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Day-Ahead Scheduling Manual

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Revision History

Version	Effective Date	Revisions
1.0	09/03/1999	Exhibit 3.1 ➢ New Exhibit Attachment A ➢ Addition of last 2 paragraphs of Attachment A. Sect. 3.2.4 Page 4 ➢ Phase Angle Regulator (PAR) Scheduling Sect. 3.3.1 Page 6, 7 ➢ SCUC Stages
2.0	06/12/2001	Sect. 1.1.1, The Day-Ahead Subsystem Bullet 3 ➢ Delete: Step 1: Commits Generators (Set 1) based on Load Serving Entity bids, firm Bilateral Transactions, reserve requirements, and regulation requirements. The Load in this step is referred to as the First Settlement load. ➢ Step 2: Commits additional Generators (Set 2) as required in the event that the New York Independent System Operator load forecast is greater than the First Settlement load in Step 1. ➢ Step 3: Security Constrained Dispatch: based on the First Settlement load from Step 1 and the Generators from Sets 1 and Set 2. Sect. 1.3, Functions ➢ Delete: Network Sensitivity (NS) — The Network Sensitivity function provides the transmission loss Penalty Factors for use by the Security Constrained Unit Commitment program. Sect. 1.3, Data Flow ➢ Delete: b. Penalty Factors — The BSYS function retrieves penalty factors from the Network Sensitivity function. ➢ h. Outage Scheduler to SCUC — SCUC retrieves the TTCs for the transfer of energy between the Zones and Area to Area export limits. Sect. 3.1, Inputs to Day-Ahead Scheduling ➢ Delete last bullet: all-lines-in DFAX Sect. 3.1, Outputs from Day-Ahead Scheduling ➢ Delete first bullet: ➢ facility outages to the Real-Time Security Analysis (RTSA) model Sect. 3.2.1 ➢ Delete first bullet: ➢ preparation of a path-oriented TTC flat file for SCUC input which is stored on the Transmission Constraint Group (TCG) file Sect. 3.2.3 ➢ Add “and commitment rules” to the end of the subsection’s title

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		Sect. 3.2.3, 2nd paragraph ➢ Replace “these” before “statuses” with “generating unit” Sect. 3.2.3, 2nd paragraph ➢ Delete 2nd sentence Sect. 3.2.3After 2nd paragraph, add: Initialization Status ➢ When SCUC initializes, the statuses of the units that bid into the Day-Ahead Market (DAM) are based on their current operating mode at the time of initialization, with modifications. The modifications are the projected changes for the remainder of the day from the previous day’s DAM schedules. If a unit is not in the mode that SCUC expects it to be at the time of initialization, the current mode of the unit overrides the projected change. No units are considered must run in SCUC. ➢ BME honors all day-ahead commitments of internal generation resulting from SCUC, except for quick-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 hour’s evaluation. Startup Time ➢ Either a startup versus downtime curve or a notification time can be provided for SCUC. If both are provided, the startup versus downtime curve overrides the notification value. ➢ SCUC posts the results for the next day’s DAM at 11:00 a.m. If a unit is down at posting time, the startup time is measured from the time of posting. The unit is recognized as unavailable until the startup notification period has elapsed. ➢ If a unit is running but projected to come down after posting time, a bid for the unit in SCUC indicates that it is willing to operate. Neither a startup versus downtime curve nor a notification time value is recognized. ➢ BME ignores both startup versus downtime curves and notification times. A bid in the Hour-Ahead-Market indicates that a unit is able to operate in that hour if scheduled. Minimum Run Time ➢ In SCUC, the minimum run time is honored within the 24-hour evaluation period only; requirements across midnight are not recognized. A unit must bid appropriately to enable commitment in the next day. ➢ BME ignores minimum run time. Minimum Down Time ➢ SCUC honors the minimum down time within the 24-hour evaluation period only; requirements across midnight are not recognized. A unit must bid appropriately to preclude commitment in the next day. ➢ The minimum down time is honored at all times by BME. Sect. 3.2.4, #2

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		➢ Replace “contingencies occur” with “maintenance facility outages are scheduled” Sect. 3.2.4 ➢ Delete # “4) Interface schedule and actual flows will be posted.” Sect. 3.3.1 ➢ Insert new # “4) Committing sufficient Capacity to meet the ISO's Load forecast and Local Reliability Rule requirements.” And renumber remaining item in list. Sect. 3.3.1 ➢ Paragraph after #5, Revise to read as follows: “To meet the above requirements, the SCUC algorithm is a five pass process in which three security constrained commitment passes and two security constrained dispatch passes are executed in sequence as follows:” Delete: ➢ Step 1: SCUC with Bid Load - A First SCUC will be based on day-ahead firm bilateral transaction schedule requests, supplier bids, and LSE load bids. This will result in Generator Set #1, and LBMPs that will be used in the Second SCUC. ➢ Step 2: SCUC with Forecast Load - A Second SCUC will result in an additional Generator Set #2. This SCUC run will use: ➢ a. The NYISO forecasted load. ➢ b. Committed generators from the First SCUC (Gen Set #1) with their start-up and minimum generation price bids set to zero for the hours they were committed, and minimum generation limit set to the First SCUC dispatch level. Additionally, their incremental energy price bids will be set equal to zero. ➢ c. Other bid generators that were not committed in the First SCUC. For the Second SCUC, the bids for the previously non-committed generators will be adjusted in the two following ways to select Gen Set #2: ➢ 1. Each will have its Min Gen Price Bid reduced by its Min Gen Bid multiplied by LBMP from the First SCUC. For example, if a non-committed generator had a $4,000/hr Min Gen Price Bid with a Min Gen Bid of 100 MW, and LBMP from the First SCUC for a specific hour was $30/MWh, then that generator's Min Gen Price Bid for that hour will be set equal to ($4,000 - (100 x $30)) = $1,000/hr. ➢ 2. Each will have its incremental energy price bid set equal to zero (this is intended to minimize the cost of providing additional operating reserves for the non-bid portion of the ISO's total load forecast, but not necessarily minimizing the cost of energy to serve that non-bid load). ➢ Step 3: SCUCD Ideal Dispatch to Set Preliminary Day-Ahead Schedule - Following completion of the two sets of SCUC, a first Day-Ahead hourly Security Constrained Unit Commitment Dispatch (SCUCD) will be performed to produce First Settlement LBMPs. This first "ideal" SCUCD will use: ➢ a. The Load Bids from the First SCUC.

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		➢ b. In the interim: the committed generators from Gen Set #1 (including Gen Set #1 committed Quickstart generators) using their actual bid data and prices, with the exception that Gen Set #1 Quickstart generators will have minimum operating levels of 0 MW and maximum operating capabilities equal to their maximum bid MW. ➢ Ultimately: the combination with or without any or all Quickstart generators from Gen Set #1 which yields the least expensive dispatch will be passed to Step #4 below. ➢ c. The committed generators from Gen Set #2 (excluding Gen Set #2 committed Quickstart generators) using their actual bid data and prices. ➢ If Quickstart generators in the first "ideal" SCUCD are dispatched to their maximums, they will set LBMP. Thus, a Gen Set #1 Quickstart generator will set LBMP only when it is needed to economically serve load. ➢ Step 4: SCUCD Real Dispatch to Set Day-Ahead Schedules and LBMPs ➢ In the Interim: SCUCD will be run a second time with the same parameters as the first SCUCD except that all Gen Set #1 generators and all Gen Set #2 generators (excluding Gen Set #2 Quickstart generators) will be run at least at minimum ➢ Ultimately: All generators in Step #3 that were dispatched above zero will be run at least at minimum. ➢ This second "real" SCUCD will be performed to produce generator schedules and load schedules to be used for First Settlement forward contracts. ➢ <u>Note:</u> Commitment means to start-up a generator to run at or above its minimum generation level. Therefore, if a Quickstart generator is shown to be needed in the first SCUCD, it is scheduled on-line to run at maximum by the second SCUCD because the minimum level for a Quickstart generator is typically the same as its maximum level. Quickstart generators have start-up times of one hour or less. Sect. 3.3.1 ➢ Insert material from Tech Bulletin #49 Sect. 3.3.2 ➢ Under “Initial Unit Commitment (IUC):” delete last bullet: “penalty factors” Sect. 3.3.3, Under “Startup and Shutdown Constraints” ➢ Delete 2nd paragraph: Conflicts between these limits and generator maintenance schedules are resolved using the constraint breaking rules established by the NYISO. Sect. 3.3.3, Under “Penalty Factors” ➢ Delete 1st paragraph: “Transmission loss Penalty Factors are input for each generator. The Penalty Factors multiply the generation operating bid cost during the schedule and dispatch optimization. A single set of Penalty Factors is used for each SCUC execution.” And replace with “The SCUC application uses

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		the ABB Security Analysis (SA) module to generate delivery factors for each time step in the commitment period. The delivery factors for each time step reflects the network topology expected for that time period and the generation dispatch from the Unit Commitment (UC) module." Sect. 3.3.5 ➢ Delete section: "NYISO Operator User Interface – Operator Participation, Operator participation is a feature of the Unit Commitment that enables the operator to override the UC solution with direct instructions as to how specific generators are to be loaded and/or dispatched. The costing and dispatching algorithms of UC are then rerun to implement these instructions. ➢ Operator participation is a "total" override capability. That is, the operator must tell whether a generator is to be ON during a specified amount of time, and if so whether it is to be ON at a specified MW level or at a level dictated by economics (economically dispatched). Also, if a generator is specified to be ON, whether it contributes toward reserve as usual or whether it does not contribute to reserve at all. ➢ It is necessary to emphasize here that the original commitment sequence of generators remains unchanged unless modified by the operator. When running under the operator participation mode, the commitment optimization algorithms are not re-executed. A consequence of this is that constraints such as minimum uptime and downtime may be violated based on operator directives. ➢ Minimum up and downtime, ramp rate, start-up and shutdown constraints are checked and violations are reported. Sect. 3.4.2 ➢ Delete material after 1st paragraph and replace with new material. 5.3, Replace current #3 Determine the zonal load forecast. ➢ The state-wide load forecast used in SCUC is based on a summation of the zonal load values. The ISO Services tariff requires that the LSE load forecasts be considered in the development of the state-wide forecast when it is consistent with the ISO forecast. The LSE zonal load forecast is considered to be consistent with the ISO forecast when the sum of the LSE zonal load forecasts on a control area basis is less than 105% of the ISO forecast on a state-wide basis and when the LSE forecast is within 100% to 105% of the ISO forecast on a zonal basis. Therefore, if the sum of the LSE zonal load forecasts is not consistent with the ISO state-wide forecast, then the LSE zonal load forecasts are not considered. Additionally, if a LSE zonal load forecast is not consistent with the ISO zonal forecast, then the LSE zonal load forecast is not considered. Therefore, the zonal load values used in SCUC are determined using the following rules:

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		The Bid Load plus Bilateral contracts zonal value is used as the zonal load value when: ➢ a) the Bid Load plus bilateral contracts zonal value is greater than the ISO zonal load forecast and, ➢ b) the Bid Load plus bilateral contracts zonal value is greater than the LSE zonal load forecast, when determined to be consistent with the ISO forecast. The ISO zonal load forecast is used as the zonal load value when: ➢ a) the ISO zonal load forecast is greater than the Bid Load plus Bilateral contracts zonal load value and, ➢ b) the ISO zonal load forecast is greater than the LSE zonal load forecast, when determined to be consistent with the ISO forecast. The LSE zonal load forecast, when determined to be consistent with the ISO forecast, is used as the zonal load value when: ➢ a) the LSE zonal load forecast is greater than the ISO zonal load forecast and, ➢ b) the LSE zonal load forecast is greater than the Bid Load plus bilateral contracts zonal value.
3.0	05/06/2003	Section 1 ➢ Replaced BME with RTC ➢ Replaced SCD with RTD ➢ Changed BSYS to Bid/Post System ➢ Changed UCP to PUC Section 2 ➢ Replaced BME with RTC ➢ Replaced SCD with RTD ➢ Corrected inaccurate information ➢ Changed UCP to PUC Section 3 ➢ Revised 3.3.1 with TB#49 ➢ Revised 3.4.2 with TB#32 ➢ Changed BSYS to Bid/Post System ➢ Changed UCP to PUC Section 4 ➢ Replaced BME with RTC Section 6 ➢ Created 6.4 with TB#13 ➢ Created 6.5 with TB#6 ➢ Changed BSYS to Bid/Post System Section 7 ➢ Question Section 8

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		Replaced BME with RTC Section 9 ➢ Question Section 10 ➢ Replaced BME with RTC ➢ Replaced SCD with RTD Attachment A ➢ Replaced BME with RTC Attachment B ➢ Removed NYPP ➢ Improved Exhibit titles and references
4.0	02/04/2013	Section 4.2.7 ➢ Incorporated Technical Bulletin #26, 32, 49, 65, 71, 86, 135, 152, 182 ➢ Changed The ABC interconnection will be scheduled … plus “an adjustment of up to 13%”, into “0%” of PJM-NYISO Day-Ahead Market hourly interchange ➢ Changed The JK interconnection will be scheduled … plus “an adjustment of up to 13%”, into “0%” of PJM-NYISO Day-Ahead Market hourly interchange Section 4.3.3 ➢ Changed The incremental energy bid for a generator is modeled as “a piecewise linear monotonically increasing cost curve” into “a series of monotonically increasing constant cost steps” Deleted Section 6.4 MIS Load Modeling and LSE Responsibilities Deleted Section 6.5 Load Forecasts for Facilities in the Market Information System
4.0	08/15/2012	Added Section 1: INTRODUCTION ➢ 1.1 Included References Re-numbered other sections Section 2 ➢ Renamed section name from Day Ahead Scheduling to OVERVIEW Figure 2-1: ➢ Changed “Hour-Ahead Bids” into “Real-Time Bids” Section 2.2 ➢ Added a paragraph about the daily reliability study over the seven-day period Broke “Functions” into Section 2.3.1: Primary Functions and Section 2.3.2: Supporting Functions Section 2.3.1 ➢ Deleted “Eligible Customers”

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		Section 2.3.2 ➢ Deleted Post Unit Commitment (PUC) ➢ Replaced Performance Tracking System (PTS) with Automatic Generation Control (AGC) Section 2.3.3 ➢ Added Automated Mitigation Process (AMP) ➢ Reserve and Regulation Requirements: Changed “on a Transmission Constraint Group basis” to “from the Energy Management System” Section 3.1 2nd paragraph ➢ Changed “general NYISO status to all Market Participants such as performing unscheduled commitment” to “generators that are committed for reliability under Operational Announcements on the ISO website” Section 3.2 ➢ Changed Bilateral Transactions into External Transactions ➢ Added a bullet on Prohibited Transmission Paths for Validity Checks Section 3.3 ➢ Deleted the section LBMP Calculation ➢ Deleted the section Loss Calculation Section 4 ➢ Changed Bilateral Transactions into External Transactions Section 4.1 ➢ Added Validated virtual generation and virtual load bids from the BID/Post System, and Lake Erie circulation assumptions in Inputs to Day-Ahead Scheduling ➢ Added in Outputs from Day-Ahead Scheduling: Non-Firm Available Transfer Capabilities (ATCs) posted on OASIS, PAR Flows posted on OASIS, Day-Ahead Limiting Constraints posted on OASIS, Commitment schedule for External Transactions Section 4.2 ➢ Changed Preliminary Zonal Load Forecast to Day-Ahead Zonal Load Forecast ➢ Moved Assemble Day-Ahead Transmission Outages to section 4.2.2 Section 4.2.3 ➢ Changed Performance Tracking into Automatic Generation Control ➢ Added: requirements across midnight are not recognized, except to the extent they are reflected in a late day start Bid Added Section 4.2.4: Scheduling a “Must Run” Generator ➢ Incorporated Technical Bulletin #26 ➢ Added Submit a Bid in Self-Committed Fixed Mode

