponding powerflow solution to ensure that all actual and contingency transmission constraints are secured to applicable limits. Generation delivery factors are calculated from the RTD powerflow solution and are used to approximate the effects of changes in generation on system transmission losses.

If there are unsecured transmission constraints, then RTC/RTD performs additional network constrained unit commitment and dispatch solutions and corresponding powerflow solutions until all actual and contingency transmission constraints are secured.

The allowable dispatch range (maximum and minimum limits) of the dispatchable Resources 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.

Figure 21: Control Area Constraints
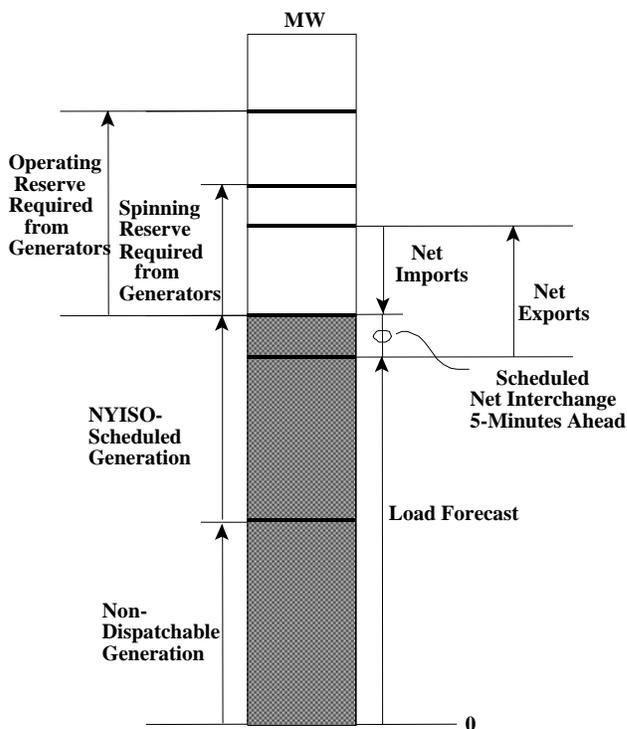
7.3.1. Limit Updates

All Resource-operating limits are taken from Resource bid information. The only changes that are made to unit operating limits are via the OOM package. This is done by a NYISO operator using information received from the TO or the Resource. For more information on OOM treatment, see table 5-8 above.

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 Resource.

If the Resource requires a modification to real-time limits which results in a derating of the Resource due to operational problems, the NYISO can lower the upper operating limit. The corresponding RTD high limit will be adjusted.

Market Participant submit updated CSR Scheduling Limits with each participating CSR Generator's hourly Bids. The CSR Scheduling Limits submitted by the two CSR Generators must match. CSR Scheduling

Limits can be reduced by the ISO via the OOM package.

7.3.2. 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 Resource that has not bid for regulation cannot be placed 'On Control'
2. If a supplier can provide 10-minute non-synchronized reserve but is not scheduled to do so in the DAM 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.

### *Schedule Changes and Ramping of Fixed Units*

Fixed units are scheduled in the Day Ahead Market on an hourly basis. The amount that a fixed unit's schedule can change for the next hour is constrained by the unit's applicable energy response rate that is effective at the unit's level of generation. Day-ahead, a Fixed unit may be scheduled for hour-to-hour changes in amounts up to 1 full hour's ramp capability at its energy ramp rate. A fixed unit is pre-ramped to reach its new schedule value at the beginning of the hour of the schedule change.

For example, if a fixed unit's schedule changes from 200 MW to 230 MW and its response rate is 2 MW/min, it will be ramped beginning 15 minutes before the start of the hour so as to be at 230 MW at the beginning of the hour of the schedule change. Fixed units will be ramped by the Automatic Generation Control (AGC) using 5-minute basepoints from Real-Time Dispatch (RTD). In the above example, the AGC would ramp the unit:

- From 200 to 210 MW over the period T–15 to T-10,

- From 210 to 220 MW over the period T–10 to T–5, and

- From 220 to 230 MW over the period T–5 to T–0.

RTD establishes Fixed unit basepoints based on schedules without regard to unit actual generation values.

When ramping down, basepoints sent to the unit will start to ramp (A) down to the new schedule during the hour prior to the effective time of the new schedule, reaching the new schedule value precisely at the start of the scheduled hour (B). The basepoints sent to the unit will follow the schedule shown below regardless of the actual output of the generator at the beginning of the ramp (A).
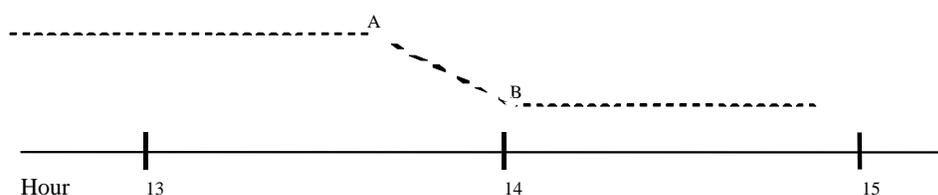
When ramping up, the unit will start to ramp up to the new schedule during the hour prior to the effective time of the new schedule (C), reaching the new schedule precisely at the start of the scheduled hour (D). The basepoints sent to the unit will follow the schedule shown below regardless of the actual output of the generator at the beginning of the ramp (C).
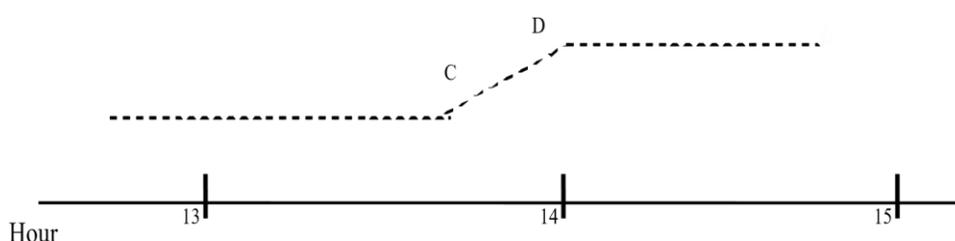
If for any reason the schedule change cannot be achieved in one full hour of ramping (i.e., MW change greater than the applicable energy response rate times 60 minutes), RTD nevertheless ramps the basepoint sufficiently fast to reach the new schedule in one hour and the unit will be responsible for buying replacement energy to make up the difference.

