



Working to Perfect the Flow of Energy

PJM Manual 11:

Scheduling Operations

Revision: 26

Effective Date: November 9, 2005

Prepared by

Market Development

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Approval

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Stuart Bresler, General Manager

Market Operations

Revision History

Revision 26 (11/09/05)

- Section 7: Overview of External Transaction Scheduling
 - ☞ Revised wording in paragraph 1 to reflect PJM's compliance with NERC Standard INT-001.

Revision 25 (08/19/05)

- Section 3: Overview of PJM Regulation Market
 - ☞ Revised PJM Regulation Market Business Rules to create a single regulation market for the PJM RTO effective August 1, 2005.

Revision 24 (05/09/05)

- Section 3: Overview of PJM Regulation Market
 - ☞ Revised PJM Regulation Market Business Rules to identify Ancillary Services Market Areas for Market Integration.
 - ☞ Revised PJM Spinning Reserve Market Business Rules to define Southern Spinning Reserve Requirement.
- Section 4: Overview of the PJM Spinning Reserve Market
 - ☞ Revised PJM Spinning Reserve Market Business Rules to identify Ancillary Services Market Areas for Market Integration.
 - ☞ Revised PJM Spinning Reserve Market Business Rules to define Southern Spinning Reserve Requirement.
- Section 7: External Transaction Scheduling

- ☞ Revised expiration times for reservations that are not scheduled against that are made to start the following day.

Revision 23 (12/7/04)

- Section 2: Overview of PJM Two Settlement System
 - ☞ Changed PJM Two Settlement Business Rules for to allow Unit Modeling Changes quarterly.

Revision 22 (10/01/04)

- Section 2: Overview of PJM Two Settlement System
 - ☞ Changed PJM Two Settlement Business Rules for Virtual Bidding at External Interfaces
 - ☞ Added PJM Two Settlement Business Rules for modeling multiple units for operating reserve calculations.
- Section 3: Overview of PJM Regulation Market
 - ☞ Changed PJM Regulation Market Business Rules to identify Ancillary Services Market Areas
 - ☞ Added/Changed PJM Regulation Market Business Rules for Market Integration
 - ☞ Changed PJM Regulation Market Business Rules to define Main/ECAR regulation requirement
 - ☞ Changed PJM Regulation Market Business Rules to define new information supplied through the Two-Settlement Market User Interface
- Section 4: Overview of the PJM Spinning Reserve Market
 - ☞ Changed PJM Spinning Reserve Market Business Rules *to identify Ancillary Services Market Areas*
 - ☞ Added/Changed PJM Spinning Reserve Market Business Rules for Market Integration

Revision 21 (01/31/04)

- Created a new section (section 7: External Energy Scheduling)

- Revised *Exhibit 1: List of PJM Manuals* to reflect additional manuals which have been created in 2003.

Revision 20 (09/01/03)

- Section 1: Overview of Scheduling Operation
 - ☞ Revised exhibit 2.
- Section 2: Overview of PJM Two Settlement System
 - ☞ Revised exhibit 2.
- Section 3: Overview of PJM Regulation Market
 - ☞ Changed High Regulation Limit to Regulation Max
 - ☞ Changed Low Regulation Limit to Regulation Min
- Section 4: Overview of the PJM Spinning Reserve Market
 - ☞ Changed PJM Spinning Reserve Market Business Rules to define new information supplied through the Two-Settlement Market User Interface: Condense Startup Cost, Condense Hourly Cost, Condense Notification Time, Spin as Condenser.
 - ☞ Added Spinning Reserve Market Business Rule regarding Balancing Operating Reserves for units that are pool-assigned Tier 2 spinning reserve.
- Section 5: Scheduling Philosophy and Tools
 - ☞ Revised exhibit 4.
 - ☞ Added exhibit 5.
 - ☞ Revised exhibit 12.
 - ☞ Revised exhibit 13.
- Removed all Attachments
- Attachment A: Markets Database Dictionary has been removed
 - ☞ The Markets Database Dictionary provides PJM Market Participants with definitions for each of the data elements in the Markets Database. The Markets Database is an Oracle

database that replaced the PJM unit commitment database. It is the repository of all generation offers, demand bid data and schedules for the day-ahead energy market, real time energy market, regulation market, and spinning reserve market. The [Markets Database Dictionary](http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf) can be found on the PJM website at <http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf>.

- Attachment B (Offer Forms) has been deleted since the forms are no longer used
- Attachment C (eMKT User's Guide) has been removed
 - ☞ The PJM eMKT Users Guide provides Market Participants with the information needed to participate in the PJM two-settlement, regulation markets and spinning reserve markets. The user guide describes the two-settlement software, the spinning reserve and regulation software, and the tasks that Market Participants can perform, as well as the expected system responses. The eMKT Users Guide can be found on the PJM website at <http://www.pjm.com/documents/downloads/user-guides/ts-userguide.pdf>
- Attachment D (Source & Sink List) has been removed
 - ☞ Instructions on how to download the valid sources and sinks for the Day-ahead Energy Market can be found in the PJM eMKT Users Guide. The eMKT Users Guide can be found on the PJM website at <http://www.pjm.com/documents/downloads/user-guides/ts-userguide.pdf>
 - ☞ Participants can also download the PJM Network Model information from the PJM website at www.pjm.com/markets/energy-market/bus-price-model.html.
- Attachment E: Interchange Energy Schedule Curtailment Order
 - ☞ This attachment has been renamed "Attachment A."
- Attachment F: External Interface Specification Guide has been removed
 - ☞ The External Interface Specification Guide is intended to help Market Participants in the PJM two-settlement, regulation and spinning reserve markets who want to develop their own interfaces for exchanging market data with PJM instead of using the default Market User Interface provided in PJM. The

External Interface Specification Guide can be found on the PJM website at <http://www.pjm.com/services/training/downloads/two-externalspecs1.pdf>.

Revision 19 (12/01/02)

- Revised Attachment E: Interchange Energy Schedule Curtailment Order.

Revision 18 (12/01/02)

- Revised Attachment E: Interchange Energy Schedule Curtailment Order.

Revision 17 (12/01/02)

- Added new Section 4: Overview of the PJM Spinning Reserve Market.
- All remaining sections re-numbered respectively.

Revision 16 (05/18/01)

- Revised Section 2: Overview of the PJM Two Settlement System. Updated 'Market Sellers' subsection to include rules involving the designation of Maximum Emergency and Maximum Economic generation, numbered items 22 and 23, respectively.

Revision 15 (02/01/01)

- Revised Section 5: Scheduling Strategy & Method. Under subsection 'External Transactions', updated 60/45/30 minute rule to the new 60/30/20 minute rule. Also added bullet: "Hourly transactions will only be accepted after 1600 EPT (1400 EPT on non-business days) of the day before the Operating Day. Lastly, listed under 'Validating and Confirming Transaction Requests', a bullet was added to read:
 - "Ensure a valid NERC Tag has been associated. A valid NERC Tag is one in which:"
 - ☞ The profile is entirely covered by the tag
 - ☞ The tag duration is not longer than the schedule
 - ☞ The tag does not overlap profiles within a schedule
 - ☞ The tag is not used for multiple schedules
- Removed Attachment A: Definitions and Abbreviations, and all references. Attachment A is being developed into a new PJM Manual for **Definitions and**

Abbreviations (M-35). All remaining attachments have been renumbered and all references have been corrected.

Revision 14 (08/24/00)

- Revised Section 5: Scheduling Strategy & Method. In subsection “*Processing Market Information*”, added text pertaining to Deviations from Day-Ahead Market for Pool Scheduled Resources, and Credits for Cancellation of Pool Scheduled Resources.

Revision 13 (08/15/00)

- Revised Section 5: Scheduling Strategy & Method. Added text pertaining to Ramp Violations.

Revision 12 (07/25/00)

- Revised Section 5: Scheduling Strategy & Method.

Revision 11 (06/16/00)

- Attachment F: Interchange Energy Schedule Curtailment Order
 - ☞ Revised Curtailment of Capacity Backed Resources.
 - ☞ Capacity Backed Exports are those transactions sourced from generators or portions of generators on the PJM system that are not designated as PJM installed capacity.
 - ☞ At Maximum Emergency, PJM will not recall any energy from a resource that is not included in PJM Installed Capacity. If a resource has been de-rated from summer peak capacity, any export that exceeds the pro-rated capacity not attributed to PJM will be reduced to that pro-rated level.
 - ☞ Example: Unit A has a summer rated capacity of 80 MW, where 60 MW is designated as installed capacity and 20 MW is not. A 20 MW export is scheduled from PJM. There is no outage on the unit. The full 20 MW export will be scheduled.
 - ☞ Example: Unit A has a summer rated capacity of 80 MW, where 60 MW is designated as installed capacity and 20 MW is not. If there is a 40 MW partial outage of the unit, 3/4 (or 60/80) of the remaining capacity is considered installed. 1/4, or 20/80, of the remaining capacity is available as non-installed capacity and will not be curtailed during a PJM Maximum Emergency. In this example 30 MW remains

as PJM installed capacity and 10 MW remains available for capacity backed exports. If the owner of Unit A scheduled a 20 MW export, 10 MW could be recalled during PJM Maximum Emergency. At the conclusion of Maximum Emergency or at the conclusion of the outage, the export would be restored to the full 20 MW.

Revision 10 (06/01/00)

- Attachment F: Interchange Energy Schedule Curtailment Order
 - ☞ Removed Non-Firm over Secondary Points schedules requested after 2:00 PM of the day before operations and Non-Firm schedules requested after 2:00 PM of the day before operations from curtailment order.
 - ☞ Added category: Curtailment of Capacity Backed Resources.

Revision 09 (06/01/00)

- Revised to reflect the Multi-Settlement Process implementation.

Revision 08 (04/01/00)

- Attachment B: Unit Commitment Database
 - ☞ Removed reference to Maximum Scheduled Generation in section Unit Commitment – Scheduling Data (Cost Capped) for Steam Unit and Schedule Data #7 Schedule Operating Data.
 - ☞ Removed reference to Maximum Scheduled Generation in section Unit Commitment – Scheduling Data (Cost Capped) CT Unit and Schedule Data #5 Unit & Schedule Operating Data.
 - ☞ Removed reference to Maximum Scheduled Generation in section Unit Commitment – Scheduling Data (Cost Capped) Diesel Unit Data #5 Schedule Operating Data.

Revision 07 (06/01/99)

- Section 3: Scheduling Strategy & Method
 - ☞ Revised to reflect the new addition of Attachment F (see below).
 - ☞ Added 'new' Attachment F: Interchange Energy Schedule Curtailment Order.

Revision 06 (10/06/98)

- Section 3: Scheduling Strategy & Method
 - ☞ Guidelines and requirements for the submission of Offer Data, and confirmation and PJM acceptance of schedules/transactions under "Spot Market Energy" and "Bilateral Transactions" of "Processing Market Information" were revised.

Revision 05 (04/01/98)

- Attachment C: Offer Forms
 - ☞ Added "Exhibit C.7: Market Seller Aggregate Bid for Non-Designated Resource (E-Schedules Contracts)"
- Attachment E: Source & Sink List
 - ☞ Added Attachment E: Source & Sink List
- Section 1: Overview of Scheduling Operations
 - ☞ Revised exhibits and text.
- Section 2: Scheduling Philosophy & Tools
 - ☞ Revised exhibits and text.
- Section 3: Scheduling Strategy & Method
 - ☞ Added exhibits and text describing Locational Marginal Pricing application to the Scheduling process.
- Section 4: Posting OASIS Information
 - ☞ Revised exhibits and text.
- Section 5: Hourly Scheduling
 - ☞ Revised exhibits and text.

Revision 04 (01/30/98)

- Section 3: Scheduling Strategy & Method
 - ☞ Changed PJM contact phone numbers for receipt of Offer Data to include 610-666-4532

➤ under “Spot Market Energy.” Added

- ☞ “A schedule is not accepted without confirmation of the schedule details with all parties.
- ☞ External offers are subject to the 500 MW ramp rule. The ramp rules outlined under “Bilaterals” in this section apply to offers.”

☞ under “Spot Market Energy.” Added

☞ “Offers Submitted More Than One Day in Advance

Offers may be submitted up to seven (7) days in advance (e.g., a bid for the tenth of the month could be submitted as early as the third of the month).

Offers submitted more than one day in advance received after 12:00 noon will not be processed until the following day.

Spot Market offers submitted more than one day in advance are not considered binding until 12:00 noon of the day before operations.

Ramp room will be held for the schedule, but neither PJM nor the market participant is bound to the schedule before 12:00 noon of the day before the operating day. Up to this time, either party may decline the offer without penalty.

A change to one day of a multi-day offer nullifies the timestamp for the rest the offer. The offer will be given a new timestamp and scheduled as though the rest of the schedule was submitted at the time of the change (including ramp room).

Transmission reservations that are not used due to cancelled spot market offers will be subject to transmission charges as appropriate.

PJM will notify the submitter of the acceptance status of offers submitted more than one day in advance by 4:00 p.m. of the day before operations or earlier as specified by the submitter. No offer will be marked as accepted before 12:00 noon of the business day before the operating day.

Offers may be withdrawn before PJM notifies the PJM Member of bid acceptance and before 4:00 p.m. of the business day

before operations or 12:00 noon of the non-business day before operations.”

- under “Spot Market Energy.”
 - ☞ Changed heading “Data Requirements” from “Aggregate Offer Data Requirements:” under “Spot Market Energy.”
- Changed
 - ☞ “identity of all parties that are engaged in the schedule (e.g., buyers, sellers, marketers, transmitters, and brokers)”
 - ☞ from
 - ☞ “identity of all parties that are engaged in the Bilateral Transactions (e.g., buyers, sellers, marketers, transmitters, and brokers)”
 - ☞ under “Data Requirements” in “Spot Market Energy.”
- Changed
 - ☞ “Offers may be withdrawn before PJM notifies the External PJM Member of bid acceptance and before 4:00 p.m. of the business day before operations or 12:00 noon of the non-business day before operations. All offers for the same period from the same Market Seller of a higher price than the withdrawn offer are also considered withdrawn.”
 - ☞ from
 - ☞ Offers may be withdrawn before PJM notifies the External PJM Member of bid acceptance and before 4:00 p.m. A withdraw of a bid after either of the aforementioned result in a non-delivery charge, unless withdrawing a resource specific offer due to a forced outage demonstrated to the satisfaction of the PJM. All offers for the same period from the same Market Seller of a higher price than the withdrawn offer are also considered withdrawn.
- under “Data Requirements” in “Spot Market Energy.”
 - ☞ Changed
 - ☞ “If the discrepancies are resolved without change to the original Bilateral Transaction request by 4:00 p.m., the schedule status is marked as confirmed. If discrepancies are resolved with changes to original Bilateral Transaction request before the scheduling deadline, the time stamp is

updated to the time at which the discrepancies are resolved with the PJM.”

➤ from

☞ “If the discrepancies are resolved without change to the original Bilateral Transaction request by 4:00 p.m., the schedule status is marked as confirmed. If discrepancies are resolved with changes to original Bilateral Transaction request before 2:00 p.m., the time stamp is updated to the time at which the discrepancies are resolved with the PJM.”

☞ under “Confirmation of Bilateral Transactions” in “Bilateral Transactions.”

➤ Attachment C: Offer Forms

☞ Changed PJM contact phone numbers for receipt of Offer Data to include 610-666-4532.

Revision 03 (01/01/98)

➤ Section 3: Scheduling Strategy & Method

☞ Changed “The Regulation Requirement for the PJM Control Area is defined as follows:

PJM -specified percentage of the PJM Valley Load Forecast (currently 1.1%). This requirement is in effect during the Off-Peak Period (0000-0459 hours).

PJM -specified percentage of the PJM Peak Load Forecast (currently 1.1%). This requirement is in effect during the On-Peak Period (0500-2359 hours).”

☞ from “The Regulation Requirement for the PJM Control Area is defined as follows:

PJM -specified percentage of the PJM Valley Load Forecast (currently 1.1%). This requirement is in effect during the Off-Peak Period (2300-0659 hours).

PJM -specified percentage of the PJM Peak Load Forecast (currently 1.1%). This requirement is in effect during the On-Peak Period (0700-2259 hours).”

☞ Changed Exhibit 3.2: Regulation Requirement Timeline.

- Attachment D: Process Diagrams
 - ☞ Added “Attachment D: Process Diagrams.”

Revision 02 (09/23/97)

- Changed selected references to PJM Member to Market Participant.
- Changed PJM phone number for receipt of Offer Data during business hours from “610-666-8947” to “610-666-4548.”
- Changed PJM phone number for checking Offer Data during non-business hours from “610-650-4307” to “610-666-4510.”
- Changed PJM phone number for receipt of Bilateral Transactions (North/West) during non-business hours from “610-666-8807 to “610-666-4510.”
- Section 1: Overview of Scheduling Operations
 - ☞ Revised “(2) Unmetered Market Buyer - An Unmetered Market Buyer is a Market Buyer that is making purchases of energy from the PJM Interchange Energy Market for consumption by metered end-users or end-users that are located outside the PJM Control Area.” in “Market Buyers” under “PJM Member Responsibilities.”
 - ☞ Revised “purchase transmission capacity reservation in order to receive generation from PJM Interchange Energy Market if the energy is being delivered to end-users that are located outside the PJM Control Area” in “Market Buyers” under “PJM Member Responsibilities.”
- Section 2: Scheduling Philosophy & Tools
 - ☞ Deleted “verifies that transmission service exists” in “Transaction Management System” under “Scheduling Tools.”
 - ☞ Revised “The deadline for both internal and external participants to submit information for the next day is 12:00 Noon of the previous PJM business day. After this deadline, no further offers are accepted for the next day and the UCDB is locked. The deadline is only extended when there is a computer problem at the PJM” in “Marginal Scheduler” under “Scheduling Tools.”
- Section 3: Scheduling Strategy & Method

- ☞ Revised “(4) PJM notifies via ALL-CALL, of the PJM Regulation Requirement” in “PJM Actions” under “PJM Regulation Requirements.”
- ☞ Revised “ (6) PJM notifies via ALL-CALL, in the event of a Regulation Requirement shortage” in “PJM Actions” under “PJM Regulation Requirements.”
- ☞ Revised “Each PJM Member, that has a requirement to serve load within the PJM Control Area, provides the PJM with a forecast of its requirements by 1200 hours on the day before the Operating Day. Regardless of how the PJM Member’s load is supplied, the PJM Member submits the following Operating Day forecast information to the PJM: in “PJM Member Load Forecasts” under “Processing Market Information.”
- ☞ Revised “Each PJM Member makes its own choice based on the information it possesses. Exhibit 3.5 illustrates the relationship between self- and PJM -scheduling for a particular resource” in “Self-Scheduled Resources” under “Processing Market Information.”
- ☞ Revised heading “Buy/Sell Request for External Energy” to “Spot Market Energy” under “Processing Market Information.”
- ☞ Revised “Spot Market requests are in the form of offers. There are general requirements for offer data, as well as specific requirements for internal and external participants” in “Spot Market Energy” under “Processing Market Information.”
- ☞ Replaced “Internal offers must be resource specific unless a schedule with an internal (metered) participant is agreed to before hand. This is because PJM must account for every MW of energy within the PJM Control Area” with “A PJM Member must be in possession of the power to sell it as Spot Market energy (i.e., no entity can be in the contract path between the PJM Member selling the energy and PJM)” in “Spot Market Energy” under “Processing Market Information.”
- ☞ Added “PJM does not accept bids where the PJM Interchange Market is the source and sink (e.g., PJM-Market Participant-PJM)” in “Spot Market Energy” under “Processing Market Information.”
- ☞ Added “PJM does not accept bids for less than one continuous hour” in “Spot Market Energy” under “Processing Market Information.”
- ☞ Revised “PJM does not accept offers for resources committed to supply Operating Reserves to another Control Area. PJM will not double count units internal to PJM for Operating Reserves. If energy is

being offered from a resource to PJM and is already included in the PJM Operating Reserve, the energy can be accepted but will not participate in PJM Operating Reserve accounting. Offers not properly submitted are rejected. The PJM Member is notified of the reason for rejection and the PJM Member may then take action to submit a new offer” in “Spot Market Energy” under “Processing Market Information.”

- ☞ Revised heading “Internal PJM Member Requirements” to “Resource Specific Offer Data Requirements” in “Spot Market Energy” under “Processing Market Information.”
- ☞ Deleted heading “External PJM Member Requirements” in “Spot Market Energy” under “Processing Market Information.”
- ☞ Deleted “External PJM Members submit offer data via both telephone and facsimile; numbers are listed under General Requirements. External PJM Members use the forms found in Attachment C to submit offers” in “Spot Market Energy” under “Processing Market Information.”
- ☞ Deleted “External Market Buyers submit the following data, for the next operating day only:
 - ☞ specific amount of energy for each hour of the day
 - ☞ dispatch rate above which it does not desire to purchase OASIS number (the “transaction” number from the “Buy/Sell ATC” page of the PJM OASIS. More details on procedures for making a transmission service request via the PJM OASIS can be found on the PJM OASIS Users Guide @ <http://oasis.pjm.com>) for the transmission service reservation(s) which will be used to deliver the energy for the desired point of receipt of the intention to purchase transmission if the offer is accepted”
 - ☞ in “Spot Market Energy” under “Processing Market Information.”
- Deleted “Valid offers are entered into the Transaction Maintenance System (TMS) for analysis by the Marginal Scheduler” in “Spot Market Energy” under “Processing Market Information.”
- Deleted “complete energy path” in “Spot Market Energy” under “Processing Market Information.”
- Added heading “Aggregate offer Data Requirements” and the following text in “Spot Market Energy” under “Processing Market Information.”

- “Aggregate offer data shall be submitted via both telephone and facsimile; phone numbers are listed under General Requirements. External PJM Members use the forms found in Attachment C of this manual to submit offers.
- A request to change offer data after an offer has been accepted (e.g., dispatch level, dispatch rate, path) will be rejected.
- PJM Members delivering Spot Market Energy to the PJM Interchange Energy Market submit the following data for the next operating day only:
 - ☞ identity of all parties that are engaged in the Bilateral Transaction (e.g., buyers, sellers, marketers, transmitters, and brokers)
 - ☞ minimum and maximum dispatch levels for each hour
 - ☞ identity of any neighboring External Control Area identifiers and priorities, if applicable
 - ☞ dispatch rate above which it does not desire to sell
- PJM Members requesting Spot Market Energy from the PJM Interchange Energy Market submit the following data for the next operating day only:
 - ☞ identity of all parties that are engaged in the Bilateral Transaction (e.g., buyers, sellers, marketers, transmitters, and brokers)
 - ☞ minimum and maximum dispatch levels for each hour
 - ☞ dispatch rate above which it does not desire to purchase
 - ☞ For Spot Market Energy to be delivered external to the PJM Control Area, OASIS number (the “transaction” number for the “Buy/Sell ATC” page of the PJM OASIS - More details on procedure for making a transmission service request via the PJM OASIS can be found on the PJM OASIS Users Guide @ <http://oasis.pjm.com>) for the transmission service reservation(s) which will be used to deliver the energy for the desired point of receipt or the intention to purchase transmission if the offer is accepted.
 - ☞ identity of any neighboring External Control Area identifiers and priorities, if applicable”
- Deleted “External Market Sellers reports the following data for aggregate offers, the next operating day, up to the next business day only:

- ☞ complete energy pay
- ☞ dispatch rate below which it does not desire to sell
- ☞ hours of energy availability
- ☞ minimum and maximum dispatch levels”
- in “Spot Market Energy” under “Processing Market Information.”
- Deleted “This data constitutes a binding offer. Valid offers are entered into the Transaction Maintenance System (TMS) system for analysis by the Marginal Scheduler” in “Spot Market Energy” under “Processing Market Information.”
- Revised “Aggregate Offer Data - PJM compares the offer characteristics to the forecasted system conditions and Marginal Scheduler output. See “Forecasting PJM Generation Requirement” in Section 3 of this manual for more information” in “Spot Market Energy” under “Processing Market Information.”
- Revised “Resource Specific Offer Data Evaluation - Resource Specific Offer Data remains in Marginal Scheduler for evaluation. If the offer is not accepted before or during the operating day, the offer is considered rejected” in “Spot Market Energy” under “Processing Market Information.”
- Revised “If an offer is accepted or rejected, the PJM Member is notified via phone and fax. A confirmation fax is sent to the PJM Member (see Attachment C). For any accepted offer the PJM Member is notified by telephone by PJM as soon a possible. For External PJM Members, the contact information requested on the fax form (Attachment C) must be listed on the offer facsimile” in “Spot Market Energy” under “Processing Market Information.”
- Added heading “Non-Delivery of Spot Market Energy” and the following text in “Spot Market Energy” under “Processing Market Information:”
- “A PJM External Market Seller will not be assessed a non-delivery charge if participants were not able to provide delivery for one or more of the following valid and documented reasons which physically prevented delivery and which was not reasonably anticipated at the time of scheduling:
 - ☞ transmission system constraints prevented delivery
 - ☞ generation outages of source generator(s) (resource must be specified in original Offer)

- ☞ supplier or intervening power system emergencies prevent delivery
- A PJM External Market Buyer will not be assessed a non-delivery charge if the participant was prevented from delivery by one or more of the three conditions described above, the participant subsequently attempted to reschedule delivery, and PJM was unable to comply with the timing requirements for continuity of the transaction.
- Non-delivery charges described in Section 1.6.5 and 1.6.6 of Attachment K of the Tariff will continue to be assessed for all other non-delivery situations.
- The interface path of a Spot Market Energy schedule will not be changed on-shift (hourly)."
- Changed heading "Data Requirements Involving PJM Members External to PJM" to "Data Requirements Involving Parties External to PJM" in "Bilateral Transactions" under "Processing Market Information."
- Revised "If a transaction is reported after 2:00 p.m. of the business day before the operating day, the transaction uses non-firm transmission, congestion is expected on the system, and the transaction might contribute to the congestion, the request for the transaction will not be accepted. These schedules are submitted to the non-business hours facsimile or telephone number provided above." in "Bilateral Transactions" under "Processing Market Information."
- Added "valid NERC TIS Tag" in "Bilateral Transactions" under "Processing Market Information."
- Deleted "identity of all PJM Members that are engaged in the Bilateral Transaction (E.g., buyers, sellers, marketers, transmitters, and brokers)" in "Bilateral Transactions" under "Processing Market Information."
- Deleted "type of transaction (wheel in, wheel out, losses, firm, non-firm)" in "Bilateral Transactions" under "Processing Market Information."
- Deleted "scheduled start/stop dates and time" in "Bilateral Transactions" under "Processing Market Information."
- Deleted "quantity of service by hour (maximum and minimum MW) in increments of 1 MW/hour (1,000 kW/hour)" in "Bilateral Transactions" under "Processing Market Information."
- Deleted "identity of any neighboring External Control Area identifiers and priorities" in "Bilateral Transactions" under "Processing Market Information."