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		Added Section 4.2.5: Multiple Response Rates for Generating Units ➢ Incorporated Technical Bulletin #71 ➢ Changed “regulating response rate” into “regulating capacity response rate” ➢ Added “The regulation capacity response rate must not be slower than the slowest energy or emergency response rate.” ➢ Changed “Customer Relations” into “Stakeholder Services” Added Section 4.2.6: Day Ahead Reliability Unit (DARU) Commitment ➢ Incorporated Technical Bulletin #182 ➢ Added “or for statewide reliability needs as initiated by NYISO,” are known as Day-Ahead Reliability Units (“DARU”) ➢ Changed the Generator’s contact may also reach out to inform the NYISO “at 518-356-6028” into “Grid Operations Department” ➢ Added: A DARU request by a Transmission Owner “or by the NYISO” may override a generator’s startup notification time Section 4.2.7 ➢ Added “The desired flows will be established for the ABC, JK, and 5018 interconnections based on the following, pursuant to OATT Section 35, Attachment CC – JOA Among and Between NYISO and PJM, Schedule C and Schedule D” and added scheduling rules for ABC, JK and 5018 ➢ Added the paragraph about scheduling of Northport PAR Section 4.3.1 ➢ Incorporated changes in Technical Bulletin #49 ➢ Pass #1: Changed the name to Bid Load, “Virtual Load and Virtual Supply” Commitment ➢ Changed “solves for supplying the Bid Load” into “commits and schedules generating units, including units nominated to be Day Ahead Reliability Units, to supply Bid Load (Physical and Virtual) less Virtual Supply” ➢ Added “Also, the program secures for certain Local Reliability Rules’ contingencies and monitored facilities” ➢ Pass #2: Changed “solves for supplying the forecast load” into “commits any additional units that may be needed to supply the forecast load” ➢ Added “Load bids (physical and virtual) and Virtual Supply bids are not considered in Pass #2” ➢ Added “In Pass #2, only the wind energy forecasts are used for scheduling intermittent resources that depend on wind as their fuel” ➢ Changed Pass #3 from “Local Reliability Rules Forecast Load Commitment” to “Reserved for future use” ➢ Pass #4: Changed “regulation” to “regulation capacity” ➢ Pass #5: Added “virtual load and virtual supply (where virtual supply is treated as negative virtual load)”

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		➢ Deleted "After this dispatch, the market power mitigation process is run to evaluate reserve price caps" ➢ Forecast Required Energy for Dispatch (FRED) *Changed "Bilateral Schedules with Internal Sinks" into "import transaction schedules"* ➢ FRED Payment Rules ➢ Added "subject to mitigation as appropriate" Section 4.3.2 ➢ Initial Unit Commitment (IUC): Changed "performance tracking system" into "Automatic Generation Control system" ➢ Deleted New York Interface constraints ➢ Changed "An input processor takes the flat files from the Bid/Post system and load them into the IUC database" into "Bid data is transferred from the Bid/Post system into the RANGER database" ➢ Unit Commitment (UC): Changed "calculates the minimum bid price" into "calculates the minimum bid cost schedule" ➢ Added "Each UC solution is comprised of a physical dispatch and an ideal dispatch. The ideal dispatch allows for GTs to be dispatched across their entire operating range. The LBMPs are determined from this dispatch. The physical dispatch uses blocked bid limits for GTs modeling the physical manner in which GTs operate. The generation schedules are determined from this dispatch. ➢ Infeasible Handling: Changed "it automatically ceases to be enforced in a hard manner and is permitted to be violated" into "the constraint is relaxed, and solved for," Section 4.3.3 ➢ Production Bid: Changed "bid operating costs" into "incremental energy, minimum generation … costs" ➢ Operating Bid: Changed "incremental operating bid" into "incremental energy bid" ➢ Added: The first segment is "determined by the minimum generation cost and" defined by the no-load cost axis intercept ($/hr) and a slope ($/MWh). The "11 incremental energy" segments … ➢ Startup Bid: Changed the generator has been "down" to "off line" ➢ Reserve Bid: Changed regulation "cost" into "bid" ➢ Added: "It is given by a regulation available capacity (MW), a regulation capacity cost ($/MW) and regulation movement cost ($/MW)" ➢ Changed: For off-line and non-dispatchable generators, "the reserve bid is given by a reserve availability cost ($/MW)" ➢ Incorporated TB135. Added the paragraphs about Losses ➢ Reserve Profile: Changed "Regulation" into "Regulation capacity" ➢ Added: Regulation "available is limited by the regulation capacity response rate" and spinning reserve "is" determined by …

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		Added Section 4.3.4: Demand Curves Section 4.3.5 ➢ Changed “1. Interruptible transactions” into “1. Regulation and reserve constraints” ➢ Changed “2. Export constraints” into “2. Transmission constraints” ➢ Changed “3. Import constraints” into “3. Interchange ramp constraints” ➢ Deleted “4. Reserve constraints” ➢ Changed “5. System generation requirement” into “4. System Demand” ➢ Changed “Soliciting additional bids” into “Dispatching generators to emergency upper operating limits” ➢ Deleted: “Requesting the” cancellation or rescheduling of outages Section 4.3.6 ➢ Bid/Post System: Deleted “and Penalty Factors”. ➢ Added: “Later SCUC provides the Bid/Post System with accepted generator, transaction, and load bids, clearing prices, etc. This information is also passed on to the Real-Time Commitment process during the Dispatch Day.” ➢ Delete the bulletin on “Performance Tracking System” ➢ Changed “Outage Scheduler” into “Energy Management System (EMS)” ➢ Added “reserve and regulation requirements, unit status history and contingency definition”. ➢ Changed “OS function” into “EMS” ➢ Changed “Post Unit Commitment” into “Load Forecaster”, and the paragraph into: ➢ “The SCUC function receives the load forecast for the Day-Ahead study period from the Load Forecasting program.” Added Section 4.4.2: Multi-Hour Block Transactions (MHBT) ➢ Incorporated Technical Bulletin #86 Deleted Section 4.5: Post Unit Commitment (UCP) Deleted the original Section 5: Transmission Constraint Group (TCG) Assembly ➢ TCG is an obsolete process. The data that previously in the TCG file was the regulation and reserve requirements, which has been incorporated into other parts of the manual. Section 5.1.2 ➢ Changed “Balancing Market Evaluation” into “Real-Time Market Evaluation” *Added “along with available Real-Time transaction bids are passed”* *Added: “The final Desired Net Interchanges for the NYCA and neighboring Control Areas are passed from the IS+ function to the Real-Time Dispatch (RTD) function through the Bid/Post System.”*

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		Section 5.3 ➢ Deleted “which then passes the information on to the BME process during the Dispatch Day” ➢ Added: “The Ancillary Services are evaluated again as part of the Real-Time Scheduling systems solutions and the accepted Ancillary Service schedules are passed to the Bid/Post System.” Section 6.1 ➢ Incorporated Technical Bulletin #65 ➢ Added: each of the “eleven” NY Control Area Zones “and at the statewide level” ➢ Added: “The Load Forecast function uses a combination of advanced neural network and regression type forecast models to generate its forecasts.” Section 6.2 ➢ Deleted the bulletin “Study Load Forecast Module” Section 6.2.1 ➢ Added: “A single Load Forecast Module is used to produce the load forecasts for all the scheduling systems. The program automatically generates the 5 minute forecasts used by RTS. The hourly forecasts required for SCUC are published on demand for the current day and up to six days for each Zone. The published forecast is posted to the NYISO website by 08:00 a.m. every day, or as soon thereafter as is reasonably possible.” ➢ Added: “The forecasts that are produced for the scheduling systems represent only the expected demand usage and do not include transmission losses. The transmission losses are specifically computed as part of the scheduling systems’ functionality.” Deleted Section 6.2.2: Study Load Forecast Module Section 6.2.2 ➢ Added: This module allows the generation of load forecasts models for each Zone “and for the New York Control Area” Section 6.2.3 ➢ Changed “Bid/Post System” into “Oracle Information Storage and Retrieval (OISR) System” ➢ Added: with the “NYCA and Zonal hourly loads for storage” ➢ Added: “The MIS, SCUC and RTS systems can then retrieve the most up to date load forecast available.” ➢ Changed “Historical Data File” into “Historical Load Data” ➢ Deleted “and weather” data ➢ Changed “from the historical data file maintained from actual data retrieved from the on-line EMS” into “from the EMS through its PI Historical data” ➢ Changed “Weather Forecast File” into “Weather Data” ➢ Added: retrieves weather forecast “data and historical weather” data

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		➢ Changed "from the weather forecast data files maintained from data received from the weather service" into "from files received from the weather service" Section 6.3 ➢ Changed: Initial forecasting is completed "by 6AM" to "prior to initializing SCUC" ➢ Deleted: "considered to be a working environment" ➢ Changed "The required files as input to the program as well as output of the program are in ASCII format which can be generated from other database tables for the input files, and be ported to other database tables for the output files" into "The required files as input to the program are in .csv format." ➢ Changed "export a load forecast file in the format required for the multi-area Unit Commitment package to utilize" into "publish the load forecast data to OISR for the SCUC package to utilize" ➢ Deleted: "The exported areas can be specified to be either individual forecast areas or super zones." ➢ Added: By 08:00 a.m., "or as soon thereafter as is reasonably possible", the NYISO develops and posts its statewide Load forecast on the OASIS. Added Section 6.4: MIS Load Modeling and LSE Responsibilities Added Section 6.5: Load Forecasts for Facilities in the Market Information System Section 7 ➢ Changed "Security Constrained Unit Commitment" into "SCUC" Section 7.1 ➢ Changed "NYISO Operations Planning" into "Energy Market Operations" ➢ Changed "after the pre-UC process" into "after MIS DAM Market closing process has completed" ➢ Changed "S.P.I.D.E.R. workstation" into "RANGER system" Section 7.2 ➢ Changed "1. ...Bid/Post" into "1. ... MIS" ➢ Changed "2. Acquire current Security Constrained Unit Commitment history" into "2. Transfer data from the EMS / Real Time server" ➢ Changed "3. Retrieve the TCG file" into "3. Perform the SRE end of the day fill in process" ➢ Deleted "7. Assemble output SCUC file" ➢ Changed "8. ... SCUC output file" into "8. ... SCUC output data" ➢ Deleted "9. Send SCUC information to the Historical Information System" Section 8.1 ➢ NYISO Actions: 1). Deleted "(using LSE forecast data, where appropriate)" Section 8.3

Version	Effective Date	Revisions
		➢ The Need for Bids: Changed “order on resources” into “commit resources in the DAM” Broke the end of Section 8.3 into a new section as 8.4 Reliability Assessment Processes ➢ Added: “The NYISO continually re-evaluates the reliability of the NYCA. There are several reliability assessments of any given Operating Day performed over various time horizons. The sequences of these evaluations are described next.” ➢ Real-Time Reliability ➢ Added: the NYISO shall commit all bid resources “subject to network security constraints;” Section 10 ➢ Removed the original contents in this section, and referred to Transmission and Dispatch Manual section 5.7.5 through 5.7.12 Attachment B ➢ Renamed the section to “NYISO Load Forecasting Model” ➢ Renamed “top/down – bottom/up” approach to “bottom/up” ➢ Changed: peak load and energy at “the NYCA and” zone level into “and obtains the NYCA level by summing over the zones” ➢ Added: “Once the peak load and daily energy are obtained, a series of hourly interval models are determined, comprised of four fifteen-minute interval models for each hour of the day.” ➢ Changed: The model’s structure flows from daily peak and energy at the “system (NYCA) level” into “zonal level” ➢ Deleted “to hourly loads at the system level, to daily energy at the zone level” ➢ Deleted: “The bottom/up component comes from using zone hourly loads and the zone’s share of load in an adjustment process that takes advantage of high quality information at the NYCA level to adjust the zone hourly loads. The next paragraphs clarify this approach.” ➢ Updated data in Table B-2: Zonal Share of New York State’s 2010 Population Deleted the paragraphs in the section “Using the Model”
4.1	02/01/2016	Section 2.3.3 ➢ Added reference to Southeastern New York reserve requirements Section 4.3.4 ➢ Updated the table providing parameters of demand curves implemented by the NYISO
4.2	02/11/2016	Version delayed until 2/11/16 to correspond with NYISO deployment and activation of the Graduated Transmission Demand Curve software Global ➢ Standardized references to NYISO Manuals and User’s Guides

Version	Effective Date	Revisions
		Section 4.3.4 ➢ Updated Demand Curve table to reflect the graduated Transmission Demand Curve Section 4.2.7 ➢ Updated the reference to the 5018 transmission line from “Branchburg-Ramapo Interconnection” to “Hopatcong-Ramapo Interconnection”
4.3	04/28/2016	Section 4.3.4 ➢ Updated middle pricing point value of Transmission Shortage Cost
4.4	10/28/2016	Section 4.3.4 ➢ Updated Demand Curve table to reflect the changes related to Comprehensive Scarcity Pricing
4.5	6/29/2017	Section 4.2.6 ➢ Updated this section to indicate that, for TO DARU requests, non-binding, advisory postings/ e-mails will be made/sent at the time of DARU entry, modification, or deletion for all units Section 4.2.7 ➢ Revised the description of the ABC, JK, and Hopatcong-Ramapo interconnection PAR desired flows
4.6	10/09/2017	Section 4.3.4 ➢ Renamed section to Ancillary Service Demand Curves ➢ Removed transmission demand curve from section description and table Section 4.3.5 ➢ Included new section 4.3.5 which describes the NYISO's transmission constraint pricing logic
5.0	06/13/2019	Section 2.1, 2.3, 2.3.1, 4.1, 4.3.1, 4.4.3 ➢ Removed obsolete references to non-firm transactions. Section 2.3.2, 3.2.5, 4.2.7, 4.3.5.1, 4.4, 5.1, 8.2, 8.4 ➢ Website redesign URL updates. Section 2.3.3 ➢ Added a reference to New York City reserve requirements. Section 4.2.4 ➢ Removed provision not applicable to the DAM. Section 4.3.4 ➢ Updated Ancillary Service Demand Curve table to reflect New York City reserve requirements. Section 4.3.5.1 ➢ Updated to reflect the ability to assign non-zero constraint reliability margin values less than 20 MW.
6.0	05/01/2020	Ministerial edits

Version	Effective Date	Revisions
		➢ Updates to version number and formatting Section 3.1 ➢ Added dual participation language to Bid/Post Functions
6.1	08/28/2020	Section 2.3.1 ➢ Added language for additional factors considered for Energy Storage Resources in SCUC Section 4.2.3 ➢ Added language in Initial Generator Status and Commitment Rules for Energy Storage Resources Section 4.2.4 ➢ Added language in Scheduling a "Must Run" Generator for Energy Storage Resources Section 4.5 ➢ Added Language for Energy Storage Resources Constraint Evaluation
6.2	09/14/2020	Section 4.3.2 ➢ Added language for Fast Start Resources
6.3	10/04/2021	Section 4.2.5 ➢ Corrected the minimum capacity response rate allowed for regulation to 0.1 MW/minute Section 4.3.4 ➢ Updated the Operating Reserve Demand Curve values
6.4	12/15/2021	Section 2.3.1 ➢ Added language to include additional factors considered by SCUC for CSR Generators Section 4.2.5 ➢ Added language to specify the response rate requirement for ESR that is a part of CSR Section 4.3.2 ➢ Added language to include additional constraints considered by UC for CSR Generators Section 4.3.3 ➢ Added language to include CSR Scheduling constraints in SCUC inputs
6.5	12/19/2022	Recertified ➢ Updated broken hyperlinks
7.0	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 v8.0. Section 4.3.5

Version	Effective Date	Revisions
		➢ Updated the description of the transmission constraint pricing logic and Transmission Shortage Cost values.
8.0	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. Section 1.1 ➢ Added NYISO Aggregation Manual as a reference. Section 2.3 ➢ Added reference to the GOCP in Figure 3. Section 2.3.1 ➢ Added language about Aggregations being ineligible to participate in a CSR. Section 2.3.2 ➢ Added description of the GOCP. Section 3.3.8. ➢ Added description of the GOCP. Global ➢ Replaced Generator with Resource throughout the document when applicable. ➢ Replaced unit with Resource throughout the document when applicable. ➢ Replaced unit with Generator throughout the document when applicable.
9.0	08/30/2024	Global ➢ Update figure numbers Section 4.3.5 ➢ 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
9.1	10/29/2024	Recertified Global ➢ Updated broken hyperlinks

1. Introduction

This *NYISO Day-Ahead Scheduling Manual* is one of a series of manuals within the Operations Manuals. This Manual focuses on describing each of the Day-Ahead scheduling processes that are facilitated and/or controlled by the NYISO.

The *NYISO Day-Ahead Scheduling Manual* consists of eleven sections and two attachments as follows:

- Section 1: Introduction
- Section 2: Overview
- Section 3: Bid/Post System
- Section 4: Day-Ahead Scheduling Process
- Section 5: Day-Ahead Interface to the Dispatch Day
- Section 6: NYISO Load Forecast Process
- Section 7: SCUC Execution
- Section 8: Reliability Forecast
- Section 9: Interchange Coordination Procedure
- Section 10: Supplemental Resource Evaluation
- Attachment A: Calculation of Incremental Losses
- Attachment B: NYISO Load Forecasting Model

Throughout this Day Ahead Scheduling 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 the document, any explicit reference to an existing NYISO participation model should be interpreted as also applicable to Aggregations classified under the same participation model – in other words, ESR, Wind, and Solar Aggregations shall follow the same rules as set forth for existing resources of those types.