7.3.3. 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 TOs 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.

7.3.4. Transmission loss treatment

The day-ahead and real-time scheduling programs each employ the same treatment of physical transmission losses. The day-ahead software is the Security-Constrained Unit Commitment (SCUC)

program, and the real-time software is the Real-Time Commitment (RTC) and Real-time Dispatch (RTD) programs. Transmission losses are calculated as part of the power flow solution for each time interval simulated by these programs for each of the eleven load zones in the NYCA.

The short-term real-time load forecast provides a forecast of the eleven zonal loads for each interval. The load forecast does not include an estimate of zonal transmission losses. The loss estimates for the load zones are determined from the network power flow solutions of the corresponding RTC/RTD intervals. The load forecast for the real-time market operation is determined for demand only and the calculation of losses within RTC and RTD are added to the forecast for total scheduling or dispatching requirements. Generating resources and external import transactions are scheduled in RTC/RTD to meet (i) the forecast of the zonal loads and (ii) the RTC/RTD zonal loss determinations and external export transactions.

7.3.5. Phase Shifter Models

The RTC/RTD programs assume 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 except for those PARs listed below, 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."

The desired flows will be established for the ABC, JK, 5018 and 1385 interconnections based on the following

- the ABC interconnection will be the current level of ABC power flows (based on PAR MW telemetry values) plus a percentage of the expected schedule changes to the PJMNYISO interchange consistent with Section 17 of the Market Services Tariff.

- the JK interconnection will be the current level of JK power flows (based on PAR MW telemetry values) plus a percentage of the expected schedule changes to the PJM-NYISO interchange consistent with Section 17 of the Market Services Tariff.

- the HopatcongRamapo interconnection will be the current level of 5018 power flows (based on PAR MW telemetry values) plus a percentage of the expected schedule changes to the PJM-NYISO interchange consistent with Section 17 of the Market Services Tariff.

  - Further information regarding the interchange percentage values can be found at the following link:
    https://www.nyiso.com/documents/20142/2268509/NY[https://www.nyiso.com/documents/20142/2268509/NY-NJ_PAR_Interchange_and_OBF.pdf/b674eb7f-159e-1c8b-407a-17bda09b7b32](https://www.nyiso.com)[NJ_PAR_Interchange_and_OBF.pdf/b674eb7f-](https://www.nyiso.com)

- the 1385 Northport-Norwalk Harbor interconnection will be determined by transaction bid evaluation on the NPX 1385 proxy bus.

7.3.6. Ancillary Service Demand curves

The unit commitment and dispatch module used in both the SCUC and RTS systems utilizes demand curves to reflect shortages for certain Ancillary Services. The demand curves allow the program to relax the application requirement if the shadow cost needed to supply the requirement exceeds a preset value. The demand curve functionality is used for the reserve and regulation requirements (except during real-time intervals when the EDRP resources and/or SCRs have been called upon by the NYISO to provide load reduction; please refer to Section 15.4.7 of Rate Schedule 4 of the Market Administration and Control Area Services Tariff and Section 6.8.1 of the Ancillary Services Manual for further details regarding the 30-Minute Reserve Operating Reserve Demand Curves that apply during real-time periods when the NYISO has activated EDRP resources and/or SCRs). The demand curves shown in Figure 23 are implemented:

Figure 22: Ancillary Service Demand Curves

New York Region	Type	Shortage Relative to Requirement (MW)	Demand Curve Price ($/MW)
NYCA	Regulation	Up to 25 MW At least 25 MW, up to 80 MW 80 MW or more	$25.00 $525.00 $775.00
	Spinning Reserve	Any shortage	$775.00
	10 Minute Reserve	Any shortage	$750.00
	30 Minute Reserve	Up to 200 MW At least 200 MW, up to 325 MW At least 325 MW, up to 380 MW At least 380 MW, up to 435 MW At least 435 MW, up to 490 MW At least 490 MW, up to 545 MW At least 545 MW, up to 600 MW At least 600 MW, up to 655 MW 655 MW or more	$40.00 $100.00 $175.00 $225.00 $300.00 $375.00 $500.00 $625.00 $750.00
Eastern New York (EAST)	Spinning Reserve	Any shortage	$40.00
	10 Minute Reserve	Any shortage	$775.00
	30 Minute Reserve	Any shortage	$40.00
Southeastern	Spinning Reserve	Any shortage	$40.00

New York (SENY)	10 Minute Reserve	Any shortage	$40.00
	30 Minute Reserve	Up to the applicable incremental SENY 30-minute reserve quantity (if applicable, a quantity not exceeding 500 MW)	$40.00
		The applicable incremental SENY 30-minute reserve quantity or more (or any shortage if no incremental SENY 30-minute reserve quantity is applicable)	$500.00
New York City (NYC)	Spinning Reserve	Any shortage	$25.00
	10 Minute Reserve	Any shortage	$25.00
	30 Minute Reserve	Any shortage	$25.00
Long Island (LI)	Spinning Reserve	Any shortage	$25.00
	10 Minute Reserve	Any shortage	$25.00
	30 Minute Reserve	Any shortage	$25.00

* If the Regulation Demand Curve is active, RTD will not set basepoints for LESR energy management.