- Revised “identity of associated transmission service reservation(s) for each hour of the Bilateral Transaction. This is the “transaction” number on the “Buy/Sell ATC” page of the PJM OASIS. Only one transmission service reservation may be applied to one energy schedule in any given hour. More details on procedures for making a transmission service request via the PJM OASIS can be found on the PJM OASIS Users Guide at <http://oasis.pjm.com>)” in “Bilateral Transactions” under “Processing Market Information.”
- Added “identity of any neighboring External Control Area identifiers and priorities” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “Bilateral Transactions scheduled for delivery to native load must be submitted by the Market Participant that reserved the Transmission Service or the LSE. The LSE ultimately receiving the energy and the Market Participant that reserved the Transmission Service must both confirm the Bilateral Transaction. All parties to the transaction must confirm the transaction” in “Bilateral Transactions” under “Processing Market Information.”
- Added “valid NERC TIS Tag is received (see www.nerc.com)” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “valid energy transaction type (firm, non-firm, wheel in, wheel out, loses)” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “if using non-firm transmission, then transaction must be reported to PJM before 2:00 p.m. of the business day before the operating day” in “Bilateral Transactions” under “Processing Market Information.”
- Added heading “Additional Validations for a Bilateral Transaction Schedule using On-Peak or Off-Peak Transmission Service Reservations” in “Bilateral Transactions” under “Processing Market Information.”
- Added Exhibits 3.10, 3.11, 3.12 and 3.13 in “Bilateral Transactions” under “Processing Market Information.”
- Added heading “Frequently Asked Questions (regarding on-peak and off-peak energy scheduling)” and the following text in “Bilateral Transactions” under “Processing Market Information.”
 - ☞ “(Q1) A Market Participant has reserved off-peak daily transmission for Wednesday, but ramp room is not available at 07:00 or 23:00.
 - ☞ (A1) Two possible solutions are 1) the energy may be scheduled from 00:00 to 08:00 or 2) the energy may be scheduled from 00:00 to 07:15 and from 23:15 to 24:00.

- ☞ (Q2) A Market Participant has reserved on-peak weekly transmission. Ramp room is available from 07:00 to 23:00 Tuesday through Friday, but ramp room is not available at 07:00 or 23:00 on Monday.
- ☞ (A2) The energy may be scheduled 07:00 to 23:00 Tuesday through Friday. One solution to the Monday ramp limit would be to schedule the energy from 06:45 to 22:45.”
- Deleted “Because Internal Bilateral Transactions do not cross a PJM interface, the 500 MW ramp rule does not apply to these transactions. Internal Bilateral Transactions are entered before the energy is scheduled to start. If a participant does not have direct access to TMS, the PJM Member can request PJM to confirm the transaction in TMS” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “identity of all parties that are involved in the Bilateral Transaction (e.g., buyers, sellers, marketers, wheelers, and brokers)” in “Bilateral Transactions” under “Processing Market Information.”
- Section 4: Posting OASIS Information
 - ☞ Replaced “Bilateral Transactions” with “transmission service reservations” under “PJM OASIS.”
 - ☞ Revised “(1) Not later than 1600 hours of the day before each Operating Day, PJM posts the following information:” in “PJM Actions” under “PJM OASIS.”
- Attachment C: Offer Forms
 - ☞ Revised PJM phone numbers on all forms.
 - ☞ Added “For Internal Use” fields to Exhibits C.1, C.3 and C.4

Revision 01 (07/08/97)

- Section 2: Scheduling Philosophy & Tools
 - ☞ Deleted “... (both those electing to curtail due to congestion and those electing to pay congestion charges) ...” under “Transaction Management System.”
- Section 5: Hourly Scheduling
 - ☞ Deleted “... (not paying congestion charges) ...” under “Hourly Scheduling Adjustments.”

Revision 00 (05/01/97)

- Changed references to PJM Interconnection Association to PJM Interconnection, L.L.C.
- Changed references to PJM to PJM buses where appropriate.
- Changed references to PJM to PJM Control Area where appropriate.
- Changed references to PJM IA to PJM.
- Changed references to IA to PJM.
- Changed references to Mid-Atlantic Market to PJM Interchange Energy Market.
- Changed references to Mid-Atlantic Market Operations Agreement to Operating Agreement of PJM Interconnection, L.L.C.
- Changed references to pool to control area.
- Changed references to parties to PJM Members.
- Changed references to External Market Participant to Non-Metered PJM Member.
- Changed references to Internal Market Participant to Metered PJM Member.

Revision 00 (03/21/97)

- This revision is a draft of the PJM Manual for ***Scheduling Operations***.

Introduction

Welcome to the PJM Manual for **Scheduling Operations**. In this Introduction, you will find the following information:

- What you can expect from the PJM Manuals in general (see “*About PJM Manuals*”).
- What you can expect from this PJM Manual (see “*About This Manual*”).
- How to use this manual (see “*Using This Manual*”).

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. Exhibit 1 lists the PJM Manuals.

Transmission	M01: Control Center Requirements	M02: Transmission Service Requests	M03: Transmission Operations
	M04: PJM OASIS Operation	M05: Power System Application Data	M06: Financial Transmission Rights
PJM Energy Market	M09: PJM eSchedules	M10: Pre-Scheduling Operations	M11: Scheduling Operations
	M12: Dispatching Operations	M13: Emergency Operations	M15: Cost Development Guidelines
	M36: System Restoration		
Generation and Transmission Interconnection	M14A: Introduction to the Generation and Transmission Interconnection Process	M14B: Generation and Transmission Interconnection Planning	M14C: Generation and Transmission Interconnection Facility Construction
	M14D: Generator Operational Requirements	M14E: Merchant Transmission Specific Requirements	M16: eDART Operations
Reserve	M17: Capacity Obligations	M19: Load Data Systems	M20: PJM Reserve Requirements
	M21: Rules and Procedures for Determination of Generating Capability	M22: Generator Resource Performance Indices	M23: eGADS User Manual
	M24: PJM eCapacity	M25b: eFuel 2.0 – User Manual	
Accounting & Billing	M27: Open Access Transmission Tariff Accounting	M28: Operating Agreement Accounting	M29: Billing
PJM	M33: Administrative Services for PJM Interconnection Agreement	M35: Definitions and Acronyms	

Exhibit 1: List of PJM Manuals

About This Manual

The PJM Manual for **Scheduling Operations** is one of a series of manuals within the PJM Energy Market manuals. This manual focuses on the day ahead and hourly scheduling activities that are performed by the PJM staff and the PJM Members. The manual describes the rules and procedures that are followed to schedule resources.

The PJM Manual for **Scheduling Operations** consists of seven sections. The sections are as follows:

- Section 1: Overview of Scheduling Operations
- Section 2: Overview of the PJM Two Settlement System
- Section 3: Overview of the PJM Regulation Market
- Section 4: Overview of the PJM Spinning Reserve Market
- Section 5: Scheduling Philosophy & Tools
- Section 6: Scheduling Strategy & Method
- Section 7: External Transactions
- Section 8: Posting OASIS Information
- Section 9: Hourly Scheduling

Intended Audience

The intended audience of the PJM Manual for **Scheduling Operations** is:

- *PJM Members* - Any participants requesting to purchase or sell energy to or from the PJM Interchange Energy Market and any participant that schedules bilateral sales or purchases.
- *PJM operations staff* - The PJM operations staff processes the market information and develops the resource schedule.
- *PJM dispatchers* - The PJM dispatchers process PJM Member requests, make hourly schedule adjustments, and post information in the OASIS.
- *Local Control Center dispatchers* - The Local Control Center dispatchers submit hourly schedule changes.

- *Local Control Center operations support staff* - The Local Control Center operations support staff support the day-ahead information requirements.

References

The References to other documents that provide background or additional detail directly related to the PJM Manual for **Scheduling Operations** are:

- EES User's Guide
- PJM Manual for Transmission Operations (M-03)
- PJM Manual for PJM OASIS Operation (M-04)
- PJM Manual for PJM eSchedules (M-09)
- PJM Manual for Pre-Scheduling Operations (M-10)
- PJM Manual for Dispatching Operations (M-12)
- PJM Manual for Operating Agreement Accounting (M-28)
- PJM Manual for Definitions & Abbreviations (M-35)

Using This Manual

Because we believe that explaining concepts is just as important as presenting the procedures, we start each section with an overview. Then, we present details and procedures. This philosophy is reflected in the way we organize the material in this manual. The following paragraphs provide an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents
- An approval page that lists the required approvals and the revision history
- This introduction
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and Market Participant actions
- Attachments that include additional supporting documents, forms, or tables in this PJM Manual

Section 1: Overview of Scheduling Operations

Welcome to the *Overview of Scheduling Operations* of the PJM Manual for **Scheduling Operations**. In this section you will find the following information:

- A description of the scope and purpose of scheduling (see “*Scope & Purpose of Scheduling*”).
- A list of the PJM scheduling responsibilities (see “*PJM Responsibilities*”).
- A list of the Market Participants’ scheduling responsibilities (see “*PJM Interchange Energy Market Participant Responsibilities*”).

Scope & Purpose of Scheduling

Operation of the PJM RTO involves many activities that are performed by different operating and technical personnel. These activities occur in parallel on a continuous basis, 24 hours a day and can be grouped into three overlapping time frames:

- pre-scheduling operations
- scheduling operations and the Day-ahead Energy Market
- dispatching and the Real-time Energy Market

In the PJM Manual for **Scheduling Operations** we focus mainly on the activities that take place one day prior to the Operating Day including the activities associated with the Day-ahead Energy Market. Exhibit 2 presents the scheduling activities in the form of a time line. The reference point for the timeline is the “Operating Day”, recognizing that every new day becomes an Operating Day. This timeline-type of description is used throughout this PJM Manual.

Generation resources fall into one of two categories, Designated Capacity Resources or Non-Designated Capacity Resources. If available, Designated Capacity Resources must submit offer data into the Day-ahead Market and may elect either to Self-Schedule or offer the resource to PJM for scheduling as a PJM RTO-Scheduled Resource. In this section we focus primarily on the PJM Day-ahead Energy Market and the Control Area reliability-based scheduling process that takes place after the Day-ahead Energy Market is cleared. Scheduling by PJM includes the Day-ahead Energy Market, the Control Area reliability-based scheduling process and the hourly scheduling process. The Day-ahead Energy Market bid/offer period closes at noon on the day before the Operating Day and the Day-ahead Market results are posted at 1600 on the day before the Operating Day. The Control Area reliability-based scheduling process occurs throughout the day before the operating

day. Hourly scheduling occurs up to sixty minutes prior to an hour during the Operating Day. During the scheduling process, PJM will:

Clear the Day-ahead Market based using Least-cost security constrained unit commitment and dispatch,

Determine a plan to reliably serve the hourly energy and reserve requirements of the PJM RTO by minimizing the cost to provide additional operating reserves above what was scheduled in the Day-ahead Market if required,

Perform hourly scheduling throughout the Operating Day as required.

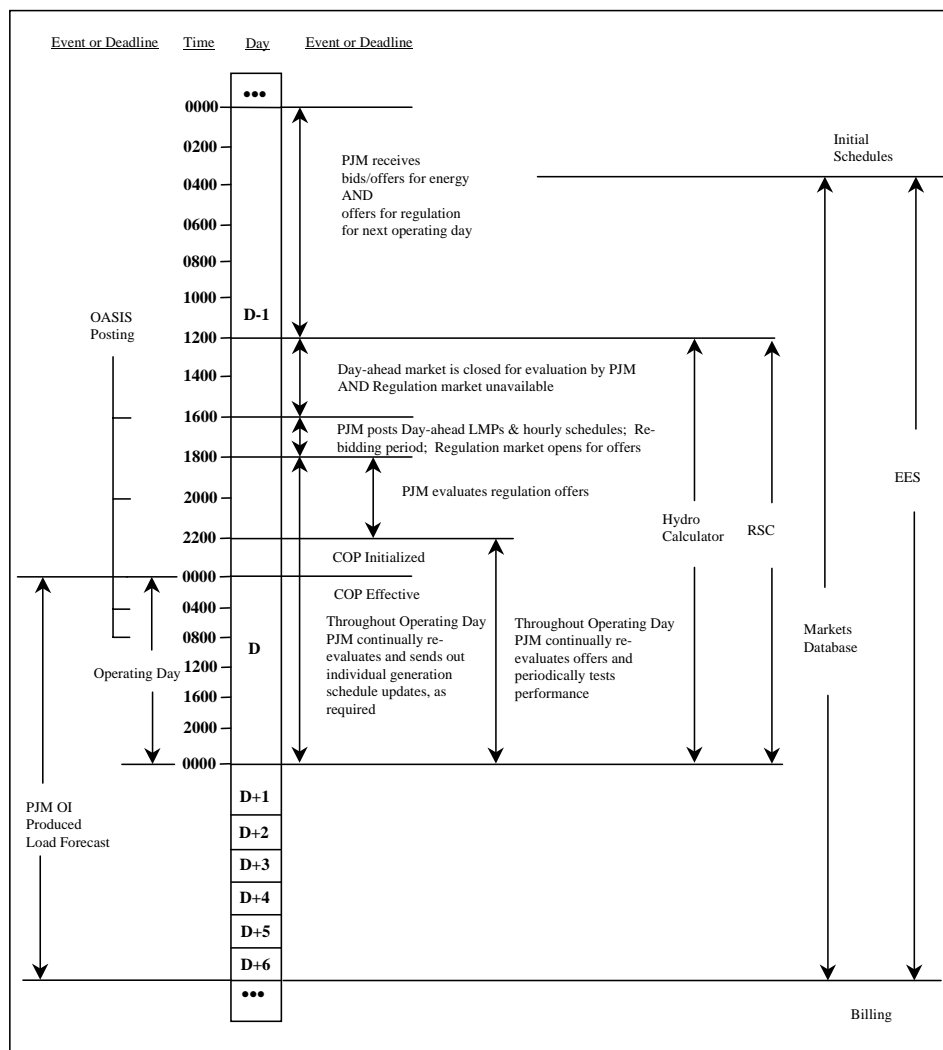


Exhibit 2: Scheduling Timeline

The following notations are used in the timeline:

- D represents the Operating Day
- D-1 represents the day before the Operating Day
- D+6 represents six days after the Operating Day
- COP is the Current Operating Plan

In this manual there is no special distinction between the terms “price” and “cost”. PJM Members submit their bids according to either actual cost or offer price as designated by the Operating Agreement of PJM Interconnection, L.L.C. for each generation resource.

PJM Responsibilities

In the Day-ahead Market, PJM determines the least-price means (minimizing production cost in terms of bid prices submitted) of satisfying the Demand bids, Decrement bids, operating reserves and other ancillary services requirements of the market buyers, including the reliability requirements of the PJM RTO. In addition to the Day-ahead Market scheduling process, PJM will also schedule resources to:

- Satisfy the reserve requirements of the PJM RTO by minimizing the cost to provide additional operating reserves above what was scheduled in the Day-ahead Market if required,
- Provide other ancillary services requirements of the market buyers,
- Satisfy all other reliability requirements of the PJM RTO. Specifically, PJM’s responsibilities to support scheduling activities for all PJM Members include:

Develop the Day-ahead Market financial schedules based upon participant-supplied bids, offers and bilateral transaction schedules using least-cost security constrained unit commitment and dispatch analysis.

Post the following information after the Day-ahead Market clears at 4:00 PM:

- Schedules for Next Day by participant (generation & demand),
- Transaction Schedules,
- Day-ahead LMPs,
- Day-ahead Binding Transmission Constraints,

- Day-ahead Net Tie Schedules,
- Day-ahead Reactive 500 kV Interface Indicator Limits,
- PJM Load Forecast,
- Aggregate Demand Bids
- PJM Operating Reserve Objective.

Perform scheduling for the PJM Forecasted load and reserves not covered by the Day-ahead Demand bids, Self-Scheduled Resources or Bilateral Transactions, including scheduling generation to relieve expected transmission constraints

Perform analysis to clear the Regulation Market and Spinning Reserve Markets simultaneously and post the Regulation Marginal Clearing Price (RMCP) and Spinning Reserve Marginal Clearing Price (SRMCP) on an hourly basis no later than 30 minutes prior to the start of the operating hour.

Maintain data and information which is related to generation facilities in the PJM RTO, as may be necessary to conduct the scheduling and dispatch of the PJM Interchange Energy Market and PJM RTO

Post the updated forecast of PJM Load and of the location and duration of any expected transmission congestion between areas in the PJM RTO

Revise schedule of generation resources to reflect updated projections of load, changing electric system conditions, availability of and constraints of limited energy and other resources

PJM Member Responsibilities

Only PJM Members are eligible to submit offers and purchase energy or related services in the Day-ahead Energy Market and in the Real-time Energy Market. PJM Members include the Market Buyers and the Market Sellers.

Market Buyers

There are two general types of Market Buyers:

- *Metered Market Buyer* - A Metered Market Buyer is a buyer that is purchasing energy from the PJM Interchange Energy Market for consumption by end-users that are located inside the PJM RTO. A Metered Market Buyer may be further classified as a Generation Market Buyer. A Generation Market Buyer is a Metered Market Buyer that owns or has contractual rights to the output of

generation resources that are capable of serving the Market Buyer's load in the PJM RTO or selling energy-related services in the PJM Interchange Energy Market or elsewhere. By definition, all Market Buyers become Market Sellers upon approval of their applications.

The scheduling responsibilities of an Internal Market Buyer are to:

Submit forecasts of its customer loads for the next Operating Day

Submit economic load management agreements to PJM

Submit hourly schedules for Self-Scheduled Resource increments

Submit a forecast of the availability of each Capacity Resource for the next seven days

Submit Offer Data for Capacity Resources for supply of energy to the PJM Day-ahead Energy Market for the next day whether Self-Scheduled or PJM scheduled

Submit Bilateral Transactions for delivery within the PJM RTO, regardless of whether the generation is located inside or outside the PJM RTO

Submit optional Offer Data to supply Regulation Services in the PJM Regulation Market.

Submit optional Offer Data to supply Spinning Reserve Services in the Spinning Reserve Market.

- *Unmetered Market Buyer* - An Unmetered Market Buyer is a Market Buyer that is making purchases of energy from the PJM Interchange Energy Market for consumption by metered end-users or end-users that are located outside the PJM RTO.

The scheduling responsibilities of an Unmetered Market Buyer are to:

- a. Submit optional requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Day-ahead Energy Market, along with Dispatch Rates (i.e. price-sensitive Demand Bids) above which it does not desire to purchase, if desired
- b. Purchase transmission capacity reservation in order to receive generation from PJM Interchange Energy Market if the energy is being delivered to end-users that are located outside the PJM RTO

Market Sellers

A Market Seller is a PJM Member that demonstrates to PJM that it meets the standards for the issuance of an order mandating the provision of transmission service under Section 211 of the Federal Power Act, submits an application to the PJM, and is approved by the Market Administrative Committee (see the PJM Manual for [Administrative Services for Operating Agreement of PJM Interconnection, L.L.C. \(M-33\)](#)).

The scheduling responsibilities of a market seller include:

- submit schedules for bilateral sales to entities outside the PJM RTO from generation within the PJM RTO
- submit optional offers for the supply of energy, capacity, and other services from Non-Capacity Resources into the Day-ahead Energy Market or the Real-time Energy Market for the next operating day only

Load Serving Entities

A Load Serving Entity (LSE) is any entity that has been granted authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-users that are located within the PJM RTO. An LSE may be a Market Buyer or a Market Seller, as described above.

Section 2: Overview of the PJM Two Settlement System

Welcome to the *Overview of the PJM Two Settlement System* section of the PJM Manual for **Scheduling Operations**. In this section you will find the following information:

- An overview description of the PJM Two Settlement System (see “*Overview of Two Settlement*”).
- A list of the PJM Two-Settlement Market Business Rules (see “*PJM Two-Settlement Market Business Rules*”).

Overview of Two Settlement

The Two-Settlement system consists of two markets, a day-ahead market and a real-time balancing market. The Day-ahead Market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day based on generation offers, demand bids, Increment offers, Decrement bids and bilateral transaction schedules submitted into the Day-ahead Market. The balancing market is the real-time energy market in which the clearing prices are calculated every five minutes based on the actual system operations security-constrained economic dispatch. Separate accounting settlements are performed for each market, the day-ahead market settlement is based on scheduled hourly quantities and on day-ahead hourly prices, the balancing settlement is based on actual hourly (integrated) quantity deviations from day-ahead scheduled quantities and on real-time prices integrated over the hour. The day-ahead price calculations and the balancing (real-time) price calculations are based on the concept of Locational Marginal Pricing.

The Day-ahead Market enables participants to purchase and sell energy at binding day-ahead prices. It also allows transmission customers to schedule bilateral transactions at binding day-ahead congestion charges based on the differences in Locational Marginal Prices (LMPs) between the transaction source and sink. Load Serving Entities (LSEs) may submit hourly demand schedules, including any price sensitive demand, for the amount of demand that they wish to lock-in at day-ahead prices. Any generator that is a PJM designated capacity resource must submit a bid schedule into the day-ahead market even if it is self-scheduled or unavailable due to outage. Other generators have the option to bid into the day-ahead market. Transmission customers may submit fixed, dispatchable or ‘up to’ congestion bid bilateral transaction schedules into the day-ahead market and may specify whether they are willing to pay congestion charges or wish to be curtailed if congestion occurs in the Real-time Market. All spot purchases and sales in the day-ahead market are settled at the day-ahead prices. After the daily quote period closes, PJM will calculate the day-ahead schedule based on the bids, offers and schedules

submitted, using the scheduling programs described in section 2 of this manual, based on least-cost, security constrained unit commitment and dispatch for each hour of the next operating day. The day-ahead scheduling process will incorporate PJM reliability requirements and reserve obligations into the analysis. The resulting Day-ahead hourly schedules and Day-ahead LMPs represent binding financial commitments to the Market Participants. Financial Transmission Rights (FTRs) are accounted for at the Day-ahead LMP values (see the PJM Manual for [Financial Transmission Rights \(M-06\)](#)).

The Real-time Energy Market is based on actual real-time operations. Generators that are designated PJM capacity resources that are available but not selected in the day-ahead scheduling may alter their bids for use in the Real-time Energy Market during the Generation Rebidding Period from 4:00 PM to 6:00 PM (otherwise the original bids remain in effect for the balancing market). Real-time LMPs are calculated based on actual system operating conditions as described by the PJM state estimator. LSEs will pay Real-time LMPs for any demand that exceeds their day-ahead scheduled quantities (and will receive revenue for demand deviations below their scheduled quantities). Generators are paid Real-time LMPs for any generation that exceeds their day-ahead scheduled quantities (and will pay for generation deviations below their scheduled quantities). Transmission customers pay congestion charges based on Real-time LMPs for bilateral transaction quantity deviations from day-ahead schedules. All spot purchases and sales in the balancing market are settled at the Real-time LMPs.

Two Settlement Market Business Rules

Bidding & Operations Time Line:

The day-ahead scheduling/bidding timeline for two-settlement consists of the following time frames:

- ☞ **1200** — Day-ahead market bid period closes. All bids must be submitted to PJM. At 1200 PJM begins to run the two-settlement software to determine the hourly commitment schedules and the LMPs for the day-ahead market. This is the first unit commitment run, which determines the unit commitment profile that satisfies the fixed demand, cleared price-sensitive demand bids, and PJM operating reserve objectives, while minimizing the total production cost (subject to certain limitations). This commitment analysis also includes external bilateral transaction schedules and external resource offers into the PJM day-ahead market.