1.1. References

The references to other documents that provide background or additional detail directly related to the NYISO Day-Ahead Scheduling Manual are:

- NYISO Emergency Operations Manual
- NYISO Accounting & Billing Manual
- NYISO Transmission & Dispatching Operations Manual
- NYISO Market Participant User's Guide
- NYISO Aggregation Manual
- New York ISO Tariffs

- NYSRC Agreement
- NYSRC - Reliability Rules Manual

2. Overview

This section describes the overall Locational Based Marginal Pricing (LBMP) process, which sets the stage for the Day-Ahead activities.

2.1. System Components

The overall Bid-to-Bill Process from the time Bids are received to the time that payments are made consists of the following major components:

- Bid/Post System
- Day-Ahead Subsystem
- Real-Time Scheduling (RTS) Subsystem
    - Real-Time Commitment (RTC)
    - Real-Time Dispatch (RTD)
- Settlement Subsystem

Additionally, the Historical Information Retention system and the Supervisory Control and Data Acquisition (SCADA) subsystem provide services to these major components.

Bid/Post System

The purpose of the Bid/Post System is to:

- Accept Resource and load bids and schedules for External Transactions
- Post the public results of the Day-Ahead Market, Real-Time Commitment (RTC), and Real-Time Dispatch (RTD).

Day-Ahead Scheduling Subsystem

The Day-Ahead scheduling process consists of the following principal functions:

- Assemble Day-Ahead Transmission Outages; Update Total Transfer Capabilities, constraints and the Security Constrained Unit Commitment (SCUC) model; post updated Total Transmission Capability on the Open Access Same Time Information System.
- Produce NYISO Day-Ahead Zonal Load Forecast, based on weather forecasts and the load forecast model.
- Perform SCUC and scheduling.
- Perform Automated Mitigation of Resource offers.

Real-Time Scheduling Subsystem

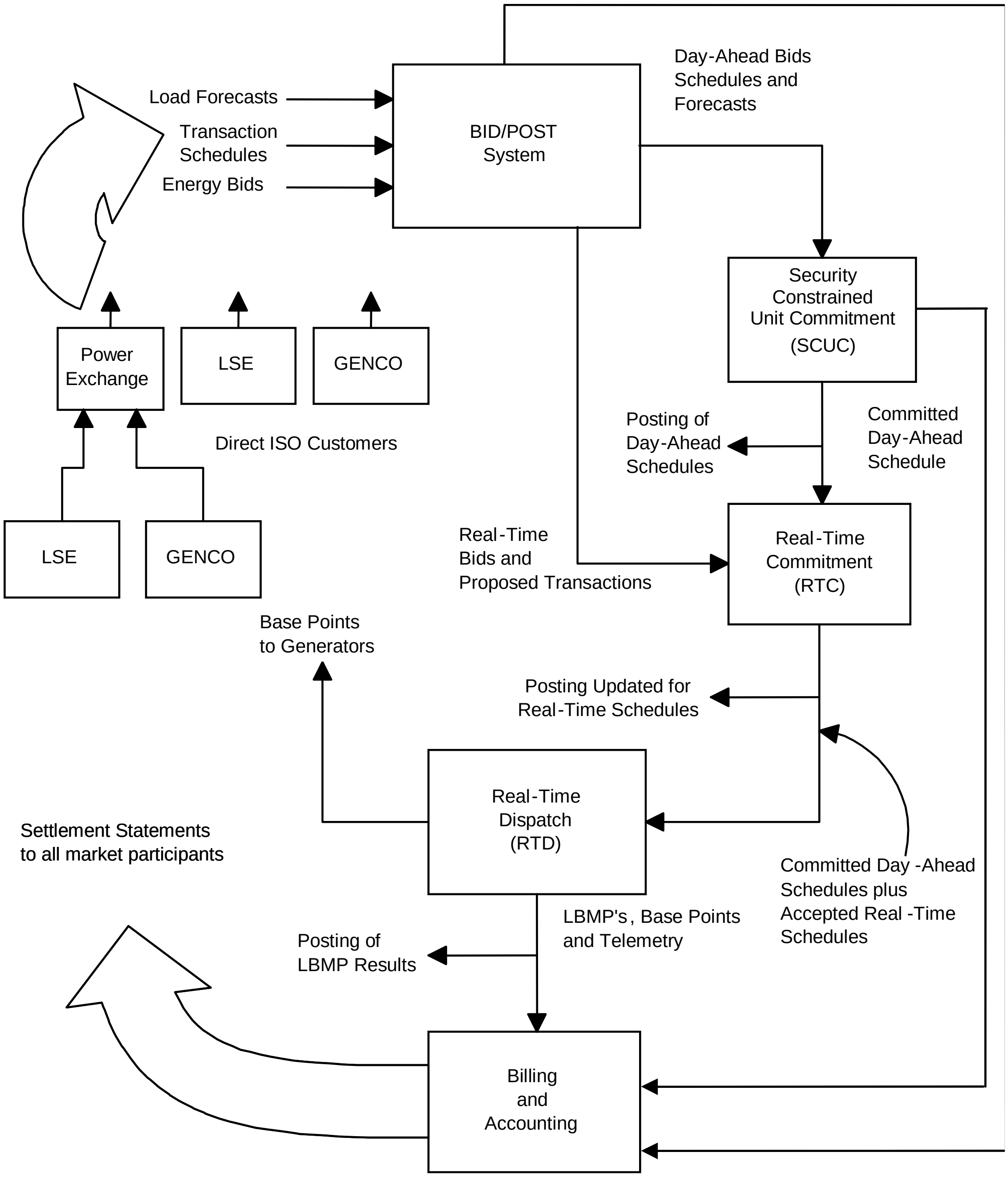
Approximately every 15 minutes, a Real-Time Commitment (RTC) evaluation takes place to ensure that the schedules meet all of the reliability requirements. Each Real-Time transaction is evaluated independently against the Day-Ahead transactions and Resource Bids, using the RTC program. If necessary, 10 and 30-minute resources will also be scheduled. The results are then posted every 15 minutes.

Approximately every 5 minutes, the Real-Time Dispatch (RTD) uses Bid curves of the New York Control Area (NYCA) Resources to dispatch the system to meet the load while observing transmission constraints. Bid curves will consist of a combination of incremental bid curves provided by Resources bidding into the LBMP market and decremental bid curves provided by Resources serving Bilateral Transactions.

Settlement Subsystem

During each hour of operation, the results of SCUC, RTS and Automatic Generation Control (AGC) are captured and stored for later use by the Billing subsystem. The NYISO will have all the information necessary to determine all of the charges and payments, which must flow between the NYISO and the Market Participants.

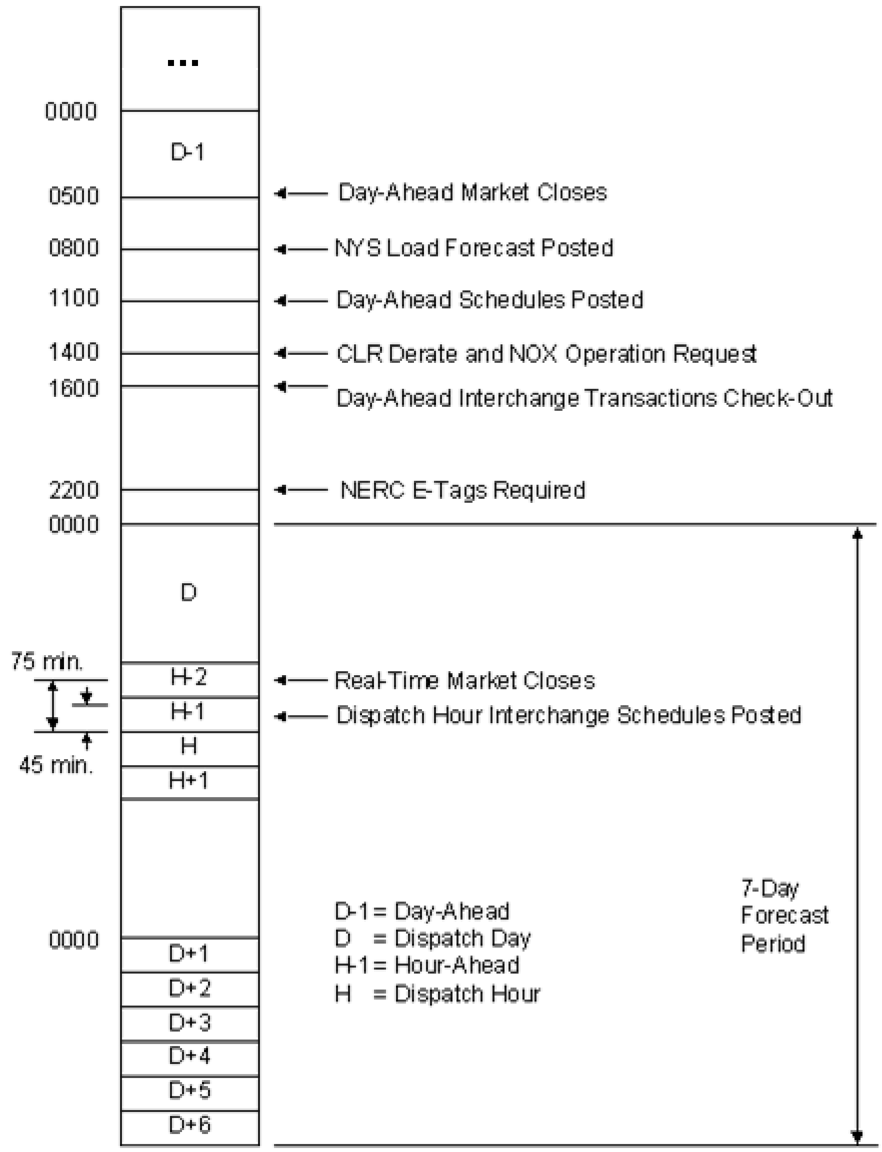
Figure 1: NYISO Bid-to-Bill Process



2.2. LBMP Time Line

The sequence of events for the implementation of LBMP is shown in Figure 2.

Figure 2: LBMP Time Line



Finalized Day-Ahead bids must be submitted by 05:00 a.m. (or by 4:50 a.m. for some External Transaction bids pursuant to MST Section 4.2.1.1) on the day prior to the Dispatch Day for the full commitment period.

By 11:00 a.m. on the day prior to the Dispatch Day, the ISO shall complete the Day-Ahead scheduling process and post on the Bid/Post System the Day-Ahead schedule as per section 4.2.5 of the Market

Services Tariff. LBMPs are posted on the Bid/Post System as public data and commitment schedules are posted on the Bid/Post System as private data.

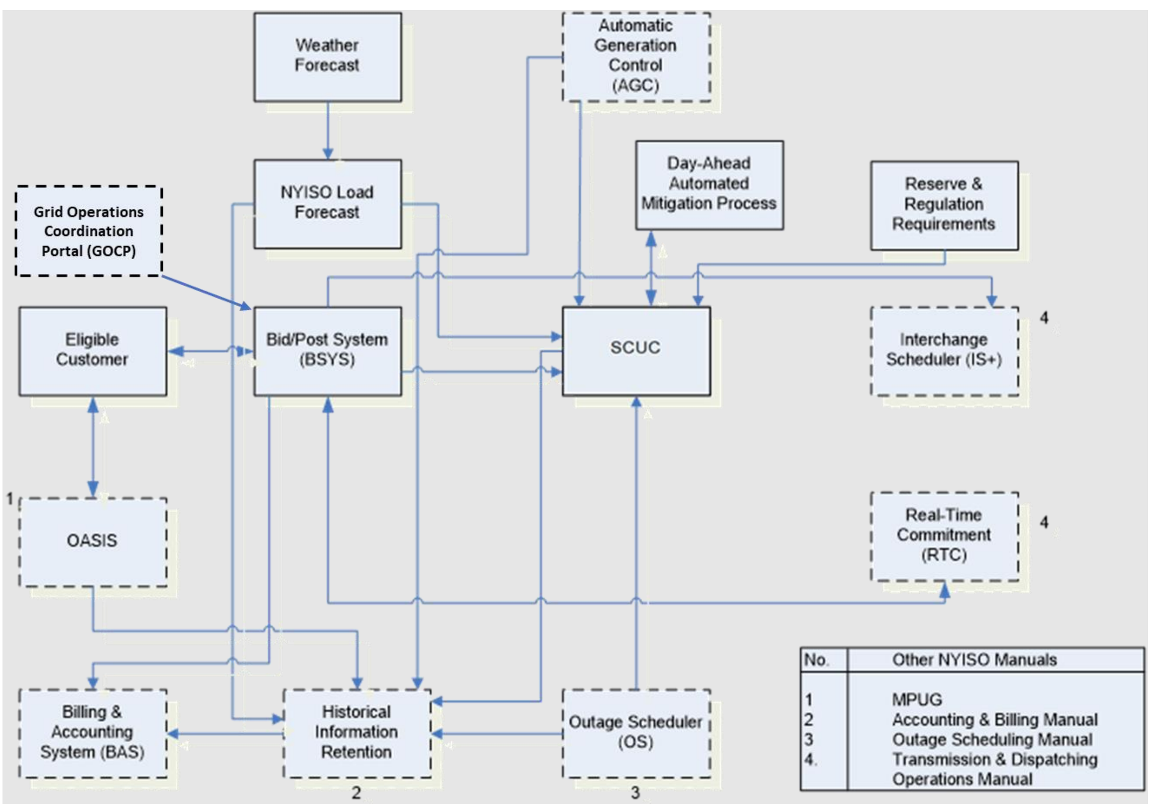
Day-Ahead bids are locked for the Day-Ahead period while under evaluation and when accepted. Bids may be left standing or withdrawn if not accepted. Standing bids may be used in Supplemental Resource Evaluation (SRE).

In accordance with section 4.2.4 of the Market Services Tariff, each day a reliability study is run over the seven (7)-day period that begins with the next Dispatch Day. This study evaluates if resources with longer start-up times are required to meet forecasted Load and reserve requirements. Resources that are committed are guaranteed a minimum generation bid cost recovery pursuant to the provisions of Attachment C of the Market Services Tariff.

2.3. Day-Ahead Functional Components

The following figure shows the interaction and data flow between the various functional components that involve the Day-Ahead process. Each of the blocks and major data flows is described after the figure.

Figure 3: Day-Ahead Scheduling Data Flow



2.3.1. Primary Functions

The following is a brief summary of each primary function block (solid line) shown in Figure 3:

***Weather Forecast* –** The Load Forecast function retrieves weather forecast data from the Weather Forecast data file maintained from data received from the weather service.

***Load Forecast (LF)* –** The Load forecast function is used by the NYISO to forecast loads for each Zone in the NY Control Area. The LF function uses historical load and weather data information for each Zone to develop forecast models. These models are then used together with Zonal weather forecast to develop a NYISO-based Zonal load forecast for the next seven days. This forecast is used in the reliability passes in SCUC.

***Reserve & Regulation Requirements* –** The following requirements are passed on to the SCUC program:

- Operating Reserve requirement for each category
- Regulation requirement

***Bid/Post System (BSYS)* –** See NYISO OATT Section 1 Definitions and Section 3 this manual.

Functionally, the Bid/Post System allows Market Participants to review results of the Day-Ahead and Real-Time scheduling and dispatch processes including accepted and rejected bids, Resource schedules, and clearing prices. Confidential data is restricted to those entities that have authorized access.

The Bid/Post System provides the Day-Ahead scheduling information to the Real-Time Scheduling Subsystems.

***Security Constrained Unit Commitment (SCUC)* –** The SCUC produces the generating unit commitment schedule and Firm Transaction schedules for the next day's operation. Factors considered by SCUC are:

- Current generating unit operating status
- Constraints on the minimum up and down time of the generators
- Generation and start up bid prices
- Plant-related startup and shutdown constraints
- Minimum and maximum generation constraints
- Generation and reserve requirements
- Transmission facility maintenance schedules
- Transmission constraints
- Phase angle regulator settings
- Transaction bids
- Minimum and Maximum Energy Level constraints (for Energy Storage Resources (ESR) only)
- Bid Beginning Energy Level for ESR (for ISO Managed ESR only)

- Co-located Storage Resources (CSR) Scheduling Limits (Only for solar/wind Intermittent Power Resource (IPR) and ESR Generators that participate in a CSR). Aggregations comprised of ESR, Wind, or Solar only are not eligible to participate in a CSR.

2.3.2. Supporting Functions

The following is a brief summary of each supporting function block (dashed line) in Figure 3.