Note: The applicable reserve requirements (including any incremental SENY 30-minute reserve quantity) are posted on the NYISO's website at the following location: https://www.nyiso.com/documents/20142/3694424/Locational-Reserves-Requirements.pdf.

7.3.7. Transmission Constraint Pricing

A graduated pricing mechanism is applied in both the Day-Ahead and real time markets to appropriately value the respective limits for certain facilities. As further described in Section 7.3.7.2 below, certain internal transmission facilities that accommodate power flows out of export constrained areas are subject to a different graduated pricing mechanism ("Identified Facilities"). For other facilities, a single price is applied to appropriately value the respective limits of such facilities.

For transmission facilities and Interfaces subject to a graduated pricing mechanism, the applicable transmission demand curve shall be applied in a manner that considers, collectively, all active transmission constraints associated with a particular transmission facility or Interface, rather than applying the transmission demand curve separately to each active transmission constraint associated with that transmission facility or Interface.

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If redundant transmission constraints are identified on in-series and/or parallel transmission facilities subject to a graduated pricing mechanism, the most limiting of such redundant transmission constraints shall be identified and utilized for application of the applicable transmission demand curve to the redundant transmission constraints.

Examples of Multiple Active Constraints Logic

Example 1: Transmission facility "X" is assigned a 20 MW constraint reliability margin (CRM). Transmission facility "X" is not an Identified Facility and is subject to the six-step transmission demand curve mechanism described in Section 7.3.7.2 below. A base case transmission constraint and a contingency case transmission constraint develop on transmission facility "X." Physical redispatch is available that can resolve both constraints. The overload on each constraint and the cost of modifying the physical dispatch to provide relief on each constraint for this illustrative example are as follows:

- Overload for Base Case Constraint: 2 MW
- Overload for Contingency Case Constraint: 1 MW
- Physical Dispatch Cost: $300/MW

The marginal cost of resolving the active transmission constraints on this facility would be $200/MW, resulting from the utilization of 2 MW of available relief from the applicable transmission demand curve, which relieves both the base case and contingency constraints at a total production cost of $400 (2 MW*$200/MW). This is less expensive from a production cost perspective than modifying the physical dispatch, which, like the transmission demand curve, would also relieve both the base case and contingency constraints, but at a total production cost of $600 (2 MW*$300/MW).

Example 2: Transmission facility "X" is assigned a 20 MW CRM. Transmission facility "X" is not an Identified Facility and is subject to the six-step transmission demand curve mechanism described in Section 7.3.7.2 below. A base case transmission constraint and a contingency case transmission constraint develop on transmission facility "X." Separate physical redispatches would be required to resolve each constraint. The overload on each constraint and the cost of modifying the physical dispatch to provide relief on each constraint for this illustrative example are as follows:

- Overload for Base Case Constraint: 2 MW
- Overload for Contingency Case Constraint: 3 MW
- Physical Dispatch 1 Cost: $100/MW; can resolve only the base case constraint
- Physical Dispatch 2 Cost: $130/MW; can resolve only the contingency case constraint

The marginal cost of resolving the active transmission constraints on this facility would be $200/MW, resulting from the utilization of 2 MW of available relief from the applicable transmission demand curve mechanism, which relieves the base case constraint and provides 2 MW of relief to the contingency constraint, as well as 1 MW of redispatch from "Physical Dispatch 2" to provide relief to the contingency constraint, for a total production cost of $530 ([2 MW*$200/MW] + [1 MW*$130/MW]). This represents the lowest cost solution from a production cost perspective compared to other options.

Example 3: Transmission facility "X" is assigned a 20 MW CRM. Transmission facility "X" is not an Identified Facility and is subject to the six-step transmission demand curve mechanism described in Section 7.3.7.2 below. A base case transmission constraint and a contingency case transmission constraint develop on transmission facility "X." Separate physical redispatches would be required to resolve each constraint. The overload on each constraint and the cost of modifying the physical dispatch to provide relief on each constraint for this illustrative example are as follows:

- Overload for Base Case Constraint: 6 MW
- Overload for Contingency Case Constraint: 4 MW
- Physical Dispatch 1 Cost: $250/MW; can resolve only the base case constraint
- Physical Dispatch 2 Cost: $130/MW; can resolve only the contingency case constraint

The marginal cost of resolving the active transmission constraints on this facility would be $250/MW. This results from using 4 MW of available relief from the applicable transmission demand curve mechanism, which relieves the contingency constraint and provides 4 MW of relief to the base case constraint. In addition, 2 MW of redispatch from "Physical Dispatch 1" is necessary to alleviate the base case constraint. Consequently, the total production cost amounts to $1,300/MW ([4 MW*$200/MW] + [2MW*$250/MW]). Since an additional 2 MW of relief beyond the initial 4 MW of relief from the applicable transmission demand curve would cost $350/MW, this solution represents the lowest cost solution from a production cost perspective compared to other options.