- ☞ **1600** — PJM posts the day-ahead hourly schedules and LMPs on a web-based Market User Interface (MUI) for the two-settlement system,

based on the first unit commitment. PJM also makes these results available in downloadable files, via the MUI, or a dedicated communication link.

- ☞ **1600 - 1800** — PJM opens the balancing market offer period. During this time, Market Participants can submit revised offers for units not selected in the first commitment.
- ☞ **1800** — The balancing market offer period closes. PJM performs a second unit commitment, which includes the updated offers, updated unit availability information, and updated PJM load forecast information and load forecast deviation. The focus of this commitment is reliability and the objective is to minimize only start-up and no load costs for any additional resources that are committed. (This analysis could result in the release of resources that were committed in the day-ahead market).
- ☞ **1800 - Operating Day** — PJM may perform additional unit commitment runs, as necessary, based on updated PJM load forecasts and updated unit availability information. PJM sends out individual generation schedules updates to specific generation owners only, as required.

Market Buyers

The following business rules apply to Market Buyers:

- (1) Each Market Participant's profile (which is defined by PJM) shall specify the transmission zones or buses for which that Participant is eligible to submit demand bids.
- (2) Market Buyers may submit hourly demand quantities for which it commits to purchase energy at day-ahead prices for consumption in the next Operating Day. Quantity bids must specify MW quantity and location (transmission zone, aggregate, or single bus).
- (3) Demand bids are assumed to include losses (transmission zone losses and share of 500 kV losses).
- (4) Price sensitive demand bids shall specify MW quantity, location (transmission zone, aggregate, or single bus), and the price at which the demand shall be curtailed.

- (5) Price sensitive demand bids are accepted in single bid blocks only. Up to nine bid blocks may be submitted per Market Participant at a specific location.
- (6) If a Market Buyer submits no day-ahead bid information, then a zero MW quantity is assumed.
- (7) For the day-ahead market, the Electric Distribution Company (EDC) shall specify the transmission zone, bus distributions, and aggregate bus distributions as a daily distribution. The default distribution for a transmission zone for the day-ahead market is the state estimator distribution for that zone at 8:00 AM one week prior to the Operating Day (i.e. if next Operating Day is Monday, the default distribution is from 8:00 AM on Monday of the previous week.).
- (8) The EDC may update the default distribution factors only after the state estimator populates the default.
- (9) EDCs shall submit a forecast of demand within their transmission zone. This is for reliability purposes only (and does not, therefore, require a binding bid).
- (10) A Market Buyer that is not an LSE or purchasing on behalf of an LSE is not required to purchase transmission service for purchases from the PJM Market to cover deviation from its sales in a day-ahead market.
- (11) The list of transmission zones, aggregates, and single buses at which demand bids are accepted is defined by PJM.
- (12) Market Buyers may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interface point (posted on the PJM website) for which an LMP is calculated. It is not required that physical generation or load exists at the location that is specified in the increment offer or decrement bid.
- (13) Price-sensitive demand bids, increment offers, and decrement bids must be consistent with the \$1000/MWh price cap.

Market Sellers

The following business rules apply to Market Sellers:

- (1) Self-scheduled generation shall submit an hourly MW schedule and may submit a price at which it would reduce output. (This is accomplished by submitting a decrement bid.)

- (2) Generators that are Capacity Resources shall submit offers into the day-ahead market, even if they are unavailable due to forced, planned, or maintenance outages.
- (3) Generators that are Capacity Resources and are self-scheduling shall submit offer data in the event that they are called upon during emergency procedures.
- (4) Capacity Resources shall submit a schedule of availability for the next seven days and may submit non-binding offer prices for the days beyond the next Operating Day.
- (5) The set of offer data last submitted for each Capacity Resource shall remain in effect for each day until specifically superceded by subsequent offers.
- (6) If a Capacity Resource is not scheduled in the day-ahead market, it may revise its offer and submit into the real-time market or it may self-schedule the resource.
- (7) Capacity Resources that have notification, startup, and minimum run times that exceed 24 hours must submit binding offer prices for the next seven days.
- (8) Each Capacity Resource must make available at least one cost-based schedule.
- (9) Generation offers may consist of startup, no-load, and incremental energy offer. A generation offer may not exceed \$1000/MWh.
- (10) Non-capacity resources may offer into the day-ahead market or real-time market.
- (11) If a non-capacity resource does not submit offer data, then the offer is assumed to be a zero MW quantity.
- (12) Only a single price-based schedule may be offered into the day-ahead market. In addition to the price-based schedule, one cost-based schedule shall be made available for PJM's use in the event that the unit is used to control a transmission constraint.
- (13) A generator offer that is accepted for the day-ahead market automatically carries over into the balancing market.
- (14) Only a single price-based offer may be submitted into the balancing market.

- (15) A generator offer for a generating unit with combined cycle capability shall make available either the schedule for the CTs or the schedule for the combined cycle unit, not both.
- (16) Only CTs may submit weather curves, which specify MW limits for CTs as a function of temperature.
- (17) Forecast points shall consist of a daytime temperature and a nighttime temperature.
- (18) There are separate weather curves for economic MW and for emergency MW.
- (19) Each CT is assigned to a weather point, which is entered by the Operating Company. As generating units change ownership it may be necessary to add weather points. The default for the weather points is the PJM temperature forecast.
- (20) The priority of generator offer operating limits is unit limits that can be overridden by daily unit schedule MW limits. Daily unit schedule MW limits can be overridden by unit hourly MW limits. Weather curves for CTs apply to both unit limits and schedule limits.
- (21) Market Sellers may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or or eligible external interface point (posted on the PJM website) for which an LMP is calculated. It is not required that physical generation or load exists at the location that is specified in the increment offer or decrement bid.
- (22) A price-based unit has the option to choose a cost-based start-up cost. A price-based unit that chooses the cost-based start-up option may change the start-up costs daily. A priced-based unit that chooses the price-based start-up cost option will continue to be able to change the start-up costs twice a year.
- (23) The choice between using cost-based and price-based startup costs can be made twice a year during the same open enrollment window (on or before 1200 hours March 31 for the period April 1 through September 30 and on or before 1200 hours September 30 for the period October 1 through March 31). Period 1 is defined as the period of time beginning April 1 and ending September 30. Period 2 is defined as the period of time beginning October 1 and ending March 31. If a priced based unit chooses a cost-based start-up cost, the decision cannot be changed unit the next open enrollment period takes place.
- (24) The no-load cost remains locked for priced-based units.

- (25) When a unit or part of a unit is designated as Maximum Emergency (ME), this means that the referenced output levels may require extraordinary procedures and that the designated MW is available to PJM only when PJM requests Maximum Emergency Generation. Designation of a unit or a portion of a unit as ME should be based on the real operating characteristics of the unit and not be used to withhold all or a portion of the capacity of a unit from the day ahead market.
- A. Designation of all or part of a unit's capacity as Maximum Emergency (ME) constitutes withholding in the day ahead market, if:
 - ↪ The capacity is not designated as ME in the bid for the real time market, or;
 - ↪ There is no physical reason to designate the unit as ME.
 - B. The consequence of withholding a unit's capacity under ME is:
 - ↪ The unit will be given an outage ticket which reflects a de-rating equal to the positive difference in capacity designated Maximum Emergency in the bid for the day-ahead market and capacity designated Maximum Emergency in the bid for the real time market.
- (26) A unit bid includes an Economic Maximum point, which is the highest output on its bid curve that the unit is offering for economic dispatch. The Economic Max represents the highest unrestricted level of MW that the operating company will operate the unit, under its offer, for economic dispatch. The Economic Max point should be based on the actual capability of the unit to operate on its bid curve and should not be used to withhold a portion of the capacity of a unit from the day-ahead market.
- a. Reduction of Economic Max MW constitutes withholding in the day ahead energy market, if:
 - ↪ The Economic Max MW is higher in the bid for the real time energy market than in the bid for the day ahead market, or;
 - ↪ There is no physical reason to designate a lower Economic Max in the bid for the day-ahead market bid than in the bid for the real time market.
 - b. The consequence of withholding a unit's capacity by reduction of Economic Max MW is:

- ↪ The unit will be given an outage ticket which reflects a derating equal to the positive difference in Economic Max output designated in the bid for the real time market and in the bid for the day-ahead market.
- (27) Generating units that are connected to the system at the same electrical location may be aggregated and offered into the PJM market as a single unit.
- (28) The aggregated unit must be offered into the PJM markets as a single unit with only one set of offer data, including startup, no load and incremental energy. This rule applies to all energy and ancillary service markets into which the unit is offered.
- (29) Hourly integrated, revenue quality meter data must be submitted to eMeter on the basis of the aggregated unit.
- (30) Real time meter data is required for each physical unit in order to support the PJM state estimator model and to allow energy settlement on an individual unit level.
- (31) Balancing Operating Reserve deviations for aggregated units will be calculated based on the hourly difference between the DA schedule for the aggregated unit and the hourly integrated revenue quality eMeter data for the aggregated unit.
- (32) Unit modeling changes in the PJM eMKT system (unit type, aggregation level, for example), not including changes based on physical changes at the plant, can be made at the beginning of each quarter.

Transmission Customers

The following business rules apply to Transmission Customers:

- (1) Transmission customers may submit external bilateral transaction schedules and may indicate willingness to pay congestion charges into either the day-ahead market or balancing market. In the day-ahead market, a transaction shall indicate willingness to pay congestion charges by submitting the transaction as an 'up to' congestion bid.
- (2) 'Up to' congestion bids shall be no larger than \$25/MWh. Any 'up to' congestion transaction that bids higher than \$25/MWh shall be treated as a fixed bilateral transaction.
- (3) Internal bilateral transactions may be designated as day-ahead or balancing market in PJM eSchedules.

- (4) Up-to congestion bids and increment offers and decrement bids shall be supported in the day-ahead market only.

PJM Activities

The following business rules apply to PJM activities:

- (1) PJM shall post on the two-settlement MUI the PJM load forecast, total bid demand, and operating reserve objective for each hour of the next Operating Day by 1600 at the completion of the day-ahead scheduling process.
- (2) PJM shall post forecasts of total hourly demand for the next four days and peak demand for the subsequent three days.
- (3) PJM shall post hourly LMP values for the next operating day at the completion of the day-ahead scheduling process at 1600.
- (4) PJM shall post the schedule of demand, supply, and bilateral transactions for private viewing by Market Participants.
- (5) PJM may perform supplemental unit commitments after the day-ahead schedule is posted in order to maintain reliable operation. Such supplemental commitments are based on minimizing startup and no-load costs.
- (6) During the various unit commitment analyses, PJM may limit its dependence on Combustion Turbines to provide reserves in order to maintain reliable operational standards. Such limits shall be based on past performance of these units.
- (7) PJM's market power mitigation procedure continues under the two-settlement procedure. If transmission limits are identified during the day-ahead scheduling process, the appropriate generators (those that are intended to control the constraint) are price-capped.
 - a. Units are price-capped at either cost (production cost + 10%) or historic LMP. Start-up and no-load components are capped at production cost + 10% for both cost-capped offers and historic LMP-capped offers.
 - b. Price caps apply for the entire operating day of the constraint (not hourly) for the real-time market. For the day-ahead market, the price caps only apply to hours when the generator is designated as on for transmission.
 - c. LMP can be set using a cost-capped or historic LMP-capped schedule.

- d. Price-caps are not applied for resources that are dispatched for western, central, and eastern reactive limits.
 - e. The Operations Planning Department sets the unit's price/capped switch to the available price-capped schedule.
 - f. Once the price-based switch is set to price (set by PJM upon request from generation owner), the generator owner cannot return to a cost-based offer (cost-capped or historic LMP-capped).
 - g. A price-based unit has the option to choose a cost-based start-up cost. A price-based unit that chooses the cost-based start-up option may change the start-up costs daily. A priced-based unit that chooses the price-based start-up cost option will continue to be able to change the start-up costs twice a year.
 - h. The choice between using cost-based and price-based startup costs can be made twice a year during the same open enrollment window (on or before 1200 hours March 31 for the period April 1 through September 30 and on or before 1200 hours September 30 for the period October 1 through March 31). Period 1 is defined as the period of time beginning April 1 and ending September 30. Period 2 is defined as the period of time beginning October 1 and ending March 31. If a priced based unit chooses a cost-based start-up cost, the decision cannot be changed until the next open enrollment period takes place.
 - i. The no-load cost remains locked for priced-based units.
- (8) Price-sensitive demand can set LMP in the day-ahead market. (Due to communication infrastructure challenges, price-sensitive demand cannot currently set LMP in the real-time market.)

Mechanical/Technical Rules

- (1) A valid generator offer consists of the following elements:
- a. For an internal Capacity Resource a valid generator offer consists of a price-based schedule (if the unit has switched to price) and at least one cost-based schedule. (Capacity Resources for which construction began after July 1, 1996 are exempt.) The default values for the schedules are:

- Day-ahead market switch is “check” or yes (1).
 - Balancing market switch is “check” or yes (1).
 - Use start-up & no-load switch is “check” or yes (1).
 - Use offer slope switch is “square box” or no (0).
 - Condense available switch is blank or no (0).
 - Startup and no load costs are zero.
 - Hourly economic max/min and emergency max/min are the unit level economic and emergency MW limits, respectively.
 - Minimum down time, minimum run time, start times, and notification times are zero.
 - Maximum run time and maximum number of starts per week are infinity.
- b. The default for incremental offer curve data is \$0. If the last MW point on the segment curve is less than the maximum emergency limit, then the curve is extended up to the emergency maximum limit using zero slope from the last incremental point on the curve.
- c. For an external resource or a non-Capacity Resource, a valid generator offer consists of a price-based schedule. The default values for the schedules are:
- Day-ahead market switch is “check” or yes (1).
 - Balancing market switch is “check” or yes (1).
 - Use start-up & no-load switch is “check” or yes (1).
 - Use offer slope switch is “square box” or no (0).
 - Condense available switch is blank or no (0).
 - Startup and no-load costs are zero.

- Hourly economic max/min and emergency max/min are the unit level economic and emergency MW limits, respectively.
 - Minimum down time, minimum run time, start times, and notification times are zero.
 - Maximum run time and maximum number of starts per week are infinity.
 - The default for incremental offer curve data is \$0. If the last MW point on the segment curve is less than the maximum emergency limit, then the curve is extended up to the emergency maximum limit using zero slope from the last incremental point on the curve.
- (2) Valid offers for demand bids, price sensitive and fixed, consist of the following items:
- a. MW, with a default value of 0 MW
 - b. Location (transmission zone, aggregate, or single bus)
 - c. Price at which demand shall be curtailed (for price-sensitive bids)

Modeling

- (1) Fixed transactions, including increment offers and decrement bids, are modeled in the Unit Commitment. Up-to congestion transactions are not modeled in the commitment, but are handled in the day-ahead dispatch. PJM does not commit additional generation to support up-to congestion transactions.
- (2) The day-ahead security analysis treats increment offers and decrement bids injections as distributed load (or generation) that create an imbalance where physical load and generation do not exist.
- (3) External dispatchable bilateral transactions with source = interface bus is modeled as a dispatchable generation at the sink bus location.
- (4) External dispatchable bilateral transactions with sink = interface bus is modeled as a price-sensitive load at the source bus location.

- (5) Only fixed transactions and transactions involving external aggregate resources are modeled in the Unit Commitment (RSC) for the day-ahead market.

Day-Ahead LMP Calculations

- (1) The day-ahead LMP calculation is based on the first unit commitment, which has the objective to satisfy the day-ahead bid demand, plus the PJM operating reserve objective requirement for that level of bid demand.
- (2) The following resources are eligible to set LMP values in the day-ahead market:
 - a. all pool-dispatchable steam units
 - b. pool-scheduled CTs and diesels whose bid price is at or below the system marginal cost
 - c. dispatchable external resource offers
 - d. increment offers
- (3) Demand bids that are eligible to set LMP values in the day-ahead market are price-sensitive demand bids and decrement bids.
- (4) Transactions that bid 'up to' congestion charges are eligible to set LMP values in the day-ahead market.

Settlements Data Requirements

- (1) Data required for day-ahead settlements :
 - a. Day-ahead LMP values by PNODE
 - b. Day-ahead schedule MW quantities by Market Participant and by PNODE
 - c. Increment/decrement bid clearing results and transaction clearing results
 - d. Binding transmission constraints
 - e. Generators that have been price-capped
 - f. Generation offer data (startup, no-load, incremental curve, availability, etc.)

- (2) Data required for balancing settlements:
- g. Generation offer data (startup, no load, incremental curve, availability, etc.)
 - h. Generation status information, via DMT
 - i. Transmission losses by transmission zone and 500 kV transmission losses

- (3) There are two Operating Reserve calculations, which require the following information:

☞ Day Ahead Operating Reserves

- (a) Number of starts for the day by class (hot, intermediate, cold)
- (b) Startup cost by class (hot, intermediate, cold)
- (c) No load cost
- (d) Unit offer data
- (e) Schedule id
- (f) Scheduled MW
- (g) Price switch (price-based unit Yes/No)
- (h) Use startup/no-load switch
- (i) Unit status
- (j) Economic Max
- (k) Economic Min

☞ Balancing Operating Reserves

- (a) Dispatch logging information, via the Unit Dispatch System (UDS) and Dispatch Management Tool (DMT)
- (b) Unit state estimated MW
- (c) Unit offer data

Day-ahead Settlement

- (1) Day-ahead settlement is based on day-ahead hourly LMPs.
- (2) For each hour of the day-ahead market:
 - ☞ Each scheduled demand pays its day-ahead LMP for the hour.
 - ☞ Each scheduled generator is paid its day-ahead LMP for the hour.
 - ☞ Scheduled transactions pay congestion charges based on day-ahead LMP differences between sources and sinks.
 - ☞ FTR holders receive congestion credits based on hourly day-ahead LMP values. Therefore, under two-settlement, congestion charges for the hour from both day-ahead and real-time markets are distributed to FTR holders based on target allocations, which are calculated as a function of day-ahead prices. Excess congestion charges are distributed in the following manner:
 - a. Stage One - PJM distributes excess Transmission Congestion Charges accumulated during the month to each holder of FTRs in proportion to, but not greater than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total target allocations for the month.
 - b. Stage Two - Any remaining excess after the stage one distribution will be used to satisfy any FTR deficiency from previous months within the calendar year on a pro-rata basis up to the full FTR Target Allocation value.
 - c. Stage Three – Any remaining excess after the stage Two distribution will be carried forward to the next month as excess congestion charges.
 - d. Stage Four - At the end of the calendar year, any remaining Excess Congestion Charges will first be used to satisfy any ARR deficiency that may exist. If insufficient funds exist to honor all ARR revenue shortfalls then the funds would be distributed by ratio of the ARR deficiency.
 - e. Stage Five - PJM distributes any excess Transmission Congestion Charges remaining after the stage four distribution to Network Customers and Firm Point-to-Point Transmission Customers in proportion to their Demand

Charges for Network Integration Service and their charges for Reserved Capacity for Firm Point-to-Point Transmission Service, regardless of whether these customers hold FTRs for their Transmission Service.

- f. Operating Reserves — There are separate operating reserve credit calculations for the day-ahead market and the balancing market. This option preserves the incentive for demand and supply to bid into the day-ahead market based on their actual expectations and preserves the incentive for generation to follow real-time dispatch signals.
- g. A unit that is accepted in the day-ahead market will be eligible to receive a day-ahead operating reserves credit. If a different schedule is made available in real-time operations, this unit is not eligible to receive a balancing market operating reserve credit.
- h. Allocation of operating reserve charges in the day-ahead market is to all day-ahead demand, accepted Decrement bids, and to exports that submit day-ahead schedules (not including bilateral transactions that are dynamically scheduled to load outside PJM).

Balancing Settlement

- (1) Balancing settlement is based on real-time LMP values averaged over the hour.
- (2) Settlement is performed on quantity deviations from day-ahead schedule values.
- (3) FTRs do not apply to balancing settlement. FTRs apply to the day-ahead settlement only, because of the market revenue adequacy issue. PJM cannot provide financial hedging in both the day-ahead and the balance markets, which in effect is selling the service twice.
- (4) Balancing operating reserves charges are allocated to all deviations from day-ahead scheduled quantities including demand deviations, generation deviations (for generation not following real-time dispatch instructions, scheduling and dispatch signals), transaction import/export deviations (but not including bilateral transactions that are dynamically schedule to load outside the PJM RTO), and for increment or decrement bid deviations. Balancing operating reserves for synchronous condensing are allocated to

Market Participants in proportion to deliveries of energy to load during the Operating Day, excluding its bilateral transactions that are dynamically scheduled to load outside the PJM RTO.

Maximum Emergency Generation in Day-Ahead Market

- (1) If the day-ahead demand bid MW cannot be satisfied with all available generation at its economic maximum MW limit, the program shall issue a Maximum Generation Warning message due to a shortage of economic generation in the day-ahead market. The program shall then perform the following steps to achieve power balance:
 - a. Increase all on-line generation up to its maximum emergency MW limit. (Increase generator MW proportionately by ratio of economic maximum, if power balance is achieved prior to reaching maximum limits). Set LMP values equal to the highest offer price of all on-line generation.
 - b. Load off-line generation that is designated as available only for maximum generation emergency conditions, as required. The order of loading is based on economic offer data. Set LMP values equal to the highest offer price of all on-line generation.
 - c. If power balance is not achieved after Step 2, drop any remaining price-sensitive demand to zero MW. Set LMP values equal to the highest price-sensitive demand bid that was cut in this step. If no price-sensitive demand was reduced in this step, the LMP values are set equal to highest offer price of all on-line generation (resulting from Step 2).
 - d. If power balance is not achieved after step 3, reduce all load proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, the price from Step 3, or the bid cap (presently \$1000/ MWh), whichever is higher.

Minimum Capacity Emergency in Day-Ahead Market

- (1) If the day-ahead demand bid MW is less than the total generation MW with all possible generation off and with all remaining generation at their economic minimum MW limit, the program shall issue a Minimum Generation Warning message due to an excess of economic generation in the day-ahead market.

The program shall then perform the following steps to achieve power balance.

- a. Reduce all on-line generation down to its minimum emergency MW limit. (Reduce generator MW proportionately, by ratio of economic minimum. If power balance is achieved prior to reaching minimum limits). Set LMP values equal to the lowest offer price of all on-line generation.
- b. Set LMP values to zero. Reduce all on-line generation below emergency minimum proportionately (by ratio of emergency minimum) to achieve power balance.

Section 3: Overview of the PJM Regulation Market

Welcome to the *Overview of the PJM Regulation Market* section of the PJM Manual for **Scheduling Operations**. In this section you will find the following information:

- An overview description of the PJM Regulation Market (see “Overview of PJM Regulation Market”).
- A list of the PJM Regulation Market Business Rules (see “PJM Regulation Market Business Rules”).

Overview of the PJM Regulation Market

As of August 1st, 2005, the PJM Regulation Markets will be combined into a single RTO Regulation Market for a six month trial period ending January 31st, 2006. PJM will provide a market competitiveness analysis after three months to determine whether all participants will be able to enter price based regulation offers. If the market is not competitive, it will revert back to separate markets. If the market is competitive, PJM stakeholders will vote to determine whether the change will be permanent.

If you have any questions or concerns, please contact the Markets Hotline at 610-666-8998.

The PJM Regulation Market provides PJM participants with a market-based system for purchase and sale of the Regulation ancillary service. Generation owners submit unit-specific offers to provide Regulation, and PJM utilizes these offers together with forecasted LMPs and generation schedules produced by the Unit Dispatch system to calculate an hourly Regulation Market Clearing Price (RMCP). This clearing price is then used to determine the credits awarded to providers and charges allocated to purchasers of the Regulation service.

PJM uses the forecasted LMPs and generation schedules from the Unit Dispatch System (UDS) to estimate the opportunity cost that would be incurred by each available unit if it were to provide Regulation during each hour of the operating day. This estimated opportunity cost is then added to the Regulation offer to determine a merit order price for each unit for each hour. All available regulating units are then ranked in ascending order of their merit order prices, and the lowest cost set of units necessary to meet the PJM Regulation Requirement in each hour is determined. The highest merit order price associated with this lowest cost set of units becomes the RMCP for that hour of the operating day. Generation owners may self-schedule Regulation on any qualified unit, and the merit order price for any self-scheduled Regulation unit is set to zero.

PJM simultaneously optimizes energy, Regulation and Spinning Reserve, and assigns both Regulation and Spinning to the most cost-effective set of units each hour of the operating day.

In the after-the-fact settlement, any units self-scheduled to provide Regulation are compensated at the hourly RMCP. Any units selected by PJM to provide Regulation are compensated at the higher of the hourly RMCP or their real time opportunity cost plus their Regulation offer price. LSEs required to purchase Regulation are charged the hourly RMCP plus their percentage share of opportunity cost credits over and above the RMCP and any un-recovered costs of units called on by PJM to provide Regulation.