Historical Information Retention – Data required for archiving, billing and accounting, as well as information required to support auditing, is saved. Data that is stored includes results of the Day-Ahead scheduling study, interchange schedule information, RTD calculated base points for every dispatch execution, equipment outage schedule information, zonal marginal prices, transmission rights information, actual reserves and reserve requirements, and actual system conditions.

OASIS – See the *NYISO Market Participant User's Guide* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for details.

Billing & Accounting System (BAS) – The BAS function itemizes those data elements stored or generated by the various subsystems so that line item settlement statements can be calculated after the fact on a monthly basis. Billing information is limited to those market systems that are in place for the initial LBMP implementation. Data is captured for every dispatch cycle and saved for off-line calculation of pertinent billing information. All consolidated billing information is stored in the historical archives for subsequent processing. See the *NYISO Accounting and Billing Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for details.

Outage Scheduler (OS) – The Outage Scheduler function is used by the NYISO to keep track of scheduled equipment outages in the NY Control Area. The OS provides a user interface for entering equipment outage schedules, as well as reviewing existing schedules. Additionally, the OS records the actual status changes of the network equipment regardless of whether its status change was scheduled. See the *NYISO Outage Scheduling Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for details.

Grid Operations Coordination Portal (GOCP): The Grid Operations Coordination Portal is used by Aggregators, TOs and 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.

Automatic Generation Control (AGC) Function– The AGC monitors the SCADA database for the on-line status of Resources and, when generating, the on/off status of their Automatic Voltage Regulator (AVR) equipment. It also monitors control performance. See NYISO OATT Section 1 Definitions. Also see the *NYISO Transmission & Dispatching Operations Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for details.

Interchange Scheduler (IS+) – The IS+ function allows NYISO personnel to monitor ongoing energy transactions. These transactions are bids accepted in either the Day-Ahead scheduling process or the Real-Time scheduling and dispatch process. This program provides facilities for reviewing existing transaction information and for adjusting transactions in real-time to address security problems. The IS+ function produces the NY Control Area Desired Net Interchange (DNI). See the *NYISO Transmission & Dispatching Operations Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for details.

Real-Time Commitment (RTC) – 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. The Day-Ahead scheduled transactions and the candidate Real-Time transactions are evaluated to assure that the interface Total Transfer Capability (TTCs) are respected. In addition, candidate External transactions are evaluated for LBMP economics against their decremental bids. See NYISO OATT Section 1 for definition. See the *NYISO Transmission & Dispatching Operations Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for details.

2.3.3. Data Flow

The following is a brief description of the data flow between the various Day-Ahead functions.

Bid Information – The Bid information that is passed to the Bid/Post System from the Market Participants is listed in the NYISO Market Participant User's Guide.

Posts Billing Information – The Bid/Post System is required to pass all schedules, pricing, and results to the Billing & Accounting System, on a daily basis.

Posts User Activities – All user access to the Bid/Post System function is logged and stored. Any data items entered or changed with the associated timing information, are stored for future tracking and auditing purposes. A complete duplicate of Bid/Post System information is retained.

Security Constrained Unit Commitment – The SCUC saves the hourly output of each Resource for energy, reserves, and regulation.

Bid/Post System to SCUC – The SCUC program requires all of the validated bid information from the Bid/Post System. External Transactions are treated in the base case as Resources and loads.

Automated Mitigation Process (AMP) – Automated mitigation relies on a second SCUC evaluation pass to assess the impact of mitigation; and a third SCUC pass to produce a final schedule. Thus, three SCUC pass evaluations are required. The first, pass 1A, determines the prices and schedules that would occur with the original set (Base-Set) of bids and offers. The second, pass 1B, determines the prices and schedules that would occur with conduct failing bids replaced with reference bids (Ref-Set). Differences between Base-Set and Ref-Set are used to determine price impact. The third Unit Commitment, pass 1C, determines final prices and schedules using mitigated bids and offers (Mit-Set) when both conduct and impact warrant mitigation.

Reserve and Regulation Requirements – The SCUC function obtains the following hourly requirements for NYCA, Eastern New York, Southeastern New York, New York City, and/or Long Island from the Energy Management System:

- Spinning 10-minute reserve
- Total 10-minute reserve (includes the spinning 10-minute reserve)
- Total operating reserve (includes the total 10-minute reserve and 30-minute reserve)
- Regulation capacity

AGC to SCUC – The AGC function prepares a list of information that contains every Resource and its last change of state.

Bid/Post System to Interchange Scheduler – The Bid/Post System function provides evaluated transactions to the IS Plus function.

SCUC to Bid/Post System – SCUC data is provided to the Bid/Post System, which then passes the information on to the Real-Time Commitment (RTC).

3. Bid/Post System

This section describes the Bid/Post System and its interfaces to other functions. See NYISO OATT Section 1 Definitions.

3.1. Bid/Post Functions

The Day-Ahead scheduling process begins when the Eligible Customers submit their Bids through the Bid/Post System. Eligible Customers provide bidding information to the NYISO for generation, load, and transactions; and review the posted results such as accepted bids, generation schedules, and clearing price information. Resources engaged in Dual Participation that submit Bids in the Day-Ahead Market to meet an obligation(s) to a distribution utility or other entity must follow all applicable NYISO bidding and scheduling requirements (see, e.g., Market Participant's User Guide Sec. 7.4).

The primary data exchanges of the Bid/Post System for the Day-Ahead scheduling function include the following:

- Eligible Customers enter Day-Ahead bids
- NYISO posts accept/reject information of bid data for Day-Ahead scheduling.
- NYISO posts marginal pricing information
- NYISO posts historical results (limited capability)
- NYISO posts the list of generators that are committed for reliability under Operational Announcements on the ISO website
- NYISO posts current operating parameters in the hour of use
- Market participants review and revise operating information

NYISO posts audit trail of information by user and time stamp.

3.2. Bid/Post Process

The following classifications of data exist for the Bid/Post System:

- Resource, LSE, and Bus Data (Private)
- Bid Data (Private)
- Posted Schedules/Other (Private)
- Posted Prices/Other (Public).

For consideration of confidential information, the first three types of data have access limited to registered Market Participants who have a right to review such information. The fourth type of data is accessible to all the registered users of the Bid/Post System.

Data Classifications

Detailed data tables of each parameter of the four data types are included in the NYISO Market Participant Users Guide.

- **Resource, LSE, and Bus Data** – Certain Resource information such as upper operating limits, minimum generation levels, and normal and emergency response rates require NYISO confirmation to become valid. The parameters, to be entered by the NYISO into the Bid/Post System, may require supporting information such as certification and testing. The NYISO provides status flags for the Resource indicating what types of bids the Resource has been qualified to submit.
- LSE information required is similar to the ownership requirements of a Resource and is supplied by a LSE's designated administrator and the NYISO. The NYISO provides the bus, sub-zone, and Zone identifications for the LSE territory, which the LSE serves.
- Bus data includes information supplied by the NYISO, including reference names, numbers, sub-zone, Zone, and other designations used by Market Participants to identify a bus.
- Almost all of the above data is considered static, in that it is not expected to change frequently and certain pieces require different levels of NYISO certification or user verification to enter and change.
- **Bid Data** – LBMP Market Participants enter bid data parameters for Resources, External Transactions, and load for the Day-Ahead Market. Users may change data already validated or submit new data for validation up to the close of the market period when evaluation of validated bids starts. Authorized users have the capability to review and modify current operating parameters (Real-Time Market) in the hour of use.
- Bid data includes timing information such as when a bid becomes valid and when it expires.
- **Posted Schedules/Other (Private)** – The sets of schedules and prices posted under LBMP result from SCUC and RTS. As schedule information is considered confidential in nature, only registered users with authorization have the right to review their schedules or rejection notices associated with their bids.
- In general, after completion of the Day-Ahead scheduling process; generation schedules, load forecasts, day-ahead LBMP prices (including congestion and loss components) for each load zone in each hour of the upcoming day, and scheduled External Transactions are posted to bidders.
- In RTC, updated load forecasts, and additional External Transactions are evaluated. In the Bid/Post System, Resource schedules are posted and LBMP bus prices calculated by RTC for the next hour are advisory in nature only. Prices used in billing are determined in the real-time market by RTD. RTC posts accepted External Transactions for the next hour also.
- **Posted Prices/Other (Public)** – Data that is posted as public implies that any user of the Bid/Post System is able to access the information (unregistered users do not have access to the Bid/Post System).
- The bus, zonal Transmission Node LBMP prices are posted after Day-Ahead commitment, after RTC, and hourly RTD results. Clearing prices for reserves are posted, and advisory NYISO load forecasts are also posted. The Bid/Post System retains this information for Market Participant review for a specified period of time (initially, 15 days). After expiration of the time interval, the Bid/Post System audit data will be only accessible through the Historical Information System. The daily Bid Production Cost Guarantee (BPCG) in aggregated total dollars from both the Day Ahead and Real-Time Markets is posted as Public Data.

- The Bid/Post System provides capability for issuing general messages from the NYISO, such as when the NYISO is performing a supplemental commitment.

Validity Checks

The data submitted to the Bid/Post System is checked for validity with bidder notification that a bid has been validated as soon as possible. If a bid is rejected because part of the data is not valid, a posting for the bidder indicates the problem and gives an opportunity to resubmit a modified bid providing the market has not closed.

Bid validity is broken into the following different types of validation checks:

- **Ownership (O)** – Ownership recognizes the bidder as having the authority to bid a particular service, such as owner of a generating plant bidding energy services.
- **Completeness (C)** – Completeness indicates that the bidder has entered all the required parameters for a particular bid to be evaluated, such as regulation bids providing regulation response rate, available capacity, and dollars per MW availability.
- **Individual Data Checks (I)** – Individual data checks look at constraints placed on individual data parameters either universally applied to a given field or constrained by qualification data, such as upper operating limit (energy bid) not exceeding the maximum operating limit of a unit.
- **Relationship (R)** – Relationship checks look at the interdependence of certain parameters supplied to the Bid/Post System.
- **Special Relationship (SR)** – Special relationship checks look at bid parameters relative to other parameters that have not been supplied with a particular bid, such as External Transaction waiting for other party confirmation, or real-time energy market bid price not exceeding Day-Ahead bid for portion committed.
- **Prohibited Transmission Paths** – Prohibited transmission paths checks filter out External Transaction schedules submitted over the eight prohibited circuitous scheduling paths. See OATT Attachment J, Section 16.3.3.8 for definitions of those scheduling paths.

Notifications

There are many different types of notifications that the Bid/Post System provides to users concerning the status of a particular bid. The currently defined notifications are as follows:

- **Validation** – Data entered through the Bid/Post System is identified as being either validated, rejected with message indicating why rejected, or a status of the validation process. For validated bids the status message is VALIDATION PASSED. For invalid bids the status indication is VALIDATION FAILED, with a message indicating reason for failure, such as one of the validation rules. The status of the validation process is only used in a special case and discussed as the next type of message notification.
- **Confirmation** – When the validation process cannot be continued because information is needed that is not submitted with part of a particular bid (e.g. certain Special Relationship checks), the indication would be WAITING CONFIRMATION. Confirmation messages identify the organization required to supply the necessary information needed for the validation process such as confirmation of an External Transaction. It is important to note that some of the Special Relationship checks, performed during the Day-Ahead and Real-Time Commitment evaluation periods, are not considered part of the validation procedure. Rather, these are

identified as acceptance criteria and used with acceptance notification. For a bid or offer to be evaluated by Day-Ahead or Real-Time Commitment, it must have a status of VALIDATION PASSED.

- **Acceptance** – During the time that the NYISO is using bids to perform commitment or real-time market evaluation, the status of a bid is shown as EVALUATING. After evaluation is complete, the results are posted and the status of the bid is tagged as BID ACCEPTED, MODIFIED, CONDITIONALLY ACCEPTED, BID REJECTED, or ADVISORY ACCEPTED. In the event that a supplemental resource evaluation is required, bids that have not reached expiration time will be considered available for evaluation and will not be allowed to expire. For example, a bid to supply energy is due to expire at 11:00 p.m. The NYISO begins an SRE at 10:40 p.m. to address an energy concern at 07:00 a.m. the following day. The bid would be utilized in the SRE evaluation.
- **Result Posting** – All accepted bids will have resulting schedules posted. The Bid/Post System clearly identifies bids that have forward contracts and those that are advisory. Included in the results posting is the ability for the user to review the past bids and results for Day-Ahead Unit Commitment, supplemental unit commitments, Real-Time Commitment, and actual operating results for a specified period of time.

Tracking & Auditing

Tracking and auditing serves the NYISO and the Market Participants. All information in the Bid/Post System is retained for auditing purposes. Limited information from the Bid/Post System on past bids and results is available to the Market Participants. All inserts, updates, and deletions to the Bid/Post System are tagged with date, time, and user identification. The audit trail is provided with table log files.

User Interface

Not all Market Participants have the same capabilities and needs for interfacing with the Bid/Post system. In order to provide convenient interface options, a number of methods for supplying data and also for reviewing results are supported. The following describes these interface methods.

- **World Wide Web** – The Bid/Post System is accessible through public Internet Web pages, utilizing hardware and software similar to that used for the OASIS System. Market Participants are able to submit data and review postings through Web pages using this method.
- **Upload/Download** – Upload and download file capabilities are provided to Market Participants, utilizing hardware and software similar to that used for OASIS. File formats or templates for these files are supplied to Market Participants.

3.3. Bid/Post Interfaces

The data exchange for each application is outlined as follows.

3.3.1. SCUC

The SCUC program has all the validated bid information when the Day-Ahead market closes. The schedules resulting from Unit Commitment are sent back to the Bid/Post System. The Bid/Post System and

SCUC exchange information bi-directionally.

3.3.2. Interchange Scheduler

The Bid/Post System sends approved transactions to the IS+ package. When there is a change in transactions the IS+ updates the Bid/Post System.

3.3.3. Real-Time Scheduling

The Real-Time Scheduling requires all new market bid information from the Bid/Post System and approved schedules from SCUC. The results of RTS are sent back to the Bid/Post System. Data exchange is bi-directional between the Bid/Post System and RTS.

3.3.4. Performance Tracking System

The Performance Tracking System provides hourly performance measurements to the Bid/Post System. When available, Data exchange is uni-directional from the PTS to the Bid/Post System.

3.3.5. Billing & Accounting System

The Bid/Post System is required to pass all schedules, pricing, and results to the Billing & Accounting System. Data exchange is uni-directional from the Bid/Post System to the BAS.

The Billing & Accounting (BAS) function itemizes those data elements stored or generated by the various subsystems, from which line item settlement statements are calculated. Refer to the *NYISO Accounting & Billing Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for a detailed description.

3.3.6. Historical Information Retention

All relevant Bid/Post System information is saved.

3.3.7. OASIS

Refer to the NYISO Market Participant User's Guide for a description of the interface.

3.3.8. GOCP

The GOCP provides updated Aggregation bids to reflect deration schedules. Data exchange is uni-directional from the GOCP to the Bid/Post System.

4. Day-Ahead Scheduling Process

This section focuses on the Day-Ahead scheduling process for the LBMP implementation. The Day-Ahead scheduling process establishes Day-Ahead schedules including External Transaction schedules. This is accomplished by the following procedures:

- Assembly of the Day-Ahead outages
- Production of a preliminary NYISO zonal load forecast
- Execution of SCUC
- Tabulation and evaluation of transactions.

4.1. Day-Ahead Inputs & Outputs

Inputs to Day-Ahead Scheduling

The primary inputs to the Day-Ahead scheduling process are:

- Transmission outage list from the Energy Management System (EMS)
- Weather forecasts
- Load forecast model
- Validated firm External Transaction requests from the Bid/Post System (converted to generation and load)
- Operating Reserve and Regulation requirements from the EMS
- Validated Day-Ahead Resource bid data from the Bid/Post System
- Validated Day-Ahead load bids from the Bid/Post System
- Price capped load bids from the Bid/Post System
- Validated virtual generation and virtual load bids from the Bid/Post System
- Lake Erie circulation assumptions

Outputs from Day-Ahead Scheduling

The primary outputs from the Day-Ahead scheduling process are:

- Updated Total Transfer Capabilities (TTCs) posted on OASIS
- Available Transfer Capabilities (ATCs) posted on OASIS
- PAR Flows posted on OASIS
- Day-Ahead Limiting Constraints posted on OASIS
- Commitment schedule for generation and load resources, operating reserves, regulation, External Transactions and bid load posted on the Bid/Post System for First Settlement
- Market Clearing Prices for operating reserves and regulation posted on the Bid/Post System
- First Settlement LBMPs posted on the Bid/Post System
- Zonal load forecast posted on the Bid/Post System.

4.2. SCUC Initialization

The next subsections describe the initialization that is performed in preparation for SCUC.