Example of Identifying Redundant Constraints

Shift factors of resources are utilized to identify redundant constraints on in-series and/or parallel transmission facilities. Shift factors represent the MW impact that 1 MW of injection/withdrawal by a resource has on a particular transmission constraint. For example, if the shift factor of a resource is 0.5 on a particular transmission constraint, it would require 2 MW of capability from such resource to relieve the constraint by 1 MW. The shift factors of resources that impact redundant transmission constraints on in-

series transmission facilities are identical. The shift factors of resources that impact redundant transmission constraints on parallel transmission facilities are linearly dependent and related by a scalar factor.

For example, assume that only two resources (Resource$_1$ and Resource$_2$) impact a set of transmission constraints (Constraint$_1$ and Constraint$_2$). The table below provides a hypothetical example of the shift factors for such resources that would identify the transmission constraints as redundant on the transmission facilities at issue. In this illustrative example, the shift factors of the resources for redundant constraints on in-series transmission facilities are equivalent, and shift factors of the resources for redundant constraints on parallel transmission facilities are related by a scalar factor of 3.

	Shift Factor for Constraint$_1$	Shift Factor for Constraint$_2$
Redundant In-Series Constraints	Resource$_1$: 0.9 Resource$_2$: 0.6	Resource$_1$: 0.9 Resource$_2$: 0.6
Redundant Parallel Constraints	Resource$_1$: 0.9 Resource$_2$: 0.6	Resource$_1$: 0.3 Resource$_2$: 0.2

7.3.7.1. Constraint Reliability Margin

A constraint reliability margin (CRM) is applied to all transmission facilities and Interfaces. The CRM represents the value below the maximum physical limit on a transmission facility or Interface that is used by the NYISO's market software as the effective limit when evaluating for economic commitment and dispatch decisions in SCUC, RTC and RTD. The NYISO assigns either a zero or nonzero CRM value to all transmission facilities and Interfaces. A list of transmission facilities and Interfaces that identifies both those facilities and Interfaces that utilize a non-zero CRM value other than 20 MW and facilities that have a zero CRM value, is available on the NYISO website at:

https://www.nyiso.com/documents/20142/2267995/Constraint_Reliability_Margin_CRM.pdf. This list also denotes the Identified Facilities and the CRM applicable to each such facility.

7.3.7.2. Transmission Constraint Pricing Logic

The following pricing logic is applied in instances of transmission shortages:

1) Except for Identified Facilities, a six-step graduated transmission demand curve mechanism is applied to all transmission facilities and Interfaces assigned a non-zero CRM value. The six-step transmission demand curve mechanism consists of following components (the MW value of additional capacity for each step will be rounded to the nearest whole number):

   I. A MW value of additional capacity equal to or less than 20% of the applicable CRM value, at a cost of $200/MWh.

II.   A MW value of additional capacity equal to or less than 40% of the applicable CRM value, but greater than 20% of CRM value, at a cost of $350/MWh.

III.   A MW value of additional capacity equal to or less than 60% of the applicable CRM value, but greater than 40% of CRM value, at a cost of $600/MWh.

IV.   A MW value of additional capacity equal to or less than 80% of the applicable CRM value, but greater than 60% of CRM value, at a cost of $1,500/MWh.

V.   A MW value of additional capacity equal to or less than 100% of the applicable CRM value, but greater than 80% of CRM value, at a cost of $2,500/MWh.

VI.   Any MW value of additional capacity greater than the applicable CRM value, at a cost of $4,000/MWh.

2)   For Identified Facilities, a two-step graduated transmission demand curve mechanism is applied. The two-step transmission demand curve mechanism consists of following components:

I.   A MW value of additional capacity equal to or less than 100% CRM value, at a cost of $100/MWh.

II.   Any MW value of additional capacity greater than 100% of the applicable CRM value, at a cost of $250/MWh.

3)   For transmission facilities and Interfaces assigned a zero CRM value, a transmission demand curve mechanism will not apply. The Shadow Price for transmission constraints associated with such transmission facilities and Interfaces shall not exceed $4,000/MWh.

7.3.7.3. Graduated Transmission Demand Curves

Figure 23: Graduated Transmission Demand Curves

NY Region	Type	Demand Curve (MW)	Demand Curve Price ($/MWh)
All	Facilities/Interfaces other than Identified Facilities with a non-zero CRM value	1) MW value equivalent to 20% of the applicable CRM 2) MW value equivalent to an additional 20% of the applicable CRM 3) MW value equivalent to an additional 20% of the applicable CRM 4) MW value equivalent to an additional 20% of the applicable CRM 5) MW value equivalent to the remaining 20% of the applicable CRM 6) Any MW value greater than the applicable CRM	1) $200 2) $350 3) $600 4) $1,500 5) $2,500 6) $4,000
All	Identified Facilities	1) MW value equivalent to the applicable CRM 2) Any MW value greater than the applicable CRM	1) $100 2) $250
All	Facilities/Interfaces with a zero CRM value	Any MW value	$4,000

7.3.8. Locational Reserves

Operating reserves will be locationally priced and the locational reserve requirements will be determined by the NYISO. There are locational reserve requirements for the NYCA, the Eastern New York area, the Southeastern New York area, the New York City area, and the Long Island area.

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 rate. During a Reserve Pickup, the NYISO will notify the TOs, 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).

7.3.9. 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 NYCA. RC monitors NYCA 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 NYCA.

7.3.10. Reserve Calculations

The following reserve calculations are implemented for the LBMP Market:

1. Reserves are calculated on a locational basis.
2. There are reserve requirements for each of the locational reserve areas with the appropriate alarming.
3. Non-synchronous reserve can only be counted on Resources that have an accepted bid and have been committed for non-synchronous reserve. This applies for both 10minute and Operating Reserve.