PJM Regulation Market Business Rules

Regulation Market Eligibility

- (1) Regulation offers may be submitted only for those units electrically within the PJM RTO.
- (2) The following unit criteria must be met:
 - Unit must have a governor capable of AGC control.
 - Unit must be able to receive an AGC signal.
 - Unit must demonstrate minimum performance standards, as set forth in the PJM Manuals.
 - New units must pass an initial performance test (minimum 75% compliance required). PJM will rely on owner's data for initial qualification. Units qualified as of June 1, 2000 are grandfathered.
 - Unit must exhibit satisfactory performance on dynamic evaluations.
 - Unit MW output must be telemetered to the PJM control center in a manner determined to be acceptable by PJM.
- (3) The following information must be supplied through the Two-Settlement Market User Interface (eMarket):
 - a. Unit Regulating Status (available, unavailable, self-scheduled)
 - b. Regulation Capability (above and below regulation midpoint, MW)

- c. Regulation Offer Price (\$/MWhr). Offer prices will be capped at \$100/MWhr.
- d. Regulation Maximum and Minimum values, considering any necessary offsets (MW)

The Regulation Offer Price must be supplied prior to 6:00 p.m. day-ahead and is applicable for the entire 24-hour period for which it is submitted. The remaining information may be submitted or changed up until sixty (60) minutes prior to the operating hour, at which time the Regulation market closes. In the event that the Regulation Maximum and Regulation Minimum limits are not the most restrictive for a given unit (i.e. the Regulation Maximum the lowest of all the high limits and the Regulation Minimum the highest of all the low limits), the regulation software will utilize the most restrictive minimum and maximum of all applicable limits for real time.

Regulation Offer Prices submitted for generators in the Dominion and AEP control zones must reflect the marginal cost of providing the Regulation service from those generators, as defined in the PJM Cost Development Manual (M-15).

- (4) The following changes in Unit Regulating Status may be made after the regulation market closes either through direct communication with the PJM Scheduling Coordinator or through the hourly updates screens of the Two Settlement MUI:
 - a. Available to unavailable
 - b. Self-scheduled to unavailable
- (5) High Regulation Limit may be decreased but not increased and Low Regulation Limit may be increased but not decreased after the regulation market closes through direct communication with the PJM Scheduling Coordinator.
- (6) Regulating capability may be decreased but not increased after the regulation market closes through direct communication with the PJM Scheduling Coordinator and through the hourly update screens of the Two Settlement MUI.
 - c. Regulation Maximum may be decreased but not increased and Regulation Minimum may be increased but not decreased after the regulation market closes through the hourly update screens of the Two Settlement MUI.
- (7) Any unit that is unavailable for energy when the Regulation market closes and becomes available during the operating hour may also be made available or self-scheduled for regulation. Any associated regulation offer

information may be changed for such units, since none was considered in the calculation of RMCP.

- (8) Units that are self-scheduled for energy that do not have an available bandwidth above the self-scheduled value and below the applicable maximum greater than or equal to twice the regulation offer cannot be evaluated for the full amount of the offer. Such units will be evaluated for regulating capability equal to half the bandwidth available.

Regulation Requirement Determination

- (1) The single Regulation Requirement for the PJM RTO is the sum of the requirements of the individual control zones based on the regional reliability councils to which they belong. Specifically, the requirement is determined in whole MW, and for each hour of the operating day is equal to the sum of :
 - (i) 1.1% of the Mid-Atlantic Region day-ahead peak load forecast for the on-peak period and valley load forecasted for the off-peak period, plus
 - (ii) 1% of the forecast peak load for the Western and Southern Regions.

The requirement percentage may be adjusted by the PJM Interconnection, if the adjustment is consistent with the maintenance of NERC control standards.

Regulation Obligation Fulfillment

- (1) LSEs may fulfill their regulation obligations by:
 - a. Self-scheduling the entity's own resources;
 - b. Entering contractual arrangements with other market participants;
or
 - c. Purchasing regulation from the regulation market.

Regulation Offer Period

- (1) Generation owners wishing to sell regulation service must supply a regulation offer price by 6:00 p.m. the day prior to operation, and the remainder of the necessary data prior to Regulation market closing as stated above in the Regulation Market Eligibility section.
- (2) Regulation offers are locked as of 6:00 p.m. the day prior to operation. The Markets Database is unavailable for entry between 12 noon and 4:00 p.m.

the day prior to operation while the commitment software is running. All units listed as available for regulation with no offer price have their offer prices set to zero.

- (3) Bilateral regulation transactions must be entered by the buyer and subsequently confirmed by the seller through the Two Settlement MUI no later than 16:00 the day after the transaction starts. Bilateral transactions that have been entered and confirmed may not be changed; they must be deleted and re-entered. Deletion of a bilateral transaction is interpreted as a change in the end time of the transaction to the current hour, unless the transaction has not yet started.

Regulation Market Clearing

- (1) PJM clears the regulation market simultaneously with the spinning market, and posts the results no later than 30 minutes prior to the start of the operating hour.
- (2) Unit merit order price (\$/MWhr) = Unit regulation offer + estimated unit opportunity cost per MWhr of capability
- (3) Estimated unit opportunity cost is calculated as follows:

- The Unit Dispatch System (UDS) supplies a forecasted energy schedule, respecting appropriate transmission constraints, together with forecasted LMPs for the operating hour to the Spinning and Regulation Optimizer (SPREGO).
- SPREGO utilizes the forecasted energy schedule and LMPs to determine the estimated opportunity cost each unit would incur if it adjusted its output as necessary to provide its full amount of regulation. The approximate formula for this opportunity cost is:

$$|LMP - ED| * GENOFF, \text{ where:}$$

- a. LMP is the forecasted hourly LMP at the generator bus,
 - b. ED is the price associated with the setpoint the unit must maintain to provide its full amount of regulation, and
 - c. GENOFF is the MW deviation between economic dispatch and the regulation setpoint.
- (4) This formula is somewhat simplistic. The actual calculation is an integration which may be visualized as the area on a graph enclosed by the unit's price curve, the points on that curve corresponding to the unit's desired economic

dispatch and the setpoint necessary to provide the full amount of regulation, and the LMP

- (5) SPREGO ranks all available regulating units in ascending merit order price, and simultaneously determines the least expensive set of units necessary to provide energy, regulation and spinning reserve for the operating hour taking into account any units self-scheduled to provide any of these services. Should the SPREGO application be unable to fulfill both the Regulation and Spinning requirements, regulation receives the higher priority.
- (6) PJM may call on units not otherwise scheduled to run in order to provide regulation, in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. If a unit is called on by PJM for the purpose of providing regulation, the unit is guaranteed recovery of start-up and no-load costs. Any unrecovered portion of these costs will be credited along with opportunity costs in the regulation settlement process.
- (7) Non-capacity resources that are self-scheduled to provide energy and do not supply an energy bid have no opportunity cost associated with providing regulation.
- (8) The highest merit order price becomes the Regulation Market Clearing Price for that hour.
- (9) The hourly RMCPs are posted on the user interface for public view.

Hydro Units

- (1) Since hydro units operate on a schedule and do not have an energy bid, opportunity cost for these units is calculated as follows:
 - The formula is the same as above, except the ED value is an average of the LMP at the hydro unit bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydro plant were operating. If this average LMP value is higher than the actual LMP at the generator bus, the opportunity cost is zero. Day-ahead LMPs are used for the purpose of estimating opportunity costs for hydro units, and actual LMPs are used in the after-the-fact settlement.
 - If a hydro unit is brought on out of schedule to provide regulation, the opportunity cost is equal to the average LMP (calculated as stated in [a]) minus the actual LMP at the generator bus. If the actual LMP is higher than the average, the opportunity cost is zero.

- During those hours when a hydro unit is in spill, the ED value is set to zero such that the opportunity cost is based on the full value of LMP. During the operating day, the operating company is responsible for communicating this condition to the PJM Scheduling Coordinator, and indicating this condition on the Regulation Hourly Updates page of the Two-Settlement MUI.
- (2) When determined to be economically beneficial, PJM maintains the authority to adjust hydro unit schedules for those units scheduled by the owner if the owner has also submitted a regulation offer for those units and made the units available for regulation.

Regulation Market Operations

- (1) The PJM Operator maintains total Regulation Zonal capabilities within a +/- 2%, but no less than +/- 15MW bandwidth around the RTO Regulation Requirement.
- The PJM Operator periodically evaluates the set of units providing regulation, and makes any adjustments to regulation assignments deemed necessary and appropriate to minimize the overall cost of regulation.
 - In the event of a regulation excess, the PJM dispatcher deselects units beginning with the highest cost unit currently providing regulation and moving downward.
 - In the event of a regulation deficiency, the PJM dispatcher selects units to provide regulation beginning with the lowest cost unit currently not providing regulation and moving upward.
 - The RMCP does not change based upon regulating unit adjustments made in real time. Any opportunity costs that exceed the RMCP are credited after the fact on a unit-specific basis.
- (2) The PJM Energy Management System (EMS) sends one Control Area Regulation signal to each Local Control Center (LCC), as well as signals to individual units or plants as requested by the owner.
- (3) The PJM Operator communicates any change in unit regulating assignments to individual Local Control Centers. Company total in-service regulating capabilities are then telemetered back to the PJM EMS via the PJM data link.

- (4) Unit regulation assignment changes during transitions between on-peak and off-peak periods begin 30 minutes prior to the new period, and are completed no later than 30 minutes after the period begins.

Settlements

- (1) Regulation settlement is a zero-sum calculation based on the regulation provided to the market by generation owners and purchased from the market by LSEs.
- (2) Regulation obligation is determined hourly for each LSE as follows:
 - (i) for an LSE in the Mid-Atlantic Region, the ratio of the Mid-Atlantic Region regulation requirement over the PJM RTO requirement is multiplied times the total regulation assigned in the RTO, and then the real time load ratio share within the Mid-Atlantic Region (adjusted for scheduled load responsibility) for the LSE is applied to the result.
 - (ii) for and LSE in the Western or Southern Region, the ratio of the of the sum of the Western and Southern Region regulation requirements over the PJM RTO requirement is multiplied times the total regulation assigned in the RTO, and then the real time load ratio share within the combined Western and Southern Regions (adjusted for scheduled load responsibility) for the LSE is applied to the result.
- (3) Regulation credits are awarded to generation owners that have either self-scheduled regulation or sold regulation into the market. Regulation credits for units self-scheduled to provide regulation are equal to RMCP times the unit's self-scheduled regulating capability. Regulation credits for units that offered regulation into the market and were selected to provide regulation are the higher of:
 - RMCP times the unit's assigned regulating capability, or
 - The unit's regulation bid times its assigned regulating capability plus opportunity cost incurred.
- (4) Opportunity cost is calculated as shown above in Market Clearing using actual integrated LMP as opposed to that which was forecasted. PJM then adjusts the opportunity cost calculated for each unit based on the actual hourly integrated value of the real time PJM regulation signal to account for the fact that the unit may have been held above or below its regulation setpoint for greater than half the hour.

- (5) Non-capacity resources that are self-scheduled to provide energy and do not supply an energy bid are not eligible to collect opportunity cost credits. These units will receive credit equal to the RMCP times the amount of regulation self-scheduled on or assigned to them.

Section 4: Overview of the PJM Spinning Reserve Market

Welcome to the *Overview of the PJM Spinning Reserve Market* section of the PJM Manual for **Scheduling Operations**. In this section you will find the following information:

- An overview description of the PJM Spinning Reserve Market (see “*Overview of PJM Spinning Reserve Market*”).
- A list of the PJM Spinning Reserve Market Business Rules (see “*PJM Spinning Reserve Market Business Rules*”).

Overview of the PJM Spinning Reserve Market

The PJM Spinning Reserve Market provides PJM participants with a market-based system for purchase and sale of the Spinning Reserve ancillary service. Generation owners submit unit-specific offers to provide Spinning Reserve, and PJM utilizes these offers together with forecasted LMPs and generation schedules produced by the Unit Dispatch system to calculate an hourly Spinning Reserve Market Clearing Price (SRMCP). This clearing price is then used to determine the credits awarded to providers and charges allocated to purchasers of the Spinning Reserve service.

PJM uses generation schedules from the Unit Dispatch system to estimate the amount of incidental Spinning Reserve present on the PJM system due to economic dispatch, and this capability is designated as Tier 1. Tier 1 is provided by any unit that is on line, following economic dispatch, and capable of increasing its output within ten (10) minutes following a call for Spinning Reserve. If the amount of Tier 1 estimated for a given hour is insufficient to meet the PJM Spinning Reserve Requirement, PJM must assign units to operate at a point that deviates from economic dispatch in order to provide the remainder of the requirement. The extra capacity that must be committed is designated Tier 2. PJM uses forecasted LMPs and generation schedules from the Unit Dispatch system to estimate the opportunity cost (including energy use) that would be incurred by each available unit if it were to provide Spinning Reserve during each hour of the operating day. This estimated opportunity cost is then added to the Spinning Reserve offer to determine a merit order price for each unit for each hour. All available Tier 2 spinning units are then ranked in ascending order of their merit order prices, and the lowest cost set of units necessary to meet the PJM Spinning Reserve Requirement in each hour is determined. The highest merit order price associated with this lowest cost set of units becomes the SRMCP for that hour of the operating day. Generation owners may self-schedule Spinning Reserve on any qualified unit, and the merit order price for any self-scheduled Spinning Reserve unit is set to zero. PJM simultaneously

optimizes energy, Regulation and Spinning Reserve, and assigns both Regulation and Spinning to the most cost-effective set of units each hour of the operating day.

In the after-the-fact settlement, any units self-scheduled to provide Spinning Reserve are compensated at the hourly SRMCP. Any units selected by PJM to provide Spinning Reserve are compensated at the higher of the hourly SRMCP or their real time opportunity cost plus their Spinning Reserve offer price. LSEs required to purchase Spinning Reserve are charged the hourly SRMCP plus their percentage share of opportunity cost credits over and above the SRMCP and any unrecovered costs of units called on by PJM to provide Spinning Reserve.

PJM Spinning Reserve Market Business Rules

Spinning Reserve Market Eligibility

- (1) Spinning offers may be submitted only for those units located electrically within the Spinning Reserve Zone.
- (2) Units participating in the spinning market are divided into two Tiers:
 - a. **Tier 1** is comprised of all those units on line following economic dispatch and able to ramp up from their current output in response to a spinning event.
 - b. **Tier 2** consists of that additional capacity that is synchronized to the grid and operating at a point that deviates from economic dispatch (including condensing mode) to provide additional spinning reserve not available from Tier 1 resources.
 - c. All units operating on the PJM system with the exception of those assigned as Tier 2 resources are by definition Tier 1 resources. Any unit capable of operating in condensing mode or willing to operate with an output less than that dictated by economic dispatch may participate as a Tier 2 resource. There is no qualification process for Tier 2 resources. However, consequences exist as described below for response by Tier 2 resources that are less than that which is committed.
- (3) The following information must be supplied through the Two-Settlement Market User Interface (eMarket):
 - a. Spinning Reserve Ramp Rate for Tier 1 resources (MW/minute). A separate rate may be submitted for multiple segments of a unit's MW range, and these rates must be greater than or equal to the real time economic ramp rate(s) submitted for the unit. Spinning

ramp rates that exceed economic ramp rates must be justified via submission of actual data from past spinning events to the PJM Performance Compliance Department.

- b. Spinning reserve maximum for Tier 1 resources. This value represents the maximum MW output a unit can achieve in response to a spinning event, and must be greater than or equal to the economic maximum for the unit.
- c. Spinning Reserve Availability for Tier 2 resources. Units may be made available, unavailable, or self-scheduled to provide Tier 2 spinning reserve.
- d. Spinning Offer Quantity for Tier 2 resources (MW). This quantity is defined as the increase in output achievable by the unit in ten (10) minutes.
- e. Spinning Offer Price for Tier 2 resources (\$/MWhr). Spinning Offer Prices will be capped at a maximum value of the unit's O&M cost (as determined by the Cost Development Task Force) plus \$7.50/MWh margin.
- f. Energy use for condensing Tier 2 resources (MW). This is the amount of instantaneous energy a condensing unit consumes while operating in the condensing mode. The value submitted as part of the spinning offer must be less than or equal to the actual energy consumed as observed in real time.
- g. Condense to gen cost. This is the cost of transitioning a condenser to the generating mode. The value submitted for this cost must be less than or equal to the condensing start cost.
- h. Condense Startup Cost. This is the actual cost associated with getting a unit from a completely off-line state into the condensing mode including fuel, O&M, etc.
- i. Condense Hourly Cost. This is the hourly cost to condense is equal to the actual, variable O&M costs associated with operating a unit in the condensing mode, including any fuel costs. It does not include any estimate for energy consumed
- j. Condense Notification Time. The amount of advance notice, in hours, required to notify the operating company to prepare the unit to operate in synchronous condensing mode. The default value is 0 hours.

- k. Spin as Condenser. This is used to identify if a combustion turbine can be committed for spinning as a condenser

Spinning Requirement Determination

Each Ancillary Service Area will have separate Spinning Reserve Zones, but operated via the same market mechanism. PJM will select resources in each Spinning Reserve Zone hourly to provide spinning reserve based on a co-optimization between energy, regulation and spinning reserve. Assignments will be communicated to the unit owners/operators by eMKT or the appropriate dispatcher.

The RTO will be arranged into four (4) zones, designated based on the reserve sharing agreements. The ECAR companies are part of a reserve sharing agreement, CE Control Zone is part of a reserve sharing agreement with MAIN, and the SERC companies are part of a separate reserve sharing agreement.

Mid-Atlantic Spinning Reserve Zone: PJM Mid-Atlantic Control Zone

Western Spinning Reserve Zone: AP, AEP, and Dayton, and Duquesne Control Zones

Northern Illinois Spinning Reserve Zone: CE Control Zone

Southern Spinning Reserve Zone: Dominion Control Zone

- (1) Total PJM Spinning Requirement for each Spinning Reserve Zone is determined in whole MW for each hour of the operating day.
 - (a) The Mid-Atlantic Spinning Reserve Zone Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. Mid-Atlantic Area Council (MAAC) standards currently set that amount at 75% of the largest contingency in that Spinning Reserve Zone provided that double the remaining 25% is available as non-synchronized 10-minute reserves.
 - (b) The Western Spinning Reserve Zone Requirement is defined as 1.5% of the peak load forecast of the Western Spinning Reserve Market Area for that day.
 - (c) The Northern Illinois Spinning Reserve Zone Requirement is defined as 50% of ComEd's load ratio share of the largest system contingency within MAIN.
 - (d) The Southern Spinning Reserve Zone Requirement is defined as the Dominion load ratio share of the largest system contingency within

VACAR, minus the available 15 minute quick start capability within the Southern Spinning Reserve Zone.

- (2) North American Electric Reliability Council (NERC) standards may impose greater requirements for spinning reserve following Disturbance Control Standard (DCS) violations. Any such impositions will be incorporated as an increase to the overall control zone spinning requirement.

Spinning Obligation Fulfillment

- (1) Each Load Serving Entity (LSE) on the PJM system incurs a spinning obligation in kWh based on their real-time load ratio share and the Market Area spinning assigned. During hours when the Spinning Reserve Market Clearing Price (RMCP) is the same throughout the Market Area, an LSE's spinning obligation is equal to its load ratio share times the amount of spinning assigned for the Market Area. During hours when congestion causes Spinning Reserve Market Clearing Prices (RMCP) to separate (as described under 'Spinning Market Clearing', in rule #3), each LSE's obligation is equal to its load ratio share within its reserve zone times the amount of spinning assigned in that reserve zone. Any PJM market participant may incur or fulfill a spinning obligation through the execution of a bilateral spinning transaction as described below.
- (2) Participants may fulfill their spinning obligations by:
 - Owning Tier 1 resources from which the Spinning Reserve Zone obtains spinning reserve;
 - Self-scheduling owned Tier 2 resources;
 - Entering bilateral arrangements with other market participants; or
 - Purchasing spinning from the spinning market.

Spinning Offer Period

- (1) Spinning Reserve offer prices for Tier 2 resources are locked as of 1800 hours on the day preceding the operating day. All units listed as available for Tier 2 spinning with no offer price have their offer prices set to zero.
- (2) The following information can be submitted and/or updated up until 120 minutes prior to the operating hour, at which time PJM begins the process of estimating the Tier 1 Spinning Reserve that will be available for the operating hour:

- a. Spinning Reserve Ramp Rate
 - b. Spinning Reserve Maximum
- (3) The following information may be submitted and/or changed up until 60 minutes prior to the start of the operating hour, at which time the Spinning Market closes:
 - a. Spinning Reserve Availability for Tier 2 resources
 - b. Spinning Offer Quantity
- (4) In general, generation owners may not self-schedule spinning resources after 60 minutes prior to the operating hour when the Spinning Market closes. However, the following exceptions exist: if a generation owner has a resource that was either self-scheduled or pool-assigned to provide Tier 2 Spinning Reserve and subsequent to either being self-scheduled or assigned that resource becomes unavailable to provide such amount of Spinning Reserve, the generation owner has the option of self-scheduling another resource in order to make up the shortfall. Also, a unit that was unavailable for energy and therefore not evaluated as part of the Spinning Market clearing becomes available during the operating hour, that unit may be self-scheduled to provide Spinning Reserve at that time.

Bilateral Spinning Transactions

- (1) Bilateral spinning transactions must be entered by the buyer and subsequently confirmed by the seller through the Two Settlement MUI no later than 16:00 the day after the transaction starts. Bilateral transactions that have been entered and confirmed may not be changed; they must be deleted and re-entered. Deletion of a bilateral transaction after its start time has passed will result in a change in the end time of the transaction to the current hour.
- (2) Bilateral spinning transactions may be entered either in MW or as a percentage of the purchaser's obligation. Participants will also be required to indicate the reserve zone for which the transaction is applicable.
- (3) PJM will calculate and post the following indexes in order to provide an approximate value of spinning reserve on which market participants may base prices for bilateral spinning transactions:
 - $(\text{Total hourly spinning cost}) / (\text{Total spinning assigned})$
 - $(\text{Total hourly spinning cost}) / (\text{Total Tier 2 assigned})$

Spinning Market Clearing

- (1) PJM clears the spinning market on an hourly basis. The following is the timeline by which this hourly clearing is accomplished:
- **90 minutes prior to the start of each hour**, PJM estimates the amount of Tier 1 spinning reserve that will be available on each unit. PJM posts this information on eMarket such that each generation owner is able to view the Tier 1 assigned for each of the owner's units.
 - **60 minutes prior to the start of each hour**, each generation owner is required to identify those units that are to be self-scheduled to provide spinning and for what quantity, if this information has changed from the previous hour.
 - **30 minutes prior to the start of each hour**, PJM simultaneously clears the spinning and regulation markets, and posts regulation market clearing prices, spinning market clearing prices and Tier 2 assignments, based on the remaining requirement not met by Tier 1 and self-scheduled Tier 2. If Tier 1 and self-scheduled Tier 2 resources are sufficient to meet the spinning requirement, the Tier 2 clearing price is zero and no Tier 2 assignments are made. If the available Tier 1 and self-scheduled Tier 2 are not sufficient to meet the requirement, the Tier 2 clearing price is set equal to the merit order price of the highest cost Tier 2 resource necessary to meet the remaining requirement. Should regulation and spinning reserve capacity be insufficient to meet both requirements, regulation will receive the higher priority in the market clearing.
 - Unit merit order price (\$/MWhr) = Unit spinning offer + estimated unit opportunity cost per MWh of capability + energy use per MWh of capability
 - a. The unit spinning offer is that which is submitted by the owner via eMarket by 1800 hours on the day preceding the operating day.
 - b. Estimated unit opportunity cost for condensing CTs is calculated as follows:

$$O.C. = [positive (forecast LMP - energy offer price)] \times MW \text{ capability} / spinning \text{ capability}$$
 - c. Estimated unit opportunity cost for non-condensing units is calculated as follows:

$$O.C. = |LMP - ED| \times GENOFF, \text{ where:}$$

- d. LMP is the forecasted hourly LMP at the generator bus,
- e. ED is the price associated with the setpoint the unit must maintain to provide its assigned amount of spinning reserve, and
- f. GENOFF is the MW amount of spinning provided.

This formula is somewhat simplistic. The actual calculation is an integration which may be visualized as the area on a graph enclosed by the unit's price curve, the points on that curve corresponding to the unit's desired economic dispatch and the setpoint necessary to provide the assigned amount of spinning, and the LMP.