4.2.1. Day-Ahead Zonal Load Forecast

The NYISO prepares a Day-Ahead zonal load forecast. This NYISO forecast is independent of the LSEs' forecast. The procedure for NYISO forecasting is as follows:

- Retrieval of actual and historical weather data and weather forecasts obtained from the weather service
- Retrieval of historical load data
- Execution of the load forecast program
- Transferring of the NYISO load forecast data for use by SCUC.

4.2.2. Assemble Day-Ahead Transmission Outages

The outage process for transmission facilities involves the following procedures:

- Transfer of the transmission outages from the EMS
- Preparation of the updated SCUC model, which is used by the SCUC function.

4.2.3. Initial Generator Status and Commitment Rules

The Automatic Generation Control System produces a list of actual generator start and stop times and dates. This start and stop information is transferred for use by the SCUC process.

In preparation for the start of a unit commitment study, the SCUC input processor updates Resource statuses.

Initialization Status

When SCUC initializes at 05:00 for the following day, the statuses of the Generator that bid into the Day-Ahead Market (DAM) are based on their current operating mode at the time of initialization, with modifications. The modifications are the projected changes for the remainder of the day from the previous day's DAM schedules. If a Generator is not in the mode that SCUC expects it to be at the time of initialization, the current mode of the Generator overrides the projected change. No Generators are considered "must run" in SCUC.

Startup Time

Either a startup versus downtime curve or a notification time can be provided for SCUC. If both are provided, the startup versus downtime curve overrides the notification value.

SCUC posts the results for the next day's DAM at 11:00 a.m. If a Generator is down at posting time, the startup time is measured from the time of posting. The Generator is recognized as unavailable until the startup notification period has elapsed.

If a Generator is running but projected to come down after posting time, a bid for the Generator in SCUC indicates that it is willing to operate. Neither a startup versus downtime curve nor a notification time value is recognized.

Minimum Run Time

In SCUC, the minimum run time is honored within the 24-hour evaluation period only; requirements across midnight are not recognized (except to the extent they are reflected in a late day start Bid). A Generator must bid appropriately to enable commitment in the next day.

Minimum Down Time

SCUC honors the minimum down time within the 24-hour evaluation period only; requirements across midnight are not recognized. A Generator must bid appropriately to preclude commitment in the next day.

Beginning Energy Level (For an ESR)

SCUC honors the Beginning Energy Level (for ESR bidding ISO Managed) within the 24-hour evaluation period only; requirements across midnight are not recognized. An ESR will be scheduled based on its Beginning Energy Level for the market day.

4.2.4. Scheduling a “Must Run” Resource

There is no such thing as a “Must Run” Resource. To improve the chances that a Resource is scheduled into the market, it must be offered such that it is positioned at the bottom of the economic bid curve.

A Resource that desires a commitment to operate might not be scheduled due to system constraints or reliability rules. For example, if a set of Resources are running to meet a particular load and all the Resources are operating at their minimum generation level, then no other Resource would be started, even if the new Resource is otherwise economic (less costly, on an incremental basis, than the Resources that are already operating). Also, if a Resource is constrained for transmission security, then it may not be scheduled to run, or it may be scheduled at a reduced amount, by Security Constrained Unit Commitment (SCUC) and Real-Time Commitment (RTC). To increase the probability that a Resource will be scheduled into the market, it must be bid at the bottom of the economic dispatch curve. The following presents a few simple guidelines to increase the chances otherwise available that a Resource would be economically scheduled.

Bid a "Start-Up Cost" of Zero Dollars

Market Participants may enter zero dollars into the "Start-Up Cost ($)" field on the Generator Bid screen in the MIS. This will prevent the SCUC or RTC from considering start-up cost.

Submit a Low Minimum Generation Bid

SCUC and RTC minimize total production costs over their respective evaluation periods. The Minimum Generation Costs are factored into this evaluation; therefore a low value in this field will increase the likelihood that the unit will be scheduled to run based on economics.

Submit a Low Incremental Energy Bid

The dispatch curve is used between the minimum and upper operating points to dispatch the Resource. If not the marginal unit, a Resource will receive the higher Locational Based Marginal Price at its bus, regardless of its bid. If many Resources are vying for a "must-run" schedule within an area, a negative bid may prove necessary to be scheduled, especially if others are bidding negative. An ESR seeking to be scheduled to withdraw Energy may need to submit a high dollar value incremental Energy Bid to ensure it receives a schedule. Also, the SCUC and RTC software minimize production costs over multiple hours, so all hours must be strategically bid together. For example, the hourly bids of a unit would be evaluated over all the hours that it could be scheduled, given its minimum run time or down time constraints.

Use Appropriate Static Generator Parameters

In the SCUC Day Ahead Market, all static generator parameters are used based on the unit's initialization. Generators that bid into the non-synchronous reserve market will not have their unit scheduled for energy if their bid is accepted in the non-synchronous reserve market. The generator may change this value by going to the Generator Commitment Parameters in the Market Information System.

Submit a Bid in Self-Committed Fixed Mode

By submitting a bid in Self-Committed Fixed mode, a Generator will be dispatched to the level indicated in the bid, subject to system security. Although submitting a bid in Self-Committed Fixed mode cannot guarantee the commitment of a Generator, there is a high possibility that the Generator will be committed in SCUC. However, a Generator bidding as Self-Committed Fixed is not eligible to submit any cost curve, so it can be scheduled regardless of the low LBMP it will get paid.

4.2.5. Multiple Response Rates for Resources

Each Resource modeled in the Market Information System (MIS) may specify up to five response rates. Three response rates are available for following basepoints in the energy market, the emergency response rate is available for providing operating reserve pick-up, and the regulating capacity response rate is available for regulation service.

In an effort to encourage Resources to place themselves in Flexible mode, multiple response rates that more accurately reflect a Resource's response capability may be specified. The energy and emergency response rates may be specified for up to three energy supply ranges. For example, the Minimum Generation MW-50MW range may have a 0.2 MW/minute response rate, the 51-150MW range may have a response rate of 8 MW/minute, and the range from 151MW to the maximum upper operating point may have a response rate of 2.2 MW/minute. Defining the three energy ranges and the response rate for the ranges is at the discretion of the Resource. It is the Resource's responsibility; however, to ensure that the response rates specified are within the capability of the Resource, provided, however, response rates that differ from those specified in the ISO Tariffs based on the capability of the unit shall be reviewed and accepted by the NYISO. The NYISO will maintain the response rates currently shown in the MIS for the Resource until the changes are accepted.

The SCUC and RTC programs, which perform Day-Ahead and Real-time scheduling calculations respectively, use the explicit response rates for each megawatt segment.

Regulation bids must be structured such that the Resource's specified capacity response rate is valid for the bid submitted. For example, a regulation capacity bid of 30MW must be supported by a regulation capacity response rate of 6 MW/minute over the 5-minute RTD interval to fully comply with regulation provider responsibilities. The regulation capacity response rate must not be slower than the slowest energy or emergency response rate.

The emergency response rate specified for a Resource will be used during a reserve pickup condition when RTD-CAM moves the Resource towards its emergency upper operating limit. Neither the emergency response rate nor the regulating response rate will be used as additional energy response rates in any dispatch other than that.

The three energy response rates and the emergency response rate must be specified in increments such that they will result in an integer MW amount over an RTD interval. In other words, response rates with an odd decimal place (i.e. .1, .3, .5, .7, or .9) are not allowed. The minimum response rate allowed for energy and the minimum emergency response rate is 0.2 MW/minute. For ESRs that participate in a CSR (not including Aggregations comprised of ESRs only), the minimum response rate allowed for energy and the minimum emergency response rate is 6.7% of their nameplate capacity/minute. The minimum capacity response rate allowed for regulation is 0.1 MW/minute. For ESRs that participate in a CSR, the minimum capacity response rate allowed for regulation is the larger of 0.1MW/min or 6.7% of their nameplate capacity/minute.

Market Participants interested in specifying multiple energy response rates for a Resource(s) must set this up by contacting their Stakeholder Services Representative.

4.2.6. Day Ahead Reliability Unit (DARU) Commitment

Background

Transmission Owners regularly request that the NYISO commit additional Generators to meet the reliability needs of their local systems. Recent changes allow the NYISO to commit these Generators in the Day-Ahead Market when notified of the need to do so by the Transmission Owners. Since a Day-Ahead commitment of these Generators produces a more efficient commitment than a commitment following the Day-Ahead market run, Transmission Owners should notify the NYISO of the need for these Generators by 01:00 a.m. prior to the Day-Ahead Market close, to allow for input into the system (e.g., a request for Saturday must be communicated to the NYISO by 01:00 a.m. Friday). Those Generators that the NYISO commits solely for reliability reasons at the request of a Transmission Owner or for statewide reliability needs as initiated by NYISO, are known as Day-Ahead Reliability Units ("DARU"). Aggregations may also be utilized to meet local reliability needs via the Supplemental Resource Availability (SRA) process. For additional information on the SRA process, please refer to the NYISO's Transmission & Dispatch Operations Manual Section 6.7.17. Supplemental Resource Availability (SRA).

Transmission Owner Requests for DARUs

When requesting the commitment of a reliability-necessary generating unit for the Day-Ahead market, TOs must give the NYISO the reliability reason for the request, the expected duration of the need, and the specific facility or constraint affected. TOs should request a DARU for all generating units needed for reliability of their local system to ensure against economic decommitments. NYISO operators will log all such TO requests. (This is consistent with the requirements that apply to TO SRE requests.) Within 5 business days, the TO requesting the reliability commitment shall provide detailed written justification for the DARU request to SREinfo@nyiso.com. The NYISO will review all these requests to ensure that practices being followed are consistent with NYISO tariffs and NYS Reliability Rules.

The TO's written justification must detail the system conditions that resulted in the need for the reliability 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; thermal transmission facility or substation voltage constraint; whether the constraint represents a predicted pre-contingency or post-contingency violation; significant transmission or generating unit outages affecting such constraint;

and special local reliability criteria. Any additional local area system conditions that resulted in the need for the DARU commitment should also be identified.

All requests by TOs to commit generators via the DARU process, as well as NYISO-initiated DARUs, will be posted to the OASIS at the time of Day-Ahead Market close. In addition to the posting at Day-Ahead Market close, non-binding, advisory postings will be made at the time of DARU entry, modification, or deletion.

An e-mail notification will also be sent to a DARU generator's contact, as entered in the Market Information System, when the Day-Ahead Market closes, indicating that the Generator has been requested for Day-Ahead reliability. A supplemental process will be used whereby a non-binding, advisory e-mail will be sent for every creation, modification, or deletion of a DARU entry by NYISO Operators. The Generator's contact may reach out to the requesting TO when there are constraints preventing the unit from being able to meet the commitment requested. If there are issues with TO communication, the Generator's contact may also reach out to inform the NYISO Grid Operations Department regarding the constraints.

NYISO Processing of Day-Ahead Reliability Unit Requests

SCUC optimizes offers and bids over the dispatch day to preserve system reliability and ensure that sufficient resources are available to meet forecasted load and reserve requirements. When a Transmission Owner notifies the NYISO of the need for a reliability unit, SCUC will first evaluate the generator for possible economic commitment. If economic, the unit's commitment will not be considered a reliability commitment. Commitment for reliability reasons renders the unit a DARU. A DARU request by a Transmission Owner or by the NYISO may override a generator's startup notification time.

4.2.7. Phase Angle Regulator Scheduling

Phase Angle Regulators (PARs) are scheduled in SCUC as follows:

1. Except for the conditions listed in Item #2, #3, #4 and #5 below, Day-Ahead PAR schedules to be input into SCUC will match the previous like day schedule for each PAR internal to or bordering the NYCA.
2. If PAR scheduling changes are anticipated or maintenance facility outages are scheduled which affect PAR operation, Day-Ahead PAR schedules to be input into SCUC are modified in accordance with published contractual agreements and/or operating procedures.
3. PARs that have been designated to be under NYISO operational control are optimized by SCUC along with other resources. The optimization allows adjustments to the original schedules of the PARs to help relieve energy transmission into congested areas.
4. The ABC, JK, and Hopatcong - Ramapo interconnection PAR desired flows are established consistent with Section 17 of the MST:

- The desired flow scheduled over the Hopatcong-Ramapo interconnection may be adjusted by an offset MW value to reflect expected operational conditions.
- Interchange percentages for each interconnection, the Operational Base Flow (OBF) MW value, and information on reductions in the OBF due to PAR outages can be found in the Interchange Percentages and OBF posting located at the following link:

https://www.nyiso.com/power-grid-data

5. The Northport PAR which is in series with the 1385 Northport-Norwalk Harbor transmission facility has been superseded by the 1385 Proxy bus in the scheduling systems.
6. PAR Schedules to be input into SCUC and SCUC results are posted by the NYISO.

4.3. Security Constrained Unit Commitment

The SCUC function is used in the LBMP implementation to produce the generating unit commitment schedules, reserve and regulation market schedules, and firm transactions schedules for the First Settlement.

4.3.1. SCUC Stages

The intent of SCUC is to develop a schedule using a computer algorithm that simultaneously minimizes the total Bid Production Cost of:

1. Supplying power to satisfy all accepted purchasers' Bids to buy Energy from the Day-Ahead Market.
2. Providing sufficient Ancillary Services to support Energy purchased from the Day-Ahead Market.
3. Committing sufficient Capacity to meet the NYISO's Load forecast and provide associated Ancillary Services.
4. Committing sufficient Capacity to meet the NYISO's Load forecast and Local Reliability Rule requirements.
5. Meeting all Bilateral Transaction schedules submitted Day-Ahead.

To meet the above requirements, the SCUC algorithm is designed as a multiple pass process in which two security constrained commitment passes and two security constrained dispatch passes are executed in sequence as follows:

Pass #1 – Bid Load, Virtual Load, and Virtual Supply Commitment

The first pass of SCUC commits and schedules generating units, including Generators nominated to be Day Ahead Reliability Units, to supply Bid Load (Physical and Virtual) less Virtual Supply while securing the bulk power transmission system. The system is secured against the normal NYISO bulk power system contingency set so that monitored facilities do not become overloaded. Also, the program secures for certain Local Reliability Rules contingencies and monitored facilities.

Once this commitment run has converged, the automatic mitigation evaluation is performed, including a recommitment/redispatch. This commitment/dispatch is evaluated by security analysis. Additional iterations of unit commitment with bids and security analysis are performed until convergence is again achieved.

Pass #2 – Bulk Power System Forecast Load Commitment

The next pass commits any additional Generators that may be needed to supply the forecast load. Load bids (physical and virtual) and Virtual Supply bids are not considered in Pass #2. At the beginning of this pass, generator limits and commitment statuses are modified to ensure that the Resources selected in Pass #1 will not be de-committed or dispatched below their Pass #1 value. Generating units selected in Pass #1 may be dispatched higher, and additional units may be committed and dispatched. Since Pass #2 is used to assure that sufficient capacity is committed to supply forecast load it considers only incremental uplift costs and does not consider energy costs when determining additional commitments. Pass #2 also secures the bulk power system. In Pass #2, only the wind energy forecasts are used for scheduling intermittent resources that depend on wind as their fuel.