All dispatchable (on-line) Resources are counted towards 10-minute synchronous reserve, whether or not they have an accepted reserve availability bid.

7.3.11. Simultaneous Activation of Reserves

The Simultaneous Activation of Reserves (SAR) is a mutual agreement among the following participating areas to provide 10-minute reserve assistance:

- Ontario
- New England/New Brunswick
- NYISO
- PJM

The NYISO acts as the central coordinator for the SAR procedure and will ensure that SAR allocations assigned to the participating areas are within their response capabilities. The SAR allocation for an area is the additional amount of energy it is assigned to provide in response to a SAR request.

Procedure

The following is a summary of the SAR procedure, which is described in greater detail in the

NPCC Regional Reliability Directory#5 Section 5.8 and Appendix#4 (December 2, 2010).

1. ***Preliminary Reserve Assignment:*** On a continuing basis, Maritimes, ISO-NE, Ontario, and PJM dispatchers shall keep the NYISO informed of the largest, single generation or energy purchase contingency on their respective 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, Ontario, 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, Ontario, or PJM, the Area experiencing the loss (Contingency Area) shall indicate whether SAR is being requested and report the following information to the NYISO via the interregional direct telephone lines:

   • Name of generation or purchase lost.

   • Total number of megawatts lost.

   • Time that contingency occurred (time zero T+0).

   • Any transmission or security problems within the Contingency Area that affect SAR allocations to Assisting Areas.

3. ***Activation of Reserve:*** After receiving notification of the SAR request and the specific contingency, the NYISO Shift Supervisor shall:

   • Determine each Area's SAR allocation in accordance with NPCC Regional Reliability Directory#5 Section 5.8 and Appendix#4 (December 2, 2010).

   • By the direct inter-Area telephone lines, immediately inform each Area of its SAR allocation, the time that the schedule change is effective, and the time that the contingency occurred.

   The SAR allocation shall become part of the interchange schedule and shall be implemented 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 Simultaneous Reserve:*** As soon as the Contingency Area has provided its SAR 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.

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.

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 simultaneous activation of reserve procedure.

    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.

    In the event that the second Contingency Area experiences a contingency that qualifies for simultaneous activation of reserve, the NYISO will allocate assistance from the remaining Assisting Areas in accordance with this procedure, upon the request of that Area.

    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 Simultaneous 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:
    - Neighboring SAR area
    - MW amount of SAR
    - 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.

   • RTC will not have a direct SAR MW input.
   • AGC will record the application of the SAR MW inputs.

Attachment A Transmission Facilities

- Table A.1 lists NYISO Facilities Requiring Coordination and Notification.

- Table A.2 lists Bus Voltage Limits.

- Table A.3 lists Bus Voltage Limits for HQ-NYISO transfers.

Table A.1: NYISO Facilities Requiring Coordination and Notification

The NYISO Facilities Requiring Coordination and Notification can be found in the Outage Scheduling Manual (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides).

Table A.2: Bus Voltage Limits

The Bus Voltage Limits can be found in the Emergency Operations Manual (available from the

NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides

)

Table A.3: Bus Voltage Limits for HQ-NYISO Transfers

The Bus Voltage Limits for HQ-NYISO Transfers can be found in the Emergency Operations Manual (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides)

Attachment B Operating Criteria

- Table B.1 lists exceptions to operating criteria for pre-contingency and postcontingency transmission facility flows and voltages.

- Table B.2 lists multiple circuit tower lines in the NYCA [MP 29-1, A].

- Table B.3 lists the NYISO thunderstorm multiple contingencies [MP 29-1, B].

- Table B.4 lists the local reliability rules of the New York Transmission Owners.

- Table B.5 displays the applications of reliability rules and cost allocation responsibility.

Table B.1: Exceptions to the NYSRC Reliability Rules

The exceptions to the NYSRC Reliability Rules are approved by the NYSRC. The current set of exception can be found at:

http://www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.html

:

Table B.2 Multiple Circuit Tower Lines in NY Control Area

The Multiple Circuit Tower Lines in the NY Control Area can be found in the Emergency Operations Manual (available from the NYISO Web site at the following URL:

https://www.nyiso.com/manuals-tech-bulletins-user-guides).

:

Table B.3 Thunderstorm Multiple Contingencies Cases

The Thunderstorm Multiple Contingencies Cases can be found in the Emergency Operations Manual (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides)

:
Table B.4 Local Reliability Rules of the New York Transmission Owners

The Local Reliability Rules are more stringent than the other NYSRC Reliability Rules because of the need to protect delivery in certain zones. The current set of Local Reliability Rules can be found in Section I of the NYSRC Reliability Rules Manual at:

http://www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.html

Table B.5: Applications of Reliability Rules and Cost Allocation Responsibility

The current version of the ARR Table is posted at: https://www.nyiso.com/reports-information

Attachment C Adjusted Offer Curve for Fast-Start Resources

For on-line Fast-Start Resources in the injection mode, the NYISO will use the following procedure to determine an adjusted offer curve for the SCUC and RTS pricing passes:

- First, the NYISO will determine the output level that minimizes the average as-offered cost of operating that unit. This may be its minimum generation level, its UOL, or anywhere in between. This cost is referred to as the "minimum average cost". The output level at which the average cost is minimized is referred to as "AC-minimizing output level".

- For all output levels that are less than or equal to the AC-minimizing output level, the NYISO will set the price on the adjusted offer curve equal to the minimum average cost.