- g. Energy use for each condensing unit is entered in MW by the owner via eMarket as part of the spinning offer. Estimated energy use is calculated as part of the merit order price as follows:

$$E.U. = \text{forecast LMP} \times \text{energy use MW} / \text{spinning capability}$$

- h. For each of these calculations, forecast LMP is the result of the 1-hour look-ahead provided by the Unit Dispatch Tool.
 - i. Non-capacity resources for which an energy offer is not submitted will be ineligible for opportunity cost credit.
- (2) PJM may call on units not otherwise scheduled to run in order to provide spinning, in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. If a unit is called on by PJM for the purpose of providing spinning, the unit is guaranteed recovery of all costs including start-up, no-load and minimum energy costs. Any unrecovered portions of these costs are credited as part of the spinning settlement process described below.
- (3) Due to transmission considerations on the PJM system, it is sometimes necessary to carry a minimum amount of spinning reserve in specific areas in PJM such that loading 100% spinning reserve will not result in an overload of any of the PJM transfer interfaces. The goal is to minimize the cost of spinning reserve such that given current system conditions, the flow on binding transmission constraints is not increased after a spinning event is initiated and the associated response is achieved. Therefore, PJM clears the Tier 2 market based on this locational spinning requirement and calculates zonal Tier 2 clearing prices. Whenever the locational spinning constraint is not binding, the clearing prices are equal. However, when more spinning

reserve is required in a given area than would have been assigned without this requirement, the clearing prices will separate. Units will be identified and receive the applicable clearing price based on their location with respect to the binding constraint(s). That is, units for which spinning response would help the constraint will receive the higher clearing price, whereas units for which spinning response would aggravate the constraint will receive the lower clearing price.

- (4) The hourly Tier 2 clearing prices are posted on the eMarket user interface for public view.

Hydro Units

- (1) Hydro units condensing to provide spinning reserve during times when they were not scheduled to generate incur no opportunity cost. There may or may not be an energy use component, as indicated by the owner as part of the spinning offer.
- (2) If a hydro unit is held off line to provide spinning during a time when it was scheduled to generate, it will incur opportunity cost. Since hydro units operate on a schedule and do not have an energy bid, opportunity cost for these units is calculated as follows:
 - The formula is the same as that shown under ‘Spinning Market Clearing’, in rule #1d, third bullet, except the ED value is the average value of the LMP at the hydro unit bus for the on-peak period, excluding those hours during which all available units at the hydro plant were operating. Day-ahead values are used for the purposes of assigning Tier 2 resources, and actual LMPs are used in the after-the-fact settlement. If the average LMP value is higher than the actual LMP at the generator bus, the opportunity cost is zero. During those hours when a hydro unit is in spill, the ED value is set to zero such that the opportunity cost is based on the full value of LMP.
 - When determined to be economically beneficial, PJM maintains the authority to adjust hydro unit schedules for those units scheduled by the owner if the owner has also submitted a spinning offer for those units and made the units available for spin.

Spinning Market Operations

- (1) The PJM Operator maintains the total Spinning Reserve Zone Capability equal to the Spinning Reserve Zone spinning requirement.
- (2) The PJM Operator evaluates the set of units providing spinning on an hourly basis, and assigns the most cost-effective set of Tier 2 resources necessary to fulfill the requirement.
- (3) The hourly Tier 2 clearing price is fixed once calculated and posted. Any opportunity cost or energy use that exceeds the clearing price is credited after-the-fact on a unit-specific basis.
- (4) The PJM Operator communicates Tier 2 condenser assignments to individual Local Control Centers via telephone.

Settlements

- (1) Spinning settlement is a zero-sum calculation based on the spinning provided to the market by generation owners and purchased from the market by participants.
- (2) Spinning obligation is determined hourly for each participant by applying the real time load ratio share (adjusted for scheduled load responsibility) to the total spinning assigned in the Spinning Reserve Zone for that hour (considering locational constraints as noted above), and then adding bilateral sales and subtracting bilateral purchases. Spinning charges are then determined for both the amount of Tier 1 applied to each participant's obligation and the amount of Tier 2 each participant purchased from the market.
- (3) Tier 1 charges for each participant are equal to the percentage share of the overall Tier 1 credits according to the amount of Tier 1 applied to their obligation. The amount of Tier 1 applied to each participant's obligation is equal to the amount of Tier 1 estimated prior to the operating hour as part of the market clearing process on that participant's own resources up to the amount of obligation, plus the remaining load ratio share of any excess Tier 1 estimated on the units of generation owners in excess of their individual obligations. Note that Tier 1 charges will only exist if a spinning event occurs within a given hour.
- (4) Tier 2 spinning charges for each participant are equal to:

- The appropriate hourly Tier 2 clearing price times the MW of Tier 2 self-scheduled toward the participant's obligation plus that which is purchased from the market plus;
- The participant's share of any un-recovered costs incurred by assigned Tier 2 resources over and above the Tier 2 clearing price plus;
- The participant's share of any un-recovered costs incurred by those units PJM committed for the sole purpose of providing spinning reserve plus;
- The participant's share of the costs of those Tier 2 resources assigned in addition to that which was estimated prior to a given hour.

The appropriate hourly Tier 2 clearing price for each LSE is the clearing price for the sub-zone or Spinning Reserve Zone which the LSE's load is located. Loads located in a reserve zone will pay that sub-zone's SRMCP. Loads not located in a sub-zone will pay the corresponding area Spinning Reserve Zone SRMCP (i.e. Mid-Atlantic, Northern Illinois or Western).

The costs listed in items b), c) and d) above are allocated as follows:

Un-recovered costs incurred by Tier 2 resources assigned by PJM either during the Tier 2 clearing process or during the operating hour due to conditions other than a reduction in available Tier 1 Spinning Reserve are allocated based on each participant's pro-rata share of Tier 2 spinning purchased from the market.

The cost of Tier 2 resources assigned by PJM during the operating hour in addition to that which resulted from the Tier 2 clearing process due to reduced availability of Tier 1 Spinning Reserve are allocated to those entities for which less Tier 1 was available during the hour than was estimated prior to the hour, in proportion to the reduction in Tier 1 availability.

- (5) During hours when the Tier 2 clearing price is the same for an entire Spinning Reserve Zone, the Tier 2 each participant purchases from the market is defined as that participant's obligation less the Tier 1 applied, less Tier 2 self-scheduled, plus bilateral sales, minus bilateral purchases. During hours when the Tier 2 clearing price varies across a Spinning Reserve Zone, the Tier 2 each participant purchases from the market is defined as that participant's load ratio share of the spinning reserve required in the appropriate Spinning Reserve Zone or sub-zone less the Tier 1 applied, less Tier 2 self-scheduled, plus bilateral sales, minus bilateral purchases.
- (6) Tier 1 spinning credits are awarded to all generation owners whose resources increased output in response to a spinning event (with the exception of those resources that were assigned Tier 2 spinning.) These

credits are equal to the integrated increase in MW output from each generator over the length of the event, times the spinning energy premium less the hourly integrated LMP. The amount of the increase in output is defined as stated in the Verification section below. The spinning energy premium is defined as the average of the 5-minute LMPs calculated during the spinning event plus \$50/MWh. In cases where a spinning event spans two or more hours, the response from each unit will be integrated according to the length of response in each hour for the purpose of calculating the Tier 1 credit.

- (7) Tier 1 credits will be awarded to each eligible unit for response up to 110% of the unit’s capability based on the spinning ramp rate(s) submitted by the unit’s owner day-ahead. Credits to individual units may be awarded for response greater than 110% of stated capability if other Tier 1 resources under-respond. Credits for response in excess of 110% of capability will be awarded on a pro-rata basis such that the aggregate Tier 1 credits awarded do not exceed 110% of the total possible credits based on the aggregate capability of all eligible Tier 1 units.
- (8) Units providing regulation at the initiation of a spinning event will be compensated for Tier 1 response according to the following formula:

$$(T1P - LMP) \times \left\{ \left[\max(0, \text{integrated}(\text{Output} - \min(\text{EcoMax}, \text{RegHighLimit}))) \right] + \left[\max\left(0, \left(\text{integrated} \left\{ \min(\text{EcoMax}, \text{RegHighLimit}, \text{Output}) - \right. \right. \right. \right. \right. \right. \left. \left. \left. \left. \text{Initial Output} - (2 \times \text{RegMW}) \right. \right. \right. \right. \right. \right. \left. \right. \right. \left. \right. \left. \right. \right\}, \text{ where :}$$

- T1P is the Tier 1 spinning energy premium (average of the five-minute LMPs during the spinning event plus \$50)
- LMP is the hourly integrated LMP for the hour in which the spinning event occurs
- Final Output is the unit’s greatest telemetered output between 9 and 11 minutes after spinning event is initiated
- Initial Output is the unit’s lowest telemetered output between 1 minute before and 1 minute after spinning event is initiated
- RegMW is the unit’s assigned amount of regulation

As a result of this formula, units that are assigned regulation when a spinning event is initiated will be compensated based on the amount of response provided beyond their regulation commitment, as well as for any response in excess of their regulation high limit or economic maximum (whichever is lower.) A unit’s regulation maximum

commitment will be defined as the unit's full regulating range (i.e. - twice the amount of assigned regulation.)

- (9) Tier 2 spinning credits are awarded to generation owners that have either self-scheduled spinning or sold spinning into the market. Spinning credits for units self-scheduled to provide spinning are equal to Tier 2 clearing price times the unit's self-scheduled spinning capability. Spinning credits for units that offered spinning into the market and were selected to provide spinning are the higher of:
 - Tier 2 clearing price times the unit's assigned spinning capability, or
 - The unit's spinning offer times its assigned spinning capability plus opportunity cost and/or energy use incurred.
- (10) Opportunity cost and energy use are calculated as shown above in Market Clearing using actual integrated LMP as opposed to that which was forecasted.
- (11) Units that are pool-assigned Tier 2 spinning reserve are therefore exempt from deviations for the purpose of accumulating operating reserves charges, for the MW reduction associated with the Tier 2 assignment, for the hours during which the Tier 2 assignment is effective.

Verification

- (1) The magnitude of each unit's response to a spinning event (both Tier 1 and Tier 2) is the difference between the unit's output at the start of the event and its output ten minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, unit output at the start of the event is defined as the lowest telemetered output between one (1) minute prior to and one (1) minute following the start of the event. Similarly, a unit's output ten minutes after the event is defined as the greatest output achieved between nine (9) and eleven (11) minutes after the start of the event. All units (both Tier 1 and Tier 2) must maintain an output level greater than or equal to that which was achieved as of ten minutes after the event for the duration of the event or thirty (30) minutes from the start of the event, whichever is shorter. The response actually credited to a given unit will be reduced by the amount the MW output of that unit falls below the level achieved after ten (10) minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

Non-Performance

- (1) There is no consequence for a Tier 1 resource that does not respond with the amount of spinning reserve that was expected of it in response to a spinning event. Tier 1 resources are simply credited for the amount of response they provide.
- (2) Since Tier 2 resources are credited with a capacity payment any time they are expected to be ready to respond to a spinning event, failure to provide that response results in an obligation to “repay” that credit following instances of non-performance. The following consequences exist for a Tier 2 resource that does not respond with its assigned amount of spinning:
 - The unit is credited for Tier 2 spinning capacity in the amount that actually responded for the contiguous hours the unit was assigned Tier 2 spinning during which the event occurred, and;
 - The owner of the unit incurs a spinning obligation in the amount of the shortfall for the three (3), consecutive, same-peak days occurring at least three (3) business days following the event. Off-peak days are defined as weekends and PJM holidays, and on-peak days are all others. Owners of assigned Tier 2 units will be permitted to demonstrate aggregate response, such that the total response from all assigned units must be greater than or equal to the total assigned amount of spinning reserve. This aggregate response will be used when determining the owner’s additional obligation.
- (3) In cases where a spinning event lasts less than 10 minutes, Tier 2 resources are credited with the amount of spinning capacity they are assigned. Tier 1 resources are credited with the amount of response provided over the length of the event, as determined via measurement parallel to that which is described above in the Verification section. That is, the output of each unit at the start of the event is defined as the lowest telemetered output between one (1) minute prior to the start of the event and one (1) minute after the start of the event, and the output at the end of the event is defined as the greatest telemetered output between one (1) minute prior to the end of the event and one (1) minute following the end of the event.

Section 5: Scheduling Philosophy and Tools

Welcome to the *Scheduling Philosophy & Tools* section of the PJM Manual for **Scheduling Operations**. In this section you will find the following information:

- A description of the PJM scheduling philosophy (see “*PJM Philosophy*”).
- A description of the tools that are used during the scheduling process (see “*Scheduling Tools*”).

PJM Philosophy

The PJM scheduling philosophy in the Day-ahead Energy Market is to schedule generation to meet the aggregate Demand bids that results in the least-priced generation mix, while maintaining the reliability of the PJM RTO. PJM will also schedule additional generation as needed to satisfy the PJM Load Forecast and the additional Operating Reserve Objective based on minimizing the cost to procure such reserves. PJM will also schedule resources based on economics to control potential transmission limitations that are binding in the Transmission Reliability analysis that is performed in parallel with and subsequent to the Day-ahead Market analysis. The scheduling process evaluates the price of each available generating unit compared with every other available generating unit. The philosophy for scheduling the PJM RTO requires:

- Scheduling sufficient generation in the Day-ahead Energy Market to cover aggregate Demand bids and Operating Reserve requirements calculated as a function of such demand bids
- Scheduling sufficient generation in the reliability-based analysis subsequent to the Day-ahead Energy Market to cover the PJM Load Forecast and additional Operating Reserve requirements
- Scheduling sufficient generation to control potential transmission limitations that are binding in the Transmission Reliability analysis
- Scheduling sufficient generation to satisfy the PJM Regulation Requirement, PJM Spinning Reserve Requirement, and other ancillary service requirements of the PJM RTO.
- Ensuring PJM Members participate in the analysis and elimination of conditions that threaten the reliable operation of the PJM RTO

Scheduling of generation resources by PJM is performed economically on the basis of the prices and operating characteristics offered by the Market Sellers, using

security, constrained dispatch and continuing until sufficient generation is dispatched in each hour to serve all energy purchase requirements, as well as the PJM RTO requirements.

Scheduling Tools

Analytical scheduling tools exist to assist PJM with the scheduling process. These tools permit PJM scheduling staff to analyze numerous scheduling scenarios. PJM personnel use several tools to assist in scheduling the generation resources for short-term and hourly activities. The scheduling tools include:

- ☞ PJM Enhanced Energy Scheduler (EES)
- ☞ PJM eSchedules
- ☞ Load Forecasting Algorithms
- ☞ Market Database System
- ☞ Unit Dispatch System (UDS)
- ☞ Hydro Calculator
- ☞ Two Settlement Technical Software (RSC, SPD and STNET)
- ☞ PJM Spinning Reserve and Regulation Scheduling Software (SPREGO)
- ☞ Transmission Outage Data System

Together these tools recognize the following conditions:

- ☞ Reactive limits
- ☞ Unit constraints
- ☞ Unscheduled power flows
- ☞ Inter-area transfer limits
- ☞ Unit distribution factors
- ☞ Self-Scheduled Resources
- ☞ Limited fuel resources

- ☞ Bilateral Transactions
- ☞ Hydrological constraints
- ☞ Generation requirements
- ☞ Reserve requirements

Enhanced Energy Scheduler (EES)

The EES program records and manages the interchange of bulk power between the PJM RTO and other utilities, marketers, and brokers. PJM personnel use EES to process daily non-firm (both those electing to curtail due to congestion and those electing to pay congestion charges) and firm Bilateral Transaction schedules that are submitted by PJM Members. In general, EES is used to perform the following activities:

- ☞ Processes PJM Members' Bilateral Transactions
- ☞ Validates transaction by verifying transaction rules

PJM eSchedules

PJM eSchedules is an internet application that is used, among other functions, to schedule internal Bilateral Transactions.

Load Forecasting

PJM scheduling staff requires load forecasts for up to ten days in the future. For each day, a 24-hour load shape is needed.

- (1) The first step in developing a load forecast is to obtain the weather information for the time period. Weather information is provided to PJM at regular intervals by a contracted-for weather service. Additional weather data sources include the National Weather Service, radio news, LSE weather information, and existing local PJM RTO conditions.
- (2) The forecast period is reviewed to determine any conditions that could affect the PJM RTO's load, including:
 - ☞ Day of week
 - ☞ Holidays
 - ☞ Special events

- ☞ Daylight savings time changes
 - ☞ Internal participant load forecasts
- (3) Peak loads and load shapes are determined using a similar day's forecast. PJM retrieves the load data from a historical file and adjusts the forecasts, as needed, to reflect growth or other discrepancies.

Exhibit 3 presents the typical approach PJM uses to forecast load.

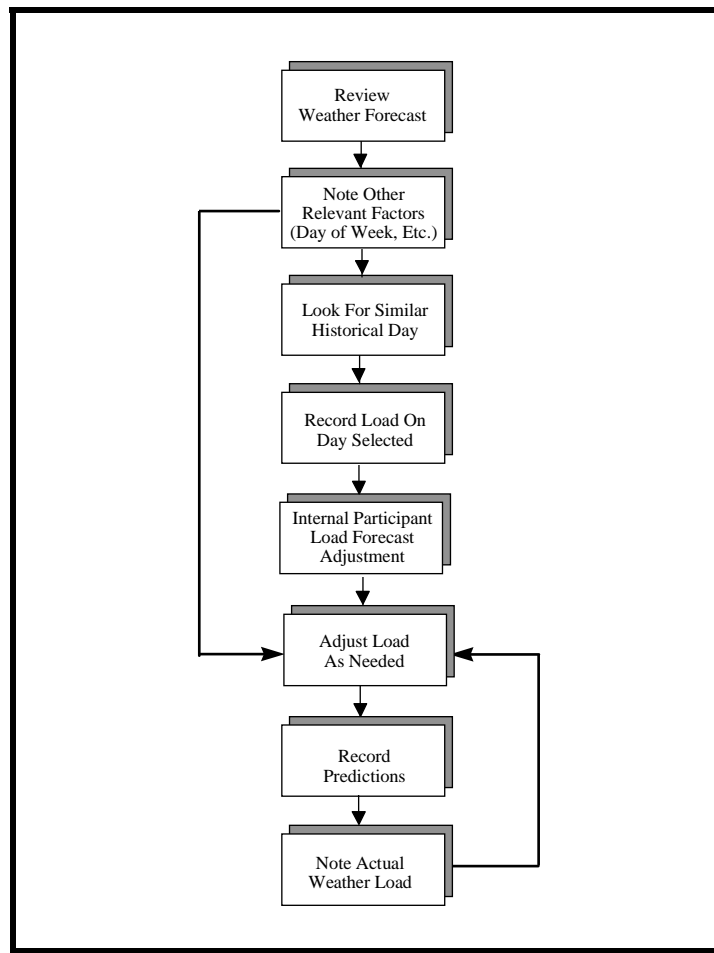


Exhibit 3: Load Forecasting Process

The load forecasts for each 24-hour period are input in the Marginal Scheduler program. PJM scheduling staff also posts these forecasts on the OASIS. (See Section 6: Posting OASIS Information for more information.)

Markets Database System

The Markets Database System is a two-part system:

- The Markets Database stores the basic unit data supplied by the PJM Members, including operating limits and unit availability.
- The eMKT website that provides the internet-based user interface that allows Market Participants to submit generation offer data, Demand bids, Increment Offers, Decrement bids and Regulation Offers into the Markets Database.

The Markets Database is a very large database that contains information on each generating unit that operates as part of the PJM Energy Market, Demand Information, Increment Offers, Decrement Bids, Regulation Offers, Spinning Reserve Offers, Day-ahead Energy Market results, Regulation Market Clearing Prices and Spinning Reserve Market Clearing Prices. A description of the Markets Database can be found in the [Markets Database Dictionary](http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf) (<http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf>).

Market participants may access the Markets Database by using the PJM eMKT website via the internet using manual entry or bulk upload/download via XML format.

The deadline for submission of Generation Offers, Demand Bids, Increment Offers and Decrement Bids into the Day-ahead Energy Market is 12:00 Noon of the day before the Operating Day. After this deadline, no further bids or offers are accepted for the Day-ahead Market and the Markets Database is locked until the Generation Re-bidding Period commences at 4:00 PM. The deadline is only extended when there is a computer problem at the PJM. The Generation Re-bidding Period allows generation that was not selected in the Day-ahead Market to submit revised offer data for the Real-time Market. The Generation Re-bidding Period for the next Operating Day is open from 4:00 PM to 6:00 PM each day. Participants wishing to sell Regulation or Spinning Reserve may supply an offer price by 6:00 PM the day prior to the operating day.

Please refer to Exhibit 4: Spinning Reserve and Regulation Market Daily Timeline.

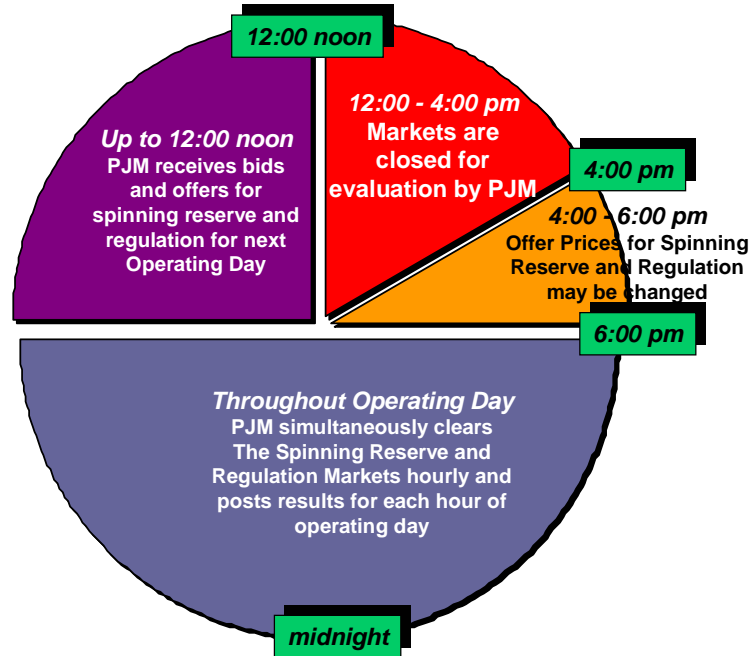


Exhibit 4: Spinning Reserve and Regulation Market Daily Timeline

Please refer to Exhibit 5: Spinning Reserve and Regulation Market Hourly Timeline.

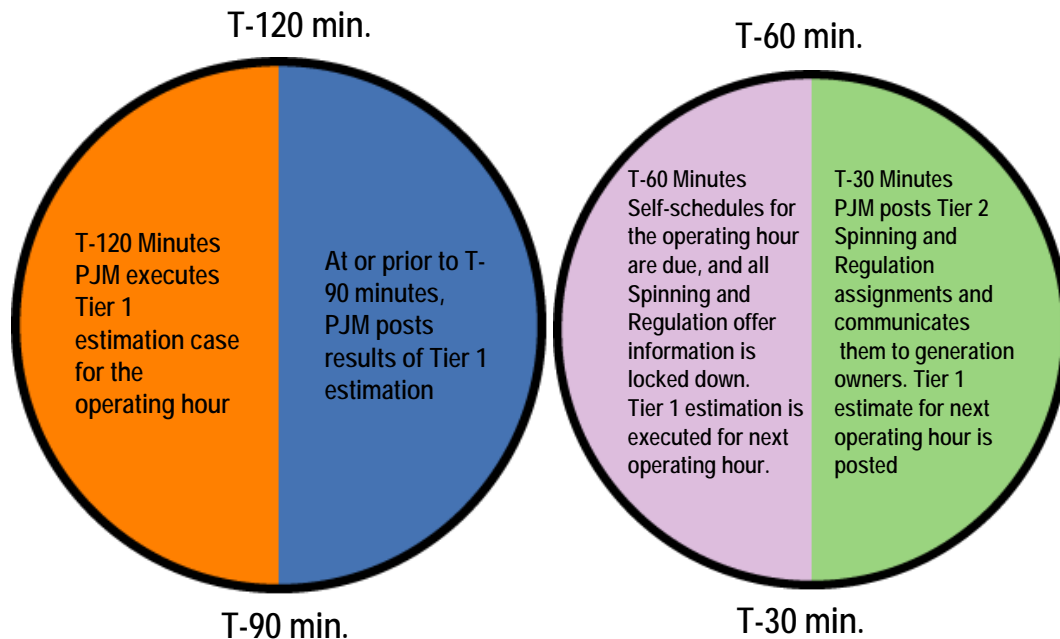


Exhibit 5: Spinning Reserve and Regulation Market Hourly Timeline

The data that needs to be submitted by PJM Members to participate in the Day-ahead Energy, Spinning Reserve, and Regulation Markets is described in detail in the [Markets Database Dictionary](http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf) (<http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf>.)

Hydro Calculator

For PJM RTO-Scheduled Resources, PJM is responsible for developing the schedules for the run-of-river and pumped storage plants located within the PJM RTO and turned over to PJM for coordination. To assure hydraulic coordination of the hydro plants, PJM uses a computer program called the Hydro Calculator. The Hydro Calculator computes hourly reservoir elevations and plant generation from input river flows and plant discharges. PJM scheduling staff uses the Hydro Calculator to concentrate on economic placement of available hydro energy.