Pass #3 – Reserved for future use

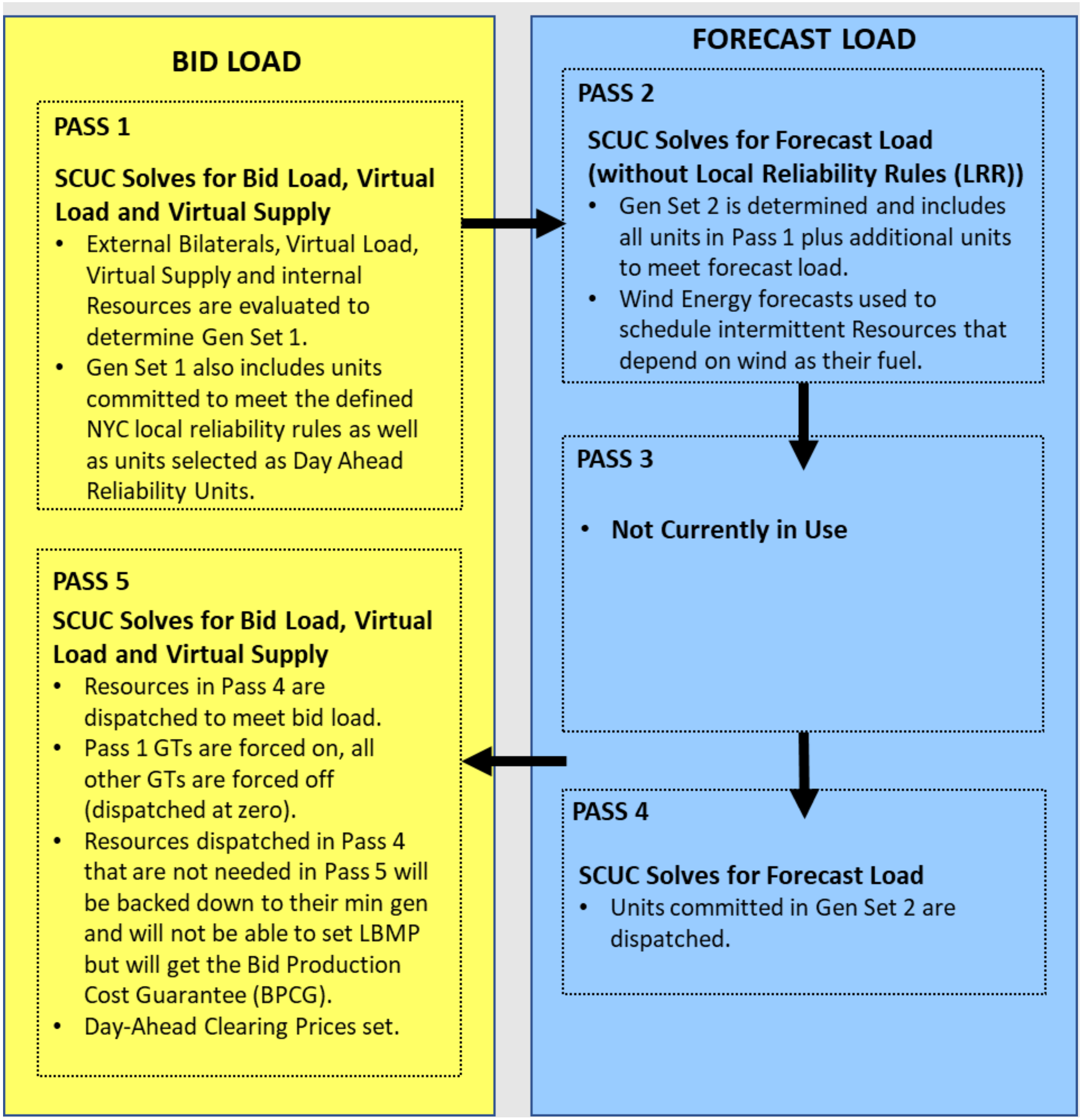
Pass #4 – Forecast Load Redispatch

In Pass #4, the set of Resources from the final commitment are dispatched using the original energy bids. The dispatch supplies the forecast load and is limited by the bulk power system constraint set produced in the Pass #2 commitment. The Resource capacities (energy + 30 minute reserve + regulation capacity) from this dispatch are used to calculate the forecast reserve for economic dispatch. The power flows are created for the transmission providers' review.

Pass #5 – Bid Load, Virtual Load and Virtual Supply Redispatch

In Pass #5, the final dispatch is determined to supply the bid load, virtual load and virtual supply (where virtual supply is treated as negative virtual load) and is limited by the constraint set produced in the Pass #1 commitment. The quick start generating units selected in the forecast pass are not dispatched Day-Ahead.

Figure 4: Multi-Pass Solution Process



Forecast Required Energy for Dispatch (FRED)

Forecast Required Energy for Dispatch (FRED) represents resources needed to serve internal load, which did not bid in Day-Ahead, but which is nevertheless forecast by the NYISO. Thus, "FRED" is additional expected energy needed to meet the NYISO forecasted load that is in excess of the sum total of Day-Ahead load bids. For each hour, FRED should at least equal the NYISO NYCA Load Forecast minus the Sum of Day-Ahead Internal Load Bids and import transaction schedules.

FRED Eligibility

All suppliers bidding into the Day-Ahead and Real-Time Energy Markets automatically qualify as potential suppliers of FRED (Day-Ahead or supplemental FRED respectively).

FRED Selection

Day-Ahead FRED is selected by SCUC. Non-committed suppliers selected to provide FRED are notified via the MIS if they are anticipated to start-up during the commitment day but do not receive a forward contract to start-up.

FRED Payment Rules

As with other suppliers, once a FRED supplier is started:

1. Supplier is guaranteed recovery of its start-up bid price and minimum generation bid price bid through the remainder of the dispatch day subject to mitigation as appropriate.
2. Supplier may set and is paid the Real-Time Energy LBMP for actual energy supplied. No availability is paid for FRED.

As is the case for all Real-Time energy suppliers including FRED, an applicable NYISO penalty is assessed to FRED suppliers for failure to provide energy.

4.3.2. SCUC Components

The SCUC function consists of the following major components:

- Initial Unit Commitment
- Network Data Preparation
- Network Constrained Unit Commitment.

Initial Unit Commitment (IUC)

The initial unit commitment (IUC) function computes the initial unit commitment schedule based upon:

- The load and generation bid data from the Bid/Post system
- Resource status data derived from the Automatic Generation Control system (AGC)
- Current schedules
- Load forecasts

Bid data is transferred from the Bid/Post system into the Network Manager (NM) database. This data includes time stamps associated with the Bid/Post system data. IUC then runs with the newly loaded database as input and produces the initial unconstrained unit commitment schedule.

Network Data Preparation (NDP)

The network data preparation (NDP) function provides an automated procedure to set up the initial conditions and various parameters of power flow cases, i.e., base cases, corresponding to the specified study period. It also validates the cases by calculating the power flow solution. A case is acceptable only when its power flow solution is successfully solved. NDP has the following essential components:

- **NPD Controller** – successively sets up the NDP case for each time step in the study and stores the resulting power flow solutions for subsequent processing
- **Schedule and Limit Retrieval** – for in/out-of-service equipment, and corresponding breaker statuses
- **Network Model Builder** – determines the network topology in the form of a bus model
- **Bus Scheduler** – sets up the power flow case
- **Load** – distributes system load to individual buses
- **Voltage Regulation** – assigned to the regulating devices
- **Generation** – economic dispatch for units (such as external) that are not considered in the initial unit commitment
- **Dispatcher Power Flow** – develops a base case power flow solution to detect data anomalies and to validate the initial unit commitment schedule.

Network Constrained Unit Commitment (NCUC)

The network constrained unit commitment (NCUC) function calculates a generation schedule for a specified study period, making sure that both unit commitment constraints and network security constraints are satisfied. NCUC has the following essential components:

- **NCUC Controller** – coordinates the NCUC solution process consisting of the following iterative steps:
    - Retrieve initial base cases and superimpose schedules from the latest Unit Commitment (UC) execution
    - Invoke DC Security Analysis (SA)
    - Invoke UC
- **DC Security analysis (SA)** – evaluates the impact of a set of given contingencies on the feasibility of the generation schedule
- **Unit commitment (UC)** – calculates the minimum bid cost schedule of the generating resources and biddable loads, subject to constraints. The components of cost include generation, startup, regulation, and reserve which are obtained from the Bid/Post system. Generation cost includes the effect of transmission loss factors. The set of constraints include:
    - Generation requirement
    - Reserve requirement
    - Resource operating limits
    - CSR Scheduling Limits (apply to Generators that participate in a CSR)
    - Generator minimum startup and down times
    - Maximum unit shutdowns per day
    - Transmission constraints
    - Transaction schedules.

If the hourly constraints on system generation requirement, reserve, or transmission do not allow a feasible solution, then UC continues to completion and reports the source of the infeasibility.

Each UC solution is comprised of an Ideal Dispatch and a Physical Dispatch. The Ideal Dispatch allows for fast-start resources to be dispatched across their entire operating range and, therefore, eligible to set price across their entire operating range. The LBMPs are determined from this dispatch. The Physical Dispatch uses blocked bid limits for fixed block units modeling the physical manner in which fixed blocked units operate. The generation schedules are determined from this dispatch.

The following modeling features are incorporated within NCUC:

- **Preventive Control Mode** – The generation schedule is determined such that no security violations will occur if any defined contingency occurs.
- **Generator Voltage Control** – Generators that are committed are modeled to regulate voltages within their reactive power capabilities.
- **System Voltage Stability** – System voltage stability is handled by imposing flow constraints on selected branch interfaces, representing the sum of the megawatt flows across the interface.
- **Infeasibility Handling** – When a network security constraint is detected as infeasible (unable to remove the violation) during the NCUC solution process, the constraint is relaxed, and solved for, subject to a penalty cost. Physical generating unit constraints, in contrast, are always enforced.

4.3.3. SCUC Inputs

Production Bid

A production bid is the composite of the incremental energy, minimum generation, startup and reserve costs as follows:

- **Operating Bid** – The incremental energy bid for a generator is modeled as a series of monotonically increasing constant cost steps. These bids are comprised of up to 12 segments. The first segment is determined by the minimum generation cost and defined by the no-load cost axis intercept ($/hr) and a slope ($/MWh). The 11 incremental energy segments are defined by MW break point and slope ($/MWh) pairs. Different curves can be input for different schedule days.
- **Startup Bid** – The startup bid is given by piecewise linear curve of bid versus time the generator has been off line prior to the start. Different values can be input for different schedule days.
- **Regulation Bid** – The regulation bid input for all units that can contribute to regulation, is given by a regulation available capacity (MW), a regulation capacity cost ($/MW) and regulation movement cost ($/MW).
- **Reserve Bid** - For off-line and non-dispatchable generators, the reserve bid is given by a reserve availability cost ($/MW).

Different costs apply to different reserve types and to reserves from off-line and non-dispatchable generators.

Startup and Shutdown Constraints

Multiple Shutdown limits constrain the number of times a generator can shut down in defined 24-hour periods. The time of day for the start of these periods is input. Shutdowns that occur at times when a generator becomes unavailable are not counted towards the multiple shutdown limit constraint. Allowed values for this limit are 0 to 9.

CSR Scheduling Limits

CSR injection and withdrawal Scheduling Limits constrain the total combined schedules of a solar or wind IPR and ESRs that participate in a CSR. Aggregations comprised of ESR, Wind, or Solar only are not eligible to participate in a CSR.

Delivery Factors

The SCUC application uses the Security Analysis (SA) module to generate delivery factors for each time step in the commitment period. The delivery factors for each time step reflects the network topology expected for that time period and the generation dispatch from the Unit Commitment (UC) module.

Losses

Power losses occur in the transmission system as energy flows from generating sources to the loads. These losses appear as additional electrical load, requiring the Resources to produce additional power to supply the losses. The SCUC, RTC and RTD each employ the same treatment of physical transmission losses. 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 load forecast for day-ahead and real-time is determined for demand only and the calculation of losses within SCUC, RTC, and RTD is added to the forecast for total scheduling or dispatching requirements. The day-ahead load forecast plus the losses determined within SCUC are used to determine day-ahead supply resource requirements. Calculating losses for day-ahead involves the following steps:

1. The day-ahead load forecast estimates eleven zonal loads for each hour of the next day. The forecast does not include an estimate of zonal transmission losses.
2. Hourly losses for the load zones are calculated within the bid load pass of SCUC.
3. Energy is scheduled in the bid load pass of SCUC to meet (i) the hourly zonal bid load demands and (ii) the calculated hourly zonal losses for bid load demand.
4. Hourly losses for the load zones are also calculated within the forecast load pass of SCUC.
5. Energy is scheduled in the forecast load pass of SCUC to meet (i) the hourly day-ahead forecast of the eleven zonal loads and (ii) the calculated hourly zonal losses for forecast load demand.

Reserve Profile

Four reserves are modeled:

- Regulation capacity
- 10-minute spinning reserve
- 10-minute reserve (includes 10-minute spinning reserve)
- Operating reserve (includes 10-minute reserve and 30-minute reserve)

Only on-line Resources can contribute to regulation and spinning reserve. Regulation capacity available is limited by the regulation capacity response rate, and spinning reserve is determined by the 10-minute generator response rate. Both on-line and off-line available Resources can contribute to 10-minute and 30-minute reserve.

The contribution to Regulation from all Resources and the contribution from non-dispatchable and off-line Resources depend on their associated input reserve cost bids.

4.3.4. 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 applicable requirement if the shadow cost needed to supply the requirement exceeds a preset value. The following demand curve functionality is used for the reserve and regulation requirements (except during real-time intervals when the Emergency Demand Response Program [EDRP] resources and/or Special Case Resources [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):

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 New York (SENY)	Spinning Reserve	Any shortage	\$40.00
	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) The applicable incremental SENY 30-minute reserve quantity or more (or any shortage if no incremental SENY 30- minute reserve quantity is applicable)	\$40.00 \$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

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.

4.3.5. 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 4.3.5.2 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.

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 4.3.5.2 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 4.3.5.2 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 4.3.5.2 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 (Resource1 and Resource2) impact a set of transmission constraints (Constraint1 and Constraint2). 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 Constraint1	Shift Factor for Constraint2
Redundant In-Series Constraints	Resource1: 0.9 Resource2: 0.6	Resource1: 0.9 Resource2: 0.6
Redundant Parallel Constraints	Resource1: 0.9 Resource2: 0.6	Resource1: 0.3 Resource2: 0.2

4.3.5.1. 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 non-zero 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.

4.3.5.2. 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.

4.3.5.3. Graduated Transmission Demand Curves

Figure 5: 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

4.3.6. Constraint Breaking

If the hourly resource constraints (i.e., system generation requirement, reserve, and transmission) specified for a given unit commitment run do not allow a feasible solution, the program relaxes the constraints in the following order:

1. Regulation and reserve constraints
2. Transmission constraints
3. Interchange ramp constraints
4. System Demand

To achieve a solution, the above constraints are relaxed incrementally in the given order until a solution can be found. All infeasibilities are reported.

In addition, the Resource constraints (i.e., input availability, minimum up and down time constraints, multiple shut down limit constraints, and ramp constraints) may preclude a feasible solution. If possible, the program relaxes these constraints in the following order:

1. Low operating limit
2. Multiple shutdown 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.

In the event that SCUC is unable to satisfy its security constraints, the NYISO must apply remedial actions, such as:

- Dispatching Resources to emergency upper operating limits
- Cancellation or rescheduling of outages.

4.3.7. SCUC Interfaces with Other Systems

- **Bid/Post System** – The SCUC function retrieves Bid data from the Bid/Post System function. Later SCUC provides the Bid/Post System with accepted Resource, transaction, and load bids, clearing prices, etc. This information is also passed on to the Real-Time Commitment process during the Dispatch Day.
- **Energy Management System (EMS)** – The SCUC function retrieves equipment outages, reserve and regulation requirements, Resource status history and contingency definition information from the EMS.
- **Load Forecaster** – The SCUC function receives the load forecast for the Day-Ahead study period from the Load Forecasting program.

4.4. Bilateral Transaction Evaluations

Refer to the *NYISO Transmission & Dispatching Operations Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for a more complete description of Bilateral Transaction Scheduling and Curtailment.

4.4.1. Firm Bilateral Transactions

Internal firm Bilateral Transactions are tabulated and automatically approved. Based upon verification with other control areas, external transactions are either approved or rejected. The results for all transactions are posted on the Bid/Post System.

4.4.2. Multi-Hour Block Transactions (MHBT)

Multi-hour block transactions are evaluated in the Day-Ahead Market relative to alternative offers and scheduled or not scheduled based upon the total production cost associated with the offer over the day. Instances may arise where a multi-hour block transaction may appear to be economic, as compared to posted Locational Based Marginal Prices (LBMPs), but was not scheduled.

The following examples describe possible scenarios where a submitted multi-hour block transaction offer was not scheduled even though it may appear to be economic as compared to the posted LBMPs:

- **Example 1** - The submitted MHBT offer is less than the posted LBMP for an hour or certain hours (but not all hours) of the offer, but was not scheduled. In this case, although the MHBT offer was less than the posted LBMP during some hours, the total cost of the bid transaction, over the hours bid, was greater than the alternative offers selected for those hours. Market rules for MHBTs do not allow for the selective scheduling of an hour or hours if less than the bid-specified minimum run time.
- **Example 2** - The submitted MHBT offer is less than the posted LBMP for all hours of the offer, but the offer was not scheduled. In this case, the MHBT offer was not selected because the offer would have resulted in even higher LBMPs than the LBMPs that were posted for some or all of the hours considered. One possible reason for this condition is that the scheduling of the MHBT in question may have precluded the scheduling of an alternative offer(s) due to minimum generation or minimum run time constraints related to the alternative offer(s). This situation would then result in a different set of resources being scheduled with an even higher priced offer setting the LBMP.

Another possibility is that the submitted MHBT was the marginal offer. In this case, scheduling of the MHBT may have exceeded the energy scheduling requirements for an hour or several hours. Since the market rules for MHBTs require that an MHBT be scheduled for the full bid MW amount for at least the minimum run time specified, alternative offers are scheduled to arrive at the most economic schedule that best meets the commitment requirements of each hour.