- For all output levels above the AC-minimizing output level, the NYISO will set the price on the adjusted offer curve equal to the price on the offer curve that was submitted.

- Start-up cost is applied to the first hour of operation in Day-Ahead Market and approximately the first 15 minutes of operation in Real-Time Market.

Example 1:

An example of the Adjusted Dispatch Cost curve calculation for the Day-Ahead Market in the first hour of operation is provided below

The Fast-Start Resource Bid components for this example are:

Table C.1: DA Injection

Parameter	Value	Units
Minimum generation cost	1000	$/hr
Minimum generation level	20	MW
Upper operating limit	50	MW
Start-up cost	500	$
Incremental energy curve point 1	40	$/MWh to increase output from 20 MW to 40 MW
Incremental energy curve point 2	60	$/MWh to increase output from 40 MW to 50 MW
Amortization period	1	hr

Total Production Cost ($) at an output level = Start-up cost + (Min gen cost + Incremental cost)*Amortization period

Average Cost ($/MWh) at an output level = Total Production Cost at an output level/ (Output level*Amortization period)

Output Level [MW]	Bid Cost ($/MWh)	Total Production Cost [$]	Average Cost [$/MWh]	Adjusted Offer curve [$/MWh]
20 MW	Min gen cost ($1000/hr)	$500 + ($1000/hr) x 1hr = $1500	$75/MWh	$57.5/MWh
40 MW	$40/MWh	$500 + ($1000/hr + (40 MW – 20 MW) x $40/MWh) x 1hr = $2300	$57.5/MWh	$57.5/MWh
50 MW	$60/MWh	$500 + ($1000/hr + (40 MW – 20 MW) x $40/MWh + (50 MW – 40MW) x $60/MWh) x 1hr = $2900	$58/MWh	$60/MWh
		Minimum average cost [$/MWh]	$57.5/MWh	
		Average cost minimizing output (MW)	**40 MW**	

In this example, the cost-minimizing output level is 40 MW. Therefore, the Adjusted Dispatch Cost curve for this Generator for this interval will be presented to the software pricing pass as follows:

• Adjusted Dispatch Cost for output levels up to and including 40 MW equals $57.50/MWh (this value is based on the average as-offered cost of operating calculation because the $57.50/MWh is above the Bid cost to provide 40 MW)

• Adjusted Dispatch Cost for outputs above 40 MW up to and including 50 MW equals $60.00/MWh (this value is based on the Generator's Bid because the $60.00/MWh is above the average as-offered cost of operating at 50 MW)

Example 2:

An example of the Adjusted Dispatch Cost curve calculation for the Real-Time Market is provided below

The Fast-Start Resource Bid components for this example are:

Table C.2: RT Injection

Parameter	Value	Units
Minimum generation cost	4000	$/hr
Minimum generation level	90	MW
Upper operating limit	100	MW
Start-up cost	400	$
Incremental energy curve point 1	30	$/MWh to increase output from 90 MW to 91 MW
Incremental energy curve point 2	40	$/MWh to increase output from 91 MW to 95 MW
Incremental energy curve point 3	50	$/MWh to increase output from 95 MW to 100 MW
Amortization period	0.25	hr

In RTS, because start-up costs are amortized over the first 15 minutes, the adjusted offer curve within the first 15 minutes includes start-up costs. After the first 15-minutes, the start-up costs are not included when determining the adjusted offer curves.

- Total Production Cost ($) at an output level within the first 15-minutes = Start-up cost + (Min gen cost + Incremental cost)*Amortization period
- Average Cost ($/MWh) at an output level within the first 15-minutes = Total Production Cost at an output level/ (Output level*Amortization period)

Adjusted Offer curve for the first 15 minutes (including the 15th minute)

Output Level [MW]	Bid Cost [$/MWh]	Total Production Cost [$]	Average Cost [$/MWh]	Adjusted Offer curve [$/MWh]
90 MW	Min gen cost ($4000/hr)	$400 + ($4000/hr) x 0.25hr = $1400	$62.22/MWh	$60.40/MWh
91 MW	$30/MWh	$400 + ($4000/hr + (91 MW – 90 MW) x $30/MWh) x 0.25hr = $1407.5	$61.87/MWh	$60.40/MWh
95 MW	$40/MWh	$400 + ($4000/hr + (91 MW – 90 MW) x $30/MWh + (95 MW – 91 MW) x $40/MWh) x 0.25hr = $1447.5	$60.95/MWh	$60.40/MWh
100 MW	$50/MWh	$400 + ($4000/hr + (91 MW – 90 MW) x $30/MWh + (95 MW – 91 MW) x $40/MWh + (100 MW – 95 MW) x $50/MWh) x 0.25hr = $1510	$60.40/MWh	$60.40/MWh
		Minimum average cost [$/MWh]	**$60.40/MWh**	
		Average cost minimizing output (MW)	**100 MW**	

For the first 15-minutes in this example, the cost-minimizing output level is 100 MW. Therefore, the Adjusted Dispatch Cost curve for this Generator for this interval will be presented to the software pricing pass as follows:

> • Adjusted Dispatch Cost for output levels up to and including 100 MW equals $60.40/MWh (this value is based on the average as-offered cost of operating calculation because the $60.40/MWh is greater than the incremental energy Bid of $50/MWh to provide 100 MW)

Total Production Cost ($) at an output level after the first 15-minutes = (Min gen cost + Incremental cost)*1hr

Average Cost ($/MWh) at an output level after the first 15-minutes = Total Production Cost at an output level/ (Output level*1hr)