Two-Settlement Technical Software

The PJM Two-settlement Technical Software is a set of computer programs, which performs a security-constrained unit commitment, an economic dispatch for the Day-ahead Market. The individual programs are:

Resource Scheduling & Commitment (RSC) - Performs security-constrained *unit commitment* based on generation offers, demand bids, Increment Offers, Decrement bids and transaction schedules submitted by participants and based on PJM RTO reliability requirements. RSC will enforce physical unit specific constraints that are specified in the generation offer data and generic transmission constraints that are entered by the Market Operator. RSC provides an optimized economic unit commitment schedule for the next seven days and it utilizes a linear programming solver to create an initial unit dispatch for the next operating day.

Scheduling, Pricing, & Dispatch (SPD) - Performs security-constrained *economic dispatch* using the commitment profile produced by RSC. SPD calculates hourly unit generation MW levels and LMPs for all load and generation buses for each hour of the next operating day. SPD utilizes a linear programming solver to develop the economic dispatch solution while respecting generic transmission constraints that affect dispatch, such as reactive interface limits, and thermal limits.

Study Network Analysis (STNET) - Creates a powerflow model for each hour of operating day based on the scheduled network topology, the generation and demand MW profile produced by SPD and the scheduled PJM Net Tie Flow with adjacent control zones. STNET performs AC contingency analysis using contingency list from PJM EMS and creates generic constraints based on any violations that are detected. These generic constraints are then passed them back to RSC and/or SPD for resolution STNET ensures that the Day-ahead Market results are physically feasible considering PJM RTO security constraints and reliability requirements.

Two Settlement Subsystems

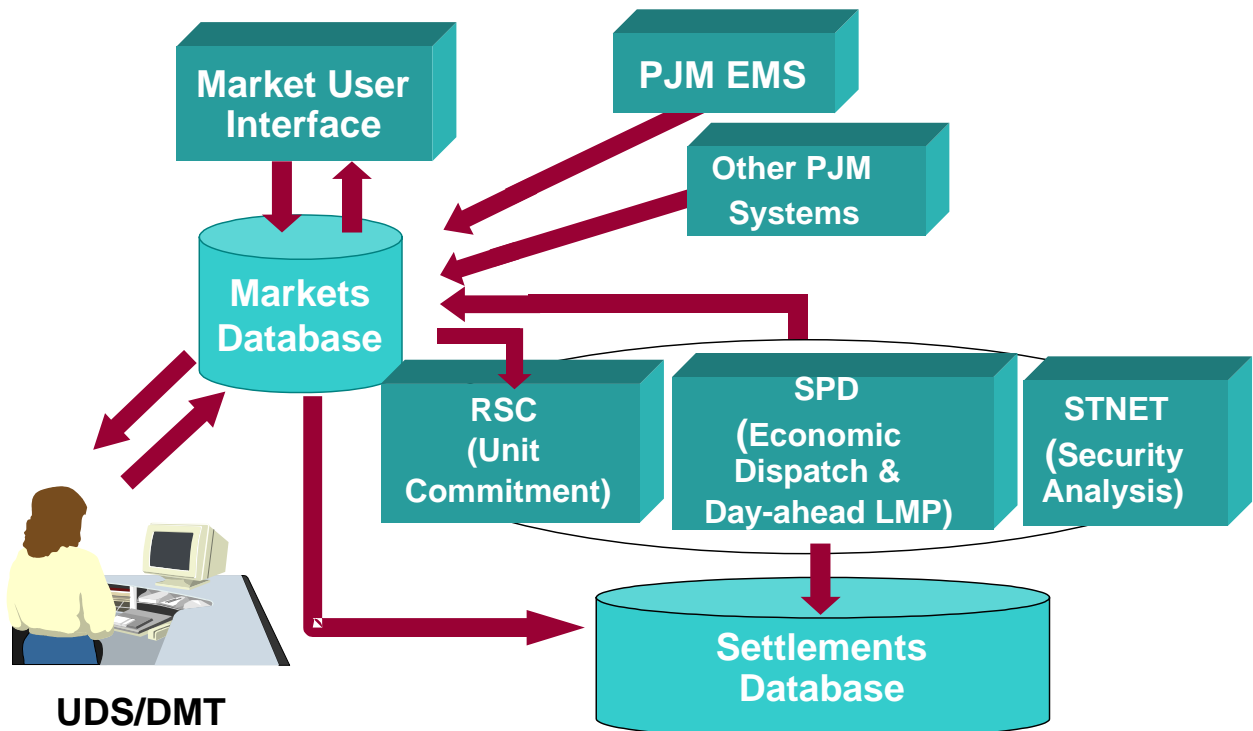


Exhibit 6: Settlement Subsystems

The Two-settlement technical software develops the Day-ahead Market results based on minimizing production cost to meet the Demand bids and Decrement bids that are submitted into the Day-ahead Market while respecting the PJM RTO security constraints and reliability requirements that are necessary for the reliable operation of the PJM RTO.

Subsequent to the close of the generation Re-bidding Period at 6:00 PM, the RSC is the primary tool used to determine any change in steam unit commitment status based on minimizing the additional startup costs and costs to operate steam units at economic minimum in order to provide sufficient operating reserves to satisfy the PJM Load Forecast (if greater than cleared total demand in the Day-ahead Market) and adjusted operating reserve requirements. The purpose of this second phase of unit commitment is to ensure that PJM has scheduled enough generation in advance to meet the PJM Load Forecast for the next operating day and for the subsequent 6 days. CTs units are included in the scheduling process and are scheduled in the

Day-ahead Market. However, the decisions concerning actual operation of pool-scheduled CT units during the operating day are not made until the current operating hour in real-time dispatch.

Download Data from Markets Database

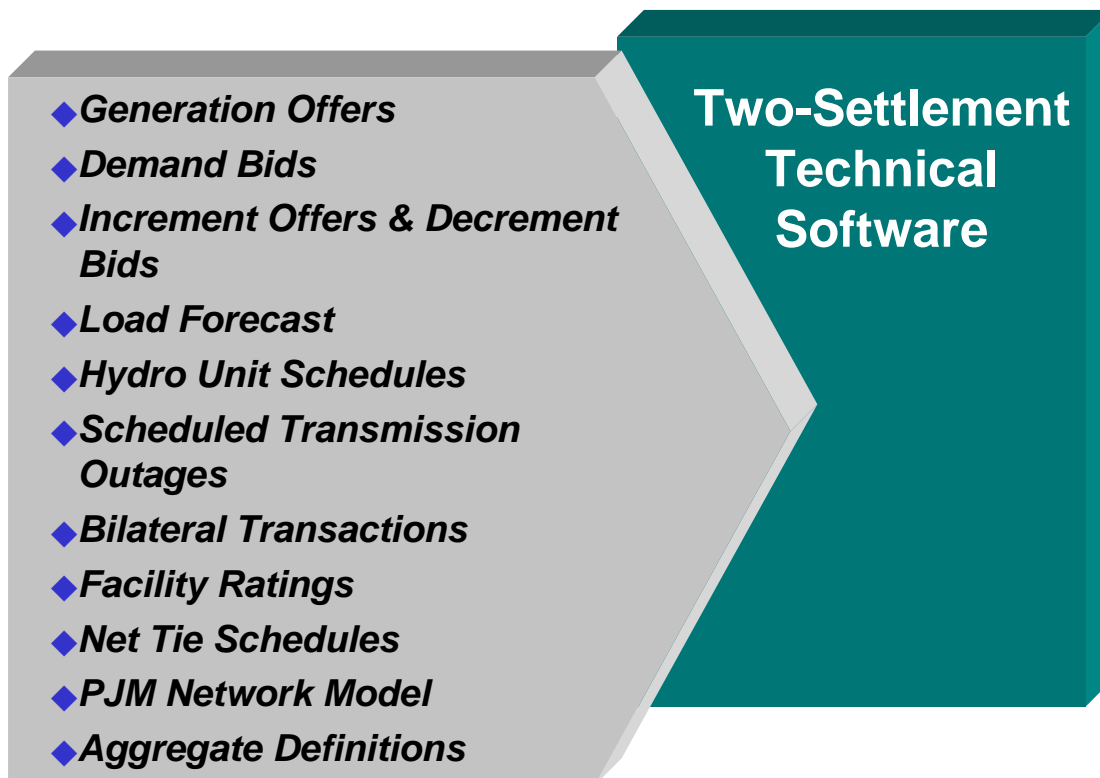


Exhibit 7: Download Data from Markets Database

Two-Settlement Data Flow

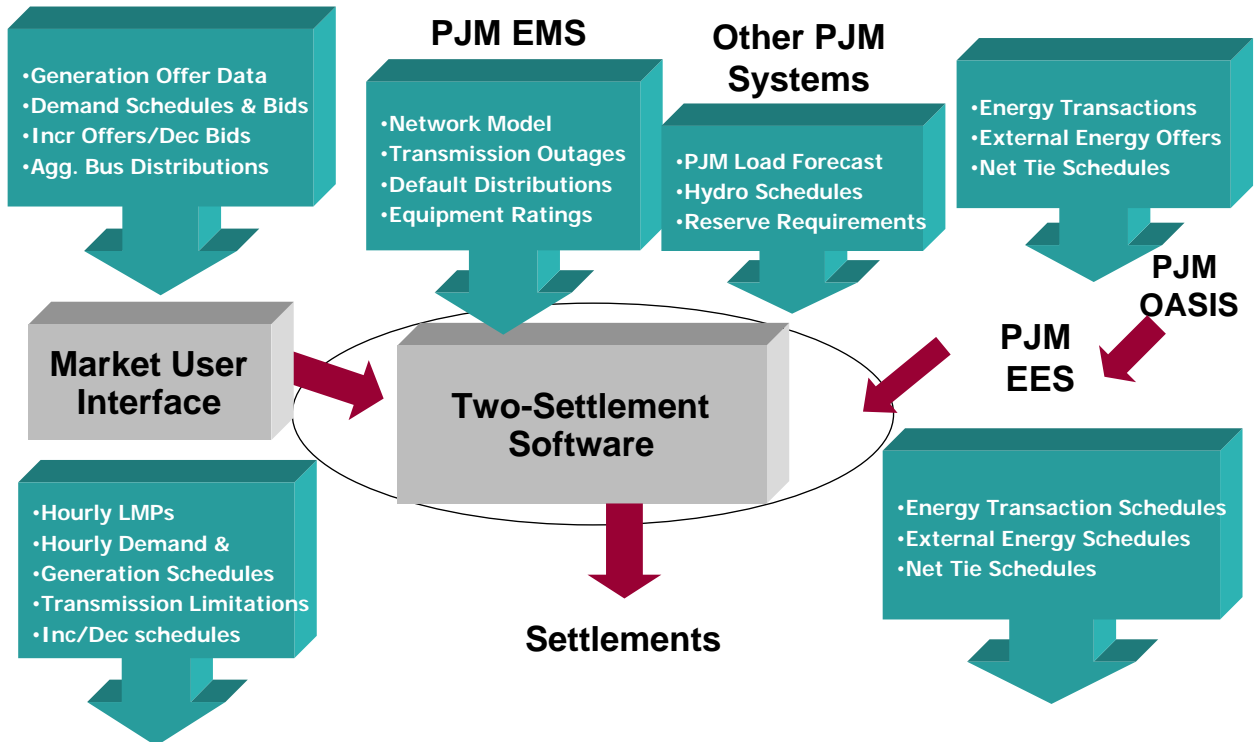
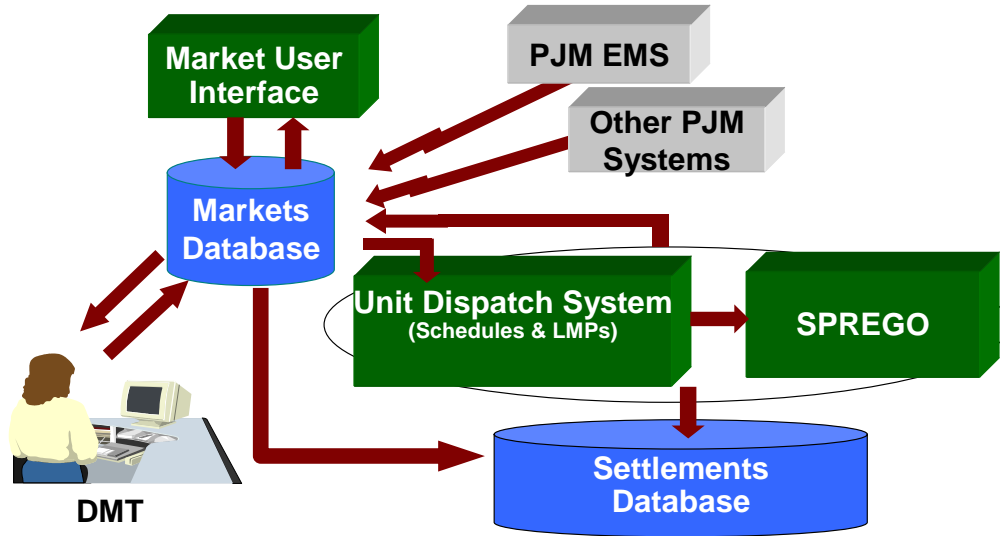


Exhibit 8: Two-Settlement Data Flow

Spinning Reserve and Regulation Scheduling Software (SPREGO)

The SPREGO is the spinning reserve and regulation market software. It uses the regulation offers, spinning reserve offers, and commitment data to determine the regulation market clearing price (RMCP) and spinning reserve market clearing price (SRMCP). It also determines a preliminary forecast of which units will provide regulation and spinning reserve. SPREGO performs regulation and spinning reserve market dispatch to minimize the total cost of energy, regulation and spinning reserve dispatch.

Spinning Reserve & Regulation Subsystems



DMT = Dispatcher Management Tool

SPREGO = Spinning & Regulation Regulation Optimizer

Exhibit 9: Spinning Reserve and Regulation Subsystems

Section 6: Scheduling Strategy and Method

Welcome to the *Scheduling Strategy and Method* section of the PJM Manual for **Scheduling Operations**. In this section you will find the following information:

- A description of the requirement/supply relationship (see “*Forecasting PJM Generation Requirement*”).
- How PJM regulation requirements are determined (see “*PJM Regulation Requirements*”).
- How PJM spinning reserve requirements are determined (see “*PJM Spinning Reserve Requirements*”).
- How the marketing information is processed (see “*Processing Market Information*”).

Scheduling bridges the gap between advance outage and market information (pre-scheduling) and real-time power system operations (dispatching). The goal of the PJM is to develop schedules that preserve the security of the PJM RTO on an unbiased basis for all PJM Members. The scheduling process for each day consists of the Day-ahead Energy Market and of the development Current Operating Plan (COP) based on reliability analysis that is performed in parallel with and subsequent to the Day-ahead Energy Market clearing.

Forecasting PJM Generation Requirement

The first step in the scheduling process is to examine the relationship between Day-ahead Demand Bids and Decrement Bids with and Generation Offers and Increment Offer and to clear the Day-ahead Market based on these bids and offers. In the reliability analysis that follows the Day-ahead Market, the relationship between PJM Load Forecast requirement and generation supply for the Real-time Energy Market is considered. Exhibit 10 illustrates the Real-time Market relationships in the form of a bar chart.

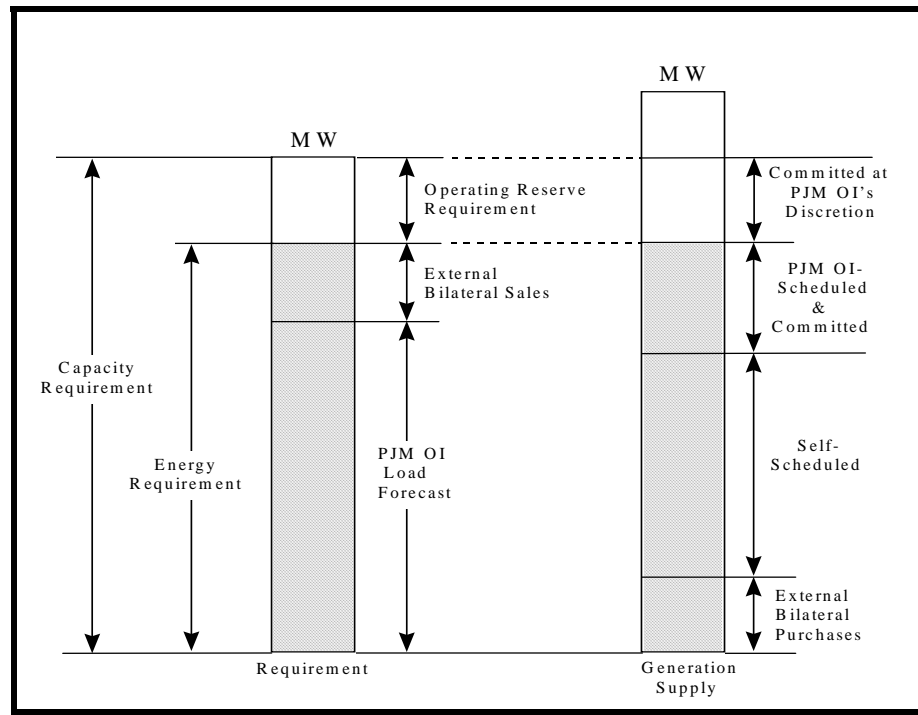


Exhibit 10: Requirement Versus Generation Supply

Exhibit 10 presents the following information:

- The PJM requirement is represented by the bar on the left. The height of this bar is the total PJM capacity requirement in MW. The capacity requirement consists of two components:
 - 1) Energy requirement, consisting of the PJM load forecast plus External Transaction sales to External Control Areas
 - 2) Operating reserve requirement for the PJM RTO
- The PJM generation supply is represented by the bar on the right which consists of four supply components:
 - 1) External Transaction purchases from External Control Areas
 - 2) Generation that is self-scheduled by the PJM Members
 - 3) Generation and capacity that has been bid into the Day-ahead Market and the Real-time Market and is scheduled by PJM to meet the energy and reserve requirement
 - 4) Additional capacity to satisfy the Operating Reserve requirement is committed at the discretion of the PJM

The identity of the generation resources that are self-scheduled or PJM RTO-scheduled is given by the market information contained in the Markets Database as shown in the [Markets Database Dictionary](http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf) (<http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf>).

The PJM RTO's load forecast is described in Section 2 of this PJM Manual. The amount of External Transactions as scheduled by the PJM Members is also considered when establishing the amount of generation that must be scheduled.

So far, we have only discussed the basic requirement/supply relationships. The details of how we actually match the generation resources with the corresponding loads for both the Day-ahead Energy Market and the Real-time Energy Market are discussed in later subsections.

PJM Regulation Requirements

The Regulation Requirement for the PJM RTO is defined as follows:

- (1) Total PJM Regulation Requirement:
 - PJM -specified percentage of the PJM Valley Load Forecast (currently 1.1%). This requirement is in effect during the Off-Peak Period (0000-0459 hours).
 - PJM -specified percentage of the PJM Peak Load Forecast (currently 1.1%). This requirement is in effect during the On-Peak Period (0500-2359 hours).
- (2) PJM West Regulation Requirement:
 - The PJM West Regulation Requirement is determined in whole MW, and for each hour of the operating day is equal to 1% of the forecast peak load for the PJM West area for that day.

PJM Actions:

The PJM actions that are performed to clear the Regulation Market by establishing the initial list of resources to provide regulation for the next On/Off-Peak Period and by calculating the Regulation Marginal Clearing Prices (RMCP) are as follows:

- (1) PJM clears the Regulation Market simultaneously with the Spinning Reserve Market, and posts the results no later than 30 minutes prior to the start of the operating hour.
- (2) The PJM Operator maintains total PJM regulating capability within a 30MW bandwidth around the Regulation Requirement.

- (3) The PJM Operator periodically evaluates the set of units providing regulation, and makes any adjustments to regulation assignments deemed necessary and appropriate to minimize the overall cost of regulation
- (4) In the event of a regulation excess, the PJM ISO dispatcher deselects units beginning with the highest cost unit currently providing regulation and moving downward.
- (5) In the event of a regulation deficiency, the PJM ISO dispatcher selects units to provide regulation beginning with the lowest cost unit currently not providing regulation and moving upward.
- (6) The RMCP does not change based upon regulating unit adjustments made in real time. Any opportunity costs that exceed the RMCP are credited after the fact on a unit-specific basis.
- (7) The PJM Energy Management System (EMS) sends one Area Regulation signal to each Local Control Center (LCC), as well as signals to individual units or plants as requested by the owner.
- (8) The PJM Operator communicates any change in unit regulating assignments to individual Local Control Centers. Company total in-service regulating capabilities are then telemetered back to the PJM EMS via the PJM data link.
- (9) Unit regulation assignment changes during transitions between on-peak and off-peak periods begin 30 minutes prior to the new period, and are completed no later than 30 minutes after the period begins.

Hourly participant Regulation obligations are determined after-the-fact, based on the LSE's actual load ratios. Participants can estimate their share of the PJM Regulation Requirement in advance by comparing their hourly load forecast to the PJM hourly load forecasts provided by the PJM.

PJM Member Actions:

- (1) PJM Members submit Individual Spinning Reserve and Regulation offer data for each Resource that is available to provide spinning reserve and/or regulation (for generation meeting the Regulation quality standard and Spinning Reserve quality standard), differentiated as self-scheduled, External Transaction sale/purchase (identifying seller and buyer) and available for PJM RTO-scheduling. This information is maintained within the PJM eMKT website and is passed to the PJM Spinning Reserve and Regulation Software (SPREGO). Exhibit 11 summarizes this information.

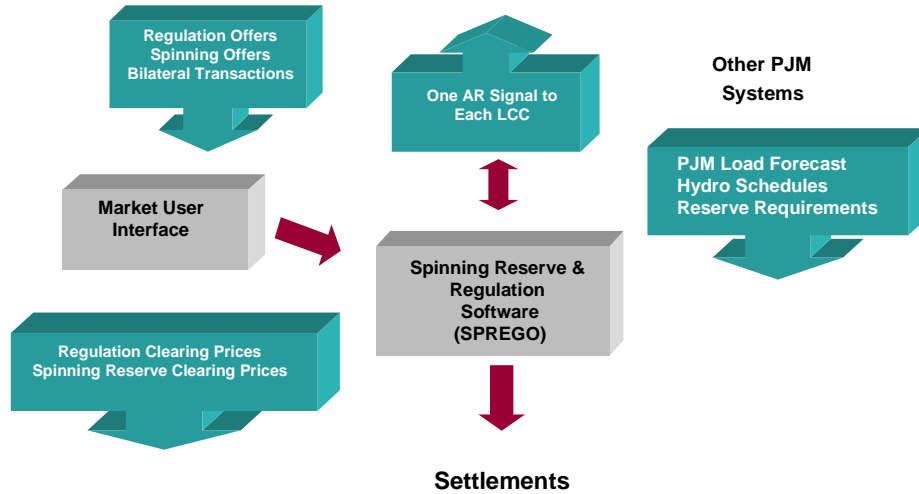


Exhibit 11: Spinning & Regulation Data Flow

PJM Members update regulating unit operating limits and availability in the PJM eMKT website.

Regulation Service

PJM operates a bidding market for Regulation services in the PJM RTO. PJM Members that have generation meeting the Regulation quality standard may submit Regulation offer data for each individual Resource that is available to provide regulation. The offer information is maintained within the PJM eMKT website and is passed to the Spinning Reserve and Regulation software (SPREGO). Generation owners wishing to sell regulation service must supply a regulation offer price by 6:00 PM the day prior to operation and is applicable for the entire 24-hour period for which it is submitted. The remainder of the necessary data may be submitted or changed up until sixty (60) minutes prior to the operating hour, at which time the Regulation market closes.

Exhibit 12 defines the Regulation parameters of a qualified generating resource.

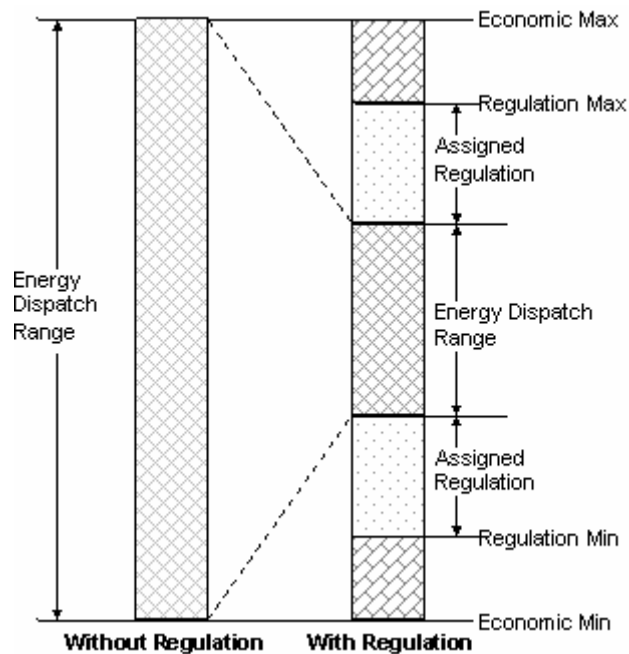


Exhibit 12: Generator Regulation Service

The PJM RTO's total available Regulation service is calculated and compared with its requirements. Any significant shortage is reported to PJM dispatcher for possible action. See the PJM Manual for [Dispatching Operations \(M-12\)](#) for a description of the Regulation allocation process during the course of system operation.