Scheduling decisions made for hours outside of the hours covered in a MHBT offer may also impact the scheduling of MHBTs. Even though a MHBT may be economic for the hours bid, scheduling the MHBT in question for those hours may result in additional costs related to resources and transactions scheduled for hours outside of the hours covered by the MHBT bid, yielding higher overall costs for the day.

LBMP calculations require consideration of numerous inter-related factors, not the least of which is system security. As a result, SCUC's decision to schedule, or not, certain MHBT offers is based on factors that may not be readily apparent from posted LBMPs.

4.5. Energy Storage Resource Constraint Evaluation

4.5.1. Energy Storage Limits Constraint

For Energy Storage Resources, only Energy will be accounted for in the storage limit (LSL and USL) constraints in DAM.

5. Day-Ahead Interface to the Dispatch Day

This section describes the primary interfaces between the Day-Ahead activities and the Dispatch Day activities.

5.1. Interchange Schedule Interface

The Interchange Schedule (IS+) function provides the primary mechanism for entering, modifying, or deleting interchange transactions for the Day-Ahead and Real-Time markets.

Data Model

The fundamental data objects within IS+ are the:

- Customer
- Contract
- Transaction
- Transaction segment
- Transaction class
- Customer contact
- NERC tag

Refer to the *NYISO Transmission Services Manual* (available from the NYISO Web site at the following URL: https://www.nyiso.com/manuals-tech-bulletins-user-guides) for additional information.

5.1.1. User Interface

The IS+ function provides video displays to enter and review data. Summary displays show transaction information filtered according to user-enterable or pre-specified filtering and ordering parameters, such as:

- Transaction chronology
- Transaction attributes
- Currently active transactions

5.1.2. Functional Interfaces

The Interchange Scheduler subsystem has interfaces with the following functions:

Automatic Generation Control

The AGC function obtains the net scheduled interchange value (DNI) for the NY Control Area from IS+.

Historical Information Retention

All relevant information from IS+ is archived.

Real-Time Market Evaluation

The accepted Day-Ahead transaction bids along with available Real-Time transaction bids are passed to the RTC function through the Bid/Post System. The RTC function passes accepted operating-day transaction schedules to the IS+ function through the Bid/Post System. The final Desired Net Interchanges for the NYCA and neighboring Control Areas are passed from the IS+ function to the Real-Time Dispatch (RTD) function through the Bid/Post System.

5.2. Generation Schedule Interface

The SCUC function (see Section 4.3.6) passes accepted generation schedules from the Day-Ahead process to the Bid/Post System, which then passes the information on to the Real-Time Commitment (RTC) process during the Dispatch Day.

5.3. Ancillary Service Schedule Interface

The SCUC function (see Section 3.5) passes the following accepted Ancillary Services schedules from the Day-Ahead process to the Bid/Post System..

- Regulation
- Spinning Reserve
- Non-spinning Reserve

The Ancillary Services are evaluated again as part of the Real-Time Scheduling systems solutions and the accepted Ancillary Service schedules are passed to the Bid/Post System.

6. NYISO Load Forecast Process

This section describes the NYISO Load Forecast process, functions and user interfaces.

6.1. Load Forecast Overview

The Load Forecast function is used to forecast hourly loads for each of the eleven NY Control Area Zones and at the statewide level. The Load Forecast function uses a combination of advanced neural network and regression type forecast models to generate its forecasts. The function uses historical load and weather data information (including temperature, dew point, cloud cover and wind speed) for each Zone to develop Zone load forecast models. These models are then used together with Zone weather forecasts to develop a Zone load forecast. The function develops the hourly load forecasts for the current day and the next six days..

6.2. Load Forecast Functions

The load forecast functional description covers the following:

- Load Forecast Module
- Load Forecast Training Module
- Load Forecast Functional Interfaces

6.2.1. Load Forecast Module

A single Load Forecast Module is used to produce the load forecasts for all the scheduling systems. The program automatically generates the 5 minute forecasts used by RTS. The hourly forecasts required for SCUC are published on demand for the current day and up to six days for each Zone. The published forecast is posted to the NYISO website by 08:00 a.m. every day, or as soon thereafter as is reasonably possible. The module uses the recent historical data; the current day historical data (up to the first hour of forecast); the weather forecast data for the forecast period, and the most recently updated load forecast models. The forecasts that are produced for the scheduling systems represent only the expected demand usage and do not include transmission losses. The transmission losses are specifically computed as part of the scheduling systems' functionality.

6.2.2. Load Forecast Training Module

This module allows the generation of load forecasts models for each Zone and for the New York Control Area. There is one load forecast model for each day of the week and each weather-defined season. Up to four seasons are allowed. The module allows for selection of model input parameters and parameters of neural network training.

The training module requires up to four years of historical hourly load and weather data for each area. The module allows for defining weather-defined season boundaries within the historical data, which is based on the load shape changes from one season to another. The module allows a complete or partial selection of historical data for training of a load forecast model. The training of the models for all areas (for all day types and all defined seasons) is automated through execution of a designated macro in the program.

6.2.3. Load Forecast Functional Interfaces

This section outlines the functional interchange of data between Load Forecast (LF) and other NYISO applications.

Oracle Information Storage and Retrieval (OISR) System

The LF function provides the OISR System function with the NYCA and Zonal hourly loads for storage. The MIS, SCUC and RTS systems can then retrieve the most up to date load forecast available.

Historical Information Retention

Load forecast results are archived.

Historical Load Data

The LF function retrieves historical load data from the EMS through its PI Historian data.

Weather Data

The LF function retrieves weather forecast data and historical weather data from files received from the weather service.

6.3. Load Forecast User Interface

The NYISO forecast is on a zonal basis and is produced by NYISO Energy Market Operations personnel. Initial forecasting is completed prior to initializing SCUC each day prior to the Dispatch Day. The forecast is for the Dispatch Day and the next six days, a total of up to 168 hours.

The Load Forecast function provides a complete set of input/output displays for a typical load zone. Input/output displays are available at the system level to present the load forecast values.

The function is accompanied with a set of displays for input, execution, and output. The required files as input to the program are in .csv format.

The function provides the capability to publish the load forecast data to the OISR for the SCUC package to utilize.

By 08:00 a.m. or as soon thereafter as is reasonably possible, the NYISO develops and posts its statewide Load forecast on the OASIS.

7. SCUC Execution

This section describes SCUC Execution procedure.

7.1. SCUC

These procedures are performed by the NYISO Energy Market Operations personnel after the MIS DAM Market closing process has completed. The procedures are executed on the RANGER system.

7.2. SCUC Execution Actions

The NYISO Energy Market Operations personnel perform the following actions:

1. Retrieve the MIS System file for the next day's Bids
2. Transfer data from the EMS / Real Time server
3. Perform the SRE end of the day fill in process
4. Execute the SCUC
5. Review and analyze results
6. Send the SCUC output data to the Bid/Post System Box
7. Save SCUC case for:
    a. Archival purposes
    b. Next SCUC History run
    c. Dispute resolution purposes

8. Reliability Forecast

This section describes the maintenance of reliability in the time frame one to seven days ahead of the Dispatch Day.

8.1. Reliability Forecast Requirements

In the SCUC program, system operation shall be optimized based on Bids over the Dispatch Day. However, to preserve system reliability, the NYISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven-day period that begins with the next Dispatch Day.

The NYISO will perform a Supplemental Resource Evaluation (SRE) for days two through seven of the commitment cycle. If it is determined that a long start-up time Generator is needed for reliability, the NYISO shall accept a Bid from the Generator and the Generator will begin its start-up sequence. During each day of the start-up sequence, the NYISO will perform a SRE to determine if long start-up time Generators will still be needed as previously forecasted. If the Generator is still needed, it will continue to accrue start-up cost payments on a linear basis. If at any time it is determined that the Generator will not be needed as previously forecasted, the NYISO shall order the Generator to abort its start-up sequence, and its start-up payment entitlement will cease at that point.

The NYISO will commit long start-up time Generators to preserve reliability. However, the NYISO will not commit resources with long start-up times to reduce the cost of meeting Loads that it expects to occur in days following the next Dispatch Day. Supplemental payments to these Generators, if necessary, will be determined according to the provisions of Attachment C of the NYISO Services Tariff, and will be recovered by the NYISO under Rate Schedule 1 of the NYISO OATT.

NYISO Actions

The NYISO shall perform the SRE as follows:

1. The NYISO shall develop a forecast of daily system peak Load for days two through seven in this seven-day period and add the appropriate reserve margin.
2. The NYISO shall then forecast its available Generators for the day in question by summing the Operating Capacity for all Generators currently in operation that are available for the commitment cycle, the Operating Capacity of all other Generators capable of starting on subsequent days to be available on the day in question, and an estimate of the net imports from External Bilateral Transactions.
3. If the forecasted peak Load plus reserves exceeds the NYISO's forecast of available Generators for the day in question, then the NYISO shall commit additional Generators capable of starting prior to the day in question (e.g., start-up period of two days when looking at day three) to assure system reliability.

4. In choosing among Generators with comparable start-up periods, the NYISO shall schedule Generators to minimize the start-up and minimum Generation Bid costs of meeting forecasted peak Load plus Ancillary Services consistent with the Reliability Rules.
5. In determining the appropriate reserve margin for days two through seven, the NYISO will supplement the normal reserve requirements to allow for forced outages of the short start-up period Generators (e.g., gas turbines) assumed to be operating at maximum output in the unit commitment analysis for reliability.

The bidding requirements and the Bid tables in Attachment D of the NYISO Services Tariff indicate that Energy Bids are to be provided for days one through seven. Energy Bids are binding for day one only for units in operation or with start-up periods less than one day. Minimum generation cost Bids for Generators with start-up periods greater than one day will be binding only for units that are committed by the NYISO and only for the first day in which those units could produce Energy given their start-up periods. For example, minimum generation cost Bids for a Generator with a start-up period of two days would be binding only for day three because, if that unit begins to start up at any time during day one, it would begin to produce Energy 48 hours later on day three. Similarly, the minimum generation cost Bids for a Generator with a start-up period of three days would be binding only for day four.

8.2. Reliability Responsibilities

NYISO Actions

To insure that the New York Control Area (NYCA) will meet its operating capability, reserve, interchange, and load requirements in a reliable manner, the NYISO Scheduling staff performs the following:

1. Determine that the NYCA has sufficient operating capability and reserve to meet the forecasted load and reserve requirements for the Day-Ahead period.
2. Determine that the NYCA has sufficient Regulation margin to meet light load requirements.
3. Coordinate, verify, and confirm the Day-Ahead transaction schedules.
4. Coordinate the scheduling of NYCA Inadvertent Interchange payback when conditions warrant.
5. Identify hours when the magnitude of External interchange schedule changes could degrade NYCA control performance and adjust transactions accordingly.

Market Participant Actions

The Market Participants must perform the following:

1. Notify the NYISO of any scheduled generation and transmission outages according to the 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) that would affect transactions.

2. Respond to NYISO directions involving security, capability, schedule changes, and light load problems.

8.3. Dealing with Insufficient Bids

The following provides procedures to deal with insufficient bids and to ensure that sufficient operating capacity is available to serve all NYCA load. To do this, a variety of measures (i.e., installed capacity, annual reliability assessments, maintenance outage coordination, seven day reliability forecasts, SCUC, etc.) will help reduce the likelihood of experiencing insufficient available bids. Notwithstanding, the NYISO needs the ability to identify potential bid insufficiencies with adequate lead-time to be able to solicit and re-evaluate additional bids.

The Need for Bids

The NYISO cannot commit resources in the DAM without receiving bids from those resources. Upon determining that it needs more Day-Ahead resources the NYISO will issue a public request for more bids. This information will be posted prominently to the NYISO web page. If the NYISO continues to have insufficient bids to serve NYCA load even after bid solicitations, it can reasonably be assumed that sufficient resources are truly not available. In this case, the NYISO should implement emergency measures that may include purchasing external emergency energy, shared activation of reserves, and load curtailment.

Reliability Assessments

The NYISO will perform a reliability assessment to determine if projected Operating Reserves over an upcoming period will be adequate. This reliability assessment will compare projected Operating Capacity with the forecast NYCA Peak Load (where Operating Capacity equals NYCA Installed Capacity less Proposed Maintenance Outage Schedules less Projected Unavailable Capacity). For instance:

Figure 6: Example Reliability Assessment - Load and Capacity Table

Assessment	MW Capacity
NYCA Installed Capacity (ICAP)	30,000 MW
Less Scheduled Maintenance Outages	(3,000 MW)
Less Forecast Unavailable	(4,000 MW)
Net Operating Capability	23,000 MW
Less Forecast NYCA Peak Load (including Firm Energy Exports)	(20,000 MW)
Net Operating Reserves	3,000 MW
Less Required Operating Reserves	(1,800 MW)
Operating Reserve Surplus (Deficiency)	1,200 MW

If Operating Capacity is expected to be deficient, the NYISO will take actions as specified below for various time frames.

8.4. Reliability Assessment Processes

The NYISO continually re-evaluates the reliability of the NYCA. There are several reliability assessments of any given Operating Day performed over various time horizons. The sequences of these evaluations are described next.

Annual Reliability

The NYISO has the responsibility to ensure sufficient capacity is expected to be available to serve all NYCA load on an annual basis. This is accomplished using the NYISO maintenance outage coordination procedure. All installed capacity providers are required to abide by NYISO maintenance coordination, and all other generating resources are required to inform the NYISO of their annual maintenance plans.

Based upon a weekly reliability assessment for the upcoming calendar year, if Operating Capacity is expected to be deficient in a certain period, the NYISO will take actions to modify Resource maintenance schedules as outlined 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).

7-Day Reliability

Similarly to the case of Annual Reliability, the NYISO will perform a reliability assessment on a rolling basis to determine if projected Operating Reserves for each day of the next seven days will be adequate. If a deficiency is forecast, the NYISO will commit generation capable of starting in time to meet the expected load. In addition, if resources are anticipated to be insufficient for any day of the rolling commitment week, the NYISO will immediately broadcast a bid solicitation message via the Market Information System (MIS) to all market participants, identifying all deficient bid times and categories.

Day-Ahead Reliability

At the close of the Day-Ahead market, the NYISO will use SCUC to evaluate bids and clear the Day-Ahead market. If SCUC cannot solve due to insufficient bids to meet Day-Ahead requirements, the NYISO shall commit all bid resources; and then solicit additional bids and initiate the Supplemental Resource Evaluation (SRE) process as described in Section 10 of this Manual. When the Day-Ahead Energy Market does not clear due to insufficient resources, the calculated Energy LBMP will be the marginal cost to supply the last MW of load; MW amounts in forward contracts for load bids will be prorated to match total supply forward contracts with load forward contracts.

Post SCUC Day-Ahead and Pre or Post RTC In-Day Reliability

Any time an event occurs such as a Resource trip or a transmission outage that renders a Day-Ahead commitment insufficient for hours that would not yet be evaluated by Real-Time Commitment (RTC) (or in Real-Time after RTC has run), the NYISO **must** perform an SRE.

Real-Time Reliability

The NYISO will use Real-Time Commitment (RTC) to evaluate Real-Time bids, and check that sufficient bids exist for the next two subsequent hours. If RTC cannot solve due to insufficient bids to meet Real-Time requirements, the NYISO shall commit all bid resources subject to network security constraints; and then solicit additional bids and initiate the SRE process.