Adjusted Offer curve after the first 15 minutes

Output Level [MW]	Bid Cost [$/MWh]	Total Production Cost [$]	Average Cost [$/MWh]	Adjusted Offer curve [$/MWh]
90 MW	Min gen cost ($4000/hr)	($4000/hr) x 1hr = $4000	$44.44/MWh	$44.11/MWh
91 MW	$30/MWh	($4000/hr + (91 MW – 90 MW) x $30/MWh) x 1hr = $4030	$44.29/MWh	$44.11/MWh
95 MW	$40/MWh	($4000/hr + (91 MW – 90 MW) x $30/MWh + (95 MW – 91 MW) x $40/MWh) x 1hr = $4190	$44.11/MWh	$44.11/MWh
100 MW	$50/MWh	($4000/hr + (91 MW – 90 MW) x $30/MWh + (95 MW – 91 MW) x $40/MWh + (100 MW – 95 MW) x $50/MWh) x 1hr = $4440	$44.40/MWh	$50/MWh
		Minimum average cost [$/MWh]	**$44.11/MWh**	
		Average cost minimizing output (MW)	**95 MW**	

In this example, after the first 15 minutes, the cost-minimizing output level is 95 MW. Therefore, the Adjusted Dispatch Cost curve for this Generator for this interval will be presented to the software pricing pass as follows:

- Adjusted Dispatch Cost for output levels up to and including 95 MW equals $44.11/MWh (this value is based on the average as-offered cost of operating calculation because the $44.11/MWh is greater than the incremental energy Bid of $40/MWh to provide 95 MW.
- Adjusted Dispatch Cost for outputs above 95 MW up to and including 100 MW equals $50.00/MWh (this value is based on the Generator's Bid because the incremental energy Bid of $50.00/MWh is greater than the average as-offered cost of $44.11/MWh)

For on-line Fast-Start Resources in the withdrawal mode, the NYISO will use the following procedure to determine an adjusted offer curve for the SCUC and RTS pricing passes:

- First, the NYISO will determine the output level that maximizes the average as-offered cost of operating that unit. This may be its minimum generation level, its UOL, or anywhere in between. This cost is referred to as the "maximum average cost". The output level at which the average cost is maximized is referred to as "AC-maximizing output level".

- For all output levels that are greater than or equal to the AC-maximizing output level, the NYISO will set the price on the adjusted offer curve equal to the maximum average cost.

- For all output levels less the AC-maximizing output level, the NYISO will set the price on the adjusted offer curve equal to the price on the offer curve that was submitted.

- Start-up cost is applied to the first hour of operation in Day-Ahead Market and approximately the first 15 minutes of operation in Real-Time Market.

Example 3

An example of the Adjusted Dispatch Cost curve calculation for the Day-Ahead Market in the first hour of operation for an Energy Limited resource that is withdrawing is provided below.

The Fast-start Resource Bid components for this example are:

Table C.3: DA Withdrawal

Parameter	Value	Units
Minimum generation cost	-5000	$/hr
Minimum generation level	-350	MW
Upper operating limit	0	MW
Start-up cost	0	$
Incremental energy curve point 1	11	$/MWh from -350 MW to -325 MW
Incremental energy curve point 2	12	$/MWh from -325 MW to -300 MW
Incremental energy curve point 3	13	$/MWh from -300 MW to -250 MW
Incremental energy curve point 4	14	$/MWh from -250 MW to -50 MW
Incremental energy curve point 5	15	$/MWh from -50 MW to 0 MW
Amortization period	1	hr

Total Production Cost ($) at an output level = Start-up cost + (Min gen cost + Incremental cost)*Amortization period

Average Cost ($/MWh) at an output level = Total Production Cost at an output level/ (Output level*Amortization period)

When a fast-start resource is withdrawing, the maximum average cost is considered when determining the adjusted offer curve.

Output Level [MW]	Bid Cost [$/MWh]	Total Production Cost [$]	Average Cost [$/MWh]	Adjusted Offer curve [$/MWh]
-50 MW	$15/MWh	$0 + (-$5000/hr + (-325 MW - (-350 MW)) x $11/MWh + (-300 MW - (-325 MW)) x $12/MWh + (-250 MW - (-300 MW)) x $13/MWh + (-50 MW - (-250 MW)) x $14/MWh) x 1hr = -$975	$19.5/MWh	$19.5/MWh
-250 MW	$14/MWh	$0 + (-$5000/hr + (-325 MW - (-350 MW)) x $11/MWh + (-300 MW - (-325 MW)) x $12/MWh + (-250 MW - (-300 MW)) x $13/MWh) x 1hr = -$3775	$15.10/MWh	$14/MWh
-300 MW	$13/MWh	$0 + (-$5000/hr + (-325 MW - (-350 MW)) x $11/MWh + (-300 MW - (-325 MW)) x $12/MWh) x 1hr = -$4425	$14.75/MWh	$13/MWh
-325 MW	$12/MWh	$0 + (-$5000/hr + (-325 MW - (-350 MW)) x $11/MWh) x 1hr = -$4725	$14.54/MWh	$12/MWh

-350 MW	Min Gen cost (-$5000/hr)	$0 + (-$5000/hr) x 1hr = -$5000		$14.29/MWh	$11/MWh
		Maximum average cost [$/MWh]		**$19.5/MWh**	
		Average cost maximizing output (MW)		**-50 MW**	

The cost-maximizing output level for this resource that is withdrawing is -50 MW. Therefore, the Adjusted Dispatch Cost curve for this resource for this interval will be presented to the software pricing pass as follows:

- Adjusted Dispatch Cost for output levels up to and including -50 MW equals $19.50/MWh (this value is based on the maximum average cost calculation)
- Adjusted Dispatch Cost for output levels beyond -50 MW up to -350 MW equals the actual as-offered cost

Example 4

An example of the Adjusted Dispatch Cost curve calculation for the Real-Time Market for an Energy Limit resource that is withdrawing is provided below.