PJM Spinning Reserve Requirements

The Spinning Reserve Requirement for the PJM RTO is defined follows:

- a. Total PJM Spinning Requirement is determined in whole MW for each hour of the operating day.

The PJM Spinning Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. Mid-Atlantic Area Council (MAAC) standards currently set that amount at 75% of the largest contingency on the PJM system provided that double the remaining 25% is available as non-synchronized 10-minute reserves.

North American Electric Reliability Council (NERC) standards may impose greater requirements for spinning reserve following Disturbance Control Standard (DCS) violations. Any such impositions will be incorporated as an increase to the overall control zone spinning requirement.

PJM Actions:

The PJM actions that are performed to clear the Spinning Reserve Market by establishing the initial list of resources to provide Spinning Reserve for the next operating day and by calculating the Spinning Reserve Marginal Clearing Prices (SRMCP) for each hour as follows:

- (1) PJM clears the Spinning Reserve Market simultaneously with the Regulation Market, and posts the results no later than 30 minutes prior to the start of the operating hour
- (2) The PJM Operator maintains total PJM spinning capability equal to the control zone spinning requirement.
- (3) The PJM Operator evaluates the set of units providing spinning on an hourly basis, and assigns the most cost-effective set of Tier 2 resources necessary to fulfill the requirement.
- (4) The hourly Tier 2 clearing price is fixed once calculated and posted. Any opportunity cost or energy use that exceeds the clearing price is credited after-the-fact on a unit-specific basis.
- (5) The PJM Operator communicates Tier 2 condenser assignments to individual Local Control Centers via telephone.

Hourly participant Spinning Reserve obligations are determined after-the-fact, based on the LSE's actual load ratios. Participants can estimate their share of the PJM Spinning Reserve Requirement in advance by comparing their hourly load forecast to the PJM hourly load forecasts provided by the PJM.

PJM Member Actions:

- (1) PJM Members submit Individual Spinning Reserve and Regulation offer data for each Resource that is available to provide spinning Reserve and/or regulation (for generation meeting the Regulation quality standard and Spinning Reserve quality standard) , differentiated as self-scheduled, External Transaction sale/purchase (identifying seller and buyer) and available for PJM RTO-scheduling. This information is maintained within the PJM eMKT website and is passed to the PJM Spinning Reserve & Regulation Software (SPREGO). Exhibit 11 summarizes this information.

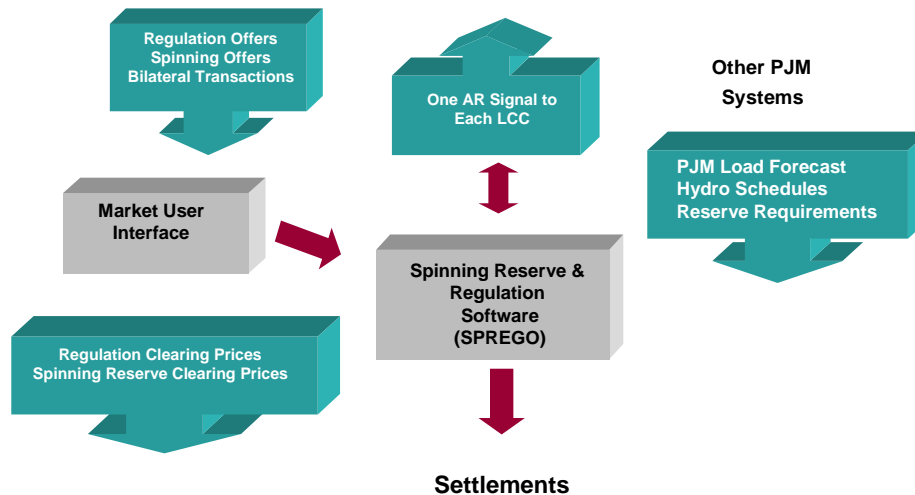


Exhibit 13: Spinning & Regulation Data Flow

PJM Members update regulating unit operating limits and availability in the PJM eMKT website.

Spinning Reserve Service

PJM operates a bidding market for Spinning Reserve services in the PJM RTO. PJM Members that have generation meeting the Spinning Reserve quality standard may submit Spinning Reserve offer data for each individual Resource that is available to provide spinning reserve. The offer information is maintained within the PJM eMKT website and is passed to the Spinning Reserve and Regulation Market software (SPREGO). Generation owners wishing to sell regulation service must supply a regulation offer price by 6:00 pm the day prior to operation and is applicable for the entire 24-hour period for which it is submitted. The remainder of the necessary data may be submitted or changed up until sixty (60) minutes prior to the operating hour, at which time the Regulation market closes.

Processing Market Information

Our attention now focuses on the elements that make up the requirement and supply picture in both the Day-ahead Energy Market and in the Real-time Energy Market. In the Day-ahead Energy Market, participants submit Demand bids, Decrement Bids, Increment Offers and Generation Offers into the Day-ahead Energy Market and PJM

clears the Market based on these bids and offers using least-cost security-constrained unit commitment and dispatch. For the PJM Real-time Energy Market, Exhibit 6.5 summarizes the PJM Members' interactions.

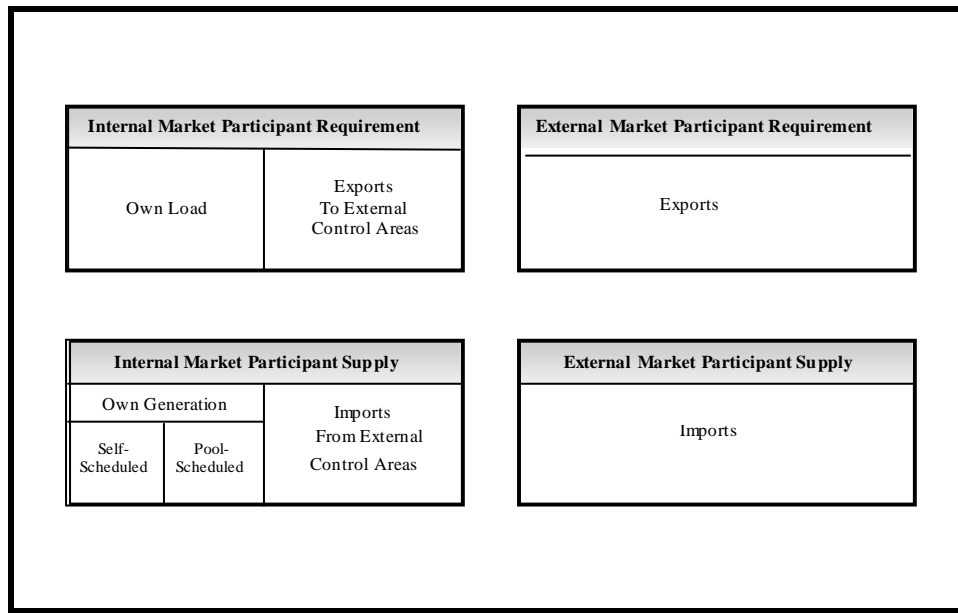


Exhibit 14: PJM Member Role In PJM Energy Market

PJM Member Load Forecasts

Each PJM Electric Distribution Company (EDC) within the PJM RTO provides PJM with a forecast of its requirements by 1200 hours on the day before the Operating Day. Regardless of how the PJM EDC's load is supplied, the PJM EDC submits the following Operating Day forecast information to the PJM:

- ☞ Midnight valley MW
- ☞ Morning peak MW
- ☞ Afternoon peak MW
- ☞ Evening peak MW

The hours for which the forecasts apply are specified and changed periodically by PJM and communicated to the PJM Members either electronically or by facsimile.

PJM compares the forecasts submitted by the PJM Members against the PJM RTO load forecast which is developed by PJM. The PJM Members' forecasts cover only four specified hours, while the PJM RTO forecast is for each hour of the Operating Day. Any significant discrepancies between the PJM Members' forecasts and the

corresponding PJM RTO forecasts are reported to PJM dispatcher. In general, the PJM RTO forecast takes precedence over the aggregate of the individual PJM Members' forecasts.

Reserve Service

The Operating Reserve objective is a PJM RTO requirement (not allocated to PJM Members individually). PJM schedules sufficient generating resources to meet the PJM Operating Reserve objective. See the PJM Manual for [Pre-Scheduling Operations \(M-10\)](#) for details.

Self-Scheduled Resources

PJM Members can choose to self-schedule their generation in the Day-ahead Market or to Offer into the Day-ahead Market and allow PJM to schedule their generation in the Day-ahead Market. Subsequent to the Day-ahead Market, any generator that was not selected in the Day-ahead Market may choose to self-schedule. Another option is to purchase generation from the market. The PJM Members' scheduling choice is dependent on their scheduling philosophy.

Exhibit 13 illustrates the relationship between self- and pool-scheduling for a particular resource.

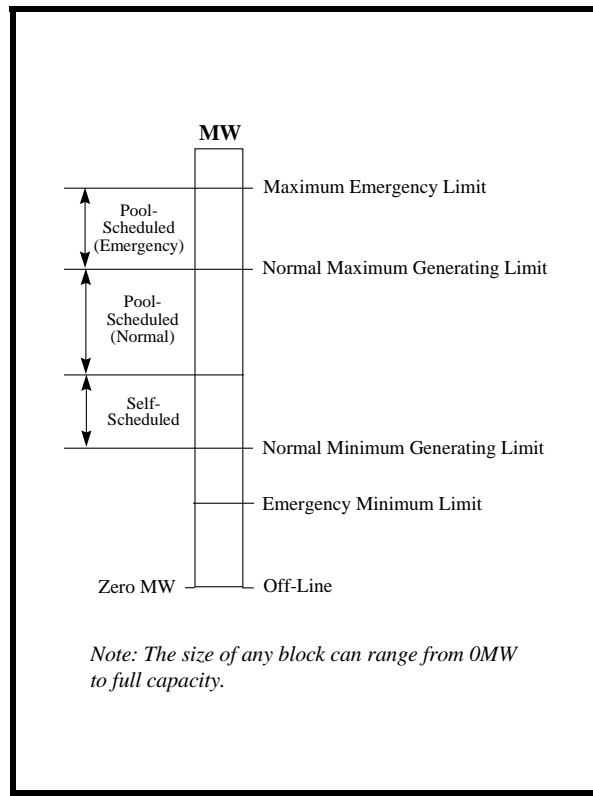


Exhibit 15: Generating Resource Scheduling

Deviations from Day-Ahead Market for Pool Scheduled Resources

If a generation resource has been scheduled in the Day-Ahead Market and wishes to deviate from that schedule (i.e. not run), the generation owner should contact the PJM Scheduling Coordinator to determine if this course of action is possible. The PJM Scheduling Coordinator will then:

- If the PJM Scheduling Coordinator determines that the generation resource is not needed for reliability purposes for the operating day, the generation owner can decide not to run the unit and no forced outage will be incurred. The generation owner will be responsible for all imbalance and operating reserve charges.
- If the PJM Scheduling Coordinator determines that the unit is needed for reliability purposes, he/she will inform the generation owner. The generation owner may still elect to not run the unit, but a forced outage for the duration of the scheduled operation of the unit will be generated. The generation owner will be responsible for all imbalance and operating reserve charges.

The guideline for notifying PJM of deviations for pool scheduled resources will be the sum of the unit's notification time plus the time to start. If this sum totals to zero,

then the minimum notification time will be 45 minutes prior to the scheduled operation of the unit. This allows PJM adequate time for determining if the unit is needed for reliability.

Credits for Cancellation of Pool Scheduled Resources

At the end of each month, PJM calculates the credits due to each PJM Member for pool-scheduled resources that were selected to run as part of the reliability study, and that PJM canceled before coming on-line. The cancellation credit equals the actual costs incurred, capped at the appropriate start-up cost as specified in the generating resource's offer data. Requests for such credits must be submitted, in writing, to the PJM Manager of Market Settlements, within forty-five days of the date of incident.

Resource Specific Data Requirements

Internal PJM Members Offer Data for resource specific offers is submitted directly into the Markets Database via the eMKT website. Exhibit 14 summarizes the data requirements for capacity and non-capacity resources.

Capacity and Non-Capacity Data Requirements		
Resource Type	UCBD Input Requirements	Data Requirements
Capacity	Next Day and Following Six Days	Availability Status Startup and No-Load, if Cost-Based (If Price-Based, Startup and No-Load fees are updated biannually as detailed in Section 1 of the PJM Manual for Pre-Scheduling Operations (M-10))
	Next Day and Optionally For The Following Six Days	Minimum Energy Maximum Energy Regulation Availability Incremental Price Points Unit Characteristics
	Next Day	Must Run Output Whether or Not to Request Bid Acceptance Notification By 4:00 p.m.
Non-Capacity	Next Day	Availability Status Must Run Output

Exhibit 16: Capacity and Non-Capacity Data Requirements

If offer data for a capacity resource is not submitted by 12:00 noon of the day before the operating day, PJM uses the offer data and unit availability previously entered into the Markets Database and considers the data a binding offer. For a more detailed description of the data, please see the [PJM Markets Database Dictionary \(http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf\)](http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf).

External Market sellers report the following data for resource-specific offers, reported on the business day before the next operating day, up to seven days in advance:

- Specific generation resource (the CCPPTTUUSS reference number and unit name from The Markets Database). This number is supplied by PJM to the PJM Member upon creation of the resource in the Markets Database. If the resource is submitted at least 30 days before the bid date, see the PJM Manual for [Pre-Scheduling Operations \(M-10\)](#).
- Minimum and maximum energy for each hour
- Minimum and maximum generation for each hour
- Minimum and maximum run times
- Unit availability for each hour
- Availability of regulation upper and lower energy limits for each hour
- Response and constraint data
- Whether or not to use start-up and no-load fees

Section 7: External Transaction Scheduling

Welcome to the *External Transactions* section of the PJM Manual for **Scheduling Operations**. In this section you will find the following information:

- An overview description of External Transaction Scheduling in PJM (see “*Overview of External Transaction Scheduling*”).
- A list of the PJM External Transaction Scheduling Business Rules (see “*External Transaction Scheduling Business Rules*”).

Overview of External Transaction Scheduling

Market participants that wish to transact energy in-to, out-of or through the PJM RTO are required to make their requests to PJM via the NERC E-Tagging software. These requests must be consistent with the more restrictive of either NERC Standard INT-001 (Interchange Transaction Tagging) or the PJM External Transaction Scheduling rules contained within this manual. The NERC E-Tagging software interfaces with PJM’s Enhanced Energy Scheduler (EES) software to create an interface that both PJM Market Participants as well as PJM Transaction Coordinators can use to evaluate and manage external transactions that affect the PJM RTO.

Based on market participant feedback, PJM has enhanced the EES tool to utilize NERC tags as the source for its external scheduling data. This change was done primarily to ease the amount of data entry required to submit external schedules in PJM as well as conform to general industry trends toward the use of the NERC tag as a schedule. This enhancement aids PJM in handling the increased number of external transactions presented by integration of other control areas in the PJM RTO. Market participants are no longer required to enter schedule data in both the EES system and on a NERC tag as the NERC tag data is utilized by EES as the schedule.

This change highlights an issue of data responsibility because of the nature of E-tagging and the fact that PJM now uses information entered on an E-tag as a schedule. Market participants scheduling in PJM are responsible for ensuring that data on PJM’s EES is consistent with that which they desire to be their energy schedule. The continuity of the tagging process dictates that PJM receives its tag data in completed form from its tag authority, as it was entered by market participants. In order to ensure this delivery of data is complete and accurate, the market participants are responsible for confirming the data in PJM’s EES to ensure it is consistent with that which they desired for their energy schedule. This

confirmation can take place by simply looking at the tag data through the EES user interface, or by viewing customer reports which are made available through EES.

An important aspect of scheduling external transactions in PJM is finding a start and end time to transact energy while respecting the PJM ramp limits imposed for security (see “Ramp Limits” section for additional information on PJM’s ramp limits). PJM allows market participants to reserve ramp in advance of completing their transactions via the EES application. This is an optional step in making external transaction requests, as the NERC E-Tag serves as the actual request for scheduling in PJM.

In cases where the NERC E-tag does not have the required fields to request a PJM market specific transaction (e.g. dispatchable, two-settlement etc.) the EES application will be used in concert with the NERC E-tag (see “Entering Dispatchable Schedules” and “Entering Two-settlement transactions” sections).

External Transaction Scheduling Business Rules

This section will outline the External Transaction Business Rules that are required by PJM. This section will include:

- PJM Contact Information
- External Transaction Timing Requirements
- General Information
- Data Requirements
- Ramp Limits
- OASIS Business Rules
- Entering Ramp Reservations
- Entering Schedules
- Entering Real-Time with Price Schedules
- Entering Two-Settlement Schedules
- Transaction Validations, Verification and Checkout

PJM Contact Information

The following numbers can be used to contact PJM regarding External Energy Transactions:

- Scheduling Fax number – 610-666-4275
- Day-Ahead Scheduling phone number – 610-666-4548, 610-666-8947 and 610-666-8949
- Hourly Scheduling phone number – 610-666-4510
- EES Hotline (used to report issues, or to ask questions during normal business hours) – 610-666-2270
- PJM Helpdesk (used to report technical issues during non-business hours) – 610-666-8886

External Transaction Timing Requirements

The following timing requirements are imposed by PJM for the submission of ramp reservations:

- Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions.
- Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration.
- Ramp reservations utilizing the Real-Time with Price option must be made prior to 1200 noon (EPT) one day prior to start time.

Ramp reservations expire if they are not used. The following timing requirements are imposed on ramp reservations that are not scheduled against:

- Hourly ramp reservations expire 30 minutes prior to start time.
- Reservations that are not scheduled against, that are made to start the following day, will expire at 1400 EST (1430 EDT) one day prior. Note that a ramp reservation will not be “split” into separate days, so if a ramp reservation is made for multiple days, and not scheduled against, and if the start time for the multi-day reservation is the next day, the entire reservation will expire.

The following timing requirements are imposed by PJM for the submission of Schedules. Schedules are submitted to PJM by submitting a valid NERC Tag. (The schedule is considered submitted when the NERC Tag is received by the PJM Tag

Approval Service, not when it is submitted by the market participant's Tag Agent software):

- Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions.
- Schedules can be submitted up to 4 hours prior to the scheduled start time for transactions that are more than 24 hours in duration.
- For a schedule to be included in PJM's Day-Ahead checkout process, they must be implemented by 1400 (EPT) one day prior to start of schedule.
- Schedules utilizing the Real-Time with Price option must be submitted prior to 1200 noon (EPT) day prior to start time.
- Schedules utilizing FIRM Point-To-Point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions submitted after 1000 (EPT) one day prior will be accommodated if practicable.

The following timing requirements are imposed by PJM for the submission of Two-Settlement Transactions:

- All Two-Settlement transactions must be submitted by 1200 noon (EPT) one day prior to start time.

General Information

- External offers can be made either on the basis of an individual generator (resource specific offer) or an aggregate of generation supply (aggregate offer).
- PJM will only accept the transaction if submitted by a member company.
- Transmission reservations that are not used due to canceled spot market offers will be subject to transmission charges as appropriate.
- PJM does not accept bids where the PJM Interchange Market is identified as both the source (GCA) and sink (LCA).
- PJM does not accept offers for resources committed to supply operating reserves to another control area. PJM does not double count units internal to PJM for operating reserves. If energy is being offered from a resource to PJM and is already included in the PJM operating reserves, the energy can be accepted, but does not participate in PJM operating reserves accounting.

- Offers not properly submitted are rejected. The PJM member is notified of the reason for rejection and the PJM member may then take action to submit a new offer.

Data Requirements

Market participants are expected to keep PJM informed of all external transactions that involve the operation of the PJM RTO. The following information is submitted to PJM via the market participants E-Tag agent service and/or EES:

- Valid NERC E-Tag
- Valid transaction path
- Start date before end date
- Start and end times in the future
- Requested MW profile
- Valid transmission (see “OASIS Business Rules” for more information)
- Price associated with transaction (if utilizing the Real-Time with Price option)

Ramp Limits

PJM validates all external transaction requests against a net interchange ramp. The ramp limit is configurable by PJM dispatch based on operating conditions. There are two separate ramps that are evaluated, a PJM Net Interchange Ramp, and a NYISO Interchange Ramp.

- PJM Variable Ramp

At no time, can the difference in the net interchange be greater than the ramp designated by the PJM dispatch at any given 15 -minute interval. Ramp room is allocated on a first come, first serve basis. Refer to Exhibit 17 for a ramp example to see how the ramp is calculated for any given 15 - minute interval.

- NYISO 1000 MW Ramp

PJM also monitors a ± 1000 MW ramp with the NY ISO. At no time can the difference in the interchange between NY and PJM be greater than ± 1000 MW at any 15-minute interval. Ramp room for NY transactions is allocated on a first come, first serve basis. NY transactions submitted to PJM will be evaluated against both the PJM ramp and the NY ISO ramp.

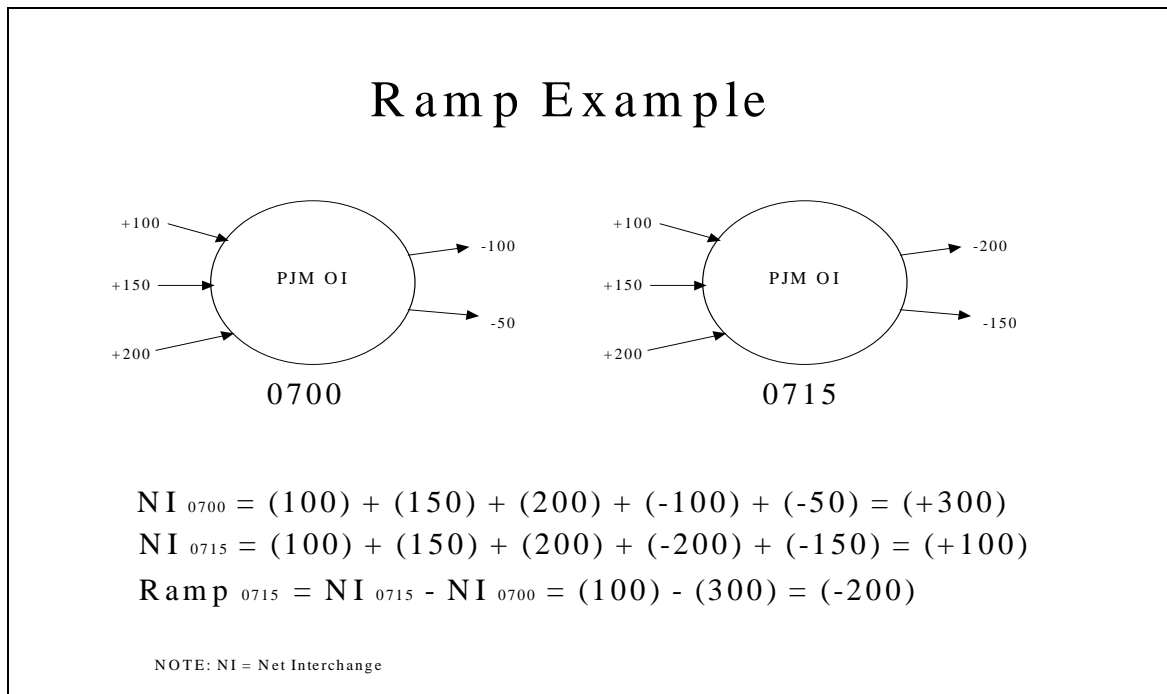


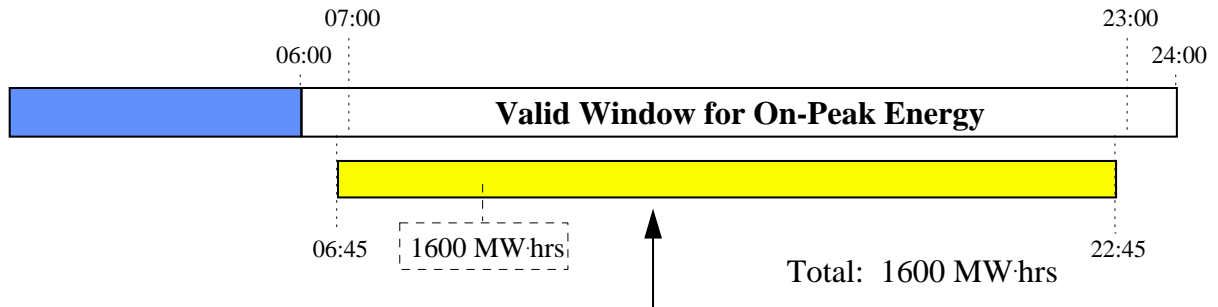
Exhibit 17: Example Ramp Calculation

OASIS Business Rules

All external transaction requests, with the exception of import spot market transactions, require a CONFIRMED transmission reservation from the PJM OASIS. PJM offers several transmission product types, such as hourly, daily, weekly, monthly, yearly, on and off-peak, non-firm, firm and network transmission. PJM also offers the opportunity to state whether or not the market participant is willing to pay congestion. These, and additional options, are further explained in the “PJM Regional Practices” document, which can be found on the PJM OASIS home page at <http://oasis.pjm.com>.