9. Interchange Coordination Procedure

Scheduled interchange must be coordinated between Control Areas to prevent:

- Frequency deviations
- Accumulation of Inadvertent Interchange
- Exceeding mutually established transfer limits

NYISO Actions

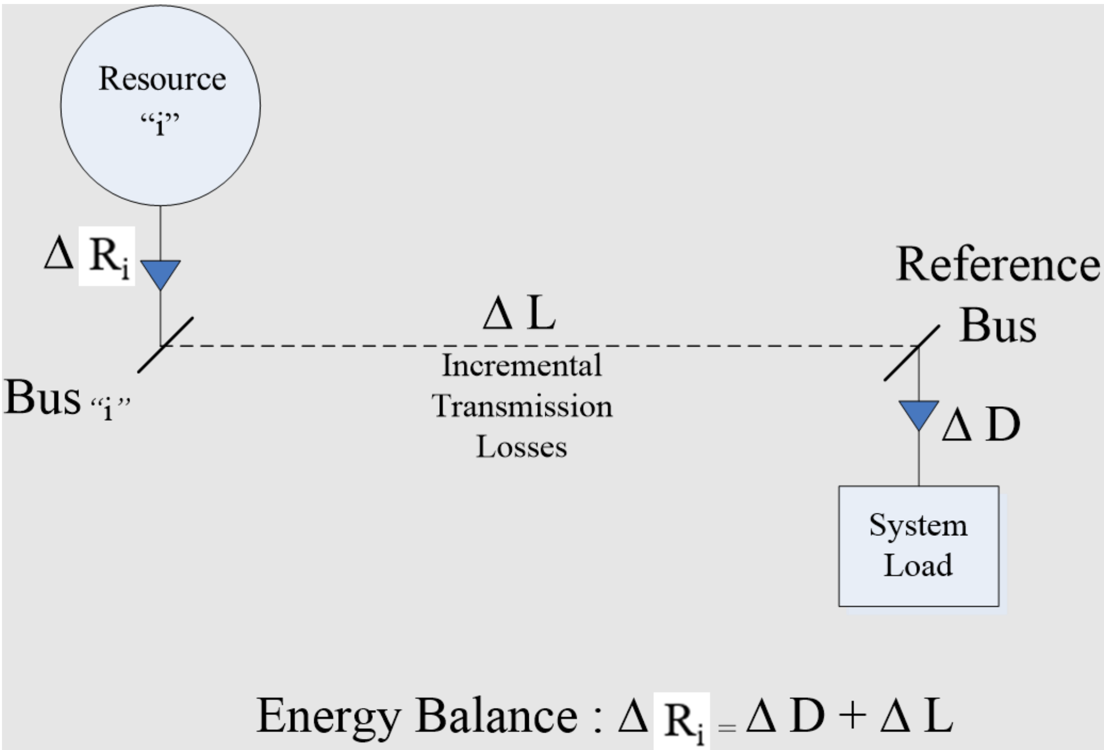
The NYISO schedules external bilateral transactions with other Control Areas in accordance with current NERC policies and procedures.

10. Supplemental Resource Evaluation One or More Days Ahead

The Supplemental Resource Evaluation (SRE) process is used to commit additional resources outside of the SCUC and RTC processes to meet NYISO reliability or local reliability requirements. The Transmission and Dispatch Manual provide more information on SREs in sections 5.7.5 through 5.7.12.

Attachment A Calculation of Incremental Losses

Figure 7: Incremental Transmission Losses



Calculation of Incremental Losses

The marginal (or incremental) effect of real power transmission losses is taken into account by the SCUC for the Day-Ahead Market, Real-Time Market, and Real-Time operations. Losses occur in the transmission system as energy flows from generation sources to the loads. These losses appear as additional electrical load, requiring the Resources to produce additional power to supply the losses. The amount of losses that occur on specific transmission lines or areas of the transmission network at any given time are dependent on network topology and the specific generation sources being used to meet the load at that time. Figure 7: Incremental Transmission Losses illustrates the concept of incremental losses:

The elements in Figure 7: Incremental Transmission Lossesare defined as follows:

ΔD = an increment of load at the reference bus with all other loads held constant

ΔGi = the increment of generation at bus "i" that is required to supply the increment of load at the reference bus

ΔL = the increment of transmission losses resulting from the transfer of power from the Resource to the reference bus load.

Penalty Factors The Penalty Factor for Resource "i" is defined as the increase required in Resource output at Bus "i" to supply an increase in load at the reference Bus with all other loads held constant, or:

- $PF_i = \Delta R_i / \Delta D$

Which, from the energy balance relationship, can also be defined as follows:

- $PF_i = 1 / (1 - \Delta L / \Delta R_i)$

Resource Energy bid prices are multiplied by Penalty Factors to account for incremental transmission losses in the dispatch process.

Delivery Factors The Delivery Factor for Resource "i" is defined as follows:

- $DF_i = \Delta D / \Delta R_i$

Which, is related to Penalty Factor as follows:

- $DF_i = 1 / PF_i$

Delivery Factors are used to calculate the marginal loss components of the LBMPs.

Losses Associated with External Transactions

External Generators and Loads can participate in the LBMP Market or in Bilateral Transactions. External Generators may arrange Bilateral Transactions with Internal or External Loads and External Loads may arrange Bilateral Transactions with Internal Resources. Charges for marginal losses for each of these types of transactions (LBMP Market or Bilateral) are limited to losses inside the NYCA. The Resource and Load locations for which LBMPs are calculated are initially limited to a pre-defined set of buses External to the NYCA. The marginal losses component for these LBMPs are calculated from points on the boundary of the NYCA (Interconnection buses) to the reference bus.

The marginal losses component of the LBMP at each External bus are a weighted average of the marginal losses components of the LBMPs at the Interconnection buses. To derive the marginal losses component of the LBMP at an External location, a hypothetical transaction is scheduled from the External bus to the reference bus. The Shift Factors for this transaction on the tie lines into the Interconnection buses, which measure the per-unit effect of flows over each of those tie lines that result from the hypothetical transaction, provide the weights for this calculation. Since all the power from this hypothetical transaction crosses the NYCA boundary, the sum of these weights is unity. The sum of the products of these weights and the marginal losses component of the LBMP at each of these Interconnection buses yields the marginal losses component of the LBMP that are used for the External bus.

Attachment B NYISO Load Forecasting Model

NYISO Load Forecasting Model

The NYISO Load Forecasting Model (LFM) is designed to meet a number of objectives. Perhaps most important of the objectives is the ability to forecast hourly loads for the day-ahead market. This particular need encompasses not only the loads for the New York Control Area (NYCA), but also the loads for each of the eleven zones that comprise the NYCA. Other objectives extend the geographic purview of the model and the timeframe for the forecasts.

The geographic reach of the model will be extended to each zone within the NYCA. Since the NYISO auction model turns on location based marginal prices (LBMP), there needs to be a mechanism to support the determination of those prices. The market-clearing price will be determined by the supply and demand for power. Since both supply and demand for power have geographic aspects, the system that provides (expected) demand information to the auction process needs geographic aspects as well.

The timeframe needs of the electricity market are quite varied, and a modeling system to support that market must also function within the various timeframes. In addition to the day-ahead market, there is a need for week-ahead demand information since some generating facilities may take that long to become fully functional. There is a need to understand what is likely to happen during a capability period since capacity may need to be procured to meet reliability requirements. It is important to understand the demand and energy profile for the entire calendar or capability year so that rational planning can take place. Finally, in the arena of longer timeframes, a five to ten year horizon meets NERC standards and allows planning for capacity to be sited and built. Retreating from the long run towards the very shortest runs, we need to understand demand in the balancing markets and in situations of highly changeable weather. These analyses would logically take place during the day in question.

There are also a number of technical objectives for the modeling system. For day-ahead forecasting, it needs to be convenient and transparent to run, in order to feed information in a timely manner to market participants and to the SCUC process. The model must be accurate to within the limits of statistical and econometric models; forecasts of weather and economic activity that drive the LFM are likely to have errors, which mean that actual loads will deviate from forecasted loads. The modeled loads need to be within an acceptable range of the actual loads after controlling for weather and economic activity. Thus, another objective is that the performance of the model can be assessed easily and quickly so that adjustments can be made appropriately. The economic components of the model structure should conform to good economic theory and practice so that the system can also yield information that is useful for policy analysis.

A Unified System

Despite a large number of seemingly disparate objectives, the unifying theme is one of providing information about future loads and energy demands across the NYCA. With this theme as backdrop, the NYISO decided that a unified modeling system using one set of equations, drivers, and historical information would best serve its information needs. In particular, using one comprehensive data set eliminates inconsistencies and the need to try to align data from different sources.

As the rest of this attachment will illustrate, creativity in model construction allows appropriate data to drive the model in the relevant timeframe. Certainly, weather is extremely important in the short run, while economic and secular data play a stronger role in the medium and longer run. What makes the system unified is that weather does not disappear in the long run (design weather is used for some scenario planning) nor does economic activity disappear in the short run (economic activity is fixed at some level for capability considerations and next day analysis).

Schematic Model Flow

The central objective of the model is to forecast hourly loads in each of eleven zones and the NYCA for the next day. Peak load and total energy consumption for the next day are extremely important ancillary objectives and might, under some circumstances, be derived from the hourly loads. In fact, the LFM uses a “bottom/up” approach which pays explicit attention to peak load and energy at zone level, and obtains the NYCA level by summing over the zones. This approach uses state or NYCA information when it contributes well to the model’s structure and zone information when it plays a premier role. Once the peak load and daily energy are obtained, a series of hourly interval models are determined, comprised of four fifteen-minute interval models for each hour of the day.

The model’s structure flows from daily peak and energy at the zonal level, to hourly interval loads at the zone level. Part of the modeling process is by inclusion of predicted values of peak or energy into the hourly interval load models at the NYCA level, from the NYCA to the zones, and in the zones as isolated units.

The zonal daily peak load and energy are specified as functions of weather, economic activity, day-type, and an installed energy-consuming equipment base (Estimation procedures are discussed below). The predicted zonal peak and energy requirements then become part of the driver set of the zonal hourly interval load models. Peak load and energy requirements in the driver sets serve to constraint the hourly interval loads to be consistent with the previously determined peak and energy requirements.

At this point there are eleven sets of (96) hourly interval zone load models and one set of (96) NYCA-level hourly interval load model obtained by summing over all the zones.

The "bottom-up" methodology utilizes the detailed information at the NYCA level and preserves the resulting profiles and forecasts for the unique behavior of each zone. They also allow for a strong concordance between peak load and energy, and hourly interval loads.

Data Considerations

Since this attachment is not a tutorial on load forecasting methodologies, it is not useful to go into too much detail about particular data series or estimation methods, but some description of each can help to illuminate the process. The core of the modeling system is the next day hourly interval load forecast, and naturally, the central data set is the set of hourly interval loads for the system and for the zones. Load data from three to four recent historical years provide sufficient experience to yield acceptable estimates of the parameters associated with the drivers of the various models. Shorter periods will better capture more recent weather-response characteristics while longer periods will better capture weekday, weekend and holiday seasonal daily and hourly load profiles. The challenge for modeling and estimation was to obtain data with hourly interval frequency or construct other data to have the required frequency. The key drivers for the day-ahead models are weather and day-type. The weather forecast provider was able to supply a number of variables with an hourly frequency, for example, dry bulb temperature, wind speed, cloud cover, dew point, wet bulb temperature, humidity, and barometric pressure. However, it is not necessary to model or forecast weather at sub-hourly intervals.

The interaction of load and weather can be quite subtle, requiring consideration of build-up effects, daily averages, recognition of maxima and minima, etc. The availability of the hourly information listed above enabled the construction of transformed data to meet the needs of modelers.

Figure 8: Albany Airport Actual and Forecasted Weather is an example of actual and forecasted weather for Albany International Airport, the official weather collection site for Albany County. Note that the minimum, maximum, and average values of the variables are determined over twenty-four hourly observations. The data for 15 April, 1999 is the set of actual observations, while the data for 16 – 25 April, 1999 is a forecast.

Figure 8: Albany Airport Actual and Forecasted Weather

DATE	MIN TMP	MAX TMP	AVG TMP	MIN DPT	MAX DPT	AVG DPT	MIN HUM	MAX HUM	AVG HUM	MIN WEB	MAX WEB	AVG WEB	MAX WSP	AVG WSP	AVG CLC
Apr. 15, 1999	28	62	48	17	32	24	18	89	47	27	44	38	18	7	33
Apr. 16, 1999	37	51	45	29	33	30	43	76	56	27	44	38	13	6	63
Apr. 17, 1999	40	57	48	34	39	37	46	96	68	27	44	38	13	9	79
Apr. 18, 1999	40	56	48	36	37	37	49	89	66	27	44	38	10	8	77
Apr. 19, 1999	36	53	45	36	37	37	36	100	72	27	44	38	12	8	75
Apr. 20, 1999	39	58	48	35	36	35	42	89	64	27	44	38	8	7	65
Apr. 21, 1999	36	62	49	33	35	34	35	92	59	27	44	38	9	7	59
Apr. 22, 1999	39	65	52	31	33	32	29	76	49	27	44	38	8	7	54
Apr. 23, 1999	42	69	56	30	31	31	24	65	41	27	44	38	11	8	52
Apr. 24, 1999	43	68	55	30	30	30	24	60	40	27	44	38	10	8	40
Apr. 25, 1999	41	64	52	30	40	35	36	86	54	27	44	38	10	7	30

The zonal forecast models use weather information gathered from seventeen weather stations across New York. The data from the stations is aggregated appropriately to best represent each zone. Thus, the information from those seventeen sites is combined into eleven zone weather sets and one state-level weather set. Figures Figure 9: Zonal Share of New York State's 2010 Population and Figure 10: Weather Station Weights Imputed to Each Zone show the state and zone weighting schemes.

Figure 9: Zonal Share of New York State's 2010 Population

ZONE	POPULATION (000)	Percent
A - WEST	1,532	7.9%
B - GENESE	1,003	5.2%
C - CENTRL	1,384	7.1%
D - NORTH	82	0.4%
E - MHK VL	891	4.6%
F - CAPITL	1,215	6.2%
G - HUD VL	1,372	7.0%
H - MILLWD	190	1.0%
I - DUNWOD	760	3.9%
J - N.Y.C.	8,186	42.1%
K - LONGIL	2,835	14.6%
TOTAL	19,450	100.0%
Upstate (A-F)	6,107	31.4%

ZONE	POPULATION (000)	Percent
Downstate (G-K)	13,343	68.6%

Figure 10: Weather Station Weights Imputed to Each Zone

Zone	Stations	Station Weight
A - WEST	Buffalo Elmira Syracuse Total	91% 5% 4% 100%
B - GENESE	Elmira Rochester Syracuse Total	5% 85% 10% 100%
C - CENTRL	Binghamton Elmira Syracuse Watertown Total	23% 14% 55% 9% 100%
D - NORTH	Plattsburgh	100%
E - MHK VL	Binghamton Massena Monticello Utica Watertown Total	20% 17% 13% 35% 15% 100%
F - CAPITL	Albany Binghamton Plattsburgh Poughkeepsie Utica Total	76% 3% 5% 6% 10% 100%
G - HUD VL	Newburgh Poughkeepsie White Plains Albany Total	68% 27% 4% 2% 100%
H - MILLWD	White Plains Total	100% 100%
I - DUNWOD	White Plains	100%
J - N.Y.C.	JFK LGA Total	21% 79% 100%

Zone	Stations	Station Weight
K - LONGIL	Islip	100%

Day-type information in the form of binary indicator variables comes from a master daily calendar. Holidays and the days surrounding holidays were also available through this master calendar. This kind of information is represented by binary variables, which indicate that a given day either is or is not a particular day of the week, or a particular holiday.

Economic data at the state, metropolitan area or county level is available at best on a monthly basis, in the case of employment, and on a quarterly or annual basis for other kinds of information. This frequency did not pose a real problem since economic activity can be considered fixed in the very short run. To incorporate levels of economic activity into the model in the short run (peak loads or daily energy), and changes in activity as the short run unfolds into the long run, the appropriate economic variables were converted (from monthly, quarterly, annually) to daily values which remained constant until a new value emerged, employment in the next month, for example.

The constancy of economic data in the very short run, combined with its variability in the medium and long run, allows the use of the same model as the time horizon unfolds. Weather data can be used in a similar way. As discussed above, weather is certainly a major driver of day-ahead and week-ahead load, and weather data is available as a forecast to feed into the driver side of a load or energy forecasting model as a set of assumptions. Longer run weather forecasts are much less certain, even for a month ahead, let alone a season, capability period, year, or decade.

For these planning periods, we incorporate the concept of design weather into the model. While each day or month can differ in accord with the design characteristics, the design pattern can be held constant for planning purposes. In fact, atypical weather patterns as well as typical or design patterns can be incorporated into the model for purposes of comparative analysis. So, analogous to the way in which economic data is fixed in the short run, weather patterns can be fixed in the longer run. It is the pliability of the model drivers that allows the use of the same model structure over very different timeframes.

As described above, the LFM actually aggregates weather from seventeen stations across New York into eleven zone points based on population and other historical weighting factors. Economic data comes from our economic forecasting vendor and is provided at the state, MSA, and county levels for subsequent aggregation into zones.

Estimation Processes

To articulate the LFM, we incorporated data into the appropriately specified equation systems via statistical estimation procedures. The intent here is straightforward. The estimation process should lead to a set of model equation parameters, which minimize the (sum of squared) errors between the actual loads and what the model predicts for load under the circumstances defined by the driver variables.

The LFM goes beyond traditional regression analysis to incorporate a technique known as “artificial neural net” (ANN) analysis. By taking a sophisticated non-linear approach to the estimation of the model’s parameters, ANN analysis allows a model to be “trained” and to “learn” from its experience as it estimates the parameters. Training takes place when a specification is articulated and parameters are estimated using a given data set. Learning takes place when new data is incorporated into the data set and the original specification is maintained. Learning can often result in some small adjustments to parameters as a result of the new experience (data). It is an efficient way to update a model without expending effort on a re-specification.