The Fast-start Resource Bid components for this example are:

Table C.4: RT Withdrawal

Parameter	Value	Units
Minimum generation cost	-3500	$/hr
Minimum generation level	-350	MW
Upper operating limit	0	MW
Start-up cost	0	$
Incremental energy curve point 1	11	$/MWh from -350 MW to -325 MW
Incremental energy curve point 2	12	$/MWh from -325 MW to -300 MW
Incremental energy curve point 3	13	$/MWh from -300 MW to -250 MW
Incremental energy curve point 4	14	$/MWh from -250 MW to -50 MW
Incremental energy curve point 5	15	$/MWh from -50 MW to 0 MW
Amortization period	0.25	hr

Total Production Cost ($) at an output level within the first 15 minutes = Start-up cost + (Min gen cost + Incremental cost)*Amortization period

Average Cost ($/MWh) at an output level within the first 15 minutes = Total Production Cost at an output level/ (Output level*Amortization period)

Adjusted Offer curve for the first 15 minutes (including the 15th minute)

Output Level [MW]	Bid Cost [$/MWh]	Total Production Cost [$]	Average Cost [$/MWh]	Adjusted Offer curve [$/MWh]
-50 MW	$15/MWh	$0 + (-$3500/hr + (-325 MW - (-350 MW)) x $11/MWh + (-300 MW - (-325 MW)) x $12/MWh + (-250 MW - (-300 MW)) x $13/MWh + (-50 MW - (-250 MW)) x $14/MWh) x 0.25hr = $131.25	-$10.5/MWh	$10/MWh
-250 MW	$14/MWh	$0 + (-$3500/hr + (-325 MW - (-350 MW)) x $11/MWh + (-300 MW - (-325 MW)) x $12/MWh + (-250 MW - (-300 MW)) x $13/MWh) x 0.25hr = -$568.75	$9.10/MWh	$10/MWh
-300 MW	$13/MWh	$0 + (-$3500/hr + (-325 MW - (-350 MW)) x $11/MWh + (-300 MW - (-325 MW)) x $12/MWh) x 0.25hr = -$731.25	$9.75/MWh	$10/MWh
-325 MW	$12/MWh	$0 + (-$3500/hr + (-325 MW - (-350 MW)) x $11/MWh) x 0.25hr = -$806.25	$9.92/MWh	$10/MWh
-350 MW	Min Gen cost (-$3500/hr)	$0 + (-$3500/hr) x 0.25hr = -$875	$10.00/MWh	$10/MWh

| | | Maximum average cost [$/MWh] | $10.00/MWh | |
| | | Average cost maximizing output (MW) | -350 MW | |

For the first 15 minutes, the cost-maximizing output level for this resource that is withdrawing is -350 MW. Therefore, the Adjusted Dispatch Cost curve for this resource for this interval will be presented to the software pricing pass as follows:

- Adjusted Dispatch Cost for output levels up to and including -350 MW equals $10/MWh (this value is based on the maximum average cost calculation)

Total Production Cost ($) at an output level after the first 15-minutes = (Min gen cost + Incremental cost)*1hr

Average Cost ($/MWh) at an output level after the first 15-minutes = Total Production Cost at an output level/ (Output level*1hr)

Adjusted Offer curve after the first 15 minutes

Output Level [MW]	Bid Cost [$/MWh]	Total Production Cost [$]	Average Cost [$/MWh]	Adjusted Offer curve [$/MWh]
-50 MW	$15/MWh	(-$3500/hr + (-325 MW - (-350 MW)) x $11/MWh + (-300 MW - (-325 MW)) x $12/MWh + (-250 MW - (-300 MW)) x $13/MWh + (-50 MW - (-250 MW)) x $14/MWh) x 1hr = $525	-$10.5/MWh	$10/MWh
-250 MW	$14/MWh	(-$3500/hr + (-325 MW - (-350 MW)) x $11/MWh + (-300 MW - (-325 MW)) x $12/MWh + (-250 MW - (-300 MW)) x $13/MWh) x 1hr = -$2275	$9.10/MWh	$10/MWh
-300 MW	$13/MWh	(-$3500/hr + (-325 MW - (-350 MW)) x $11/MWh + (-300 MW - (-325 MW)) x $12/MWh) x 1hr = -$2925	$9.75/MWh	$10/MWh
-325 MW	$12/MWh	(-$3500/hr + (-325 MW - (-350 MW)) x $11/MWh) x 1hr = -$3225	$9.92/MWh	$10/MWh
-350 MW	Min Gen cost (-$3500/hr)	(-$3500/hr) x 1hr = -$3500	$10.00/MWh	$10/MWh
		Maximum average cost [$/MWh]	$10.00/MWh	
		Average cost maximizing output (MW)	-350 MW	

After the first 15 minutes, the cost-maximizing output level for this resource that is withdrawing is -350 MW. Therefore, the Adjusted Dispatch Cost curve for this resource for this interval will be presented to the software pricing pass as follows:

- Adjusted Dispatch Cost for output levels up to and including -350 MW equals $10/MWh (this value is based on the maximum average cost calculation)