On some occasions, due to PJM ramp rules, market participants are required to shift their energy requests. If the market participant shifts their energy up to one hour in either direction, they are not required to purchase additional transmission. Likewise, if the market participant chooses to fix their ramp violation by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded. For graphical representations of these scenarios, refer to Exhibit 18 through Exhibit 21.

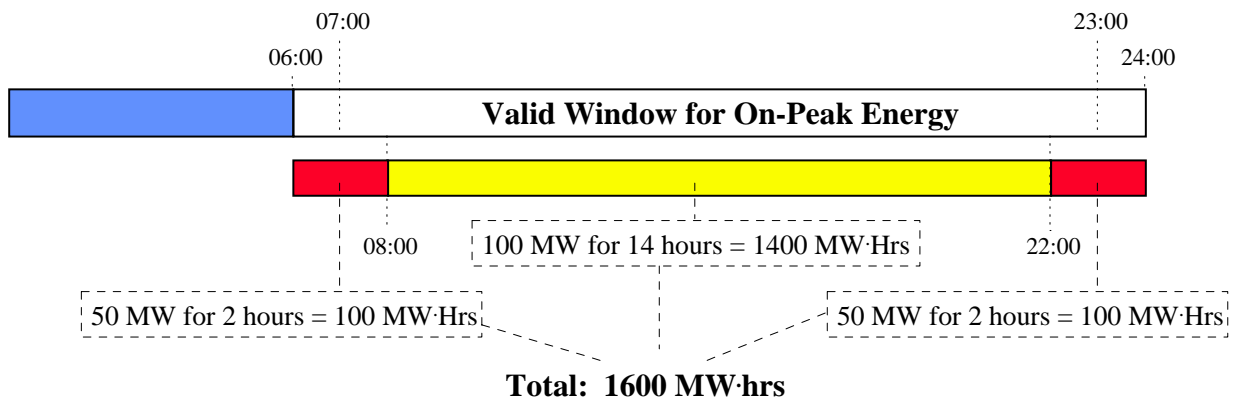
On-Peak Monday-Friday



Example of Valid Energy Schedule using a 100MW Capacity
 On-Peak Transmission Service Reservation
 Over 16 Hour Period

Exhibit 18: On-Peak Transmission Service Over 16 Hour Period Example

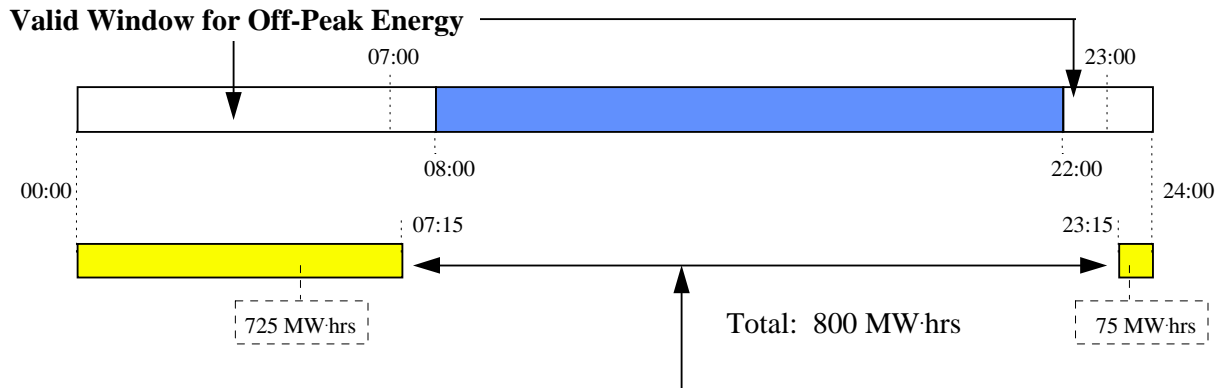
On-Peak Monday-Friday



Example of Valid Energy Schedule using a 100MW Capacity
 On-Peak Transmission Service Reservation
 Over 18 Hour Period

Exhibit 19: On-Peak Transmission Service Over 18 Hour Period Example

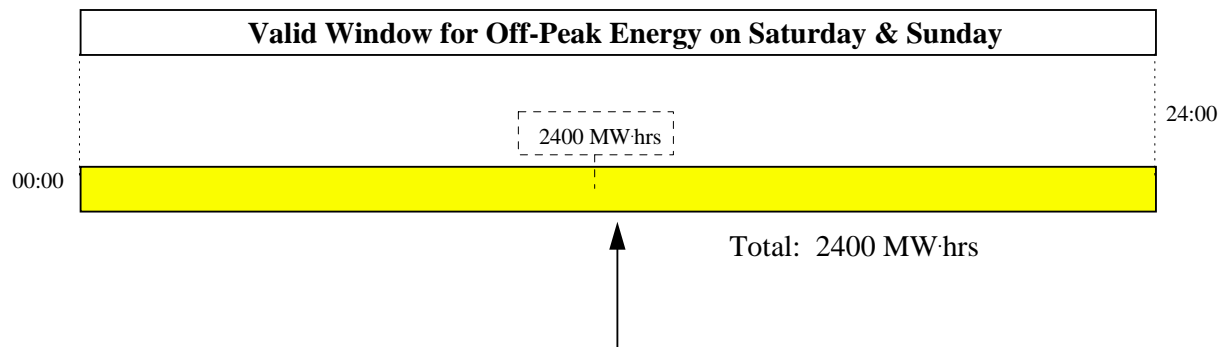
Off-Peak Monday-Friday



**Example of Valid Energy Schedule using a 100MW Capacity
 Off-Peak Transmission Service Reservation**

Exhibit 20: Off-Peak Monday-Friday Transmission Service Example

Off-Peak Saturday & Sunday



Example of Valid Energy Schedule using a 100MW Capacity Off-Peak Transmission Service Reservation

Exhibit 21: Off-Peak Saturday-Sunday Transmission Service Example

Frequently Asked Questions (regarding on-peak and off-peak energy scheduling):

(Q1) A market participant has reserved off-peak daily transmission for Wednesday, but ramp room is not available at 07:00 or 23:00.

(A1) Two possible solutions are 1) the energy may be scheduled from 00:00 to 08:00 or 2) the energy may be scheduled from 00:00 to 07:15 and from 23:15 to 24:00.

(Q2) A market participant has reserved on-peak weekly transmission. Ramp room is available from 07:00 to 23:00 Tuesday through Friday, but ramp room is not available at 07:00 or 23:00 on Monday.

(A2) The energy may be scheduled 07:00 to 23:00 Tuesday through Friday. One solution to the Monday ramp limit is to schedule the energy from 06:45 to 22:45.

Entering Ramp Reservations

Each PJM Member Company that is authorized to do business in PJM's energy market is given an EES account. It is in the EES application that ramp reservations are made.

Ramp reservations are an optional step in scheduling transactions in PJM. A ramp reservation can be made to "hold" ramp room while market participants complete their scheduling responsibilities. Ramp reservations are then associated on the

NERC Tag when the market participant wishes to submit the schedule. The ramp reservation is validated against the submitted NERC Tag to ensure the energy profile and path matches. Ramp reservations are generally used to ensure the ability to schedule prior to purchasing transmission or making other potentially cost affecting decisions.

To make a ramp reservation, the market participant enters the EES application, and navigates to the “Ramp Reservation” screen. On this screen, the market participant enters the path for which they are interested in transacting energy, their energy profile and any other unique information that may apply to a schedule (i.e. special exceptions, notes, outside ID’s, internal naming conventions etc.). Upon submission of a ramp reservation, PJM validates the information against ramp availability. If it passes the current ramp limits, the ramp reservation will pass, and will move into a status of “pending tag”. At this point, the market participant is holding a valid reservation that can then be associated on a NERC Tag for scheduling.

Entering Schedules

Market participants enter schedules in PJM by submitting a valid NERC Tag. As noted in the previous section, if the market participant holds a ramp reservation in the status of “Pending Tag”, they can associate the ramp reservation on the NERC Tag. This is done by placing the ramp reservation in the “miscellaneous” column on the PJM Transmission Provider line, of the “physical segment” portion of the NERC Tag.

If no ramp reservation was made prior to scheduling, a NERC Tag can be submitted without a reservation. NERC Tags that are submitted without a ramp reservation will automatically have a ramp reservation created that matches the energy profile and path of the NERC Tag. This newly created reservation will be evaluated against ramp, and an approval or denial will be made based on the validation. If there is enough ramp room, PJM will continue with other validations (See “Transaction Verification and Checkout”). If all validations pass, an approval message will be sent to the NERC Tag, and upon IMPLEMENTATION of the NERC Tag, the transaction will be scheduled by PJM.

Because of the nature of NERC tagging, it is possible for the market participant who enters a NERC tag to not be consistent with the market participants listed for each TP segment on a particular tag. In this instance, the financially responsible party (FRP) entering the tag is effectively acting on behalf of other market participants that are listed. Because PJM will now be identifying a NERC tag as a market participant’s schedule, it will be necessary for those market participants who have had a tag entered on their behalf to acknowledge this tag through the EES.

Entering Real-Time with Price Schedules

Real-Time with Price schedules differ from other schedules in that an action **must** be made in EES in addition to the submission of a NERC Tag. To enter a Real-Time with Price schedule, the market participant must first make a ramp reservation in EES using the “Real-Time with Price” tab in the notebook section of the ramp reservation screen. In addition to the information entered for a Real-Time schedule, market participants are also required to enter a price associated with each energy block. Upon submission, the Real-Time with Price request will automatically move to the “Pending Tag” status, as Real-Time with Price schedules do not hold ramp.

Once the information is entered in EES, a NERC Tag must be submitted with the ramp reservation associated on the NERC Tag. This is done by placing the ramp reservation in the “miscellaneous” column on the PJM Transmission Provider line, of the “physical segment” portion of the NERC Tag. For Real-Time with Price schedules, the NERC Tag energy profile must match exactly for the tag to be approved.

Entering Two-Settlement Schedules

Market participants can submit two settlement schedules to the eMarket application through EES. These schedules do not require a NERC tag, as they are only financial obligations, and are not considered physical schedules for actual flow. Two settlement schedules are submitted using the “Two Settlement” tab in the notepad section of the ramp reservation screen.

Two settlement schedules require an OASIS number to be associated upon submission. The market participant can use SPOT as their OASIS reservation. If this option is chosen, a PJM RTO control area must be selected as well as the interface where the two settlement request is to be evaluated. The market participant must then choose a pricing point or points for which they wish their bid to be evaluated (import pricing point for an import, export pricing point for an export or both import and export pricing points for wheels). If an actual OASIS reservation is being used, the selection of PJM RTO and interface is not required, as the path will be identified on the actual OASIS reservation.

In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. The option to choose fixed, dispatchable and up-to are also displayed in the notepad section. The type “fixed” acts as a price taker, “dispatchable” sets a floor or ceiling price criteria for acceptance and “up-to” sets the maximum amount of congestion the market participant is willing to pay for acceptance in the two settlement market. Graphing energy is done the same way as a Real-Time or Real-Time with Price request.

Transaction Validations, Verification and Checkout

Transactions must pass specific validations and evaluations prior to being scheduled. The following validations and evaluation and checkout procedures are done to ensure accurate information and reliable scheduling in PJM.

➤ Validations

On submission, the following validations are performed on ramp reservations:

- Path Identified
- Stop time after start time
- Energy Profile Identified
- Price associated with Energy Profile (only applicable for Real-Time with Price)
- Ramp Availability (not applicable for Real-Time with Price)
- Timing Requirements are met for submission deadlines

On submission, the following validations are performed on NERC Tags:

- Syntax validation (See NERC Tagging Policy for complete list of syntax validations for NERC Tags)
- Path on NERC Tag matches ramp reservation (if identified) and OASIS path
- Timing requirements are met for submission deadlines
- PJM Loss type must be financial (FIN)
- Ramp availability (if no ramp reservation is identified)
- OASIS validation for valid OASIS, valid path, instantaneous capacity, total capacity, date-time, priority and vertical stacking (not allowed)
- Token and Value fields (in miscellaneous column) have valid inputs
- FRP check

On submission, the following validations are performed for Two Settlement requests:

- Path identified
- Timing requirements are met for submission deadlines
- OASIS validation for valid OASIS, ensure that the reservation is willing to pay congestion, OASIS is valid for period covered by the two settlement contract and capacity checks
- Pricing point(s) have been identified
- Stop time is after start time
- Energy profile is identified
- Price is associated for energy profile (for dispatchable option only)
- Congestion amount is identified for energy profile (for up-to congestion option only)

➤ Real-Time Evaluation and Checkout

If all validations pass on a Real-Time schedule, PJM will approve the tag. Once the tag is approved by all parties associated on the tag and the status of the tag becomes “IMPLEMENTED”, the schedule will be ready for the Control Area to Control Area Checkout. If during the Control Area to Control Area checkout, both parties agree to the interchange on the NERC Tag, the schedule will flow.

➤ Real-Time with Price Evaluation and Checkout

Real-Time with Price schedules are verified differently than Real-Time schedules. Real-Time with Price schedules are evaluated hourly to determine if they will be loaded or not for the upcoming hour. This evaluation is done by the PJM Generation Dispatcher. If the dispatcher feels that the economics for the schedule warrant the transaction to be loaded or unloaded, they will inform the transaction coordinator to load or unload the contract. This evaluation is based on a very conservative approach, and works similar to the way the generation dispatcher would call on or off generation. In addition to the economics of the transaction, the generation dispatcher may also take into consideration the ramp availability for the loading or unloading of the schedule. Since Real-Time with Price schedules do not hold ramp room, there may be times where the economics warrant a schedule to be loaded, but due to security issues related to ramp, the schedule will not be

called on to flow. Once a Real-Time with Price schedule has been called on to flow, a reload request will be issued by the PJM Transaction Coordinator. If all external parties approve the reload request, and it passes the Control Area to Control Area checkout process, the schedule will flow.

➤ Two Settlement Evaluation and Checkout

For Two Settlement scheduling, EES serves only as an interface to the eMarket application. Two Settlement transactions are evaluated by the PJM Markets Department, and the results are fed back to EES to allow market participants to view the results. There is no Checkout performed on two-settlement schedules, as they are considered financially binding transactions, not physical schedules.

Section 8: Posting OASIS Information

Welcome to the *Posting OASIS Information* section of the PJM Manual for **Scheduling Operations**. In this section you will find the following information:

- ☞ A description of the information posted by PJM and the PJM Member's responsibilities (see "*PJM OASIS*")

PJM OASIS

PJM is responsible for providing the OASIS node for the PJM RTO. OASIS serves as an information network for the use by PJM, PJM Members and other authorized users. Refer to the PJM Manual for [PJM OASIS Operation \(M-04\)](#) for additional information. OASIS is used for the dissemination of transmission, generation, and Ancillary Services information. For this PJM Manual, we are concerned with the following OASIS information:

- ☞ Total load forecasts (hourly for next four days)
- ☞ Peak load forecasts (for next seven days)
- ☞ Generation resources
- ☞ Transmission service reservations
- ☞ Transmission congestion
- ☞ Ancillary Services

PJM Actions:

1. No later than 1600 hours of the day before each Operating Day, PJM posts the following information:
 - ☞ forecast of the location and duration of any expected transmission congestion and major sub-areas of the PJM RTO that are expected to result from such transmission congestion
2. At PJM-designated times during the day (currently, 1600 and 2000 hours of the day ahead and 0000, 0400, and 0800 hours of the Operating Day), PJM posts the following information:
 - ☞ a revised forecast of the location and duration of any expected transmission congestion between major sub-areas of the PJM RTO

3. As required by PJM, the following information is posted:
- ☞ Curtailment or interruption of Bilateral Transactions with entities that are External to the PJM RTO
 - ☞ Availability of transmission services to PJM Members whose External transactions were curtailed or interrupted
 - ☞ Any interconnected operations service requested or offered by PJM, together with the price or discount for that service

PJM Member Actions:

None for scheduling purposes.

Section 9: Hourly Scheduling

Welcome to the *Hourly Scheduling* section of the PJM Manual for **Scheduling Operations**. In this section you will find the following information:

- How schedules may be adjusted on an hourly basis (see “*Hourly Scheduling Adjustments*”).

Hourly Scheduling Adjustments

During the course of power system operations, planned and unplanned events may continually occur. This section discusses the process by which pre-planned operating schedules may be changed by PJM or PJM Members to reflect new conditions.

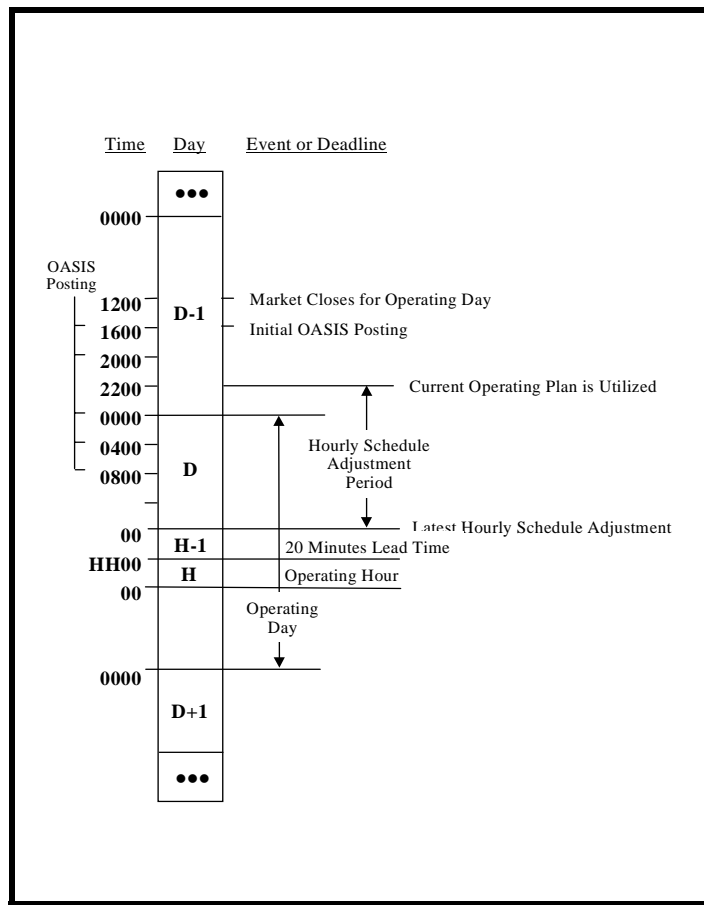


Exhibit 22: Hourly Scheduling Timeline

A PJM Member may adjust the schedule of a resource under its dispatch control (Self-Scheduled Resource) on an hour-to-hour basis beginning at 2200 of the day before the Operating Day under the following conditions:

- Subject to the right of PJM to schedule and dispatch Self-Scheduled Resources in an Emergency
- Provided that PJM is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect

The following adjustments may be made:

- A PJM Member may self-schedule any of its resource increments, including hydro power resources not previously designated as Self-Scheduled Resources and not selected as a PJM RTO - Scheduled Resource
- A PJM Member may request the scheduling of a new Bilateral Transaction that uses non-firm transmission service
- A PJM Member may remove from service a resource increment, including a hydro power resource that it had previously designated as a Self-Scheduled Resource, provided that PJM has the option to schedule energy from such resource increment at the price offered in the scheduling process, with no obligation to pay any start-up fee
 - ☞ An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase by notifying PJM dispatcher of the adjustment in deliveries not later than 20 minutes prior to the hour in which the adjustment is to take effect. Any such refusal of delivery shall be subject to non-delivery charges as described in the PJM Manual for [Operating Agreement Accounting \(M-28\)](#).

Attachment A: Interchange Energy Schedule Curtailment Order

Curtailment of Transmission or Recall of Energy:

The following is the curtailment order used by PJM for curtailing due to system constraints, Maximum Emergency and other PJM Emergencies. This curtailment order is used for transmission as well as capacity related curtailments.

PJM Dispatch may deviate from this pattern as necessary to maintain reliability. The *(italicized)* text below represents likely system events as they would occur during a transmission constraint.

(Constrained System)

Non-Firm over Secondary Points not willing to pay congestion charges

Firm transmission used for a path other than the OASIS POR/POD. (NERC Transmission Bucket 1) Curtail by energy timestamp (LIFO).

Non-Firm not willing to pay congestion charges (NF-NPC)

Curtail descending by transmission time block (hour - NERC Transmission Bucket 2, day - NERC Transmission Bucket 3, week - NERC Transmission Bucket 4, and then month - NERC Transmission Bucket 5)

- Within a time block, curtail on/off-peak before curtailing all day reservations.
- Within the above categories curtail lower priced transmission first.
- Within the above categories curtail by transmission timestamp (LIFO).

Network Import not willing to pay congestion charges (Net-NPC)

(NERC Transmission Bucket 6) Curtail by energy timestamp (LIFO).

(Redispatch System)

Spot Market Import (SPTIN)

(NERC Transmission Bucket 6) Unload based on dispatch rate (non-zero rate schedules)

(Zero Dispatch Rate if applicable)

Unload spot market imports with zero dispatch rates

(Declare Emergency if applicable)

Must-take spot market import schedules are to be curtailed after non-firm not willing to pay congestion (npc) but before non-firm willing to pay congestion (wpc).

Non-Firm over Secondary Points willing to pay congestion charges

Firm transmission used for a path other than the OASIS POR/POD. (NERC Transmission Bucket 1) Curtail by energy timestamp (LIFO).

Non-Firm willing to pay congestion charges (NF-WPC)

Curtail descending by transmission time block (hour – NERC Transmission Bucket 2, day – NERC Transmission Bucket 3, week – NERC Transmission Bucket 4, and then month – NERC Transmission Bucket 5).

- Within a time block, curtail on/off-peak before curtailing all day reservations.
- Within the above categories curtail lower priced transmission first.
- Within the above categories curtail by transmission timestamp (LIFO).

Network Import willing to pay congestion charges (Net-WPC)

(NERC Transmission Bucket 6) Curtail by energy timestamp (LIFO).

Firm

Curtail schedules that effectively relieve the constraint, proportionally among Native Load customers, Network customers and customers taking Firm Point-to-Point transmission service. (NERC Transmission Bucket 7)

Example of Recall of Energy

An example of curtailment of capacity is curtailment of interchange energy schedules due to a maximum generation emergency. After schedules using non-firm energy (which effectively relieves the constraint) are curtailed in the order specified above, schedules using firm transmission would be curtailed. Note: the transmission is not curtailed; the energy is curtailed.

Based on the PJM Transmission Tariff, PJM formed the following wording, which describes the method for curtailing energy using a firm transmission reservation.

Firm

Curtail schedules that effectively relieve the constraint, proportionally among Native Load customers, Network customers and customers taking Firm Point-to-Point transmission service. (NERC Transmission Bucket 7)

Exports would be curtailed for maximum generation emergency; Native Load, Network Customers, and other imports would not be curtailed (imports are helpful during times of capacity shortage). This guideline is used for curtailment (on a whole contract basis) of energy schedules using firm transmission.

The method used to determine which firm schedules to curtail and in what order is explained below:

First, all effective cuts of schedules using lower priority transmission reservations (non-firm) are curtailed. Then recallable energy using firm transmission service is curtailed. The energy schedules using firm transmission service are cut on a whole contract basis and approximately proportionately among the transmission customers. The method used is to subdivide the schedule into two approximately equal segments, with about half of the any given companies energy in each block. These blocks are then subdivided repeatedly until each block is less than or equal to 400 MW. The blocks are then cut from first to last, as needed to follow load. If a block is to be subdivided and there are multiple customers, each with only one schedule in that block, the last customers to submit their energy schedules will be curtailed first. Similarly, a transmission customer's schedules will be curtailed in descending timestamp order.

Curtailment of Capacity Backed Resources

Capacity Backed Exports are those transactions sourced from generators or portions of generators on the PJM system that are not designated as PJM installed capacity.

At Maximum Emergency, PJM will not recall any energy from a resource that is not included in PJM Installed Capacity. If a resource has been de-rated from summer peak

capacity, any export that exceeds the pro-rated capacity not attributed to PJM will be reduced to that pro-rated level.

Example: Unit A has a summer rated capacity of 80 MW, where 60 MW is designated as installed capacity and 20 MW is not. A 20 MW export is scheduled from PJM. There is no outage on the unit. The full 20 MW export will be scheduled.

Example: Unit A has a summer rated capacity of 80 MW, where 60 MW is designated as installed capacity and 20 MW is not. If there is a 40 MW partial outage of the unit, 3/4 (or 60/80) of the remaining capacity is considered installed. 1/4, or 20/80, of the remaining capacity is available as non-installed capacity and will not be curtailed during a PJM Maximum Emergency. In this example 30 MW remains as PJM installed capacity and 10 MW remains available for capacity backed exports. If the owner of Unit A scheduled a 20 MW export, 10 MW could be recalled during PJM Maximum Emergency. At the conclusion of Maximum Emergency or at the conclusion of the outage, the export would be restored to the full 20 MW.